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Potential Health Hazards from Shale Gas Exploration and Exploitation

Drinking Water and Ambient Air

Presented to

Health Canada Santé Canada

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May 4, 2012

O/Ref.: RA11-410
Y/Ref.: SO No. 4600000047

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Executive Summary

Shale gas is a natural gas (i.e. a mixture of hydrocarbon gases mainly composed of methane) generated in shale, a sedimentary rock. Although the term *gaz de shale* is the correct translation for shale gas, the term *gaz de schiste* is more commonly used by Francophones. According to geologists, more than 688 shale deposits exist worldwide and the global shale gas resource is estimated to be approximately 16,000 trillion cubic feet (450,000 km^3). Shale gas has become an increasingly important source of natural gas in the United States, where there is already active shale gas exploitation. In Canada, exploration is taking place in several provinces and shale gas is currently produced in Western Canada. However large-scale commercial production has not yet been achieved. Outside North America, shale gas has not yet been produced commercially. However exploratory activities are being undertaken in some countries. Although there is a large increase of interest for this resource, shale gas exploration/exploitation has raised a lot of concerns in several countries (e.g. France and Canada) due to their potential impacts on the water resources and air quality.

The present report aims to present an overview of the potential health hazards of shale gas exploration/exploitation related to both drinking water and ambient air (i.e. identification of the principal sources of contamination and of the contaminants released from shale gas exploration/exploitation activities) and to provide a general overview of the Canadian and international activities related to the shale gas industry (i.e. occurrence of the resource, exploration and exploitation as well as regulatory framework). This report does not address issues related to the sustainability of water resources, greenhouse gas emissions, psychosocial impacts or public safety.

Information presented is primarily based on reports released by governments or agencies and on published papers; all sources are listed at the end of the document. Most information was based on data obtained in the United States, where shale gas exploitation has taken place for nearly two decades.

In order to provide the reader with background knowledge and to facilitate further understanding of the environmental issues, the processes of shale gas exploration and exploitation were described at the beginning of the report. Briefly, shale gas exploration and exploitation involve different stages (well drilling and development, shale gas recovery, well production, gas transport and well closure) as well as related activities (e.g. flaring and venting, wastewater disposal, transport or use of mechanical equipment) and potential incidents (e.g. spills, releases or well blowouts). Shale gas is usually extracted using hydraulic fracturing, a method involving the injection of hydraulic fluid (a mixture of water, sand and chemical additives) into the shale formation, although alternative technologies exist. Hydraulic fracturing involves the use of a large quantity of water and the generation of large quantities of wastewater that must be disposed of. The review addressed the potential sources of water and ambient air contamination at each step of shale gas exploration/exploitation, for each related activity and each type of incident. It was concluded that all of these events were potential sources of water and air contamination, and the steps/activities/incidents presenting the highest risks were identified based on the information available.

The potential sources of water contamination are both direct (e.g. drilling, hydraulic fracturing and shale gas production) and indirect (wastewater treatment and disposal, spills and releases, well and rock integrity, and well blowout and stormwater runoff). These steps/events may represent a hazard to water quality, and hydraulic fracturing and wastewater disposal were identified as the main potential sources of risk. Although the risks related to hydraulic fracturing itself (creation of multiple cracks underground) and to further injection of chemicals are currently unknown (lack of monitoring data and lack of information on migration through cracks in the long-term), it is anticipated that this practice could potentially contaminate the groundwater after several years or decades. Wastewater disposal appeared to be amongst the most potent sources of water contamination, due to either the risk of leakage from the pits, the possible inadequacy/inefficiency of the treatment before release into the environment or the possibility of migration into the groundwater when wastewater is disposed of by injection underground. The contaminants of interest potentially released into surface or groundwater by all the sources may include:

- Compounds naturally present underground, such as metals, salts and naturally occurring radioactive materials (NORMs);
- Compounds intentionally added during the processes to facilitate drilling or for hydraulic fracturing (organic and inorganic additives, such as methanol, ethylene glycol, naphthalene, benzene, ethylbenzene, copper or lead);
- By-products possibly resulting from the degradation of the fracturing chemicals or from reactions between fracturing chemicals and compounds naturally present underground. No data about the occurrence and identity of such by-products is currently available.

The potential sources of air contamination are also direct (e.g. well completion, shale gas production and processing) and indirect (e.g. transport, equipment, storage and distribution, well blowouts and spills, flaring and venting, and wastewater disposal). The contaminants of interest are mostly the same as those encountered in any conventional natural gas exploitation process, since the sources are similar. However, there may be additional contaminants specific to shale gas operations, such as the volatile chemicals potentially present in wastewater (including flowback water). The whole set of pollutants potentially emitted into the air by shale gas exploration/exploitation includes:

- Air pollutants originating from vehicles and engines fuelled by diesel: nitrogen oxides (NOx), particulate matter (PM), sulphur oxides (SOx) and carbon monoxide (CO);

- Volatile organic compounds (VOCs) potentially emitted by leaks from equipment, wells, gas transport, venting and flaring or volatilization from wastewater;
- Other shale gas constituents, such as methane (main constituent) and heavier hydrocarbons (e.g. ethane, propane and butane) and impurities (e.g. H_2S, CO_2 and N_2);
- Naturally occurring contaminants including NORMs (e.g. radon gas).

The toxicity of some chemicals potentially released or emitted by the shale gas industry into water resources and ambient air is documented. Data indicate that chemicals used, emitted and/or released during shale gas exploration/exploitation include chemicals known for their carcinogenicity to human and/or animals, for their acute and/or chronic toxicity (e.g. adverse effects on the respiratory tract, the central nervous system, the skin, eyes and sensory organs, etc.) and for their potential for endocrine disruption. It should be reiterated that carcinogenic compounds are thought to present a risk at any dose and that endocrine disruptors usually act at very low doses.

Thus, although quantitative data are lacking, the qualitative data available indicate that potential contamination of water and atmospheric emissions related to the shale gas industry may present hazards to public health, especially for local population. The potential hazards to water and air are directly related to:

- The processes used for exploration/exploitation, including (not limited to) the method used for fracturing (e.g. hydraulic fracturing) and the type of wells (horizontal, vertical, stacked);
- Well-specific characteristics, such as well depth or composition of the hydraulic fluid (specific to each well and to each injection);
- Well pad-specific characteristics, including (not limited to) the management of wastewater (e.g. storage in pits, treatment, underground injection), the management of stormwater runoff, venting and flaring;
- Site-specific characteristics, especially those related to the geological and hydrogeological context, such as shale depth, water table depths and permeability of the soil between the shale and the water table;
- The regulatory framework and the conformity to regulations, standards and good practices by the exploiting company and its subcontractors.

Considering that the risk of hazards to water and air are mainly specific to the project, it may be difficult to assess the impacts of the shale gas industry to human health on a generic basis. Rather, impacts to human health should be estimated on a case-by-case basis. However, the present review revealed that to conduct a reliable assessment, many data gaps should be filled. The following list is an overview of the data to be obtained to assess the impacts on human health (a more detailed list of the data gaps is provided in the report):

- A thorough project description, with identifications and descriptions of each potential source of release/emission, emission/release rates into the environment for each chemical, scenarios of emissions/releases representative of various conditions that could occur, estimates of the potential of migration to ground water in the short- and long-term, etc.;
- Detailed geological and hydrogeological description of the region;
- Identity and quantity of the chemicals used, brought from underground to surface or generated during all exploration and exploitation phases, as well as the environmental fate of these chemicals;
- Monitoring data (ambient air and water resources) before, during and after (years to decades for ground water) the beginning of exploration and exploitation, for each chemical of interest;
- Characteristics of the potentially exposed population, such as the distance between the population and the emission sources, use of the water resource or occurrence of susceptible population (e.g. children);
- Toxicological data for all the chemicals potentially released into water (intentionally or unintentionally, in the short-term, intermediate and long-term) or emitted into the air;
- Data for the parameters involved in atmospheric dispersion (e.g. meteorological data and topography).

The regulatory framework is relatively similar in the United States and in Canada, although its development in Canada is less mature.

- In the United States, the development and production of oil and gas (including shale gas) are regulated under a complex set of federal, state and local laws;
- In Canada, oil and gas drilling and production fall under provincial jurisdiction except on federal land, and under territorial jurisdiction in the Yukon.

For most provinces, the environment and natural resource ministries share responsibility for regulating oil and gas exploration, extraction, and disposal of waste and wastewater. Some governments are currently working to document the issues related to shale gas exploitation. Reviews conducted by the governments of Québec and New Brunswick are expected in 2012-2013. Regulations of the oil and gas sector vary between jurisdictions. Regulations related to exploitation currently exist in Alberta and British Columbia, where shale gas exploitation already occurs. There are also some regulations in the other provinces and further regulations are expected in the future. For instance, in Quebec, a certificate of authorization must be obtained prior to all drilling work to explore for or produce oil or natural gas from shale as well as prior to hydraulic fracturing operations. In addition, public consultation must be done prior to the delivery of the certificate of authorization.

On federal lands, the National Energy Board (NEB) is responsible for regulating the exploration, development and production of crude oil and natural gas as well as for enhancing worker safety and protecting the environment. It is also responsible for the environmental assessment of projects within its jurisdiction.

Federally, jurisdiction over shale gas development falls under the mandate of several departments, agencies and boards. For example, Health Canada and Environment Canada use two Acts to help protect the health of Canadians and the environment. Under the Canadian Environmental Protection Act (CEPA), they share the mandate of assessing the potential risks associated with the use of new and existing chemical substances in Canada as well as undertaking risk reduction measures where necessary. The Canadian Environmental Assessment Act (CEAA) requires certain federal projects to undergo an environmental assessment before receiving approval. Environment Canada is also responsible for the administration and enforcement of the pollution prevention provisions of the Fisheries Act, which prohibits the deposit of deleterious substances in water frequented by fish or in a place where that substance may enter such water, unless the deposit is authorized by regulation under a federal act.

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List of Abbreviations/Acronyms

2WS	Second White Speckled
ARI	Advances Resources International Inc.
BAPE	*Bureau d'Audiences Publiques sur l'Environnement* (Québec, Canada)
BLM	Department of Interior's Bureau of Land Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and enforcement
BTEX	Benzene, Toluene, Ethylbenzene and Xylenes
CAA	Clean Air Act (United States)
CAS	Chemical Abstracts Service
CEAA	Canadian Environmental Assessment Act
CEPA	Canadian Environmental Protection Act
CO	Carbon Monoxide
CWA	Clean Water Act (United States)
CWS	Canada-Wide Standards (CWS)
ECHA	European Chemical Agency
EIA	Energy Information Administration (United States)
EPA	U.S. Environmental Protection Agency
ERCB	Energy Resources Conservation Board (Alberta, Canada)
ESL	Effects Screening Level
FRAC	Fracturing Responsibility and Awareness of Chemicals (Act) (United States)
GWPC	Ground Water Protection Council (United States)
H_2S	Hydrogen sulphide
IARC	International Agency for Research on Cancer
LEAF	Legal Environmental Assistance Foundation (United States)
LPG	Liquefied Petroleum Gas
mcf	Thousand cubic feet
MDDEP	Minister of Sustainable Development, Environment and Parks (Quebec, Canada)
MDDEP	*Ministère du Développement Durable, de l'Environnement et des Parcs* (Québec, Canada)
mmcf	Million cubic feet
MNR	Ministry of Natural Resources (Ontario, Canada)
MRM	Minerals Revenue Management (United States)
MSDS	Material Safety Data Sheet

NAAQOs	National Ambient Air Quality Objectives (Canada)
NBDENV	New Brunswick Department of Environment
NBDNR	New Brunswick Department of Natural resources
NEB	National Energy Board (Canada)
NESHAPs	National Emission Standards for Hazardous Air Pollutants (United States)
NNSR	Nonattainment New Source Review (United States)
NORM	Natural Occurring Radioactive Material
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System (United States)
NSPS	New Source Performance Standard (United States)
NYSDEC	New York State Department of Environmental Conservation (United States)
OGAA	Oil and Gas Activities Act (British Columbia, Canada)
OGCR	Oil and Gas Conservation Regulations (Alberta, Canada)
OGSRA	Oil, Gas and Salt Resources Act (Ontario, Canada)
OSHA	Occupational Safety and Health Administration (United States)
PAHs	Polycyclic Aromatic Hydrocarbons
PM	Particulate matter
ppb	Parts per billion
PSD	Prevention of Significant Deterioration of Air Quality (United States)
REACH	Registration, Evaluation, Authorisation and Restriction of Chemical substances
Ro	Thermal maturity
SDWA	Safe Drinking Water Act (United States)
SEA	Strategic Environmental Assessment
SOx	Sulphur Oxides
SPCC	Spill Prevention Control and Contingency (United States)
STRONGER	State Review of Oil and Natural Gas Environmental Regulations (United States)
SWPP	Stormwater Pollution Prevention Plan (United States)
TCEQ	Texas Commission on Environmental Quality
Tcf	Trillion cubic feet
TDS	Total Dissolved Solids
TOC	Total Organic Content
VOCs	Volatile Organic Compounds
WRAP	Western Regional Air Partnership (United States)

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1. INTRODUCTION

1.1 Context

Shales are fine-grained sedimentary rocks that can be rich sources of petroleum or gas. Although the term *gaz de shale* is the correct translation for shale gas, the term *gaz de schiste* is more commonly used by Francophones. Shale is a source of natural gas currently exploited in the United States and in some other countries, including Western Canada. Shale gas exploitation is usually done using hydraulic fracturing, an extraction method which involves the injection of hydraulic fluid (a mixture of water, sand and chemical additives) into the shale formation.

Exploitation of this resource is related to several environmental issues, including greenhouse gas emissions, sustainability of water resources (quality and quantity) and atmospheric emissions of chemicals/pollutants. These environmental issues have motivated a growing movement of protestation against shale gas exploitation in the USA, where shale gas has been exploited for more than 20 years, and in other countries, such as Canada, where shale gas exploitation is beginning or under development (exploration phase). Several international and provincial institutions have already produced reviews, policies and/or regulations regarding shale gas exploration/exploitation.

In this context, Health Canada asked Sanexen Environmental Services Inc. to prepare an overview on the potential health hazards of shale gas exploration/exploitation related to both drinking water and ambient air.

1.2 Objectives

The objectives of this report are:

a. To provide an overview of the existing methods to extract shale gas;

b. To address the potential health hazards associated with shale gas exploration/exploitation activities that have been identified in previous reviews and scientific literature, providing a description of both the sources of hazard and the chemicals/pollutants involved. The health hazards to be considered are limited to those in relation with ambient air and drinking water (i.e. surface and groundwater);

c. To compile the provincial/territorial information related to shale gas in Canada (i.e. occurrence of the resource, exploration and exploitation);

d. To compile the international activities (exploration/exploitation) related to shale gas (i.e. occurrence of the resource, exploration and exploitation).

The report does not address issues related to the sustainability of water resource, greenhouse gas emissions and psychosocial impacts or public safety (e.g. related to explosion).

The report was intended for managers and had to be accessible to non-specialists. Its principal aims were i) to identify the principal sources of contamination and the contaminants released from shale gas exploration and exploitation activities, and ii) to provide a general overview of the regulatory framework related to this industry, especially in Canada. When judged relevant, some quantitative data were occasionally reported.

1.3 Organization of the Report

The contents of the present report are resumed below:

- Section 1: **INTRODUCTION** – This first section presents the context (1.1), the objectives (1.2) and the organization of the report (1.3).

To understand how shale gas exploration and exploitation led to potential health risks for the population related to air and water contamination, it is important to know what shale gas is and how the exploration/exploitation processes occur. Sections 2 and 3 are thus intended to describe these topics.

- Section 2: **SHALE GAS** – This section briefly presents what are shale and shale gas (2.1), how this gas is generated and stored (2.2) and what are the resources estimates worldwide (2.3).
- Section 3: **OVERVIEW OF SHALE GAS EXPLORATION AND EXPLOITATION** – This section presents a rapid overview of the different phases of shale gas exploration and exploitation beginning with well construction and development (3.1), hydraulic fracturing and its alternatives (3.2 and 3.3) and well production and closure (3.4).
- Section 4: **REGULATORY FRAMEWORK** – This section is intended to give a general idea of the regulatory framework of shale gas production and development in the United States (4.1), Europe (4.2) and Canada (4.3). In this way, the reader will be better equipped to understand Section 5 in which more specific details concerning the regulatory framework of different countries is given.
- Section 5: **HEALTH HAZARDS RELATED TO SHALE GAS EXPLORATION AND EXPLOITATION** – This section addresses the health hazards related to the potential impacts of shale gas exploration and exploitation on the quality of surface and ground

water (5.1) and of ambient air (5.2). Each section presents an overview of the issues of concern, detailed information for each stage of shale gas exploration and exploitation (i.e. sources of contamination, risk probabilities, mitigation, preventive or regulatory actions and data knowledge as well as data gaps), the applicability to the Canadian situation and a summary of the health hazards for water or air.

- Section 6: **INTERNATIONAL ACTIVITIES RELATED TO SHALE GAS EXPLORATION AND EXPLOITATION** – This Section is intended to give a general idea of shale gas activities and resources in the world, and especially in the United States. Indeed, this is the only country where shale gas commercial production occurs at large scale.

- Section 7: **PROVINCIAL/TERRITORIAL CANADIAN ACTIVITIES RELATED TO SHALE GAS EXPLORATION AND EXPLOITATION** – This Section is intended to give a general idea of the shale gas resources and related activities in the different Canadian Provinces and Territories.

- Section 8: **SUMMARY OF DATA GAPS** – This Section summarizes the major data gaps identified in this report that are necessary to identify adequately the health hazards related to shale gas exploration and exploitation.

- Section 9: **CONCLUSION.**

- Section 10: **REFERENCES.**

2. SHALE GAS

2.1 What Are Shale Gas and Shale?

Shale gas is a natural gas. It is a mixture of hydrocarbon gases mainly composed of methane. It is generated in shale, a sedimentary rock that principally contains consolidated clay-sized particles. Shale is generally composed of clay, silica, carbonate and organic material. It typically functions both as a reservoir and a source of shale gas.

Gas shales are often referred to as resource plays. Resource plays are basically hydrocarbon systems where the source and reservoir are the same rock unit or formation. They are typically a few dozen to hundreds of metres thick and they extend over very wide geographic areas. They are classified as unconventional gas reservoirs because they have low permeability, small gas content per rock volume and the gas is dispersed over large areas (New Brunswick Canada (2011)). For simplification, the term 'shale' referring to 'gas-producing shale' or 'gas shale' will be used throughout the present report.

2.2 How Is Shale Gas Generated and Stored?

Shales are deposited as mud in deep, quiet water with dead organic matter such as plants and algae. The mud is transformed into shale during shallow burial and the organic matter is transformed into oil and gas (New Brunswick Canada (2011)). Shale gas can be generated in two different ways (although a mixture of gas types is possible) (Rokosh*, et al.* (2009), Lechtenböhmer*, et al.* (2011)):

- Thermogenic gas is formed when organic matter or oil is compressed at high temperatures and high pressures for a long period of time (process named thermal cracking);
- Biogenic gas is formed at shallow depths and low temperatures by anaerobic bacteria.

The origins of shale gas are important when evaluating shale-gas prospects. Indeed, thermogenic systems can produce significant quantities of heavy hydrocarbons with methane (which can add value to production) or impurities (e.g. carbon dioxide which can be costly to remove), whereas biogenic gas primarily contains methane. Moreover, thermogenic systems tend to flow at high rates but their exploitation is expensive whereas biogenic systems tend to flow at lower rates but their exploitation through shallow wells is less expensive (National Energy Board (2009)).

Shale gas can be naturally stored in three different ways:

- Adsorbed gas, which is gas attached to organic matter and clays;
- Free gas, which is gas held within the pore spaces or fractures of the rock;

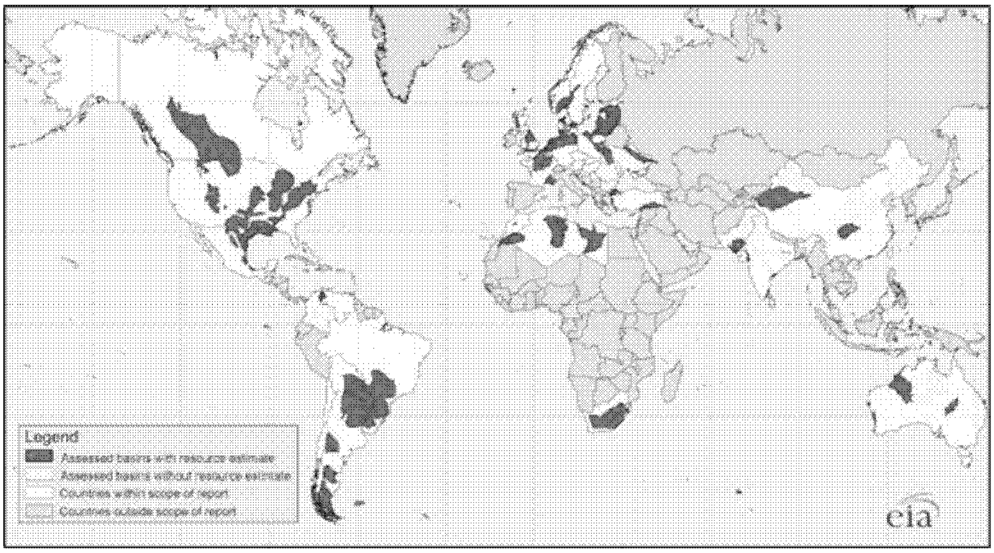
- Solution gas, which is gas held within liquids (e.g. bitumen and oil).

Higher free gas content in shale gas wells generally results in higher initial rates of production because the free gas resides in fractures and pores and hence is easier to collect than adsorbed gas. The high, initial flow rates decline rapidly to a slow, steady rate within approximately one year as adsorbed gas is slowly released from the shale (Alberta Geological Survey (2011)).

2.3 What Are the Shale Gas Resources Estimates Worldwide?

The U.S. Energy Information Administration (EIA) performed an initial survey assessing recoverable shale deposits in 32 countries located in 14 regions outside the United States (Figure 1 shows the location of the regions analyzed).

In its report, EIA indicated that although the shale gas resource estimates will likely change over time as additional information becomes available, the international shale gas resource base is vast. EIA's initial and conservative estimate of technically recoverable shale gas resources in the 32 countries examined was 5,760 Tcf. When adding the United States estimate of the shale gas technically recoverable resources (862 Tcf), the total shale resource base was estimated to be 6,622 Tcf. This represents over 40% of the total technically recoverable gas resources in the world (EIA (2011a)).



Source: EIA (2011a)

FIGURE 1: Map of 48 Major Shale Gas Basins in 32 Countries

3. OVERVIEW OF SHALE GAS EXPLORATION AND EXPLOITATION PROCESSES

To understand why shale gas exploration and exploitation may lead to potential health risks for the population related to air and water contamination, it is important to know how these processes occur. The different phases of shale gas exploration and exploitation are summarized in the following Table and detailed in the Sections below.

The shale gas exploitation process occurs after the initial exploration and site preparation phases have taken place.

► The exploration phase is performed in several stages (New Brunswick Canada (2011)):

- **Stages 1 and 2**: Identification of potential resource play and acquisition of key geological information - sites potentially containing shale gas are analyzed through various methods (e.g. seismic reflection profiles to map out the various underground formations (aquifers, rock formations), drilling for core sampling, mineralogical and geotechnical characterization of the unit);
- **Stage 3**: Initiation of a pilot project – horizontal drilling and hydraulic fracturing tests are performed to define rock properties, provide some indication of reservoir production and identify possible completion/stimulation technologies;
- **Stage 4**: Expansion of pilot projects – different tests (e.g. drilling multi wells from one pad, testing and optimization of completion techniques, production testing, pipeline planning and development) are performed to further optimize stimulation methodologies as well as to determine production profiles and apply techniques to determine areas for cost saving efficiencies;
- **Stage 5**: Commercial development - a site is selected when it is considered to yield substantial quantities of shale gas at low costs and when the optimized development plans are initiated.

► After a site (called a 'well pad') has been selected and the operator has obtained an exploitation permit, the preparation phase can begin. This phase consists in site clearance to provide space for the wells and all the equipment needed during the exploitation. It also consists in the building or improvement of roads to support heavy equipment (EPA (2011)).

► After the exploration and preparation phases have been completed, the shale gas exploitation can begin. It consists of the main stages detailed below:

- Well construction and development;
- Shale gas recovery (after hydraulic fracturing or alternatives techniques);
- Well production and closure.

► It is important to note that, even if the exploration phase is performed at a smaller scale than the exploitation phase and even if a shale gas exploration well does not correspond to a shale gas well in full exploitation, some stages, such as well drilling and hydraulic fracturing process, are found in both exploration and exploitation phases. Consequently, in the following Table and in the rest of the report, there will be no specific distinction between the exploration and exploitation phases.

TABLE 1: Site Preparation and Phases of the Shale Gas Exploration and Exploitation Process

OPERATION	ACTIVITIES	DURATION[1]
ACCESS ROAD AND WELL PAD CONSTRUCTION	Once permits are received, roads are constructed to access the well-site. Well pads are constructed to safely locate the drilling rig and associated equipment during the drilling process. Pits may be excavated to contain drilling fluids.	Several days to weeks
DRILLING	A drilling rig drills the well and multiple layers of steel pipe (called casing) are put into the hole and cemented in place to protect fresh water formations.	Weeks or months
HYDRAULIC FRACTURING	A specially designed fracturing fluid is pumped under high pressure into the shale formation. The fluid consists primarily of water along with a proppant (usually sand) and between 0.5% and 2% of chemical additives. This process creates fractures in rocks, deep underground, that are "propped" open by the sand, which allows the natural gas to flow into the well.	Days
PRODUCTION	Once the well begins production, parts of the well pad that are no longer needed for future operations are reclaimed. The gas is brought up the well, treated to a useable condition, and sent to market. Once the well has been completed, the site is partially reclaimed.	Years
WORKOVERS	Gas production usually declines over the years. Operators may perform a workover which is an operation to clean, repair and maintain the well for the purposes of increasing or restoring production. Multiple workovers may be performed over the life time of a well.	Several days to weeks
PLUGGING AND ABANDONMENTS/ RECLAMATION	Once a well reaches its economic limit, it is plugged and abandoned according to regulatory standards. The disturbed areas, including well pads and access roads, are reclaimed back to the native vegetation and contours, or to conditions requested by the landowner.	Reclamation: Days

Based on: New Brunswick Canada (2011)

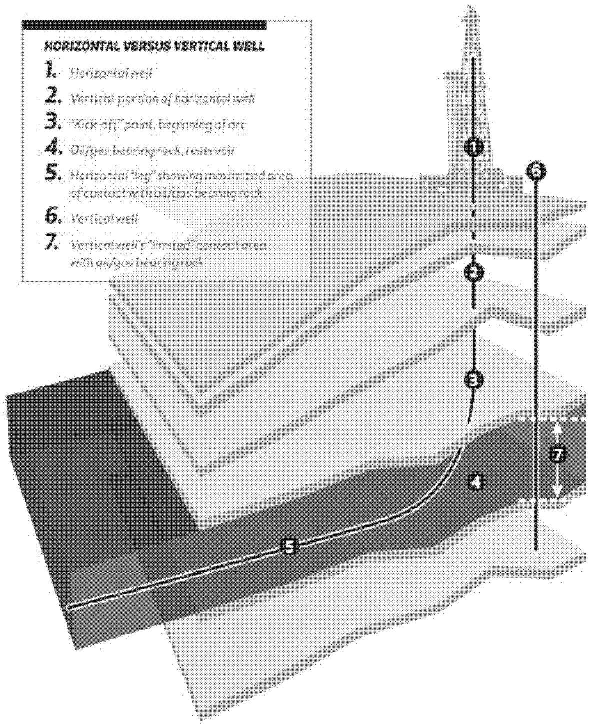
[1] Estimated duration of each operation may be shorter or longer depending on site specific circumstances.

3.1 Well Construction and Development

3.1.1 Well Types

Shale gas can be produced from vertical and horizontal wells (Figure 2). Vertical wells are composed of a vertical leg whereas horizontal wells are composed of both vertical and horizontal legs. The vertical leg can extend to more than a mile (1.6 km) below the ground surface and the horizontal leg can be almost two miles (3.2 km) from the vertical leg (EPA (2011)). For a typical vertical well, the well pad site is approximately one acre (0.4 hectare) whereas for a horizontal well, it can be as large as three to five acres (1.2-2 hectares) (Goddard (2010-2011)).

Horizontal wells are far more expensive than vertical wells but they increase access to the reservoir because the horizontal drilling provides more exposure to a formation as opposed to a vertical well. Moreover, they decrease environmental disturbances on the ground surface because fewer wells are needed to access the shale formation (EPA (2011)). Despite these advantages, vertical wells are still drilled in some shales because of, for example, borehole collapsing risks (e.g. in the Cretaceous Second White Speckled Shale of Alberta and Saskatchewan) (National Energy Board (2009)).

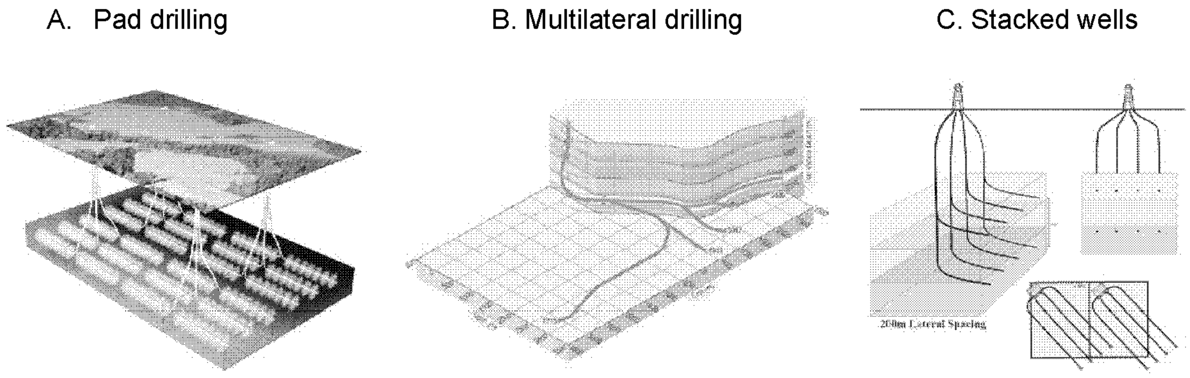


Source: http://50.23.239.111/~jwntestc/eatest/index.php/departments/how-it-works/130-horizontal-drilling

FIGURE 2: Schematic Representation of Horizontal and Vertical Wells

The following drilling techniques have been developed in recent years to reduce infrastructure costs and land use, and to increase gas production rates (Figure 3) (3Legs Resources plc (2011)):

- Pad drilling: a single drill pad is used to drill multiple wells;
- Multilateral drilling: horizontal wells are drilled at the same depth (but in different directions) from one single vertical well bore;
- Stacked wells: horizontal wells are drilled at different depths from one single vertical well bore.


A. Pad drilling B. Multilateral drilling C. Stacked wells

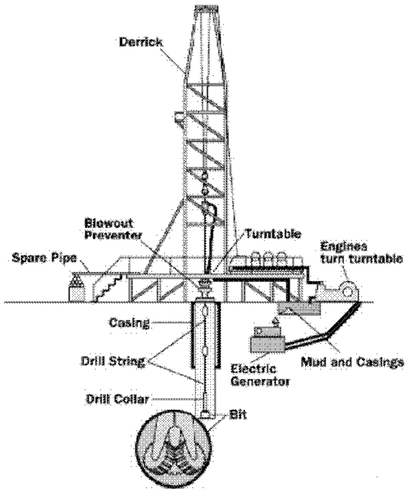
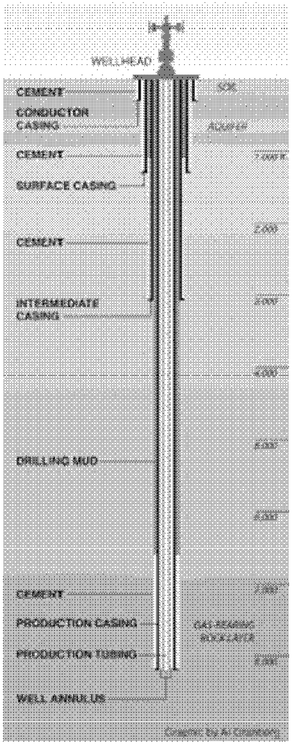
Sources: Figures 3A and 3B (3Legs Resources plc (2011)); Figure 3C (National Energy Board (2009)) (the upper-right view is cross-sectional whereas the lower-right view is a map view of the estimated well density)

FIGURE 3: Schematic Representation of Improved Horizontal Drilling Techniques

3.1.2 Well Construction and Design

Three steps (drilling, casing and cementing) are repeated several times from the beginning of the well construction until its completion. These steps are very important and must be done properly in order to protect the population (e.g. explosion) and the natural resources (e.g. ground water), and to ensure adequate shale gas production. The three steps are detailed in the following Table.

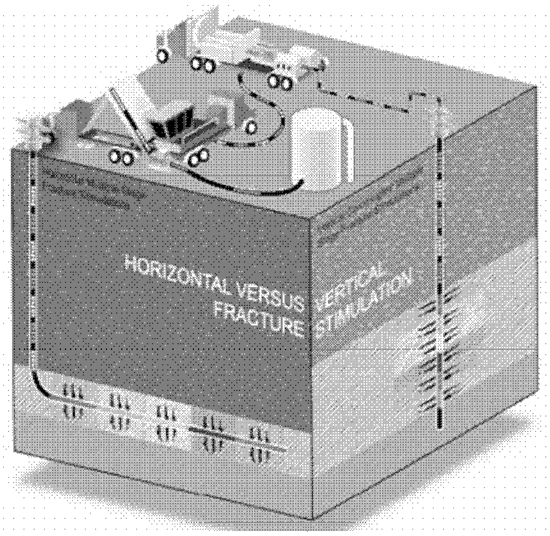
TABLE 2: Well Construction Steps

STEPS	DETAILS	FIGURES
DRILLING	*Vertical and horizontal wells:* A drill string composed of a drill bit, drill collars and a drill pipe is used to drill the well. As the drill bit grinds away, a drilling fluid such as compressed air or a mixture of water and additives (see Table 3), called 'mud', is pumped into the hole. This fluid serves multiple purposes such as cooling the drill bit, lubricating the drilling assembly, removing the formation cuttings, maintaining the pressure control of the well and stabilizing the hole. At different stages of the drilling process, the drill string is taken out of the hole for tool and bit changes and put back in (process called 'tripping pipe'). It is also taken out of the hole when casings are installed and cemented. *Vertical wells:* The drilling continues until it reaches the production depth. *Horizontal wells*: At the depth called the 'kick off point' (see Figure 2), which is the point where the curve begins, a drilling motor guides the drilling in a curving arc that re-orients the wellbore horizontally. The distance to make the curve from the kick off point to where the wellbore becomes horizontal is about 300 to 450 m. When the curve is completed, the horizontal section of the well is drilled (EPA (2011), Goddard (2010-2011), Parfitt (2010)).	 **Source:** http://petroleum-uir.blogspot.com/2011/03/drill-string-component.html
CASING	Casings are steel pipes lining the borehole. They have several purposes (e.g. isolation of the geological formation from material, equipment, fluid and gas, borehole caving prevention and pressure control). There are typically four types of well casing installed and cemented in place (Natural Gas Supply Association (2004-2010), EPA (2011)): • *Conductor casing*: first casing installed to prevent the top of the well from caving and to help in the process of circulating the drilling fluid up to the surface; • *Surface casing*: casing installed to isolate fresh water deposits near the surface and to protect from contamination during drilling, completion and operation of the well; • *Intermediate casing*: casing installed to protect the well from subsurface formations (e.g. underground salt-water deposits); • *Production casing*: casing that provide a conduit from the surface of the well to the shale gas formation.	 **Source:** New Brunswick Canada (2011)
CEMENTING	Cement is pumped down the casing and up the annular space between the rock and the outside of the casing. In the vertical portions of the wells, cement acts as a barrier to the migration of fluids up the wellbore behind the casing and it mechanically supports the casing (EPA (2011)).	

After the completion of a well, holes are made through the production casing and the casing cement to allow the hydrocarbons in the gas shale to flow into the well. This process is called perforating or 'perfing' the casing.

During perforation, a perforating gun can be lowered into the targeted section of the production casing. Then, an electrical current is sent to the perforating gun and induces the formation of small holes (Goddard (2010-2011)). Another technique is the use of explosive charges introduced into the well (EPA (2011), Lechtenböhmer*, et al.* (2011)).

Multi-stage perforating is used extensively. It consists in repeating the perforating process several times to cover the entire production casing (see Figure 4).



***Source**:* National Energy Board (2009)

FIGURE 4: Schematic Representation of Multi-Stage Perforating in Horizontal and Vertical Wells

3.2 Hydraulic Fracturing

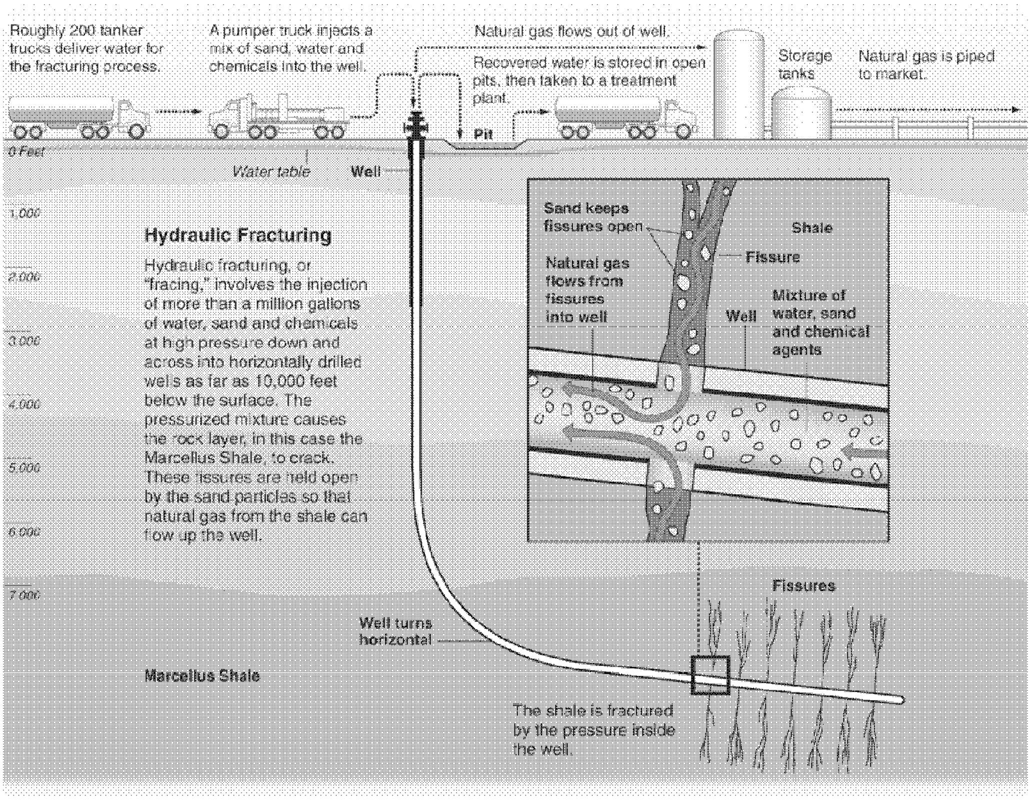
After the well is constructed and holes have been made through the production casing and cement, shale gas does not move freely from the gas shale formation into the well at high rates. Indeed, as seen in Section 2, gas shales have low permeability. Thus, in order to access the shale gas, it is necessary to improve this permeability and one of the widely used technique is called 'hydraulic fracturing' (also named 'fraccing', 'fracking' or 'fracing') (New Brunswick Canada (2011)).

3.2.1 What Is Hydraulic Fracturing?

Hydraulic fracturing is the injection of fluids and proppant (hydraulic fluid) at high pressure to create or restore small fractures in a formation. Thus, it increases the shale formation's permeability and stimulates gas production (National Energy Board (2009), New Brunswick Canada (2011)).

Multi-stage fracturing is a new technology which permits the fracturing of one specific segment of the wellbore at a time by isolating, perforating and fracturing portions of the horizontal or vertical wellbore starting at the far end (see Figure 4). For example, a 1.2 km horizontal well will require 8 to 13 fracturing stages.

Multi-stage fracturing is conducted to maintain sufficient pressure to fracture the entire length of the wellbore, to achieve better control of fracture placement and to allow changes from stage to stage to accommodate various geological formations if necessary. Thus, it increases the cumulative production in a shorter time frame (NYSDEC (2011)).



Graphic by Al Granberg

Source: http://www.swarthmore.edu/x29688.xml

FIGURE 5: Schematic Representation of the Hydraulic Fracturing Process

Hydraulic fluid is mainly composed of water loaded with proppant (98 to 99.5%), mostly sand, and chemical additives (National Energy Board (2009)) (see Section 3.2.2). The choice of the hydraulic fracturing fluid depends on many factors, such as the nature of the shale gas formation and the well depth (NYSDEC (2011)).

During hydraulic fracturing, hydraulic fluid (1,000 to 20,000 m^3 (260,000 to 5,300,000 gallons) per fracturing stage (Picot (2011), NYSDEC (2011))) is pumped down the well until the pressure (more than 76 MPa (Picot (2011))) surpasses the rock strength and causes the shale gas reservoir to crack. When the pressure is released, recoverable fluid (named 'flowback'), typically 25-50% of the hydraulic fluid, is returned to the surface leaving the proppant behind, which prop the fractures open (see Figure 5) (EPA (2011)).

After shale gas production has declined below past production rates or below the estimated reservoir potential, shales can be re-fractured, thus allowing access to reservoirs missed during the initial hydraulic fracturing or reopening fractures closed with the release of pressure. Depending on the shale formation, it can take less than one year or greater than ten years to re-fracture a reservoir (NYSDEC (2011), New Brunswick Canada (2011)).

3.2.2 What Are the Chemicals Used in Hydraulic Fracturing?

Hydraulic fluid contains a small proportion of additives (typically between 0.5 to 2%) However, as thousands of cubic meters of hydraulic fluid are used per well, the volumes of additives is not negligible. For example, between 2005 and 2009, 14 leading oil and gas service companies in the United States reported the use of 3 million cubic meters (or 780 million gallons) of hydraulic fracturing products in their fluids (Waxman*, et al.* (2011)).

Hundreds of different types of additives are used in hydraulic fracturing. For example, between 2005 and 2009, the 14 leading oil and gas service companies in the United States reported more than 2,500 hydraulic fracturing products containing 750 chemicals and other components (Waxman*, et al.* (2011)).

There are 13 different classes of additives which can be found in hydraulic fracturing fluid, each class corresponding to a particular purpose (e.g. biocide, friction reducer and surfactant) (NYSDEC (2011)). For example, gelling agents are mixed with the water to improve its ability to transport the proppant by increasing the hydraulic fluid viscosity. Once the pumping is finished, these agents change (the gel 'breaks') and the hydraulic fluid can flow back to the surface.

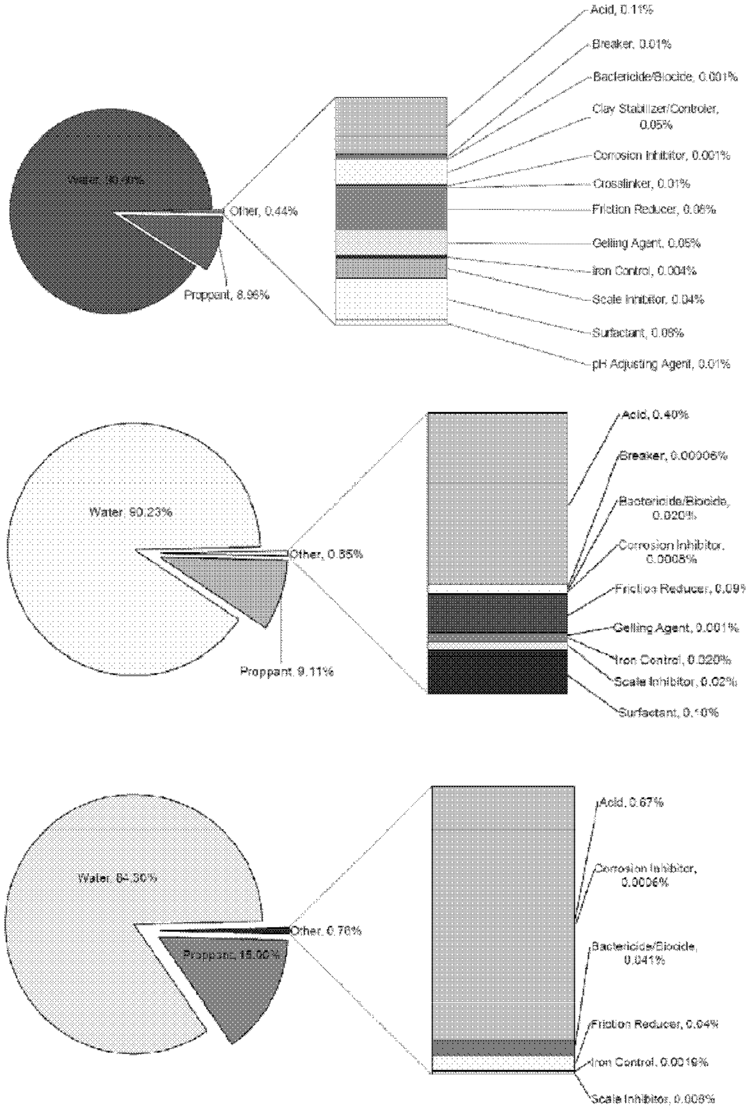
The different classes of additives, as well as some chemicals examples, are described in the following Table.

TABLE 3: Classes of Additives Used in Shale Gas Exploitation by Hydraulic Fracturing

Additive Class	Purpose	Used In	Examples of chemicals
Acid	Removes cement and drilling mud from casing perforations prior to fracturing fluid injection, and provides accessible path to formation.	Stimulation fluid Pre-fracture fluid	Hydrochlorid acid (3 to 28%) or muriatic acid
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhances the recovery of the fracturing fluid.	Post-fracturing fluid	Peroxydisulfates, ammonium persulphate, sodium chloride, magnesium peroxide, magnesium oxide, calcium chloride
Bactericide/ Biocide/ Antibacterial Agent	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Drilling mud Fracturing fluid	Gluteraldehyde, 2,2-dibromo-3-nitrolopropionamide, ammonium chloride, quaternary ammonium chloride, tetrakis hydroxymethyl- phosphonium sulphate
Buffer/ pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers.	Drilling mud Fracturing fluid	Sodium or potassium carbonate, acetic acid, sodium or potassium hydroxide
Clay Stabiliser/ Control/ Potassium Chloride	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Drilling mud Fracturing fluid	Salts (e.g. tetramethyl ammonium chloride, potassium chloride, choline chloride and calcium chloride)
Corrosive Inhibitor (including oxygen scavenger)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Drilling mud Fracturing fluid	Methanol, isopropanol, formic acid, acetaldehyde, ammonium bisulfate for oxygen scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Fracturing fluid	Petroleum distillate, potassium metaborate, triethanolamine zirconate, sodium tetraborate, boric acid, zirconium complex, ethylene glycol, methanol, potassium hydroxide, borate salts
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Drilling mud Fracturing fluid	Sodium acrylate-acrylamide copolymer, polyacrylamide, petroleum distillates, hydrotreated light petroleum distillate, methanol, ethylene glycol
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Drilling mud Fracturing fluid	Guar gum, petroleum distillates, hydrotreated light petroleum distillate, methanol, polysaccharide blend, ethylene glycol
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Fracturing fluid	Citric acid, acetic acid, thioglycolic acid, sodium erythorbate
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Drilling mud Fracturing fluid	Ammonium chloride, ethylene glycol, copolymer of acrylamide and sodium acrylate, sodium polycarboxylate, phosphonic acid salt
Solvent	Additive which is soluble in oil, water and acid-based treatment fluids is used to control the wet ability of contact surfaces or to prevent or break emulsions.		Various aromatic hydrocarbons, lauryl sulphate, isopropanol, ethylene glycol
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Drilling mud Fracturing fluid	Methanol, isopropanol, ethoxylated alcohol, lauryl sulphate, ethanol, naphthalene, 2-butoxyethanol

Source: NYSDEC (2011), Bishop (2010), FracFocus (2012)

Although there are 13 different classes of additives, it is important to note that any single fracturing job will not use all the types of additives. Moreover, there are also several types of products in each additive class but only one type of product from each class will be used in any given fracturing job. Each additive is also made up of one or more chemicals and several suppliers/manufacturers provide similar products with different formulations (NYSDEC (2011)). In fact, the composition of the fracturing fluid varies largely depending on various parameters such as the fracturing job, the company performing it, the shale gas formation and the well depth.



A. Fayetteville Shale (2009)

B. Marcellus Shale (2011)

C. Marcellus Shale (2011)

Source: NYSDEC (2011)

FIGURE 6: Examples of Fracturing Fluids Composition (by Weight) in Different Wells Drilled in the Marcellus and Fayetteville Shales (United States)

3.3 Alternatives to Hydraulic Fracturing

Since gas shales have low permeability, it is necessary to use a technique that increases this permeability to have access to the natural gas (see Section 2). Although the water-based hydraulic fracturing technique is widely used in shale gas exploitation, some alternative techniques have also been developed and are presently in use in the United States and in Canada (but to a lesser extent than hydraulic fracturing).

3.3.1 Liquefied Petroleum Gas (LPG) Fracturing Process (GASFRAC Energy Services)

The liquefied petroleum fracturing process does not use water during fracturing. Instead, it uses gelled LPG. LPG is a mixture of petroleum and natural gases that exists in a liquid state at ambient temperatures when under moderate pressures (less than 1.5 MPa or 200 psi).

During the fracturing process, LPG is pumped as a gelled liquid delivering proppant into the formation and is then drawn back out as propane. Thus, there is a 100% virtual recovery of the frac fluid (propane) and no wastewater is generated. The propane can be directly recovered during flowback to a pipeline along with the shale gas. As propane is inert, it does not react with the formation and the formation fluids (Smith (2008), GasFrac Energy Services Inc (2007), Kargbo*, et al.* (2010)).

3.3.2 Liquid-Free Stimulations

Dry Frac is a technique which has been successively used in Canada in some types of reservoirs. This technique does not use water during fracturing. Instead, it uses liquid CO_2 with proppant (CO_2/sand fracturing liquid) (Kargbo*, et al.* (2010)).

In certain situations, ice can be formed in wells because of the use of liquid CO_2. Thus, the technique has been improved and can use nitrogen gas reducing the ice formation (N_2/CO_2 fracturing liquid) (Mazza (1997)).

3.4 Well Production and Closure

When the well is producing shale gas, some parts of the well pads are no longer needed for future operations. Those parts are thus reclaimed.

During production, shale gas is brought up the well, treated and sent to the market. For example, wells in the Marcellus Shale produce gas at a typical rate of:

- 2.8 mmcf (million cubic feet) per day (equivalent to 80,000 m^3/day) during the first 5 years of exploitation;

- 550 mcf (thousand cubic feet) per day (equivalent to 15,000 m^3/day) after 5 years of exploitation;
- 225 mcf per day (equivalent to 6,000 m^3/day) after 10 years. Then, the production rate decreases to approximately of 3% per year (NYSDEC (2011)).

During this phase, operators may perform some operations to clean, repair and maintain the productive wells (New Brunswick Canada (2011)).

Once a well is no longer economically interesting, it is plugged and abandoned according to regulatory standards to prevent possible fluid migration that could contaminate the environment. Then, the well pad areas as well as the access roads built for the shale gas exploitation are reclaimed back to their original state or to conditions requested by the landowners (EPA (2011), New Brunswick Canada (2011)).

4. REGULATORY FRAMEWORK

The sections below briefly summarize the regulatory framework of shale gas production and development in the United States, Europe and Canada. They present an overview of the main laws and regulations that may apply to the shale gas industry however they do not intend to provide an exhaustive list of all the laws, regulations or restrictions that may apply at any governmental level.

4.1 United States

The development and production of oil and gas, such as shale gas, are regulated under a complex set of federal, state and local laws in the United States. All of the laws, regulations and permits applying to conventional oil and gas exploration and exploitation also apply to shale gas development (Ground Water Protection Council and ALL Consulting (2009)).

The U.S. Department of Interior's Bureau of Land Management (BLM) is responsible for permitting and managing most onshore oil and gas activities on federal lands. The BLM has a well established program for managing shale gas activities to protect human health and the environment where shale gas operations occur on federal lands. Resource protection is considered throughout the land use planning process, when Resource Management Plans are prepared and when an Application for Permit to Drill is processed. Moreover, the BLM's inspection, enforcement and monitoring program is designed to ensure that operators comply with relevant laws and regulations as well as specific stipulations set forth during the permitting process (Ground Water Protection Council and ALL Consulting (2009)).

The U.S. Environmental Protection Agency (EPA) administers most of the federal laws. These laws govern most environmental aspects of shale gas development. For example:

- The Clean Water Act (CWA) regulates surface discharges of water associated with shale gas drilling and production, as well as stormwater runoff from production sites;

- The Safe Drinking Water Act (SDWA) regulates the underground injection of fluids from shale gas activities but currently, the US EPA does not regulate the injection of hydraulic fracturing fluids under the SDWA due to an exemption written in the Energy Policy Act of 2005. However, the use of diesel fuel during hydraulic fracturing is regulated under the SDWA.

The US EPA currently groups underground injection wells into five classes for regulatory purposes and has proposed a sixth class:

1. Class I wells may inject hazardous and nonhazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost underground source of drinking water;
2. Class II wells may inject brines and other fluids associated with oil and gas production;
3. Class III wells may inject fluids associated with solution mining of minerals;
4. Class IV wells may inject hazardous or radioactive wastes into or above an underground source of drinking water and are banned unless specifically authorized under other statutes for ground water remediation;
5. Class V includes all underground injections not included in Classes I-IV;
6. Class VI has been proposed specifically for the injection of CO_2 for the purpose of sequestration, but has not yet been established.

- The Clean Air Act (CAA) limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production.

State agencies implement and enforce federal laws. However, they also have their own sets of state laws to administer. State laws often add additional levels of environmental protection and requirements. State regulation can more effectively address the regional and state-specific characteristics of the shale gas exploitation compared to the one-size-fits-all regulation at the federal levels (e.g. topography, climate, geology and hydrology). Moreover, a number of organizations and activities are developing and improving state regulations of oil and gas operations, such as shale gas development. The Ground Water Protection Council (GWPC) has a program to review state implementation of the Underground Injection Control program. The State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is a non-profit partnership between industries, nonprofit groups and regulatory officials. This program has developed guidelines for state regulations of oil and gas wastes. It periodically reviews state regulations, and encourages States to improve certain regulations.

In addition to state and federal requirements, other levels of government may impose additional requirements regarding oil and gas operations in specific locations. For example, cities, counties, tribes and regional water authorities may each set operational requirements that affect the location and operation of wells or require additional permits and approvals. When operations occur in or near populated areas, local governments may establish ordinances requiring additional permits to protect the environment and the general welfare of its citizens (e.g. traffic, noise).

4.2 Europe

In Europe, the activities relating to exploration/exploitation of shale gas are subject to European and national laws and regulations (Philippe and Partners (2011)). For example, some European Directives cover:

- Authorizations for exploration/production (Hydrocarbons Directive);
- Water protection (Water Framework Directive and Mining Waste Directive);
- The use of chemicals (REACH (Registration, Evaluation, Authorisation and Restriction of Chemical substances) administered by ECHA (European Commission Agency));
- The requirement for an Environmental Impact Assessment as well as public access to environmental information (general legislation);
- The operators may be subject to liability for damages under the Environmental Liability Directive and the Mining Waste Directive.

Specific national regulatory actions are reported in Sections 5 and 6.

4.3 Canada

In Canada, oil and gas drilling and production fall under provincial jurisdiction except on federal land, and under territorial jurisdiction in the Yukon. On federal lands, the National Energy Board (NEB) is responsible for regulating the exploration, development and production of crude oil and natural gas as well as for enhancing worker safety and protecting the environment. As lead agency, the NEB is also responsible for the environmental assessment of projects within its jurisdiction (Office of the Auditor General of Canada (2010)).

Federally, jurisdiction over shale gas development falls under the mandate of several departments, agencies and boards. For example, Health Canada uses two Acts to help protect the health of Canadians and the environment. These Acts are the Canadian Environmental Protection Act, 1999 (CEPA 1999) and the Canadian Environmental Assessment Act (CEAA). Under CEPA 1999, Health Canada as well as Environment Canada share the mandate of assessing the potential risks associated with the use of new and existing chemical substances in Canada as well as undertaking risk reduction measures where necessary. CEAA requires certain federal projects to undergo an environmental assessment before receiving approval. Environment Canada is also responsible for the administration and enforcement of the pollution prevention provisions of the Fisheries Act, which prohibit the deposit of deleterious substances in water frequented by fish or in a place where that substance may enter such water, unless the deposit is authorized by regulation under a federal act (Office of the Auditor General of Canada (2010)).

For most provinces, the environment and natural resources ministries share responsibility for regulating oil and gas exploration, extraction, and disposal of waste and wastewater. Regulations of the oil and gas sector vary between jurisdictions. Details on regulations for Alberta, British Columbia, Quebec, Nova Scotia and New Brunswick, in which many companies are now exploring for and/or developing shale gas resources, are presented below.

► In Alberta, the Energy Resources Conservation Board (ERCB) is an independent agency, quasi-judicial agency of the Government of Alberta, that regulates the safe, responsible, and efficient development of Alberta's energy resources (Government of Alberta (2012b)). In 2009, the ERCB embarked on the vision to 'be the best non-conventional regulator in the world by 2013'. In 2009, the ERCB initiated the Unconventional Regulatory Framework Project to ensure regulatory requirements continue to protect the public and the environment, and support responsible energy development and conservation.

All companies – regardless of whether they are developing conventional or unconventional resources including shale gas – are subject to all ERCB requirements and regulations that uphold public safety, environmental stewardship, and resource conservation. These include the Energy Resources Conservation Act, the Oil and Gas Conservation Act and Oil and Gas Conservation Regulations (OGCR) (Alberta Regulation 151/171). Many specific requirements are written in various directives. Directive 008: Surface Casing Depth Requirement and Directive 009: Casing Cementing Minimum Requirements are examples of Directives that protect groundwater by providing a barrier between the wellbore and any nearby water resources (see ERCB (2011) for more ERCB Directives).

► In British Columbia, the Ministry of Energy and Mines remains the primary ministry responsible for oil and gas development policies. Responsibility for oversight and implementation of the oil and gas regime lies with the Oil and Gas Commission (The Pembina Institute (2011)).

British Columbia's Oil and Gas Activities Act (OGAA) came into effect in October 2010 (British Columbia Government (2012)) to respond to increased pressures on its regulatory system as well as to better regulate the new technologies employed in modern oil and gas production. The regulatory powers in the new Act enable specific regulations to be developed for special projects such as shale gas. These powers will enable the B.C. government to manage shale gas projects differently from conventional operations to ensure that safety and environmental goals are met (Office of the Auditor General of Canada (2010));

► In Quebec, the jurisdiction and control of gas exploration and production fall under the responsibility of the Quebec's *Ministère des Ressources naturelles et de la Faune* and the *Ministère du Développement durable, de l'Environnement et des Parcs* (MDDEP). Following the Quebec government's acceptance of the report released by the *Bureau d'Audiences Publiques sur l'Environnement* (BAPE) on February 2011, a strategic environmental assessment (SEA) began on the development of the shale gas industry in Quebec. This report was initiated in May 2011 and the time required to perform this assessment is estimated to be between 18 to 30 months.

Quebec is currently undertaking the development of a new regulatory framework for oil and gas production in the province (BAPE (2011), Quebec Government (2011)). To date, two regulations have been adopted:

- In June 2011, the regulation respecting the application of the Environment Quality Act (R.S.Q., c. Q-2) was amended to implement certain recommendations of the BAPE concerning the sustainable development of the shale gas industry in Quebec. Thus, since June 2011, a certificate of authorization must be obtained for any drilling work to explore, or produce petroleum or natural gas from shale as well as all hydraulic fracturing operations to explore or produce petroleum or natural gas. Specific requirements in connection with public information and consultation also applying before delivery offer a certificate of authorization (Quebec Government (2012a));
- In 2011, another regulation came into effect ('Règlement sur la transmission de renseignements lies à l'exécution de certains travaux de forage et de fracturation des puits gaziers ou pétroliers'). This regulation aims to provide technical and scientific information to the MDDEP and to the governmental Committee performing the SEA (Quebec Government (2012c)). It should be noted that on April 3, 2012, the Committee performing the SEA indicated that it would not recommend the authorization of fracturing activities to acquire scientific and technical information. It will rather rely on laboratory experiments on fracking (Quebec Government (2012b)).

► In April 2011, the Government of Nova Scotia appointed an internal committee of officials from the Departments of Energy and of Environment to examine the environmental issues associated with hydraulic fracturing in shale gas formations and make recommendations on any additional regulatory measures required. The Committee will also identify potential environmental issues, determine how they are managed in other jurisdictions and identify industry best practices. It is anticipated that this review will be completed in early 2012 (Province of Nova Scotia (2012));

► The New Brunswick's Oil and Natural Gas Act for conventional oil and gas industries is administered by the New Brunswick Department of Natural Resources (NBDNR). The NBDNR and the New Brunswick Department of Environment (NBDENV) are actively reviewing the legislation to account for potential shale gas industries. This review is part of the new environmental protection plan whose first phase will be released in the spring of 2012. It will aim to identify immediate, intermediate and long-term actions to ensure New Brunswick is positioned to protect citizens and their property as well as the vital aspects of their environment.

In the future legislation, it seems that the NBDENV will require future oil, shale gas and natural gas companies to undergo a Phased Environmental Impact Assessment process. This process will identify potential environmental impacts so they can be avoided or reduced. It will begin prior to approval of well pad construction. Oil, shale gas and natural gas companies will also be required to obtain Approvals to Construct and Operate. The Approvals will contain conditions intended to reduce impacts from the project, as well as requirements from the Environmental Impact Assessment (New Brunswick Canada (2011));

► In Ontario, shale gas regulation is under the Oil, Gas and Salt Resources Act (OGSRA) administered by the Ministry of Natural Resources (MNR). This Act was amended in 2010 to include shale gas extraction. Large-scale shale gas wells may also require an Injection Permit under the OGSRA. The MNR plays a key role in ensuring the safe and sustainable development of Ontario's oil, natural gas, salt solution-mining and underground storage resources (Ontario Ministry of Natural Resources (2011)).

In Canada, the Council of Canadian Academies is assembling an Expert Panel on Harnessing Science and Technology to carry out an assessment of the state of knowledge of potential environmental impacts from the exploration, extraction and development of Canada's shale gas resources (Council of Canadian Academies (2012)). This report is expected to be completed in late 2013.

5. HEALTH HAZARDS RELATED TO SHALE GAS EXPLORATION AND EXPLOITATION

The health hazards related to the potential impacts of shale gas exploration and exploitation on the quality of surface and ground water and of ambient air are detailed in the present Section. An overview of the issues of concern for water (Section 5.1) and air (Section 5.2) is first presented. Detailed information for each stage of the shale gas exploration/exploitation (i.e. the source of potential impacts, the risk probabilities, the mitigation, preventive actions or regulatory actions and the data knowledge as well as data gaps) is presented in the further corresponding subsections. The applicability to the Canadian situation and a summary of the health hazards for water and air are presented in the last corresponding subsections.

5.1 Surface and Ground Water

The information available regarding the potential impacts of shale gas exploration/exploitation on surface and ground water indicates that all processes, from exploration to shale gas extraction including transport and wastewater treatment, are potential sources of contamination of the water resources.

During each shale gas exploitation stage, fluids/gases are used (e.g. hydraulic fracturing fluid, fuel) and/or obtained (e.g. natural gas, drilling mud, wastewater). Thus, each of these stages can potentially lead to the migration of contaminants in the surface and ground water. Moreover, general accidents (e.g. well blowout, leaks and spills) can occur during the exploration and exploitation stages, and can also lead to the migration of contaminants in the surface and ground water. The direct and indirect sources of potential water contamination (i.e. direct sources (1 to 3) and indirect sources (4 to 7)) are illustrated in Figure 7. Information relative to each of these sources of potential water contamination is presented in the following subsections; Sections 5.1.1 to 5.1.3 address the hazards related to direct sources whereas Sections 5.1.4 to 5.1.7 address the hazards related to the indirect sources.

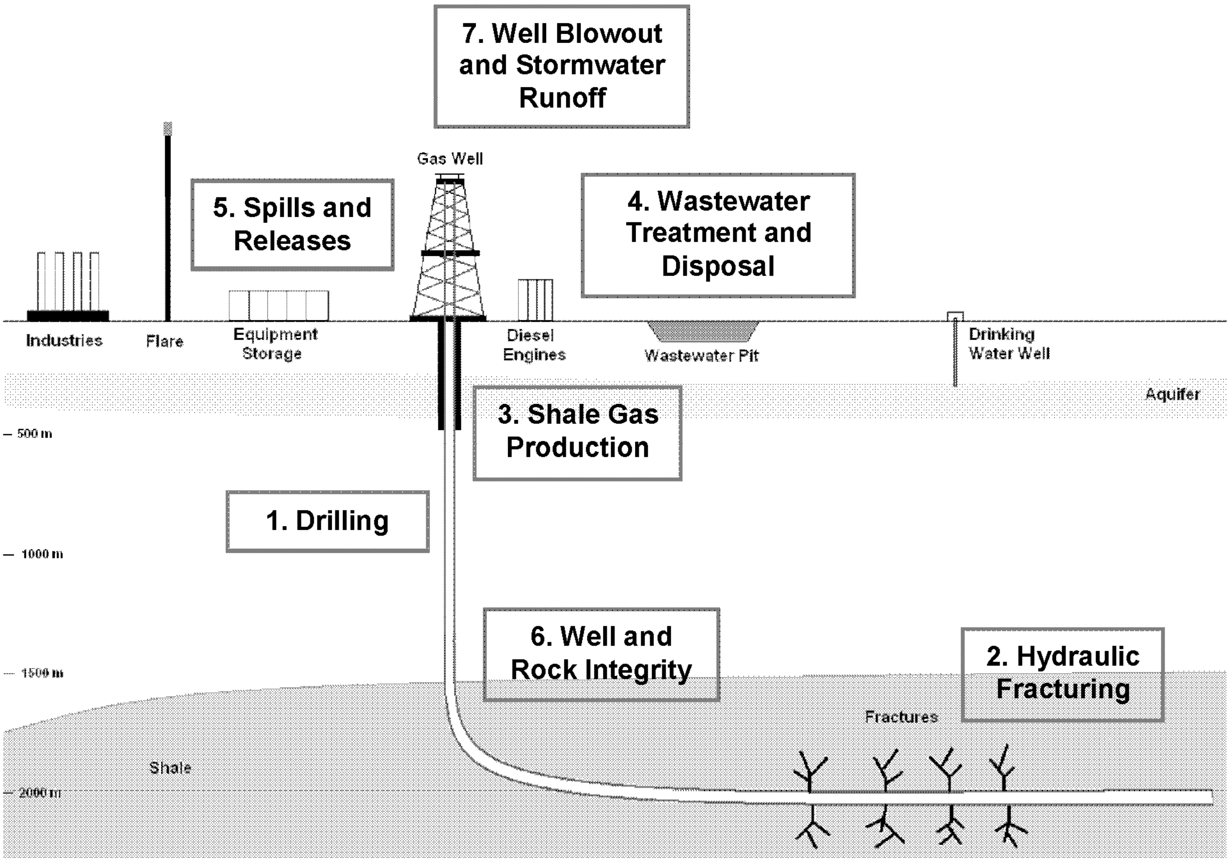


Diagram not to scale

Note: Direct sources of potential impact are in red; indirect sources of potential impact are in green.

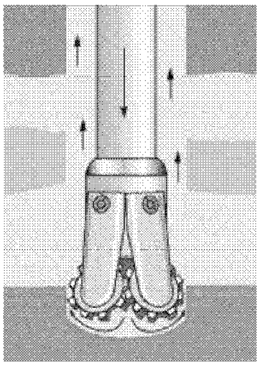
FIGURE 7: Overview of Potential Activities that can Impact Water Resources

5.1.1 Drilling

Sources of Potential Impacts

Wells are drilled using either compressed air or drilling mud that may be water-based, potassium chloride/polymer-based with a mineral oil lubricant, or synthetic oil-based; additives can be added to improve its efficiency. Chemical additives increase the density and weight of the fluids in order to facilitate boring, to reduce friction, to facilitate the return of the drilling fluid to the surface, to shorten drilling time and to reduce accidents (Colborn, *et al.* (2011)).

Drilling mud returns to the surface with rock cuttings (i.e. rock chips and very fine-grained rock fragments) through the annular space between the drill string and the walls of the borehole (see Figure 8).



Source: MDDEP (2010)

FIGURE 8: Drilling Mud Circulation

Drilling fluid (drilling mud and rock cuttings) is then contained and managed on-site through a series of piping, separation equipment and tanks. The separation equipment includes shale shakers, desanders, desilters and centrifuges which separate the mud from the rock cuttings. Drilling mud is typically reconditioned for further use at a subsequent well. When it is no longer suitable for drilling, drilling mud is disposed of (see Section 5.1.4). The disposal method is determined by the composition of the fluid (NYSDEC (2011), MDDEP (2010)).

The drilling process lasts several weeks or months and may pose the following risks:

- Well blowouts (see Section 5.1.7);
- Fluid migration from the borehole to the surface or ground water;
- Drilling fluid spills (see Section 5.1.5);
- Improper drilling operations (e.g. improper handling of mechanical equipment) can also impact the surface and ground water.

Compressed air can be used in low pressure formations (e.g. Marcellus Shale in the State of New York) instead of drilling mud. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. However, the use of air (without biocides) introduces a risk of contaminating surface water with bacteria and other microbes from brine, where they often flourish. One bacteria of particular concern is the sulphate-reducing bacteria which produces hydrogen sulphide, a gas rising health concerns (Bishop (2010)).

Risk Probabilities

According to NYSDEC (2011), operators that use standard drilling practices and employ good oversight in compliance with their permits would not impact surface and ground water. However, good standards practices are not always followed because several water contamination cases have been reported in the literature (see below).

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, several preventive and regulatory actions associated with well drilling and construction exist. They are presented in Section 5.1.6.

► In Canada, some provinces (e.g. Alberta) have developed directives relative to well development. In Quebec, a certificate of authorization must be obtained prior to any drilling work to explore or produce oil/shale gas (see Section 4.3).

► In France, shale gas drilling has been suspended since February 2011 pending assessment of the environmental impact (Philippe and Partners (2011)).

Data Knowledge and Data Gaps

► During drilling, large volumes of water are used and will thus have to be disposed. These volumes vary substantially between wells and shale gas plays. For example, the estimated volumes of water needed for drilling a well in the Barnet, Fayetteville, Haynesville and Marcellus Shales vary between 230 and 3,800 m^3 (60,000-1,000,000 gallons) (see Table 4) (Ground Water Protection Council and ALL Consulting (2009)).

► During drilling, large volumes of drilling fluid (drilling mud and rock cuttings) return to the surface. For example, the Quebec Minister of Sustainable Development, Environment and Parks (MDDEP) (MDDEP (2010)) reports that:

- The quantity of drilling fluid returning to the surface can be approximately 100 m^3 (c.a. 26,500 gallons) for a vertical well drilled to a total depth of 2,000 m (6,500 feet);

- The quantity of drilling fluid returning to the surface can be approximately 125 m^3 (c.a. 33,000 gallons) for a vertical well drilled to a total depth of 2,000 m and having a lateral section of 900 m (3,000 feet).

However, the New York State Department of Environmental Conservation (NYSDEC) (NYSDEC (2011)) reports the same residual volumes for the rock cuttings only:

- A vertical well with surface, intermediate and production casings drilled to a total depth of 2,100 m (7,000 feet) produces approximately 117 m^3 (154 cubic yards) of cuttings;
- A horizontally drilled well with the same casings and the same depth with a 1,220 m (4,000 feet) lateral section produces a total volume of approximately 166 m^3 (217 cubic yards) of cuttings (i.e. about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.

TABLE 4: Estimated Water Needs for Drilling and Fracturing Wells in the United States

SHALE GAS PLAY	VOLUME OF DRILLING WATER PER WELL (gal - m^3)	VOLUME OF FRACTURING WATER PER WELL (gal - m^3)	TOTAL VOLUME OF WATER PER WELL (gal - m^3)
Barnett Shale	400,000 - 1,500	2,300,000 - 8,700	2,700,000 - 10,200
Fayetteville Shale	60,000 - 230*	2,900,000 - 11,000	3,060,000 - 11,600
Haynesville Shale	1,000,000 - 3,800	2,700,000 - 10,200	3,700,000 - 14,000
Marcellus Shale	80,000 - 300*	3,800,000 - 14,400	3,880,000 - 14,700

Based on: Ground Water Protection Council and ALL Consulting (2009)

* Drilling performed with an air mist and/or water-based or oil-based mud for deep horizontal well completions.

Note: The volumes are approximate and may vary substantially between wells

► Rock cuttings consist of a mixture of the different types of rocks through which a well is bored. They are typically composed of shale, sand, and clays that are often coated with, or contain, residual contaminants from the drilling mud or from the borehole. They may also contain naturally present radioactive materials. For example, field and sample surveys on composited Marcellus rock cuttings and cores indicated background levels of radioactivity; these levels were considered a low exposure concern for workers or the general public (Kargbo, *et al.* (2010)).

► Additives used during the hydraulic fracturing process are also used in drilling mud (see Table 3), except two chemical additives only used during drilling activities: barium sulfate and bentonite (Bishop (2010)).

► The potential health effects of chemicals used during drilling were explored by The Endocrine Disruption Exchange for the Oil and Gas Accountability Project in 2004 (Colborn, *et al.* (2011)). The authors were able to identify 22 drilling chemicals (not identified in the paper) from a well blowout in Wyoming and analyzed the profiles of health effects for these chemicals. The results indicate that all the chemicals used in the drilling fluids were associated with respiratory effects and that most chemicals were associated with other effects on the skin, eyes and sensory organs, gastrointestinal tract, liver, kidney, immune system, hormonal regulation, as well as cancer (see Table 5).

TABLE 5: Profile of Possible Health Effects of 22 Chemicals Used to Drill a Well in Wyoming

HEALTH EFFECTS	APPROXIMATE PERCENTAGE OF CHEMICALS WITH HEALTH EFFECTS (n=22 chemicals in total)
Respiratory	100
Skin, Eye and Sensory Organs	90
Gastrointestinal and Liver	76
Other	58
Immune	54
Kidney	46
Endocrine Disruption	39
Mutagenic	37
Cancer	36
Brain and Nervous System	32
Cardiovascular and Blood	26

Based on: Colborn, *et al.* (2011)

► A large number of drinking resource contamination is associated with gas-well drilling activities and hydraulic fracturing. However, in most cases, the detailed cause of the accident was not established. Thus, it is not possible to know if the contamination event was specifically associated with the drilling process. Examples of contamination cases are reported in Section 5.1.3.

► One of the most often reported impacts during oil and gas drilling is the increased turbidity in drinking water wells due to mobilization (caused by vibrations and pressure pulses) of material (e.g. iron, manganese) naturally present in the underground water (see

Section 5.1.2.2). The turbidity can influence the microbiological quality of water and can be associated with changes in water color (e.g. red, orange) as well as unpleasant tastes and odours (Brisson*, et al.* (2010)).

In an isolated case in 2007, an operator used compressed air for many hours through the drill string in an attempt to free a drill bit stuck in a well in the Town of Brookfield (Madison County). The compressed air migrated through natural fractures in the shallow bedrock because no casing was in place (NYSDEC (2011)).

► Valuable data may be obtained in the coming years in Quebec, where a recent regulation requires the shale gas industry to provide technical and scientific information related to drilling work and hydraulic fracturing. However, on April 3, 2012, the Committee performing the SEA indicated that it would not recommend the authorization of fracturing activities to acquire scientific and technical information. It will rather rely on laboratory experiments on fracking (Quebec Government (2012b)) (see Section 4.3).

5.1.2 Hydraulic Fracturing

During the hydraulic fracturing process, hydraulic fluid (composed of water loaded with proppant and chemical additives) is pumped down the well. Then, a part of this fluid (named flowback water) returns to the surface (see Section 5.1.2.1). Brine, originally present in shale and natural gas, is transported to the surface with this flowback water and during all shale gas production (see Section 5.1.2.2).

5.1.2.1 Hydraulic Fracturing Fluid and Flowback Water

Sources of Potential Impacts

The fracturing process lasts a couple of days to a week. Surface and ground water might be contaminated with chemical additives used during this process. The possible migration paths are:

- Accidents and spills by truck transport (see Section 5.1.5);
- Leaks of wastewater ponds, storage containers and compressors (see Section 5.1.5);
- Spills from on-site accidents (e.g. blowout) (see Section 5.1.7);
- Damage to the cementation and casing (see Section 5.1.6.1);
- Migration through artificial or natural cracks of formations (see Section 5.1.6.2).

Another concern with hydraulic fracturing is cumulative impact. Indeed, contaminants can move between gas wells, fractured in proximity to one another, in events known as 'communications' (Parfitt (2010)). As seen in Section 3.1.1, different drilling techniques have been developed in recent years to reduce infrastructure costs and land use. These techniques involve the development of multiple wells from a single well pad as well as multiple horizontal wells from one single vertical well bore, thus increasing the risks of 'communication' between wells. Moreover, a 'kick' can occur when the formation fluid is driven by a formation pressure that is greater than the pressure exerted on it by the column of the drilling well in the wellbore (a 'kick' is an unintended entry of water, gas, oil, or other formation fluid into a wellbore that is under control and can be circulated out). If the formation fluid is not controlled, it may result in a blowout (B.C. Oil and Gas Commission (2010)).

Risk Probabilities

► Spills and releases will always exist because the shale gas industry operates on a large scale (see Section 5.1.5).

- ► Damages to the well cementation and casing inducing leakages are reported in Canada, Norway and in the United States at different rates depending of the report (from 2% to 43% of the wells leak). The leakage rate is assumed to increase dramatically during the lifespan of the wells (see Section 5.1.6.1).

- ► The probability that contaminants can reach aquifers through cracks induced by hydraulic fracturing is discussed in Section 5.1.6.2. On one hand, it is stated that the distance between the fractured zone and the aquifer is large enough to prevent the propagation of the cracks to the aquifers. However, on the other hand, it is reported that the rock between the shale formation and the surface is not impermeable. The hydraulic fracturing process can open up pathways upward to drinking water resources as faults and fractures naturally exist in the rocks. Moreover, the hydraulic fracturing process is not fully controlled and the time for fluid to migrate through the fractures is poorly understood.

- ► Spills from on-site accidents occur and are mostly related to incorrect handling, either by untrained personal or through incorrect behaviour (see Section 5.1.7).

Mitigation, Preventive Actions or Regulatory Actions

Information concerning mitigation, preventive actions or regulatory actions related to the hydraulic fracturing process principally originates from the United States but there is also some information from Canada and the European Union.

- ► In the United States, hydraulic fracturing authorization is attained when a company ensures proper well construction and surface monitoring by trained personnel.

Before operators or service companies perform a hydraulic fracturing treatment of a well, a series of tests has to be performed to ensure that the well, well equipment and hydraulic fracturing equipment are in proper working order and will safely withstand the application of the fracture treatment pressures and pump flow rates.

Moreover, hydraulic fracturing stimulations are continuously monitored by operators and service companies. For example, the monitors track the volumes of each additive and of the water used, and ensure that equipment is functioning properly. For example, for a 504,000 gallon (2,000 m^3) fracture treatment of a vertical shale gas well, around 30 and 35 people may be on site to monitor the entire stimulation process.

The multi-stage fracturing along the length of the lateral leg of the horizontal well allows the fracturing process to be performed in a very controlled manner and allows changes to each portion of the completion zone to accommodate site-specific changes in the formation (e.g. variations in shale thickness, presence or absence of natural fractures, proximity to another wellbore fracture system, and boreholes that are not centered in the formation) (Ground Water Protection Council and ALL Consulting (2009)).

► In general, industries in the United States do not have to report the water quality data before and after hydraulic fracturing, thus eliminating a baseline for testing. However, in the state of New York, it is proposed to require, via permit condition, that the operator samples and tests all residential water wells within 1,000 feet (with the property's owner permission) or 2,000 feet of the well pad (in the case when no well can be sampled within 1,000 feet). An initial sampling and analysis should be performed before site disturbance at the first well on the pad, and before drilling additional wells on multi-well pads. Moreover, other tests should be performed at established intervals after drilling and hydraulic fracturing to detect potential contamination (NYSDEC (2011)).

In Canada, for example, a private well water sampling and analysis program is required to obtain approvals to construct and operate shale gas operations in New Brunswick.

► Currently, the US EPA does not regulate the injection of fracturing fluids under the Safe Drinking Water Act (SDWA) (see Section 4.1) unless the use of diesel fuel is involved in the process. Indeed, the US EPA stated that a shale gas well is 'not an injection well because it is used primarily for gas extraction'. However, in 1994, the Legal Environmental Assistance Foundation (LEAF) petitioned the US EPA to regulate the hydraulic fracturing practice in Alabama under the SDWA because hydraulic fracturing of coal beds to produce methane is a form of underground injection. In 1999, Alabama amended its Underground Injection Program to include the regulation of injection of fluids for coal bed reservoirs as Class II wells (see Section 4.1) under the SDWA, and the US EPA approved (NETL (2007), Nguyen (2010)).

In the 'Fracturing Responsibility and Awareness of Chemicals Act of 2009' (FRAC Act), amendments to the Safe Water Drinking Act were proposed to include 'the underground injection of fluids or propping agents pursuant to hydraulic fracturing operations related to oil and gas production activities' as well as the disclosure of the 'chemical constituents (but not the proprietary chemical formulas) used in the fracturing process'. The Act is currently on hold in Congress pending US EPA action/research. Although it is suggesting more stringent regulations on hydraulic fracturing, there are several controversies surrounding it (e.g. deterrence on state regulations, violations on corporate trade secrets and a possible decline in the economy) (Nguyen (2010)).

► Fracturing companies in the United States are generally exempt from publicly disclosing the chemical compounds used in their fluids even though some of them are carcinogens. Indeed, hydraulic fracturing is not federally regulated under the SDWA. However, states have the option to choose to regulate this activity. Thus, even in the absence of baseline standards between states, 18 states require a list of materials used in the hydraulic fracturing process and 19 specify some of the volumes used. For example, the Colorado Oil and Gas Commission requests the disclosure of information related to the contents of hydraulic fracturing (Nguyen (2010)). However, as the reporting requirements vary from state to state, county to county and company to company, the reported composition of the different products used in hydraulic fracturing could easily be incomplete (e.g. divulgation of the functional category name such as 'biocides' but not of the product name). In some states, the list of the components present in the hydraulic fracturing fluid must be uploaded to Fracfocus.org. This is a hydraulic fracturing chemical registry website created by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

In British Columbia (Canada), public disclosure for hydraulic fracturing fluid is mandatory and the list of ingredients must be uploaded to Fracfocus.ca (a registry built by this province), within 30 days of finishing completion operations (FracFocus (2012)).

► In the United States, companies are fined when they violate state laws and thus, potentially induce the contamination of surface or ground water (Lechtenböhmer*, et al.* (2011)).

► In Canada, the Alberta Energy and Utilities Board issued a directive for shallow fracturing operations (coal seams) in August 2009. This directive prohibits fracking within a 200 m radius of water wells. Moreover, it requires a distance of at least 50 m between a water well's lowest depth and the shallowest depth of a frack zone (ERBC (2009)).

On February 2011, the province's *Bureau d'Audiences Publiques sur l'Environnement* (BAPE) released a report on sustainable development of the shale gas industry in Quebec. This report was created because citizens and citizen associations expressed their concerns and opposition about shale gas development. The BAPE's central recommendation, to which the government has agreed, was to push back adoption of new rules for shale gas exploration and development pending completion of a strategic environmental assessment (SEA) which begins in 2011. All hydraulic fracturing activities were originally prohibited while the SEA was being carried, except if they were required for the purpose of conducting the SEA (BAPE (2011), Quebec Government (2011)). However, on April 3, 2012, the Committee performing the SEA indicated that it would not recommend the authorization of fracturing activities to acquire scientific and technical information. It will rather rely on laboratory experiments on fracking (Quebec Government (2012b)).

► In Europe, hydraulic fracturing raises a lot of concern in several countries. For example, in France, the National Assembly set a moratorium for the shale gas exploitation and hydraulic fracturing is only allowed for scientific reasons, under strict control of a committee composed of lawmakers, government representatives, non-governmental organizations and local citizens (law approved by the Senate in June 2011). In North Rhine-Westphalia (Germany), a moratorium was pledged by the State Parliament until improved knowledge becomes available (Lechtenböhmer, *et al.* (2011)). In Bulgaria, the parliament decided to ban the exploration of shale gas reserves using hydraulic fracturing for 6 months, pending the adoption of new acts. It also withdrew the US permit for Chevron to prospect for shale gas (The Guardian (2012)).

The report of the European Parliament (Lechtenböhmer, *et al.* (2011)) indicates that most of the accidents and ground water intrusions in the USA seem to be due to incorrect handling despite the fact that regulations exist. Thus, the basic problem is not inadequate regulation, but their enforcement through adequate supervision. It must be guaranteed that best practice is not only available, but also commonly applied.

Information on the indirect sources that can potentially lead to the migration of hydraulic fracturing fluid and flowback water in the drinking water resource is available in Sections 5.1.4, 5.1.5, 5.1.6 and 5.1.7.

Data Knowledge and Data Gaps

► During hydraulic fracturing, large volumes of water are used. These volumes vary substantially between wells. For example, the estimated volumes of water needed for fracturing a well in Barnet, Fayetteville, Haynesville and Marcellus Shales vary between 8,700 and 14,400 m^3 (2,300,000-3,800,000 gallons) (see Table 4) (Ground Water Protection Council and ALL Consulting (2009)).

► The fracturing fluid typically consists of about 98-99.5% water and sand, as well as 0.5-2% chemical additives. Although these additives represent less than 2% by volume of the total fracturing fluid, as the process of hydraulic fracturing is a water-intensive process, the volume of additives is not negligible because the total volume of water of hydraulic fracturing fluid is elevated. For instance, the use of 10,000 m^3 (2,600,000 gallons) of hydraulic fluid may involve up to 200 m^3 (52,800 gallons) of additives (2%) for a single well.

► There is no exhaustive list of all the chemicals used in the hydraulic fracturing process because chemical additives used in this process vary largely depending on several parameters such as the fracturing job, the company performing it and the shale formations (see Section 3.2.2). Companies do not often have to disclose the chemicals used in this process and/or are not aware of all the chemicals they use. Moreover, some chemicals can have different names and some chemicals reported by the industry do not have a chemical registry number (CAS number). It is thus difficult to create an exhaustive list without duplicating the information.

► Lately, the Committee on Energy and Commerce of the United States launched an investigation concerning hydraulic fracturing. They asked the 14 leading oil and gas service companies to disclose the types and volumes of the hydraulic fracturing fluids they used between 2005 and 2009 (see also Section 3.2.2). It appeared that these 14 companies used more than 2,500 products during their hydraulic fracturing process and that these products contain 750 different chemicals (Waxman, *et al.* (2011)).

Some components used in the hydraulic fracturing process were common and generally harmless (e.g. salt and citric acid) or were unexpected (e.g. instant coffee and walnut hulls). However, other components were extremely toxic, such as benzene (a known carcinogen to humans) and lead (causing neurological problems in children as well as health effects in adults including reproductive problems, high blood pressure and nerve disorders) (see Appendix A for the list of each of the 750 chemicals reported by the oil and gas companies).

The most commonly used chemicals present in the 2,500 hydraulic fracturing products are reported in Table 6. Methanol was the most commonly used chemical (342 products). It is a hazardous air pollutant and a candidate for regulation under the SDWA. Hydraulic fracturing companies also largely used 2-butoxyethanol (126 products) as a foaming agent or surfactant. This chemical is easily absorbed and rapidly distributed in humans following inhalation, ingestion, or dermal exposure and studies have shown that it can cause hemolysis (destruction of red blood cells) and damage to the spleen, liver, and bone marrow.

TABLE 6: Chemical Additives Most Commonly Used in Hydraulic Fracturing Products between 2005 and 2009

CHEMICAL ADDITIVES	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL ADDITIVE
Methanol (Methyl alcohol)	342
Isopropanol (Isopropyl alcohol, Propan-2-ol)	274
Crystalline silica – quartz (SiO_2)	207
Ethylene glycol monobutyl ether (2-butoxyethanol)	126
Ethylene glycol (1,2-ethanediol)	119
Hydrotreated light petroleum distillates	89
Sodium hydroxide (Caustic soda)	80

Source: Waxman, *et al.* (2011)

Of the 2,500 hydraulic fracturing products reported by the oil and gas companies, 29 chemicals present in 652 different products are (1) known or possible human carcinogens, (2) regulated under the SDWA for their risks to human health, and/or (3) listed as hazardous air pollutants under the Clean Air Act (CAA). Table 7 lists these toxic chemicals and their frequency of use. It can be seen that, between 2005 and 2009, the 14 leading oil and gas companies in the United States used:

- 14 different carcinogens contained in 95 products. Overall, the companies injected 39,000 m^3 (10.2 million gallons) containing at least one of these carcinogenic chemicals;

- 8 chemicals regulated under the SDWA, including carcinogenic chemicals. Overall, the companies injected 44,300 m^3 (11.7 million gallons) of products containing one of these chemicals. BTEX compounds (benzene, toluene, ethylbenzene and xylene) represent a large part of these chemicals. In addition to individual chemicals, the companies also injected more than 113,500 m^3 (30 million gallons) of fuel or hydraulic fracturing fluids containing diesel in wells (diesel contains BTEX);

- 24 different hazardous air pollutants (e.g. methanol, ethylene glycol, hydrochloric acid, BTEX) contained in 595 products.

TABLE 7: Chemical Additives of Concern for Human Health that Were Used in Hydraulic Fracturing Products between 2005 and 2009

CHEMICAL ADDITIVES	CHEMICAL CATEGORY[1]	NUMBER OF PRODUCTS USING THE CHEMICAL ADDITIVE (n=652)
Diesel (containing BTEX)	Carcinogen, SDWA, CAA	51
Ethylbenzene	Carcinogen, SDWA, CAA	28
Benzene	Carcinogen, SDWA, CAA	3
Di (2-ethylhexyl)phthalate	Carcinogen, SDWA, CAA	3
Acrylamide	Carcinogen, SDWA, CAA	2
Lead	Carcinogen, SDWA, CAA	1
Naphthalene	Carcinogen, CAA	44
Formaldehyde	Carcinogen, CAA	12
Benzyl chloride	Carcinogen, CAA	8
Acetaldehyde	Carcinogen, CAA	1
Ethylene oxide	Carcinogen, CAA	1
Propylene oxide	Carcinogen, CAA	1
Sulphuric acid	Carcinogen	9
Thiourea	Carcinogen	9
Nitrilotriacetic acid	Carcinogen	6
Xylene	SDWA, CAA	44
Toluene	SDWA, CAA	29
Copper	SDWA	1
Methanol (Methyl alcohol)	CAA	342
Ethylene glycol (1,2-ethanediol)	CAA	119
Hydrogen chloride (Hydrochoric acid)	CAA	42
Diethanolamine (2,2-iminodiethanol)	CAA	14
Cumene	CAA	6
Dimethyl formamide	CAA	5
Phenol	CAA	5
Hydrogen fluoride (Hydrofluoric acid)	CAA	2
Phthalic anhydride	CAA	2
Acetophenone	CAA	1
p-Xylene	CAA	1

Source: Waxman, *et al.* (2011), IARC

Blue lines correspond to carcinogen additives.

[1] Carcinogen: known or possible human carcinogens;
SDWA: regulated under the Safe Drinking Water Act for their risks to human health;
CAA: Listed as hazardous air pollutants under the Clean Air Act.

► In 2009, the state of New York provided a list of 260 chemicals present in 197 products used in the hydraulic fracturing process as well as their CAS number. The Tyndall Centre for Climate Change Research (Wood*, et al.* (2011)) analyzed these chemicals using the European Chemical Substances Information System. Their result suggested that 58 of the 260 substances (i.e. 22%) have one or more properties that may give rise to concern for human health and/or the environment (see Appendix B):

- 15 substances are listed in one of the four priority lists. i.e. they require immediate attention because of their potential effects to man or the environment;
- 6 are present in list 1 (Acrylamide, Benzene, Ethyl Benzene, Isopropylbenzene (cumene), Naphthalene and Tetrasodium Ethylenediaminetetraacetate);
- 1 is currently under investigation as a persistent, bioaccumulative and toxic (PBT) compound (Naphthalene bis (1-methylethyl));
- 2 are present on the first list of 33 priority substances for which member states must progressively reduce pollution (Naphthalene and Benzene);
- 17 are classified as being toxic to aquatic organisms (acute and/or chronic);
- 38 are classified as being acutely toxic (human health);
- 8 are classified as known carcinogens to humans;
- 6 are classified as suspected carcinogens to humans;
- 7 are classified as mutagenic;
- 5 are classified as having reproductive effects.

► The potential health effects of chemicals used during drilling, hydraulic fracturing and delivery of shale gas were explored by The Endocrine Disruption Exchange for the Oil and Gas Accountability Project in 2004 (see Section 5.1.1 for the results of the chemicals used during drilling). During the study, 353 chemicals were identified with their registry number (not reported in their paper) and the health effect profiles of these chemicals were analyzed (see Table 8).

The authors found that more than 75% of these chemicals can affect the skin, eyes, and other sensory organs, the respiratory system, the gastrointestinal system, and the liver (see Table 8). More than half of the chemicals show effects on the brain and nervous system. All these effects would likely be expressed upon immediate exposure, e.g. eye and skin irritation, nausea and/or vomiting, asthma, coughing, sore throat, flu-like symptoms, tingling, dizziness, headaches, weakness, fainting, numbness in extremities, and convulsions. Normally, none of these chemicals would normally be ingested during natural gas operations, but immediate eye, nasal, dermal contact, and inhalation could lead to rapid absorption and cause direct exposure to the brain and other vital organs.

Moreover, they found that a large proportion of the chemicals used can have chronic and long-term organ and system damage including the nervous system (52%), cardiovascular system and blood (46%), kidney (41%), immune system (40%) and the endocrine system (36%). More than 25% of the chemicals can also cause cancer and mutations.

TABLE 8: Profile of Possible Health Effects of Chemicals Used in Shale Gas Operations Using Hydraulic Fracturing

HEALTH EFFECTS	APPROXIMATE PERCENTAGE OF CHEMICALS WITH HEALTH EFFECTS (n=353 chemicals in total)
Skin, Eye and Sensory Organs	86
Respiratory	83
Gastrointestinal and Liver	77
Brain and Nervous System	52
Cardiovascular and Blood	46
Other	42
Kidney	41
Immune	40
Endocrine Disruption	36
Cancer	26
Mutagenic	25

Based on: Colborn, *et al.* (2011)

► After the hydraulic fracturing process, when the pumping pressure has been relieved from the well, the fracturing fluid mixed with any natural forming water or natural gas, begins to flow back through the well casing to the wellhead.

Flowback water recoveries vary between wells and have typically been reported to range between 25-50% (EPA (2011)); however this percentage largely varies depending on the fracturing company. Based on the hydraulic fracturing fluid volume of 8,700- 14,400 m^3 per well (2,300,000-3,800,000 gallons) (see above), flowback water volumes could range between 2,175 and 7,200 m^3 per well (600,000-1,900,000 gallons). The flowback water is generally recovered within two to eight weeks. Then the well's water production rate declines and a few barrels per day are recovered for the remainder of its producing life.

Flowback water includes the fracturing fluids (water and chemical additives) pumped into the well, any new compounds that may have been formed due to reactions between chemical additives and substances (such as salts, metals and radioelements) mobilized from within the shale formation due to the fracturing operation (see production brine in Section 5.1.2.2). Some portion of the proppant may also return to the surface, but operators strive to minimize proppant return.

The nature and concentrations of the different substances present in the flowback water vary from one shale formation to another. Typical classes of parameters present in flowback fluids, as reported in the Marcellus Shale, are summarized below (NYSDEC (2011)) (see also Appendix C for the results of the composition analysis of flowback fluids from Pennsylvania and West Virginia):

- Dissolved solids (chlorides, sulfates, and calcium);
- Metals (calcium, magnesium, barium, strontium);
- Suspended solids;
- Mineral scales (calcium carbonate and barium sulfate);
- Bacteria - acid producing bacteria and sulfate reducing bacteria;
- Friction reducers;
- Iron solids (iron oxide and iron sulfide);
- Dispersed clay fines, colloids and silts;
- Acid gases (carbon dioxide, hydrogen sulfide).

Moreover, the composition of the flowback water changes with time over the course of the flowback process, depending on a variety of factors. Limited time-series field data from Marcellus Shale flowback water indicate that:

- The concentrations of TDS (total dissolved solids), chloride, and barium increase;
- The levels of radioactivity increase (the Marcellus Shale contains more radioactive components than other shales);
- Calcium and magnesium hardness increases;
- Iron concentrations increase, unless iron-controlling additives are used;
- Sulfate levels decrease;
- Alkalinity levels decrease, likely due to use of acid;
- Concentrations of metals increase.

► A large number of drinking resource contamination is associated with gas-well drilling activities and hydraulic fracturing. However, in most cases, the detailed cause of the accident was not established. Thus, it is not possible to know if the contamination event was specifically associated with the hydraulic fracturing process. Examples of contamination cases are reported in Section 5.1.3.

► Communication events between wells are not often documented. However, in 2010, the British Columbia Oil and Gas Commission reported 18 fracture communication incidents in British Columbia and one in Western Alberta (B.C. Oil and Gas Commission (2010)):

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

The incidents occurred in horizontal wells with separation distances between wellbores ranging from 50 to 715 m. Invading fluids included water, carbon dioxide, nitrogen, sand, drilling mud, other stimulating fluids and small amounts of gas.

► Data regarding the chemicals used during hydraulic fracturing and the composition of the flowback water are incomplete. Moreover, the chemical additives used during drilling and hydraulic fracturing can interact between them or with the natural shale components, can experience biodegradation or can react to the pressure and temperature experienced during the operations to create new unknown compounds (Brisson, *et al.* (2010)). In addition, there is no toxicological evaluation of hydraulic fracturing fluids. Health risks linked to these compounds are thus completely unknown.

► There are huge gaps concerning the quantities of chemical additives used and fracturing fluid left stranded in the formation. Also, there are large data gaps about the chemical fate and transport over the time of hydraulic fracturing fluids staying underground, as well as about the groundwater quality several years after hydraulic fracturing.

► The impacts of successive fracturing operations on the aquifers are difficult to predict because geological formations and aquifers are physically complex (Parfitt (2010)).

► Valuable data may be obtained in the coming years in Quebec, where a recent regulation requires the shale gas industry to provide some technical and scientific information related to some drilling work and hydraulic fracturing (see Section 4.3)

5.1.2.2 Production Brine

Sources of Potential Impacts

During the hydraulic fracturing process, brine originally present in shale and natural gas (see Section 5.1.3) is transported to the surface with the flowback water. Production brine contains minerals native in the formation and metals. Moreover, shale gas originates from shales that can potentially contain radioactive components. Thus, natural occurring radioactive material (NORM) can also be found in the production brine.

Production brine can contaminate the surface and ground water through spills and leaks (see Section 5.1.5). Moreover, it can move through cracks in the rock into the ground and surface water (See Section 5.1.6.2).

Risk Probabilities

In the United States, the Ground Water Protection Council and ALL Consulting (2009) reports that the regulations, standards and practices ensure that oil and gas operations present negligible risks to the general public with respect to potential NORM exposure. It also reports that when proper controls are implemented, the risk to workers is negligible. However, the risk probability depends on the concordance of the regulation, standards and practices related to production brine (e.g. monitoring, treatment efficiency) and on the actual application of these administrative/technical rules.

Mitigation, Preventive Actions or Regulatory Actions

► NORMs are not subject to direct federal regulation in the United States. Instead, states producing oil and gas are responsible for promulgating and administering regulations to control the re-use and disposal of NORM-contaminated equipment, produced water, and oil-field wastes. In general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard oilfield waste. However, if NORM concentrations are above regulatory limits, then the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure (Ground Water Protection Council and ALL Consulting (2009)).

► In the state of New York, it is proposed to require, via permit condition and/or regulation, that radiation surveys be conducted at specific time intervals for the wells using hydraulic fracturing on all accessible well piping, tanks, or other equipment that could contain NORMs. These surveys should be required for as long as the facility remains in active use (NYSDEC (2011)).

► The report of the European Parliament (Lechtenböhmer*, et al.* (2011)) indicates that radioactive particles should be evaluated at each individual shale and tight gas basin separately and that the composition of a core sample of specific shale under investigation should be disclosed before any production permission is granted.

Data Knowledge and Data Gaps

► Natural formation water has been in contact with the reservoir formation for millions of years. It thus contains minerals native to the reservoir rock. Its composition differs from shale to shale. Natural formation water can be:

- Brackish (i.e. 5,000 ppm to 35,000 ppm TDS (total dissolved solids));
- Saline (i.e. 35,000 ppm to 50,000 ppm TDS);
- Supersaturated (i.e. 50,000 ppm to >200,000 ppm TDS). Some operators even reported TDS values greater than 400,000 ppm (Ground Water Protection Council and ALL Consulting (2009)).

Metals (e.g. iron, aluminium, cadmium, zinc) are part of any geological formation and are thus also found in the natural formation water. Moreover, shales can contain natural occurring radioactive materials (NORMs) that can then be found in this natural formation water. The amount of NORM differs from shale to shale. For example, the Marcellus Shale in the United States contains more radioactive particles than other geological formations (Lechtenböhmer*, et al.* (2011)). Results of NORM analysis of Marcellus brine, produced in New York, report the presence of different isotopes of cesium, cobalt, ruthenium, zirconium, radium, thorium and uranium (Ground Water Protection Council and ALL Consulting (2009)).

TABLE 9: NORM Concentrations in Flowback Water Samples from the Marcellus Shale

PARAMETERS	TOTAL NUMBER OF SAMPLES	NUMBER OF DETECTIONS	CONCENTRATIONS (Picocuries Per Liter, pCi/L)	
			MINIMUM	MAXIMUM
Gross-alpha	15	15	22.41	18,950
Gross-beta	15	15	62	7,445
Total Alpha Radium	6	6	3.8	1,810
Radium-226	3	3	2.58	33
Radium-228	3	3	1.15	18.41

Source: NYSDEC (2011)

► When radioactive chemicals are found in natural formation water, flowback water containing brine also contains NORMs (see also Section 5.1.2.1). NORM concentrations vary depending on the formation and can be elevated. For example, NYSDEC (2011) reports NORM concentrations in flowback water samples from the Marcellus Shale varying from 1.15 to 18,950 pCi/L (see Table 9). For comparison, the Canadian Drinking Water Quality Guidelines are set to 5.4 pCi/L for lead-210 and to 13.5 pCi/L for radium-226 (Health Canada (2009)).

The Energy Institute (2012) reports that the most common NORM constituents in flowback and production brine are Radium 226 and Radium 228 arising from the decay of Uranium-238 and Thorium-232, respectively. These NORMs occur in the form of Ra^{2+} cations and are present in aqueous solution in concentrations from 0 to a thousand pico-curies per gram (1,000 pCi/L equivalent to 1 ppb Ra-226). The authors reported that these concentrations are not hazardous, except when concentrated by the precipitation of carbonate or sulfate scales that typically accumulate inside pipes, storage tanks, and other well-head equipment that flowback and produced water flow through.

► A list of naturally occurring compounds that could be present in flowback waters is presented in the Table below. Among these compounds, eight (30% of the compounds) have a carcinogen potential (known or possible carcinogen to humans).

TABLE 10: Natural Compounds Present in Various Flowback Waters

COMPOUNDS	CARCINOGENICITY (IARC CLASSIFICATION)
Cadmium	Group 1
Radium-226	Group 1
Thorium-234	Group 1
Uranium-235	Group 1
Cobalt	Group 2B
Lead	Group 2B
Lead-210	Group 2B
Nickel	Group 2B
Selenium	Group 3
Aluminium	
Antimony	
Barium	
Bore	
Chlorates	
Cyanide	
Iron	
Lithium	
Magnesium	
Manganese	
Methane	
Molybdenum	
Phosphorus	
Salts	
Sulfates	
Thallium	
Titanium	
Zinc	

Source: Brisson, *et al.* (2010)
Blue lines correspond to carcinogenic compounds.

IARC (International Agency for Research on Cancer) Carcinogenicity Classification

- Group 1: Carcinogenic to humans;
- Group 2B: Possibly carcinogenic to humans;
- Group 3: Not classifiable as to its carcinogenicity to humans.

► Production brine is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling (Ground Water Protection Council and ALL Consulting (2009)). Treatment and disposal are further discussed in Section 5.1.4.

5.1.3 Shale Gas Production

Sources of Potential Impacts

The rising of natural gas to the surface is accompanied by brine naturally present in the shale. The quantity of brine can be negligible or very important depending on the shale. It has to be removed from the natural gas and properly handled (Brisson*, et al.* (2010)).

Shale gas production is a process lasting several years. During this process, natural gas and brine could impact surface and ground water. Moreover, accidents such as leaks and spills (treated in the other sections) can occur.

Risk Probabilities

The probability that natural gas development degrades groundwater quality was estimated to range from 1.2 to 1.9% (Bishop (2010)). The authors also indicated that as new construction accounts for most spills and other mishaps, a groundwater contamination rate of 5.7% is expected. These probabilities are based on incidents that occurred in Colorado (1,549 spills from January 2003 to March 2008), Pennsylvania (1,670 violations between January 2008 and late August 2010) and New Mexico (705 groundwater contaminating incidents between 1990 and 2005).

Mitigation, Preventive Actions or Regulatory Actions

In order to document the surface and groundwater contamination issue, the US EPA launched a research program to improve understanding of the surface and ground water contamination risks associated with the shale gas extraction. Initial results are anticipated at the end of 2012.

Data Knowledge and Data Gaps

► Shale gas exploitation has increased in the recent years in the United States (see Section 6). However, even with the large quantity of wells in production, the number of contamination cases of water resources reported in the literature and that have been subject to evaluation are limited. Indeed, water resource supervision is generally performed only after the occurrence of an accident (e.g. spill, releases and explosion) or when the contamination of a water resource is clearly obvious (e.g. bad taste, colour or odour of the drinking water, complaint of health problems). Moreover, when the contamination of a water resource is detected, governmental agencies cannot often conclude undoubtedly that the contamination is the result of shale gas exploitation because industries do not generally have to report the water quality data before shale gas exploitation. Consequently, the number of cases of shale gas production-related contamination of groundwater is not indicative of the actual number of contamination cases. In addition, groundwater contamination may be a question of time (migration of the contaminants up to the groundwater resources may require several years or decades; see Section 5.1.6).

► Some contamination cases reported in the literature are (Michaels*, et al.* (2010)):

- In 2009, in the town of Dish (Texas), water quality was tested in response to many complaints of human illnesses and even animal deaths. Elevated levels of arsenic, lead, chromium, butanone, acetone, carbon disulfide and strontium up to 21 times above the allowable concentrations, were detected. As there was no other industrial activity in that region, gas extraction activities in and around the city were believed to be the only source of these impacts;

- In the city of Midland (Texas), levels of hexavalent chromium 50 times above the acceptable levels were detected in a private well in 2009. The Texas Commission on Environmental Quality is investigating a link to natural gas drilling activities;

- In Pavillion (New York), the US EPA investigated the source and nature of residential well contamination in response to complaints of foul odours and taste. The US EPA detected several petroleum hydrocarbons (e.g. benzene and methane) and inorganic compounds (e.g. sodium and sulphates) in drinking and ground water wells. Moreover, 2-butoxyethanol, which is a common solvent used in hydraulic fracturing fluids that can cause kidney failure, toxicity to the spleen, liver cancer and fertility problems, was detected in several of the wells analyzed. Oil and gas activity in the region was identified as the potential source of contamination.

A recent study performed by Osborn*, et al.* (2011) provided systematic evidence of methane contamination associated with shale-gas extraction in aquifers overlying the Marcellus and Utica Shale formations (northeastern Pennsylvania and upstate New York). Methane concentrations were detected in 85% of 60 drinking-water wells sampled across the region, regardless of industry operations. However, methane concentrations were found to be 17-times higher (19.2 mg/L), on average, in areas with active drilling and extraction than in non-active areas (1.1 mg/L), with some drinking water wells having concentrations (64 mg/L) well above the recommended defined action level (10-28 mg/L) for hazard mitigation. Average and maximum methane concentrations were higher in shallow water wells within approximately 3,000 feet (1,000 m) of active shale-gas wells. Moreover, isotopic data for methane found in the drinking water resources were consistent with gas found in deep reservoirs such as the Marcellus and Utica Shales and matched gas found in gas wells nearby. It should be noted that no baseline data was available for these wells prior to shale gas activity. This study did not find evidence of contamination of drinking water resources with deep saline brines and fracturing fluids.

5.1.4 Wastewater Treatment and Disposal

Sources of Potential Impacts

Large volumes of wastewater are generated during the different stages of shale gas exploitation. The wastewater corresponds to the drilling mud and cuttings, the hydraulic fracturing fluid and the produced water (also called 'brine') rising to the wellhead.

Cuttings may be managed within a closed-loop tank or within pits. Then, they may be buried on-site when generated during compressed air drilling or when generated during drilling with fresh water (they have to be removed from the site when generated during drilling with polymer- or oil-based muds) (NYSDEC (2011)).

Wastewater is commonly stored in pits but can also be placed in tanks or other aboveground containment systems (in certain situations, these containment systems are required because of the specific geologic conditions). In certain cases, wastewater can be transported by pipeline to a pit. All of these containment and transporting systems can leak and conduct to the emission of wastewater in the environment which can then reach the surface and ground water (U.S. Department of Energy (2009)). It should be noted that the requirements for wastewater disposal vary from country to country and even within each country according to state/provincial laws.

Options exist or are being developed for treatment, recycling and reuse of flowback water. The on-site treatment technologies that can be employed include: physical and chemical separation, dilution, membrane/reverse osmosis, thermal distillation, ion exchange and ozonation. However, proper disposal is required for flowback water that cannot be reused (i.e. high contaminants concentrations, no treatment options, etc.) (NYSDEC (2011)).

For disposal, wastewater can be injected deep underground (limited by geological constraints and regulatory requirements) or be treated in water treatment plants. Another disposal option is the spreading of the wastewater on the road. This technique is typically limited to the application of drilling wastes such as mud and tank bottoms (U.S. Department of Energy (2009)).

At a global level, wastewater management may involve all of these options. For example, from July 2009 to July 2010, 729,000 m^3 of fracturing wastewater was reported in Pennsylvania. In total, 77.5% was sent to wastewater treatment facilities, 16% was reused, 5% was sent to municipal wastewater treatment facilities, 1% had unknown disposal, 0.5% was injected in the ground and 0.07% was spread on roads (Rozell and Reaven (2011)).

Wastewater contaminants could reach the surface and groundwater from the deep injection underground wells and from the water treatment plants. Indeed, injecting wastewaters that are typically very salty and that may contain chemicals and heavy metals into underground wells can contaminate drinking water. Moreover, municipal water treatment plants may not be designed or intended to deal with the contaminants present in the wastewater (e.g. salts, metals, NORMs and additives) (Parfitt (2010)).

Risk Probabilities

In their paper, Rozell and Reaven (2011) estimated that it was very likely than an individual well would release at least 200 m^3 of contaminated fluids in the environment. This estimation was based on probability bounds analyses using data from the Marcellus Shale. The authors also indicated that the potential contamination risk associated with the hydraulic fracturing of wastewater disposal was several orders of magnitude larger than the other pathways (i.e. transportation spills, well casing leaks, leaks through fractured rock and drilling site discharge).

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, management of liquid and solid wastes from shale gas development is subject to a host of federal and state regulations applying to oil and gas operations in general.

States regulate the on-site storage of wastes to prevent soil and water contamination. In 19 states, an authorization from the regulatory agency is required for the use of a pit and, in some states, a separate permit is required for each functional pit in use (e.g. drilling, fluid storage and emergency). Moreover, 19 states require the issuance of a prior authorization or permit before a pit is constructed or used, and 16 states also specify the duration of time for which a pit may be used (U.S. Department of Energy (2009)).

In order to prevent the infiltration of fluids into the subsurface, 23 states require that certain kinds of pits or pits placed in a particular location have a natural or artificial liner. Typically, these liners are constructed of compacted clay or synthetic materials such as polyethylene or treated fabric. Moreover, 10 states require pits used for long term storage of fluids to be placed at a minimum distance from surface water to prevent potential overflows that could result in an unauthorized discharge to water. Twelve states also either explicitly prohibit or restrict the use of pits that intersect the water table. Further, 16 states require that the levels of fluids present in the pits remain below the top of the pit wall. This corresponds to a safety margin to prevent pit overflows in the event of significant rainfall (U.S. Department of Energy (2009)).

Currently, wastewaters associated with shale gas extraction are prohibited from being directly discharged to waterways and other bodies of water of the United States. Thus, some of the shale gas wastewater is reused or re-injected, but a significant amount still requires disposal. Most wastes associated with oil and gas development (e.g. produced water, drilling fluid, flowback water, drill cuttings) are exempt from federal hazardous waste disposal requirements. Disposal of these wastes varies from state to state and depends on the type of waste.

Wastewater disposal is primarily done by underground injection in western and southern shale gas producing states (the Safe Drinking Water Act (SDWA) regulates the underground injection of some fluids, such as brines, from shale gas activities (see Section 4)). In contrast, wastewater is primarily disposed of by discharge to public treatment plants in eastern states. However, wastewater discharge to these treatment plants has been prohibited in some states (e.g. Pennsylvania) and some other states have also implemented new regulations requiring pre-treatments before discharge (Energy Institute (2012)).

The US EPA is initiating a rulemaking to control wastewater produced by natural gas extraction from underground shale gas formations. The standards should be released by 2014 (US EPA (2012)).

► In Canada, as in the United States, wastewater disposal varies from jurisdiction to jurisdiction according to provincial laws. In Alberta, the use of unlined storage pits and the reintroduction of treated water into waterways are strictly forbidden. The ERCB requirements for waste fluid handling and disposal are presented in several directives (Directives 050, 051, 055 and 058). Fluids that cannot be recycled or reused must be reinjected and stored in rock formations deep underground, far below groundwater resources.

► The report of the European Parliament (Lechtenböhmer, *et al.* (2011)) indicates that most water contaminations are due to improper practices. Thus, very strict handling of these issues is mandatory.

Data Knowledge and Data Gaps

► The proper disposal of wastewater is a major issue as large quantities of wastewater are created. Many problems associated with the improper disposal of wastewater are reported. For example, in Pennsylvania:

- ‘Talisman Energy’ was fined for a spill in 2009 that sent over 4,200 gallons (16 m^3) of flowback fluid into a wetland and a tributary of Webier Creek (Lechtenböhmer, *et al.* (2011));
- ‘Atlas Resources’ was fined for violating environmental laws at 13 well sites, in January 2010. They discharged diesel fuel and hydraulic fracturing fluids into the ground (Pennsylvania Department of Environmental Protection (2010));

- 'Fortune Energy' illegally discharged flowback fluids into a drainage ditch and through a vegetated area, eventually reaching a tributary of Sugar Creek (Michaels, *et al.* (2010)).
- The borough of Jersey Shore was fined in February 2010 for violations associated with its treatment of industrial gas drilling wastewater during 2008 and 2009. The borough's wastewater treatment plant illegally processed wastewater with excessive chloride and exceeded other limits (Michaels, *et al.* (2010)).

► In October 2008, the Pennsylvania Department of Environmental Protection determined that levels of total dissolved solids in the Monongahela River exceeded federal and state water quality standards. To address this problem, the Department directed all sewage treatment plants accepting gas drilling wastewater and discharging it to the Monongahela River or its tributaries to reduce the volume of gas drilling wastewater they accept to 1% (instead of 20%) of their daily flow. The Department traced that the high TDS levels (twice the allowable limit) originate from natural gas drilling operations. In October 2009, the Department announced again that TDS levels in the Monongahela River exceeded drinking water quality standards (Michaels, *et al.* (2010)).

► Underground injection wells have already caused several cases of drinking water contamination in the United States. For example, the GAO (1989) reported 23 known contamination cases in the United States before 1987. The three principal causes were (1) leaks in the casing of the injection wells, (2) direct injection into the underground drinking water sources and (3) migration of brines from operating injection wells into nearby oil and gas wells that had been left unplugged or improperly plugged. In the majority of the cases, the contamination was discovered when it had become obvious to the people affected (e.g. when the well water became too salty to drink, when the crops were ruined, or when people could see water flowing at the surface of old wells).

► There is a lack of knowledge associated with the disposal and the characterization of wastewater (e.g. volumes, disposal method, concentrations of contaminants, salinity and pH).

There is no information concerning the membrane integrity, the storage installations and the duration of wastewater storage in the pits. No data could be found concerning the ability of wastewater treatment plants to treat wastewaters originating from the shale gas industry (potentially salted and contaminated with radioactive elements, various organic and inorganic chemicals) and to deal with increased volumes of wastewater, nor concerning the quality of the water and the sludge after treatment. Sludge quality may be an important issue where sludges are used as biosolids to improve the fertility of soils (especially agricultural soils). Moreover, no monitoring data could be found concerning the quality of groundwater closed to underground injection wells. This information is necessary to determine human health risks associated to wastewater treatment.

5.1.5 Spills and Releases

Sources of Potential Impacts

A large number of activities can impact surface and ground water from spills and releases that occur on-site or off-site. In addition to drilling operations (Section 5.1.1), hydraulic fracturing (Section 5.1.2) and wastewater treatment and disposal (Section 5.1.4), these activities include (NYSDEC (2011)):

- Truck traffic;
- Fuelling and refilling activities;
- Material and chemical storage;
- Chemical mixing, material handling and loading/unloading areas;
- Bulk chemical/fluid storage tanks;
- Equipment cleaning;
- Vehicle and equipment storage/maintenance areas;
- Lumber storage and/or processing areas.

The contaminants that can impact surface and groundwater include:

- Hydrocarbons (i.e. from trucks and equipment using oil or diesel);
- Products used in the maintenance of mechanical equipment (e.g. lubricants);
- Drilling mud (Section 5.1.1), hydraulic fracturing additives (Section 5.1.2.1), production brine (Section 5.1.2.3) (i.e. leaks from storage tanks, spills from trucks, etc.).

Risk Probabilities

As mentioned by the Department of Natural Resources (2011), the oil and gas industry operates on a large scale. Thus, spills, releases and other impacts will unfortunately always exist. In their report, they indicate that the industry in Colorado spilled 2 million gallons of fluids during the first eight months of 2011, 20% of the spills involved water contamination. This represents about 0.05% of the overall volume of fluids (10 billion gallons) handled by the shale gas industry in Colorado.

Using probability bounds analyses, Rozell and Reaven (2011) assessed the likelihood of water contamination from transportation spills. The risk of water contamination by this pathway was found negligible compared to other pathways (e.g. wastewater disposal).

Mitigation, Preventive Actions or Regulatory Actions

The most effective way to reduce the risk of spills is to replace the use of toxic chemicals with non-toxic substances, when possible, or by arranging for just-in-time delivery to reduce risks of on-site storage (Energy Institute (2012)).

► In the United States, regulations impose a variety of requirements to prevent spills and releases from occurring. For example, in Colorado, Rule 604 imposes sitting, construction, operating, and secondary containment requirements on all storage tanks and maintenance as well as inspection requirements on all valves, pipes and fittings (Department of Natural Resources (2011)).

► Some states also require Spill Prevention Control and Contingency (SPCC) plans which specify the best practices to be used in the case of a release. For example, in Colorado, Rule 906 requires operators to investigate and clean up spills as soon as practicable, to implement measures to prevent similar spills in the future, to notify the Colorado Oil and Gas Conservation Commission if the spill impacts or threatens any state water, residence or occupied structure, livestock, or public byway, if the spill exceeds 210 gallons. Moreover, a fine can be assessed in certain cases (Department of Natural Resources (2011)).

► Incidents and/or accidents with trucks hauling different contaminants (e.g. hydraulic fracturing additives, waste fluid) can affect surface and groundwater. Efforts can be made to reduce vehicle traffic and to enforce speed limits in order to limit adverse impacts. For example, in the United States, permanent pipelines have been constructed in the Barnett Shale play to transfer produced water from well sites to disposal facilities. Traffic can be further reduced when multiple directional wells are developed from a pad. Moreover, members of the public or local municipalities often have the ability to limit traffic volume in residential areas by developing restrictions in neighbourhood lease agreements or by developing ordinances that prevent road construction in certain areas (Ground Water Protection Council and ALL Consulting (2009)).

► In Canada, the requirements to avoid spills and releases from occurring vary from one province to another. For example, in New Brunswick, a company must possess a containment system plan to obtain applicable Approvals to Construct and Operate. This plan must describe how fluid and material contaminants will be contained within the facility during construction, drilling and production activities (New Brunswick Canada (2011)).

Data Knowledge and Data Gaps

► The equipment present on a well pad principally includes storage tanks, a blender, pumping units, a sand conveyor, test and monitoring equipment, and the wellhead, in addition to trucks. It was estimated that a horizontal exploitation well using hydraulic fracturing needs between 900 and 1,300 truck loads in which 500 to 600 are executed by tankers (Sampité (2011)).

► NYSDEC (2011) reports that the trucks used for the transport of hydraulic fracturing additives are flat-bed trucks carrying a number of plastic totes encased in metal cages (220 to 375 gallons) which contain the liquid products. However, liquid products used in small quantities are transported in one-gallon sealed jugs carried in the side boxes of the trucks while some liquid constituents (e.g. hydrochloric acid) are transported in tank trucks. Dry additives are carried in 50-55 lbs bags set on pallets containing 40 bags each and shrink-wrapped, or in five-gallon sealed plastic buckets. However, dry products used in small quantities are contained in a double-bag system carried in the side boxes of the trucks. Water is typically stored in 500-barrel tanks.

► There is a significant amount of spills reported in the literature. For example, in Colorado, the Colorado Oil and Gas Conservation Commission reported 1,549 spills and leaks in the period from January 2003 to March 2008 (on average, one incident every two days) (Department of Natural Resources (2011)) (no data was available concerning Canadian spills and releases).

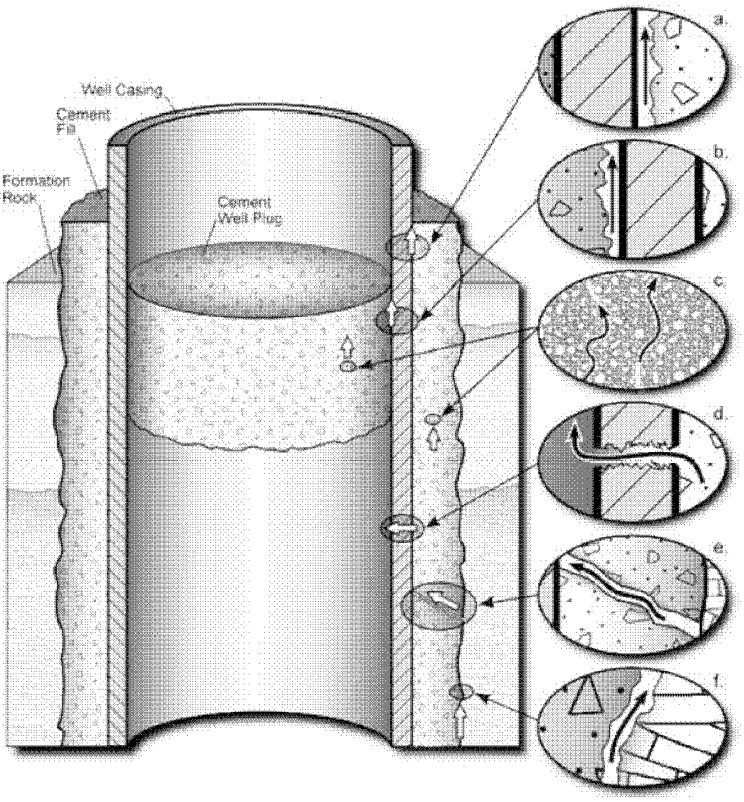
5.1.6 Well and Rock Integrity

During and after shale gas exploration and exploitation, fluids used in these processes (e.g. hydraulic fracturing fluid) and fluids naturally present in shale formations (e.g. production brine) can potentially migrate into water resource. Contaminant migration can occur through the wells if casing and/or cementing are imperfect (Section 5.1.6.1) and via rock faults and cracks (Section 5.1.6.2).

5.1.6.1 Well Casing and Cementing

Sources of Potential Impacts

During well construction, different types of casings cemented in place are installed in the borehole. These structures serve different purposes such as the isolation of the geological formations from gas (see Section 3.1.2). However, gas migration along the (active/inactive) wells can occur in various ways during or after construction (see Figure below) (Durand (2011a)):



a. Empty space between the casing and the cement fill caused by temperature and pressure cycles.

b. Empty space in contact with the cement well plug and the casing (cement well plug installed at the end of the exploitation process to close the shale gas well, thus preventing fluid migration).

c. Porosity and permeability of the cement well plug and cement fill.

d. Casing perforation due to corrosion.

e. Fissures and fractures in the well plug.

f. Empty space or fractures between the cement fill and the roc, and fractures in the roc.

Source: Celia, *et al.* (2004)

FIGURE 9: Potential Gas Migration Paths along a Well

There are various reasons why well cementing may be imperfect. Among these reasons, the circulation of cement is more difficult to accomplish in deep wells than in shallow wells and the cementing occurs in different stages which can result in a poor job or damages if not properly done (U.S. Department of Energy (2009)). Moreover, practices such as efficient borehole cleaning of drilling mud, a sufficient drilling job and casing centralization are necessary for a good zonal isolation. For example, if drilling mud stays in the borehole, sufficient bonding between cement and rock or casing is unlikely. Indeed, drilling mud is liquid and will form channels of communication between zones along the borehole or casing (Bellabarba*, et al.* (2008)).

In addition, leaks can occur along the casing of wells several years after production has ceased, even if the well has been plugged and abandoned. Different hypothesis are advanced such as channelling, poor cake removal, shrinkage, and high cement permeability. In view of Dusseault*, et al.* (2000), the most probable reason is cement shrinkage leading to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing.

Risk Probabilities

► In Alberta, 4.6% of the wells have leaks (316,000 wells analyzed) while in the Norwegian sector of the North Sea, the leakage concerns 13 to 19% of the production wells (less than 1,000 wells analyzed in two studies) (Nygaard (2010), Randhol and Carlsen (2008)). Further estimates from the Gulf of Mexico indicate that 43% of 6,692 offshore wells have sustained casing pressure, which is believed to be caused by gas flow through cement matrix (Bruffato*, et al.* (2003)). Bruffato*, et al.* (2003) also reports that by the time a well is 15 years old, there is a 50% probability that it will have sustained casing pressure.

► Browning and Smith (1993) have reported higher well failure rates for Class II injection wells. They studied the rates and reasons for failure with over 10,000 scheduled mechanical integrity tests (performed every 5 years) in different States (Louisiana, Michigan, Nebraska and Pennsylvania) over two 5-year cycles. They found failure rates ranging from 3 to 12% for scheduled mechanical integrity tests but reported that the actual rate of well failure was at least 50% greater (i.e. at least 4.5 to 18%).

► A report by the Underground Injection Practices Council (Underground Injection Practices Council (1987)) estimated a 2% leak rate into underground sources of drinking water for a Class I wastewater injection well. This estimation was based on 43 wells.

► In their paper, Rozell and Reaven (2011) estimated the probability of a well leaking to be 1/7,000 (0.15%) in one year. This probability was based on the facts that there were 52 isolated cases of methane migration in a five-year period ending in 2009 in

Pennsylvania counting approximately 71,000 active wells. Assuming a lifespan equivalent to 10 years, the well leaking risk would be 1 in 700 (1.5%).

► The U.S. Department of Energy (Ground Water Protection Council and ALL Consulting (2009)) reports the results of the American Petroleum Institute (Michie & Associates (1988)) that analyzed the level of corrosion that occurred in Class II injection wells in the 1980's. The analyses were performed in basins in which there was a possibility of casing corrosion. The American Petroleum Institute estimated that the probability that fluids injected at depth could impact an underground source of drinking water would be between one well in 200,000 and one well in 200,000,000.

Mitigation, Preventive Actions or Regulatory Actions

► The quality of the well construction is primordial in preventing fluid movement from deep zones to groundwater. One of the most critical factors during well construction is the proper sealing of annular spaces with cement, creating a hydraulic barrier to both vertical and horizontal fluid migration (U.S. Department of Energy (2009)).

In the United States, different tools exist to minimize the risk of cement and casing failures. The American Petroleum Institute develops and updates standards and 'Recommended Practices' for oil and gas exploration and production activities. It specifies the length, thickness, tensile strength and composition of casing as well as standards for cement types (U.S. Department of Energy (2009)).

Moreover, state oil and gas regulatory agencies often specify casing requirements in order to protect the groundwater resources (Ground Water Protection Council and ALL Consulting (2009)). For example, the Arkansas oil and gas commission requires minimum surface casing depths and minimum time required for cement to set before additional drilling (Arkansas Oil and Gas Commission (2009)). In 2010, the Environmental Quality Board of Pennsylvania approved a proposed set of regulatory improvements to make natural gas wells significantly safer by making them subject to more stringent construction standards (Commonwealth of Pennsylvania (2010)). The Department of Environmental Protection used the public's input to make the changes to the regulations, which further improved the well design requirements to prevent gas migration incidents. These changes include:

- A provision that requires operators to have a pressure barrier plan to minimize well control events;
- A provision that requires operators to condition the wellbore to ensure an adequate bond between the cement, casing and the formation;

- Provisions that require the use of centralizers to ensure casings are properly positioned in the wellbore;
- A provision that improves the quality of the cement placed in the casing that protects fresh groundwater.

In some US States, personnel can witness the running and cementing of casing strings or submit a completion report detailing the amounts and types of casing and cement used during the well construction in order to show evidence of proper well construction (U.S. Department of Energy (2009)). Moreover, to ensure the quality of the bonds between the casing, cement and rock, many states in the United States (e.g. Alaska, Michigan and Ohio) require operators to perform different checks. These checks may include acoustic logging (measure of the amplitude of a sonic signal that has traveled through a section of the casing) and hydraulic testing (internal pressure applied along the entire casing) (Bellabarba*, et al.* (2008), Ground Water Protection Council and ALL Consulting (2009)).

► After a well is no longer producing, operators must plug the well and reclaim the site in accordance to the state regulation in order to protect the ground and surface water as well as the soil. In the state of New York, for example, financial security to ensure funds for well plugging is required before the accordance of a permit to drill. This security must be maintained for the life of the well (NYSDEC (2011)).

Data Knowledge and Data Gaps

► There are many cases of well casing and cementing failures that induced gas migration in drinking water resources. For example, in 2007, a well that had been drilled in Bainbridge, Ohio, was not properly sealed with cement, allowing gas from a shale layer to travel through the annulus into an underground source of drinking water. The methane eventually built up until an explosion in a resident's basement alerted state officials to the problem (Zoback*, et al.* (2010)).

► In Pennsylvania, from 1992 to 2008, seven explosions occurred at operating wells due to gas migration resulting from problems with casings or the pressurization of the annulus (four cases) and from leaks or failures of the casing (three cases) (Michaels*, et al.* (2010)).

► The impacts of gas drilling operations and constructions are not limited to new or currently active gas wells. Many abandoned or legacy wells date from the early 1900s and some were completely abandoned without casing or plugging the boreholes; in many cases, nobody knows where these wells are located. The wells are the source of stray gas migration in drinking water wells as well as gas accumulation within or adjacent to structures. Concerning the drinking water contamination, remediation has included plugging or venting the wells (when located) and installing treatment systems on drinking water wells (Michaels, *et al.* (2010)); however problems persist in many cases. For example, a natural gas migration problem in Versailles has existed for many years as over 175 wells were drilled from 1919 through 1921 and a lot of them were abandoned without casing or plugging (DEP (2009)).

► The data concerning well integrity are scarce. Moreover, for a lot of accidents inducing the contamination of water resources, the causes of the accident are not established and could be linked to well casing and cementing defaults. Thus, there is a probable underestimation of the number of accidents related to well casing and cementing defaults.

5.1.6.2 Rock Integrity

Sources of Potential Impacts

Another source of potential water contamination is the presence of cracks caused by hydraulic fracturing in the rock. These cracks can provoke contaminant migration from the fractured zone to the aquifer. Moreover, contaminants can move between gas wells, fractured in proximity to one another (Parfitt (2010)) (see Section 5.1.2). The contaminants include hydraulic fracturing fluid, contaminants naturally occurring in formation water and natural gas.

Risk Probabilities

There are different theories concerning the probabilities that contaminants can reach aquifers through cracks caused by hydraulic fracturing.

► On one hand, it is stated that the distance between the fractured zone and the aquifer is large enough to prevent the propagation of the cracks to the aquifers. For example, in Quebec, the Ministry of Natural Resources and Wildlife indicates that the Utica Shale is between 600 m and 3,000 m deep whereas aquifers are generally closed to the surface (i.e. in the first 100 m); the Utica Shale thickness varies between 100-250 m and 750 m, and shale gas exploitation, if any, should occur between 1,000 and 2,500 m deep (Ministère des Ressources Naturelles et de la Faune (2010)).

The Ground Water Protection Council and ALL Consulting (2009) also indicates that ground water is protected during the shale gas fracturing process by the thousands of feet of rock present between the fractured zone and the aquifers; most shale gas wells in the United States (except the Antrim and New Albany Shales) are expected to be drilled at depths greater than 900 m (3,000 feet) below the land surface. The thousands of feet of rocks thus act as seals holding the gas in the target formation. To support their assumption, the Ground Water Protection Council reports that a fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and therefore could never be trapped and produced in usable quantities.

It is also stated that operators have strong economic incentives to ensure that cracks do not rise beyond the target shale formation and into adjacent rock strata. Thus, some techniques such as modelling, microseismic fracture mapping and tilt-meters are used to accomplish effective, economic and successful fracture stimulations. For example, the modelling programs allow geologists and operators to modify fracture design and evaluate the height, length, and orientation of potential fracture developments. They also allow to define the success and orientation of the fractures created (Ground Water Protection Council and ALL Consulting (2009)).

Extensive mapping of hydraulic fracture geometry has been performed using microseismic and tiltmeter technologies in the Barnett (Worth Basin in Texas) and Marcellus Shales (Appalachian Basin) (Fisher (2010)). The results indicate that the shallowest fracture tops are ± 1,400 m (4,500 feet) below the land surface whereas the aquifers are ± 450 m (1,500 feet). Moreover, the vertical fractures extensions can reach 550 m (1,800 feet) in the two shales.

However, it seems that for approximately 75,000 hydraulic fracturing stages conducted in the United States in 2009, only 3% were seismically monitored (Zoback, *et al.* (2010)). Moreover, monitoring the hydraulic fracturing process does not control it.

► On the other hand, some experts such as Marc Durand (Durand (2011a)), an Engineer- Geologist and Anthony Ingraffea (Parfitt (2010)), a professor of Civil and Environmental Engineering at Cornell University and a member of the Cornell Fracture Group, report that it is not right to say that thousands of feet of impermeable rock between where the shale formation is fracked and the point higher up prevent contaminant migration.

Shale rock has existing natural fractures (cracks) before the fracking process begins. These cracks are what companies in the hydraulic fracturing business look for as less energy is needed to break them. For example, Ingraffea reports that much of the Marcellus Shale underlying portions of New York, Pennsylvania and West Virginia is composed of interlocking, blocky rock, with joints running vertically. The fracturing process, in increasing the pressure in the rock formation for a short period of time, could open up a pathway upward to freshwater. This depends on different factors such as the density of the rock as well as pre-existing faults and fractures.

Marc Durand indicates in his personal webpage (Durand (2011b)) that the hydraulic fracturing process is uncontrolled. For example, he reports the case of a well (Champlain well 1H) drilled closed to Trois-Rivières (Quebec) by the company Forest Oil Ltd. The horizontal portion of this well was drilled 35 m (115 feet) higher than expected (600 m below the land surface and 500 m below the aquifer). When citing the results of Fisher (2010), he reports that the vertical fracture extensions were initially established to be less than 120 m (400 feet) but reached 550 m (1,800 feet). Moreover, he indicates that the microseismic technology does not take into consideration the presence of natural faults and cracks that open in traction under the hydraulic pressure and that can meet the aquifer.

► Rozell and Reaven (2011), using probability bounds analyses, assessed the likelihood of water contamination from leaks through fractured rocks. Results indicated that the risk of water contamination by this pathway was negligible compared to other pathways (e.g. wastewater disposal).

Mitigation, Preventive Actions or Regulatory Actions

Various techniques (i.e. modelling, microseismic fracture mapping and tilt-meters) can be used to accomplish fracture stimulations and ensure that the cracks will not propagate beyond the target formation into the aquifer (Ground Water Protection Council and ALL Consulting (2009)).

Data Knowledge and Data Gaps

► The time for fluid to migrate through the fractures is poorly understood. However, it seems likely that drinking water resources would be affected years or decades after the well construction. The fracture behaviours are also largely unknown.

5.1.7 Well Blowout and Stormwater Runoff

Sources of potential impacts

During all the phases of shale gas development (initial land clearing, drilling, well testing, well completion, production or workover activities, and reclamation), different accidents can happen and impact the water resources. These accidents include blowouts and stormwater runoffs.

A blowout is an uncontrolled release of crude oil or natural gas from a well after pressure control systems have failed (Nguyen (2010)).

Stormwater, a result of rainfall or snowmelt, is the source of water for lakes, streams and aquifers. It is thus a valuable resource. However, when it interacts with developed areas (i.e. buildings, parking areas, roads), it is a pathway for contaminants to be conveyed from the land surface to streams, lakes and groundwater (NYSDEC (2011)). On a shale gas exploitation site, stormwater can convey different contaminants off-site and contaminate the surface and ground water. For example:

- Initial land clearing for access roads, equipment and well pads exposes soil to erosion and more rapid runoff. Thus, equipment using hydraulic fluid, fuel and lubricating fluids as well as equipment and spilled materials (i.e. additive chemicals and fuel), not properly contained, can be sources of contaminants;

- Steep access roads, well pads on hill slopes and well pads constructed by cut-and-fill operations pose particular challenges, especially if there is an on-site drilling pit;

- A production site, including access roads, can be a source of stormwater runoff impacts due to its hydrologic characteristics differing from the pre-developed condition. For example, stormwater runoff and high sediment load can carry excess levels of nutrient phosphorus and nitrogen that is a major cause of algae bloom, low dissolved oxygen and other water-quality impairments.

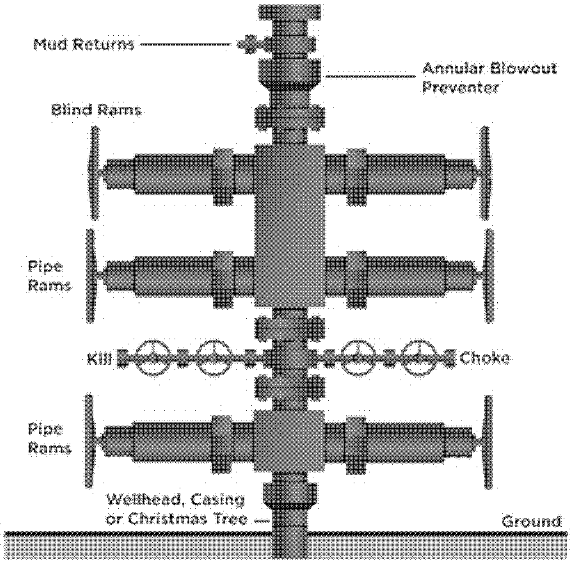
Risk Probabilities

Blowout can occur if the existing pressure in the drilled zone is superior to the pressure exerted by the drilling mud (MDDEP (2010)). Accidents are mostly related to incorrect handling, either by untrained personnel or through incorrect behaviour (Lechtenböhmer*, et al.* (2011)).

All phases of natural gas well development have the potential to cause water resource impacts during rain and snow melt events if stormwater is not properly managed (NYSDEC (2011)).

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, some States require blowout preventers for all wells. A blowout preventer (see Figure below) is a large valve at the top of a well that can be closed immediately if warranted by a change in pressure. For example, in Colorado, blowout prevention equipment shall be installed on any well expected to flow and shall be operated in accordance with the Colorado Oil and Gas Conservation Commission regulations (Colorado Oil and Gas Conservation Commission (2009)).



Source: http://www.askchesapeake.com/Barnett-Shale/Drilling-and-Production/Pages/Blowout-Preventer.aspx

FIGURE 10: Blowout Preventer

► In the United States, the Clean Water Act states that operators of 'Coal and mineral mining and oil and gas exploration and processing' have to develop a Stormwater Pollution Prevention Plan (SWPPP) that complies with a National Pollutant Discharge Elimination System (NPDES) industrial stormwater permit. This permit is issued by the State or the US EPA (US EPA (2009)).

A SWPPP is a site-specific written document used for controlling runoff and pollutants from a site during and after construction activities. Failing to develop a SWPPP can result in enforcement action by the US EPA or a State (US EPA (2009)). The objectives of a SWPPP are to:

- Identify potential sources of stormwater pollution at the industrial facility;
- Describe stormwater control measures that are used to reduce or eliminate pollutants in stormwater discharges from the industrial facility;
- Identify procedures the operator will use to comply with the terms and conditions of the EPA's 2008 Multi-Sector General Permit (i.e permit applying to five states: Alaska, Idaho, New Mexico, Massachusetts and New Hampshire) or a state general industrial stormwater permit.

For example, potential adverse impacts can be avoided or minimized by planning development fitting site characteristics (i.e. avoiding steep slopes and maintaining sufficient separation from environmentally sensitive features, such as streams and wetlands), diverting uncontaminated water away from excavated or disturbed areas, rapidly stabilizing disturbed areas, following equipment maintenance and rapid spill cleanup (NYSDEC (2011)).

► In Europe, strict regulations and monitoring are recommended to minimize the risks of blowout and accidents by collecting the statistics about accident at the European level and by analyzing the causes and consequences of the accidents. Companies with negative track records could be excluded from further exploration or production rights (Lechtenböhmer, *et al.* (2011)).

Data Knowledge and Data Gaps

► Blowout preventers are not failsafe. Indeed, numerous well blowouts were reported in the United States even if blowout preventers were installed. For example, from 1997 to 2006, there were 14 blowouts in Wise County wells and 4 in Denton County (Barnett Shale) (Nguyen (2010)). Recently, there had been blowouts in Pennsylvania and West Virginia (Marcellus Shale) during drilling operations. In 2010, a well in Clearfield County, Pennsylvania suffered a leak and expelled approximately 35,000 gallons of gas as well as wastewater into the air over a 16-hour period until it was capped the following day. The well suffered a faulty blowout preventer. A couple of days later, another blowout occurred in West Virginia when drillers encountered an unexpected pocket of methane in an abandoned coal mine approximately 300 m (1,000 feet) below the surface, and a blowout preventer had not yet been installed (Zoback, *et al.* (2010)).

5.1.8 Applicability to the Canadian Situation

The probability of surface and ground water contamination related to shale gas exploration and exploitation activities may vary on a case-by-case basis depending on different parameters such as the laws and regulations applying in the province of concern, the proximity of the depth of the aquifer, the depth of the horizontal well, the practices used during the shale gas operations. However, although each resource play, each project and each well presents their own particularities, several determinant parameters are common at a global scale. For instance:

- Similar exploitation methods (e.g. hydraulic fracturing) involving similar types of fluids (e.g. drilling mud and hydraulic fracturing fluid) may be used;
- Natural cracks and fractures are present in any shale;
- Poor practices and accidents may occur in spite of the regulation;
- Accidents similar to those reported in the United States have been documented in Canada.

Consequently, it is reasonable to anticipate that the risks of water contamination and the related health hazards reported in the United States may be similar in Canada if the practices (e.g. method of extraction) are comparable.

5.1.9 Summary of Health Hazards

All processes, from exploration to shale gas extraction including transport and wastewater treatment, are potential sources of contamination of the water resources. A summary Table presenting the potential sources of contamination, the risk probabilities and the mitigation, preventive actions and regulatory actions is provided in Appendix D.

Shale gas exploitation generates a large variety of potential contaminants, including inorganic compounds (e.g. metals and salts), radioelements (e.g. radioactive isotopes of lead, radon and cesium) and organic chemicals. These contaminants can have various origins:

- Some are naturally present underground (e.g. some metals and radioelements);

- Some are intentionally added during the processes to facilitate drilling or for hydraulic fracturing (organic and inorganic additives);

- Some may be formed due to the reactions between fracturing chemicals or to the reaction between fracturing chemicals and the naturally present compounds (these reaction products have not been characterized to date).

The quantification of the health impacts posed by all of these chemicals was not part of this mandate. However, the reviews available indicate that more than 750 compounds can be used in the hydraulic fracturing fluid; benzene and naphthalene, for example, are known or possible carcinogens to humans. In addition, 25% to 86% of the chemicals present in the hydraulic fracturing fluid are known to produce acute and/or chronic health effects such as irritation (86%), effects on the immune system (40%), endocrine disruption (36%) and cancer (26%). The presence of carcinogenic chemicals is of particular concern to human health since for such compounds, there is no safe exposure (it is generally assumed that any exposure may lead to the development of tumors).

Although quantitative data are lacking, the qualitative data available indicate that potential contamination of water related to the shale gas industry may present hazard to the public health, especially for local population. Any step of shale gas exploration/exploitation may represent a potential source of water contamination, and it appears that wastewater treatment/disposal is among the most important sources of risk. However, the risks related to hydraulic fracturing itself (creation of multiple cracks underground) and injection of chemicals at long-term is unknown. Moreover, there is a possibility of groundwater contamination after several years or decades.

A review of the large quantity of information available relative to the events of incidents/accidents of concern for water contamination in the United States (where shale gas has been exploited for more than 20 years) revealed that even if the regulations, standards and practices are in place, water contamination was reported in many cases. Although the number of cases may appear to be low in regards to the number of wells, it must be kept in mind that contamination cases were usually reported because of claims from citizens or accidents (e.g. explosions due to the presence of methane) and that, to date, there is almost no monitoring of the ground water quality before and after the well installation, use and closure. It is thus probable that the number of reported cases is highly underestimated compared to the actual number of groundwater contamination cases. In addition, it must be noted that due to the depth of the wells and to the slow migration of gases and fluids in some geological formations, it may be expected that contamination of the upper groundwater tables may happen after several years or decades. The impact of such a contamination at a large scale would be a major hazard to the drinking water resource.

5.2 Air

The available information related to the potential impacts of shale gas exploration/exploitation indicates that these processes result in the emission of numerous air pollutants originating from the shale gas resource itself (e.g. methane) and from the diesel engines, tanks and equipment used on-site (e.g. nitrogen oxide, particulate matter, sulphur oxide and volatile organic compounds).

The potential sources of emissions are illustrated in Figure 11. Indirect sources (1 to 4) are present at each phase of shale gas exploration and exploitation. Direct sources (5 to 6) are related to shale gas production. Information relative to each of these sources of potential air contamination is presented in the following subsections; Sections 5.2.1 to 5.2.4 address the hazards related to the indirect sources whereas Sections 5.2.5 and 5.2.6 address the hazards related to the direct sources.

In addition to these sources of air contamination, indoor air quality may also be affected by the use of contaminated drinking water (through volatilisation into the building). The sources of surface/ground water contamination were described in the preceding Section (Section 5.1.).

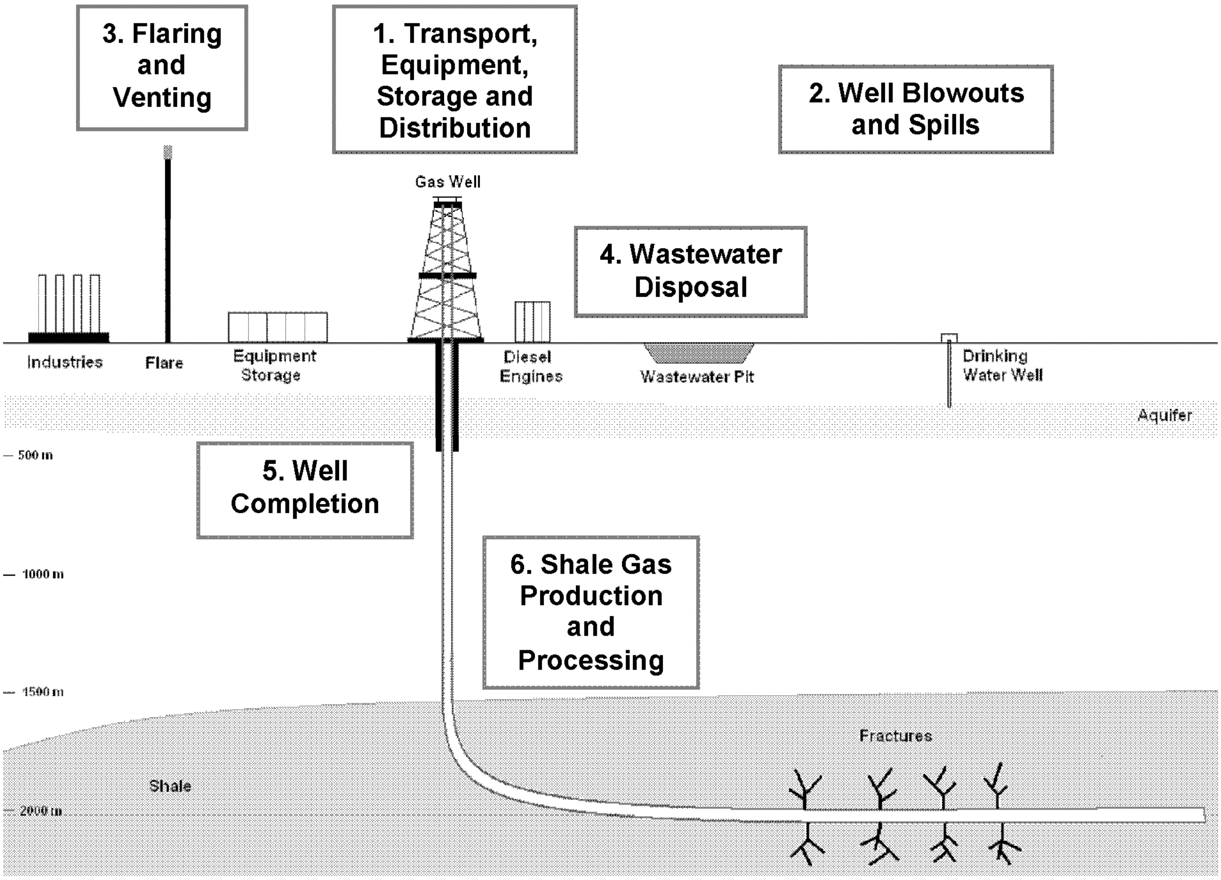


Diagram not to scale

Note: Direct sources of potential impact are in red; indirect sources of potential impact are in green.

FIGURE 11: Overview of Potential Activities that can Impact Air Quality

5.2.1 Transport, Equipment, Storage and Distribution

Sources of Potential Impacts

Fugitive shale gas emissions can occur during gas transport, storage and distribution. It should be noted that shale gas composition varies from one area to another, from one formation to another and even within the same formation (Bullin and Krouskop (2009)). Methane (CH_4) is the main component of shale gas, usually accounting for 70-90% of the total volume produced. When shale gas is thermally mature, it consists primarily of methane and is called dry gas. Wet gas, which is less thermally mature, may also contain heavier hydrocarbons (such as ethane, propane and butane). Moreover, diluents and contaminants/impurities naturally present such as water, hydrogen sulphide (H_2S), carbon dioxide (CO_2) and nitrogen (N_2) can also be found in shale gas (see Table 11). Thus, fugitive shale gas emissions primarily contain methane but can also contain various hydrocarbons as well as impurities. When shale gas originates from shales containing radioactive components (NORMs), such as uranium or thorium and their daughter products (radium-226 and radium-228), radon gas (a radium daughter) may also be found in shale gas (Reskinoff (2012)).

In addition, complex mixtures of pollutants related to equipment and operations (transport, storage and distribution) are emitted during all shale gas exploration and exploitation phases. These pollutants include:

- Nitrogen oxides (NOx);
- Particulate matter (PM);
- Sulphur oxide (SOx);
- Volatile organic compounds (VOCs), including benzene;
- Carbon monoxide (CO).

The principal sources of NOx, SOx, CO and fine PM (<2.5 µm or $PM_{2.5}$) are vehicles and engines fuelled by diesel and used for shale gas exploration, extraction and processing (e.g. compressor engines, drilling rigs, pumps and trucks). These pollutants result from the fossil fuel burned to provide power to the machinery (Brisson*, et al.* (2010)).

Larger particles are also emitted during shale gas operations. The principal sources of these particles (>2.5 µm) are the dust or soil entering the air pad construction and traffic on access roads (Ground Water Protection Council and ALL Consulting (2009)).

VOCs are organic compounds containing one or more carbon atoms that have high vapour pressures and therefore evaporate readily to the atmosphere. There are literally thousands of compounds that meet this definition, but most programs (not identified) focus on the 50 to 150 most abundant compounds containing 2 to 12 carbon atoms. VOCs do not include photochemically non-reactive compounds (e.g. methane, ethane) and the chlorofluorocarbons (Environment Canada (2010)). VOCs can be emitted during shale gas operations. For example, the equipment such as separators, condensers and compressors can leak, causing these VOCs to enter the air (Volz*, et al.* (2010)).

Moreover, some of the airborne pollutants, like VOCs, can react with sunlight to create secondary pollutants such as ozone (O_3).

Risk Probabilities

Air pollutants are emitted during all shale gas exploration/exploitation processes as vehicles and engines are always in use on the well pad. Thus, air quality may decrease in the areas where shale gas operations occur. High levels of contaminants have been reported in several locations (see 'Data knowledge and data gaps' below).

There is also a large quantity of gas (mainly methane) that can be emitted in the air due to leaks during its transport, storage and distribution. Although large quantities of methane can be emitted, it is not a public health issue. Indeed, methane is an inert gas acting like an asphyxiant. It does not lead to other physiological effects even if it is present in high concentrations (1%) in the air (Clayton and Clayton (1993)). However, like VOCs, methane is an ozone precursor.

According to the Railroad Commission of Texas, the presence of NORMs in shale gas is generally not a problem because the levels are typically low unless it becomes concentrated in some manner (e.g. through temperature and pressure changes or during gas processing activities) (Railroad Commission of Texas (date unknown)).

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, the US EPA sets standards (e.g. New Source Performance Standard (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPs)), monitors the ambient air across the Country and has active enforcement programs (e.g. Prevention of Significant Deterioration of Air Quality (PSD), Nonattainment New Source Review (NNSR)) to control air emissions from all sources, such as those from the shale gas industry (NYSDEC (2011)).

Moreover, several voluntary governmental programs have been established to encompass avoidance, minimization, and mitigation strategies applicable to exploration and production activities. An example of a voluntary program is the Natural Gas STAR program which is a partnership between the US EPA and the natural gas industry. The primary goals of the program are to promote technology transfer and implement cost-effective best management practices while reducing methane emissions (see Section 5.2.3 for some examples of technologies) (Ground Water Protection Council and ALL Consulting (2009)).

In July 2011, the US EPA proposed a number of regulatory requirements to reduce air emissions from the oil and gas industry. The new standards were proposed for several processes that have not previously been subject to federal regulation, such as well completions at new hydraulically fractured gas wells and at existing gas wells that are re-fractured. The requirements include the reduction of VOCs through the use of reduced emission completions (RECs), which simultaneously reduce VOCs and methane emissions. These rules are expected to take effect in April 2012 (ARI (2012)).

Several states, such as Colorado and New York, have also adopted VOC regulations including requirements such as emissions reductions, sitting stipulations (distances from buildings, and VOC capture requirements. Moreover, municipalities, such as Fort Worth, have implemented air emission controls including VOC capture requirements, reduced emission stipulations, and exhaust mufflers (Energy Institute (2012)).

► In Canada, provincial governments have the primary responsibility for many aspects of air pollution control. However, federal actions are integrated with those of the provinces. The Canadian Environmental Protection Act (CEPA) is the principal Act for the regulation of environmental contaminants. Under the CEPA, the federal government can assess air pollutants and control their impact through the setting of National Ambient Air Quality Objectives (NAAQOs) and Canada-Wide Standards (CWS).

► In Europe, Lechtenböhmer, *et al.* (2011) recommend that emissions during development should be restricted and monitored as well as emissions from gas processing and transportation when many gathering lines add up.

Data Knowledge and Data Gaps

► Shale gas composition varies from one area to another, from one formation to another and even within the same formation. Shale gas primarily contains methane. However, heavier hydrocarbons (such as ethane, propane and butane) as well as diluents and contaminants/impurities such as water, hydrogen sulphide (H_2S), carbon dioxide (CO_2) and nitrogen (N_2) can also be found in shale gas (Bullin and Krouskop (2009)). Table 11 presents some examples of the major components present in the shale gas before its processing. These data were taken from two shale plays, the Marcellus and the Barnett plays.

TABLE 11: Examples of Shale Gas Composition in the Marcellus and Barnett Shales (United States)

Component (Volume %)	Marcellus Shale (Site 1)	Marcellus Shale (Site 2)	Marcellus Shale (Site 3)	Barnet Shale (Site 1)	Barnet Shale (Site 2)	Barnet Shale (Site 3)
Methane	79.4	95.5	83.8	80.3	81.2	93.7
Ethane	16.1	3.0	12.0	81	11.8	2.6
Propane	4.0	1.0	3.0	2.3	5.2	0.0
Carbon Dioxide	0.1	0.3	0.9	1.4	0.3	2.7
Nitrogen	0.4	0.2	0.3	7.9	1.5	1.0
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0

Based on: Bullin and Krouskop (2009)

Howarth, *et al.* (2011) provided the first comprehensive study on the greenhouse gas footprint of shale gas. They estimated that 1.4% to 3.6% of shale gas (in which methane is the major component) leaks during transmission, storage and distribution. The lower limit was from Lelieveld, *et al.* (2005) that took measurements in Russia along the world's largest gas-transport system and found that methane leakage was of 1.4% in the region. The upper limit (3.6%) was the mean between 2000 and 2007 of Texas data for missing and unaccounted gas (i.e. difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers) as reported by Percival (2010).

It should be noted that the Howarth, *et al.* (2011) publication was challenged by Cathles, *et al.* (2011) (see Section 5.2.7 for more details). Moreover, since the Howarth, *et al.* publication in April 2011, there have been many other studies on methane emissions from shale gas operations. Thus, other estimates of shale gas leakage exist. For example, Burnham, *et al.* (2011) estimated that 0.67% of the shale gas produced is lost during transmission and distribution (leakage and venting). This estimate was based on EPA data.

► When shale gas leaks occur (during transmission, storage and distribution), methane as well as other shale gas components can be emitted in the air. For example, in 2009, a pipeline rupture in British Columbia occurred and induced a leakage of natural gas associated with hydrogen sulphide(H_2S), a toxic gas (no health data related to this incident was available) (Brisson, *et al.* (2010)).

► Shale gas originating from radioactive shales, such as the Marcellus Shale, may contain radon gas, a radium daughter (Reskinoff (2012)).

For example, Reskinoff (2012) calculated the wellhead concentrations of radon in shale gas from the Marcellus Shale. He found that the wellhead concentrations in the Marcellus Shale were up to 70 times higher than the average concentration in natural gas throughout the United States. The range of radon concentrations were between 36.9 and 2,576 pCi/L.

Radon present in shale gas can be transported through natural gas pipelines and can also become concentrated on equipment (e.g. tanks and pits). If shale gas is directly distributed to homes and centers after its production, radon can also be distributed to these homes and centers as it has a half-life of 3.8 days. It should be noted that radon exposure can cause lung cancer (Reskinoff (2012)).

► A complex mixture of pollutants is emitted during all shale gas exploration and exploitation phases. These pollutants (SO_2, NO_x, PM, CO and VOCs) originate from various sources such as equipment as well as vehicles and engines fuelled with diesel. For example, Lechtenböhmer*, et al.* (2011) reported estimates of air emission of these pollutants from stationary diesel engines used for drilling, hydraulic fracturing and well completion, based on the use of the Global Emission Model for Integrated Systems (GEMIS) (Table 12).

TABLE 12: Typical Specific Emission Rates of Air Pollutants from Stationary Diesel Engines Used for Drilling, Hydraulic Fracturing and Completion

AIR POLLUTANT	EMISSIONS PER ENGINE MECHANICAL OUTPUT (g/kWh)	EMISSIONS PER ENGINE FUEL INPUT (g/kWh)	EMISSIONS PER NATURAL GAS THROUGHPUT OF WELL (g/kWh)
SO_2	0.767	0.253	0.004
NOx	10.568	3.487	0.059
PM	0.881	0.291	0.005
CO	2.290	0.756	0.013
VOCs (except methane)	0.033	0.011	0.000

Source: Lechtenböhmer, *et al.* (2011)

► The impact of shale gas development on the air was evaluated in the Fort Worth area where shale gas drilling has been going on since the late 1990s and where the Texas Commission on Environmental Quality (TCEQ) has established a large-scale monitoring program. Monitoring study results for this area are presented below.

It should be kept in mind that the following studies were performed over short periods and that, in some cases, the authors may have inadequately compared short-term air samples to long-term air monitoring comparison values.

The first study conducted in the Fort Worth area was commissioned by the town of Dish (Texas) (Wolf Eagle Environmental (2009), TCEQ (2009a)). This study was undertaken because residents complained of illnesses as well as of odours and noises coming from gas well pads and engines. Wolf Eagle Environmental collected six 24-hour field samples in the town (downwind of compressor stations) on August 17 and 18, 2009 and analyzed these samples for 40 target VOCs as well as tentatively identified compounds, fixed gases, and NOx. A Gaussian dispersion model was used to predict pollutant concentrations. A 1-hour averaging time was selected for short-term concentrations to facilitate comparisons with TCEQ short-term Effects Screening Levels (ESLs) that are based on a 1-hour averaging time. An annual averaging time (based on 2 days of sampling at different locations) was selected for long-term concentrations to facilitate comparisons with the TCEQ long-term ESLs that are based on annual averaging times. The study reported that both short- and long-term ESLs were exceeded for several pollutants (benzene, carbon disulfide, carbonyl sulfide, dimethyl disulfide, styrene, toluene and 1,2,4-trimethylbenzene), with the exception of long-term ESLs for styrene and toluene (see Table below).

TABLE 13: Modeled Maximum 1-hour and Annual Average Concentrations in the Fort Worth Area (Texas) Compared with TCEQ ESLs

Air Pollutant	MAX. 1-HOUR AVERAGE MODELED CONCENTRATIONS (µg/m^3)	TCEQ 1-HOUR ESL (µg/m^3)	MAX. ANNUAL AVERAGE MODELED CONCENTRATIONS (µg/m^3)	TCEQ ANNUAL ESL (µg/m^3)
Benzene	472.8	170	39.8	4.5
Carbon disulfide	35,942	30	3,025	3
Carbonyl sulfide	10,404	135	875.7	2.6
Dimethyl disulfide	7,661	20	644.8	2
Styrene	454.0	110	38.2	140
Toluene	2,081	640	175.1	1,200
1,2,4-Trimethylbenzene	2,743	1,250	230.9	125

Source: Wolf Eagle Environmental (2009)

On March 2, 2010, the environmental group Earthworks also performed a short-term emissions study in Dish and detected 15 VOCs in the air, associated with a methane plume. Earthworks reported high levels of carbon disulfide (16.9 ppb) and dimethyl disulfide (11.0 ppb) exceeding both short-term (10 and 5 ppb, respectively) and long-term (1 and 0.5 ppb, respectively) ESLs; methylethyl disulfide concentration (4.70 ppb) also exceeded long-term ESL (0.5 ppb). Benzene concentrations (0.41 ppb) were found to be below short- (54 ppb) and long-term (1.4 ppb) ESLs (Earthworks (2010)).

In December 2009, the TCEQ carried out an intensive three day survey of air emissions (testing for 22 VOCs such as benzene) associated with approximately 126 gas production sites in the City of Fort Worth. Ethane, propane and n-hexane were the only compounds detected in this study and their concentrations did not exceed TCEQ short and long-term ESLs (TCEQ (2009b)). However, it seems that the results from the field and laboratory analysis were inaccurate and not designed to detect the presence of certain compounds at low levels. For example, the detection limit for benzene (3.0 ppb) was above the long-term ESL (1.4 ppb) (TCEQ (2010)).

In June 2010, another report on ambient air quality in the Fort Worth Arlington area was released by Titan Engineering Inc. Samples were collected at 10 natural gas sites in the cities of Arlington and Fort Worth including two compressor stations and eight completed well sites (study performed during the June 1-15, 2010 in inactive drilling sites). A total of 93 VOC samples including both 1-hour samples (48) and 24-hour samples (45), 7 formaldehyde 1-hour samples and 21 sulphur compounds 1-hour samples were collected. The study found benzene concentrations below the short-term ESL (180 ppb) for all samples. However, two samples collected downwind from the Encana Mercer Ranch facility (1-hour sample: 3.15 ppb and 24-hour sample: 1.96 ppb) exceeded TCEQ's long-term ESL (1.4 ppb). Formaldehyde levels measured around the Quicksilver Lake Arlington site exceeded the short-term ESL (41 ppb) while the reported levels of H_2S (between 5 and 29 ppb) were below the state standard of 80 ppb (TCEQ (2011)).

Zielinska, *et al.* (2010) performed a pilot monitoring study over a 4 week period (April-May) in the Shale Creek Area which is a very active area of shale gas production located north of Fort Worth. Source apportionment performed by Chemical Mass Balance indicated that for the sum of measured VOCs (13 species), the dominant source category was motor vehicle emissions (46 ± 14%). Combined natural gas and condensate tank emissions were estimated to contribute about the same amount (43 ± 5%) whereas small gasoline engines accounted for 17 ± 7% of the total. Modelling studies also reported that 70-80% of benzene was attributed to fugitive emissions of natural gas whereas other VOCs were from motor emissions.

► Unconventional gas exploitation has been associated with the production of ground level ozone (O_3). For example, in a rural Wyoming community within proximity of gas exploitation sites, ozone concentrations higher than those recorded in Houston and Los Angeles were detected (Urbina (2011)). During the summer of 2009, the natural gas industry in the Barnett Shale area produced more smog-forming emissions than the emissions produced by all motor vehicles in the Dallas-Fort Worth metropolitan area (Armendariz (2009)).

Exposure to ground level ozone has been linked to respiratory effects (e.g. irritation, coughing, wheezing, breathing difficulties, inflammation, increased susceptibility to respiratory illnesses and lung damage) (Volz*, et al.* (2010)).

► Short-term daily exposure to primary air contaminants (i.e. NOx, SOx and PM) has been associated with respiratory symptoms, a decrease of the pulmonary capacity, an increase of hospitalizations and an increase of premature mortality. The daily exposure to $PM_{2,5}$ has also been associated to an alteration of the cardiac rhythm and to an increase in mortality rates associated with cardiovascular problems. Concerning long-term effects, the exposure to $PM_{2,5}$ has been related to an alteration of pulmonary development as well as asthma in children, and to an increased mortality rate due to cardio-pulmonary problems and cancers (Brisson*, et al.* (2010)).

The effects of VOCs on human health have only been documented in occupational settings and at higher concentrations than those reported in the ambient air. However, toxicological data obtained in animals are also available. Most VOCs induce a variety of effects and it seems that short- or long-term exposures to these compounds have been linked to behavioural and cognitive effects in humans (Brisson*, et al.* (2010)). Moreover, some VOCs have a carcinogenic potential. For example, benzene is a known carcinogen and ethylbenzene is a possible human carcinogen (IARC (1982), IARC (2000)).

► The risks to human health will depend on both the impacts of shale gas exploration and exploitation, and on the levels of human exposure. To adequately characterize the population health risks associated with air emissions of contaminants from shale gas exploration and exploitation, site-specific data should be documented:

- Number and type of mechanical equipment used as well as their source of energy (e.g. natural gas, diesel);
- Duration of the mechanical equipment use;
- Emission rates from the mechanical equipment;
- Data on parameters influencing atmospheric dispersion of airborne contaminants such as the distance between the population and the emission sources, the topography or meteorological data;
- Characteristics of the population.

All these parameters have to be evaluated on a case-by-case basis because they are highly variable between shale gas projects.

5.2.2 Well Blowouts and Spills

Sources of Potential Impacts

During all phases of shale gas development, different accidents can happen and impact the air. These accidents include blowouts and spills.

The fluids and contaminants that can be released in the environment and that can volatilize in the air include hydrocarbons, products used in the maintenance of mechanical equipment, drilling mud and hydraulic fracturing additives, as well as radioactive elements present in the production brine (see Section 5.1).

Risk Probabilities

As already indicated in Section 5.1, the oil and gas industry operates on a large scale and the probability of accidents is always present.

Mitigation, Preventive Actions or Regulatory Actions

► As previously stated in Section 5.1, in the United States, regulations impose a variety of requirements to prevent spills and releases from occurring. However, it appears that the accidents are mostly related to incorrect handling, either by untrained personnel or through incorrect behaviour (Lechtenböhmer*, et al.* (2011)). Moreover, as the gas industry expands and operates on a larger scale, spills are inevitable (Colorado's Department of Natural Resources (2011)).

► In Europe, strict regulations and monitoring are recommended to minimize the risks of accidents by collecting accident statistics at the European level and by analyzing the causes and consequences of these accidents. Companies with negative track records could be excluded from further exploration or production rights (Lechtenböhmer*, et al.* (2011)).

Data Knowledge and Data Gaps

► In the United States, several blowouts and spills have occurred. For example, on April 1, 2010, both a tank and an open pit used to store hydraulic fracturing fluid caught fire at an Atlas well pad. The flames were at least 100 feet (33 m) high and 50 feet (15 m) wide and led to contaminant emissions (Lechtenböhmer*, et al.* (2011)) (see Section 5.1.5 and 5.1.7 for more examples).

5.2.3 Flaring and Venting

Sources of Potential Impacts

Throughout the different shale gas production stages, operators vent or flare some shale gas (i.e. emissions occur during drilling as 'shallow' gas is vented). This may be intermittent, for example, during well maintenance or when equipment failure occurs. It may also be operational in nature as shale gas is continuously released from pneumatic valves and compressors.

Usually, flaring emits CO_2 whereas venting primarily releases methane (methane generally represents between 70% and 90% of the shale gas composition) and other shale gas constituents (e.g. heavier hydrocarbons, CO_2, H_2S and N_2) (see Section 5.2.1). Natural gas flaring also produces several other chemicals including polycyclic aromatic hydrocarbons (PAHs), BTEX and other VOCs (e.g. formaldehyde, acetaldehyde, hexane, acrolein and propylene). VOCs and NOx, present in vented gas, are the precursors of ozone (GAO (2010), Witter*, et al.* (2008)).

Radon gas may also be found in shale gas (as well as in natural gas from conventional exploitation activities) and may be emitted during venting and flaring. As radon is an inert gas, it is emitted into the atmosphere along with CO_2 when shale gas is flared (Black and Cory (2011)).

Risk Probabilities

Venting and flaring duration and frequency vary depending on the technologies and practices used on the well pad to limit air contamination. However, venting and flaring always occur during shale gas operations and therefore result in the emission of different contaminants (e.g. methane, CO_2, PAHs and VOCs).

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, Natural Gas STAR is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt proven, cost-effective technologies and practices that improve operational efficiency and reduce methane emissions (US EPA (2011)). This Program has identified many technologies and practices that can reduce methane emissions in the air during gas production and processing, gas storage, gas transmission and gas distribution. For example (see EPA's Natural Gas STAR Web site for more details and examples):

- During gas production and processing, the program recommends to perform 'reduced emissions completions' (see also Section 5.2.4), to install plunger lifts to facilitate liquid unloading, to perform aerial leak detection using laser/and or infrared technology, and to eliminate unnecessary equipment and/or systems;

- During gas storage, the program recommends, for example, to reduce methane emissions from compressor rod packing systems;
- During gas transmission, the program recommends, for example, the installation of vapour recovery units that capture gas vapours from storage tanks and the use of fixed/portable compressors for pipeline pump down;
- During gas distribution, the program recommends, for example, the replacement of pneumatic devices that release gas at a high rate, the survey and repair of leaks.

► No information was found regarding specific actions to control or reduce emissions of contaminants other than methane. However, the practices and methodologies reported above, by decreasing methane emissions, also reduce the emissions of contaminants present in the shale gas vented and flared.

► In Canada, specific flaring and venting requirements exist. They vary depending on the jurisdiction. For example, in British Columbia, venting is not an acceptable alternative to flaring. Indeed, if gas is not conserved and gas volumes are sufficient to sustain stable combustion, the gas must be burned (BC Oil and Gas Commission (2011)). In Alberta, ERCB Directive 060 contains the requirements for flaring, incinerating, and venting activities conducted by all upstream petroleum industry wells and facilities. These requirements have been developed to eliminate or reduce the potential and observed impacts associated with these activities and ensure that public safety concerns and environmental impacts are addressed prior to commencing flaring, incinerating, and venting activities (ERBC (2011)).

Data Knowledge and Data Gaps

► In the United States, wells are typically tested to determine their productivity, economic viability, and design criteria for a pipeline gathering system. If no pipeline exists, produced gas is flared during the test.

In the Marcellus Shale, operators have reported that flaring is minimized by construction of the gathering system ahead of well completion. Flaring is thus only necessary during the initial 12 to 24 hours of flowback operations while the well is producing a high ratio of flowback water to gas. However, when no gathering system is in place, operators report that the initial cleanup or testing of a well requires flaring for 3 days (NYSDEC (2011)).

► In 2009-2010, GAO (2010) examined the estimates of the volumes of vented and flared natural gas on federal leases. To do this, they analyzed data on venting and flaring that oil and gas producers submitted to the Interior's Minerals Revenue Management (MRM) program, which is responsible for collecting revenue from federal leases. They also analyzed US EPA estimates and the Western Regional Air Partnership (WRAP) estimates of vented and flared natural gas. The data from 2006 to 2008 were for federal leases only.

Operators reported to MRM that about 0.13% of the natural gas was vented or flared each year for the period 2006 to 2008. However, it seems that this percent represented only intermittent events like completions, liquid unloading or necessary releases after equipment failures. In contrast, EPA's estimate of venting and flaring was approximately 4.2% of gas production for the same period and included both intermittent and operational sources. This represented 126 billion cubic feet (3.5 billion m^3). Similarly, WRAP's estimate of venting and flaring for five production basins in Colorado was as much as 5% (range of 0.3 to 5%) of the total natural gas produced.

Howarth, *et al.* (2011) indicates that once a well is completed and connected to a pipeline, the same technologies are used for both conventional (natural gas) and shale gas. Assuming that the post-completion fugitive emissions are the same for shale and conventional gas, they reported, based on the GAO (2010) data (see above), that 0.3% to 1.9% of the life-time production of a shale gas well is lost due to routine venting and equipment leaks (estimate not including accidents or emergency vents).

Additionally, liquid unloading events can be required in some shale gas wells. These events are required to mitigate water intrusion as reservoir pressure drops. Using GAO (2010) data for conventional gas, Howarth, *et al.* (2011) reports that 0% to 0.26% of total life-time production of a shale gas well is vented as methane during liquid unloading.

► Detailed data concerning the venting and flaring of shale gas during all the exploration and exploitation stages are unavailable.

5.2.4 Wastewater Disposal

Sources of Potential Impacts

Wastewater corresponds to the drilling mud, hydraulic fracturing fluid and production brine rising to the wellhead during the different stages of the exploitation. In the United States, it is typically disposed of in ponds that can lead to the evaporative emission of chemicals. The chemicals can originate from different fluids and/or can result from chemical reactions in the ponds. Wastewater is then treated, recycled, reused or injected deep underground. Another disposal option is the spreading of the wastewater on the road (see Section 5.1.4).

Risk Probabilities

The wastewater disposed of in ponds is a mix of different organic (e.g. additives used in the hydraulic fracturing process) and inorganic (e.g. radioelements, metals) chemicals. Some of these compounds are volatile and will be emitted into the air. Their concentration in the air will depend on different parameters including their relative volatility, the duration of disposal, the temperature, the pond surface area and the atmospheric dispersion.

Mitigation, Preventive Actions or Regulatory Actions

No data.

Data Knowledge and Data Gaps

► The wastewater disposed of in ponds, impoundments and pits contains flowback water composed of the additives present in the hydraulic fracturing fluid and of compounds mobilized from the shale layers. Some shales contain numerous organic hydrocarbons. For example, the Marcellus Shale contains from 3% to 12% of organic carbon (Arthur*, et al.* (2008)). VOCs present in the hydraulic fracturing fluid and in the shale layers can then be emitted into the air when brought to surface and disposed of in pits (Volz*, et al.* (2010)).

► The risks to human health will depend on both the impacts of shale gas exploration and exploitation, and on the levels of human exposure. To adequately characterize the population health risks associated with air emissions of contaminants from wastewater ponds, the following data are required:

- Volumes of wastewater present in the ponds;
- Pond surface area;
- Wastewater temperature;
- Duration of the wastewater disposal;

- Nature and concentrations of the contaminants evaporating from the wastewater ponds;
- Data on parameters influencing atmospheric dispersion of airborne contaminants such as the distance between the population and the emissions sources, the topography or meteorological data;
- Characteristics of the population.

All of these parameters have to be evaluated on a case-by-case basis because they are highly variable between shale gas projects.

5.2.5 Well Completion (Hydraulic Fracturing and Flowback)

Sources of Potential Impacts

In addition to the general air pollutants reported in the sections above (e.g. NOx, SOx, PM and VOCs), fugitive shale gas emissions occur during well completion. Indeed, when flowback water returns to the surface, it is accompanied by large quantities of shale gas, primarily composed of methane but also containing variable amounts of heavier hydrocarbons (such as ethane, propane and butane) and impurities (e.g. H_2S, CO_2 and N_2). Moreover, shale gas is emitted during the 'drill-out' stage in which the plugs, set to separate fracturing stages, are drilled out to release gas for production (Howarth*, et al.* (2011)).

Exposure to radioelements (NORMs) can also occur during well completion. Indeed, NORMs can be brought to the surface with the flowback water, the rock cuttings and the shale gas.

Risk Probabilities

Fugitive emissions of shale gas components always occur during well completion, principally during the flowback period and the drill-out stage. These emissions are reduced when the operators use green technologies.

If NORMs are naturally present in the shale formation, they are brought to the surface during well completion.

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, methane emissions occurring during the flowback period could be reduced by up to 91% through 'reduced emissions completions technologies' or 'green completion technologies' (US EPA (2007), US EPA (2010), GAO (2010)). For example, sand, water and gas during initial flowback can be separated using specifically designed flowback equipment. Then, the gas can be routed to sales lines through the production equipment. This technology was used in the Piceance Basin well and, between 2002 and 2006, 91.1% of the flowback gas was recovered (i.e. 23,701,000 cubic feet or 671,140 m^3). Green technologies can also be used during the drill-out phase (US EPA (2007)).

In July 2011, the US EPA proposed a number of regulatory requirements to reduce air emissions from the oil and gas industry. These rules are expected to take effect in April 2012 (ARI (2012)) (see Section 5.2.1).

► In British Columbia (Canada), green completions are currently used for about 54% of Montney wells and 67% of Horn River wells. This should continue to increase as the plays mature and the infrastructure for gathering systems expands (BCOGC (2012)).

Data Knowledge and Data Gaps

► Shale gas is usually composed of 70-90% of methane but its composition varies largely between areas and formations. Thus, it should be expected that between 10-30% of the losses associated with flowback water and drill-out may be composed of heavier hydrocarbons and impurities. Moreover, radon can be brought to the surface with shale gas and can also be emitted.

Howarth, *et al.* (2011) compiled data from two shale gas formations and three tight-sand gas formations in the United States (see Table below). They found that between 0.6% and 3.2% (i.e. 255,000 to 6,800,000 m^3) of the life-time production of gas from wells is emitted as methane during the flowback period. They decided to represent gas losses from flowback water as the mean value of 1.6%.

They also estimated that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. Thus, combining losses associated with flowback water (1.6%) and drill-out (0.33%), they estimated that 1.9% of the total production of gas from unconventional shale-gas wells is emitted during the well completion stage. They reported that this estimate is conservative but uncertain, because the data used for the estimation were not well documented.

TABLE 14: Methane Emissions during the Flowback Period and Gas Production for Five Unconventional Wells in the United States

Shales	Methane Emitted During Flowback (1,000 m^3)	Methane Emitted per Day During Flowback (1,000 m^3/day)	Initial Gas production at Well Completion (1,000 m^3/day)	Life-Time Production of Well (1,000 m^3)	Methane Emitted During Flowback as % of Life-Time Production
Haynesville (Louisiana, shale)	6,800	680	640	210,000	3.2
Barnett (Texas, shale)	370	41	37	35,000	1.1
Piceance (Colorado, tight sand)	710	79	57	55,000	1.3
Uinta (Utah, tight sand)	255	51	42	40,000	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Source: Howarth, *et al.* (2011)

Lechtenböhmer, *et al.* (2011) re-estimated the methane emissions of the Haynesville Shale given that, according to Cook and Charpentier (2010), the mean value for the life-time production per well is lower than the value estimated by Howarth, *et al.* (2011) (approximately 75 million m^3 (2.7 billion cubic feet)). Based on this life-time production, methane emissions from flowback (6,800,000 m^3) would represent 9.0% instead of the 3.2% reported by Howarth, *et al.* (2011).

It should be noted that Howarth, *et al.* (2011) publication was challenged by Cathles, *et al.* (2011) (see Section 5.2.7). Moreover, there have been other studies on methane emissions from shale gas operations that have estimated shale gas leakages. For example, Burnham, *et al.* (2011) estimated that 0.46% of the shale gas produced is lost during well completion and workovers (venting). This estimate is based on US EPA's data.

► Air monitoring data in the vicinity of well pads were recently published in a paper aimed to assess the risks to human health related to the flowback stage of shale gas well completion (McKenzie, *et al.* (2012)). The study was performed by researchers from the University of Colorado-Denver School of Public Health and was conducted in western Garfield County, a rural area where agriculture and nonconventional gas development are the main economies.

Ambient air monitoring was performed over a period of 3 years at a station located in the midst of rural homes and ranches and unconventional natural gas developments, during both well development and production; 24-hour air samples (n=163) were collected every 6 days in the period from January 2008 to November 2010. A second series of ambient air samples was collected in summer 2008 on the perimeters of 4 well pads (at each cardinal direction) during both well development and production. These samples (n=16) were collected over 24 to 27-hour intervals and when at least one well was on uncontrolled (emissions not controlled) flowback into collection tanks vented directly into the air; they included emissions from both flowback and diesel engines. A background sample was also collected 0.33 to 1 mile from each well pad. A third series of samples was collected in the summer of 2010, at 350 and 500 feet from a well pad center, during well completion activities (8/12 wells already producing salable gas, 1/12 drilled but not completed, 2/12 being hydraulically fractured during daytime hours, with ensuing uncontrolled flowback during night-time hours, and 1/12 on uncontrolled flowback during night-time hours). Air samples were analyzed for up to 78 hydrocarbons.

More than 20 aromatic and aliphatic hydrocarbons (e.g. BTEX, alkanes and alkenes) with toxicity values were detected in all the samples, and more than 30 hydrocarbons without toxicity values were detected in most samples. The authors indicated that shale gas exploitation was likely the major source of the hydrocarbons observed in the monitored areas, and that emissions from flowback operations were likely the major source of the hydrocarbons observed in the well completion samples (i.e. the two last series of samples).

The human health risk assessment was conducted by estimating hazard indices (HI) for subchronic and chronic exposure (non-cancer effects) and estimating the risk of cancer based on a cumulative exposure. The estimates were based on a 30 years-exposure (5 years of well development for all well pads followed by 20 to 30 years of production). The HI estimated for subchronic exposure to air pollutant attained the value of 5 for residents living within half a mile from the wells. These results were consistent with the subchronic health effects reported by the residents (headache and throat and eye irritation) during well completion. For chronic effects, the HI attained the value of 1 and 0.4 for residents living ≤0.5 miles and >0.5 miles from wells, respectively, and the cumulative cancer risks were 10 in a million (1 in 100 000) and 6 in a million (0.6 in 100 000) for these residents, respectively (McKenzie*, et al.* (2012)).

► Detailed data concerning the radioactivity experienced during well completion are missing.

5.2.6 Shale Gas Production and Processing

Sources of Potential Impacts

In addition to the general air pollutants reported in the preceding sections (NOx, SOx, PM), exposure to radioelements (NORMs) and methane emissions can occur during shale gas production and processing in the following ways:

- During shale gas production, NORMs can be brought to the surface (in rock pieces, produced water and gas) and emit radiations into the air;
- When natural gas is of insufficient quality (during unconventional or conventional natural gas exploitation), i.e. when it contains heavy hydrocarbons and impurities, it has to be processed. During this processing, shale gas (usually composed of 70-90% of methane) can be emitted.

Risk Probabilities

If NORMs are naturally present underground, they are brought to the surface during shale gas production. Moreover, if the natural gas needs to be processed, shale gas can potentially be emitted.

Mitigation, Preventive Actions or Regulatory Actions

► In the United States, the Ground Water Protection Council and ALL Consulting (2009) reports that the general public does not come into contact with gas field equipment for extended periods, so there is very little risk exposure from gas field NORMs. Concerning gas field workers, the Occupational Safety and Health Administration (OSHA) requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards.

Data Knowledge and Data Gaps

► Howarth, *et al.* (2011) estimated that between 0% (when no processing is required) and 0.19% of gas produced is lost during processing (shale gas, like all natural gas, is primarily composed of methane). Their results are based on the US EPA's default large/complex refinery fugitive emission factor for gas processing (0.19%) (Shires, *et al.* (2009)). According to the authors, their estimate is very conservative.

It should be noted that Howarth, *et al.* (2011) publication was challenged by Cathles, *et al.* (2011) (see Section 5.2.7). Moreover, there have been other studies on methane emissions from shale gas operations that have estimated shale gas leakages. For example, Burnham, *et al.* (2011) estimated that 0.15% of the shale gas produced is lost during processing (leakage and venting). This estimate based on US EPA's data.

Shale gas is usually composed of 70-90% of methane but its composition varies largely between areas and formations. Thus, it is expected that between 10-30% of the losses associated with shale gas production and processing may be composed of heavier hydrocarbons and impurities. Moreover, radon can be brought to the surface with shale gas and can also be emitted.

► Detailed data concerning the air quality as well as the radioactivity experienced during shale gas production are missing.

5.2.7 Total Air Emissions of Methane Related to the Development of Shale Gas

Shale gas is usually composed of 70-90% of methane. Thus, when shale gas is emitted during the development of shale gas, this is the principal pollutant emitted. This, and the fact that methane is a potent greenhouse gas, explains why methane concentrations related to shale gas development are generally reported in the scientific papers. However, shale gas composition varies largely between areas and formations and, heavier hydrocarbons (e.g. ethane, propane and butane) and impurities (e.g. H_2S, CO_2 and N_2) that can also be present in shale gas can be emitted into the atmosphere. Moreover, radon can be brought to the surface with shale gas and can also be emitted.

► Howarth, *et al.* (2011) evaluated that 3.6% to 7.9% of the methane from shale-gas production escapes into the atmosphere in venting and leaks over the life-time of a well. They reported that the highest emissions from shale gas occur when wells are hydraulically fractured and during drill-out following the fracturing. Considering the life-time production of a well (35,000,000 m^3 to 210,000,000 m^3, see Table 14), methane emissions can occur at a range of 1,260,000 m^3 to 16,590,000 m^3 per well (i.e. 45,000,000 cubic feet to 590,000,000 cubic feet per well).

Based on the lifetime production per well at the Haynesville Shale provided by Cook and Charpentier (2010) (Lechtenböhmer, *et al.* (2011)) and using the emission rates provided by Howarth, *et al.* (2011) (3.6% to 7.9%), methane emissions could occur at a range of 1,260,000 m^3 to 5,925,000 m^3 per well (i.e. 45,000,000 cubic feet to 209,000,000 cubic feet per well) (see Table 15).

► It should be noted that Howarth, *et al.* (2011) publication was challenged by Cathles, *et al.* (2011). Indeed, Cathles, *et al.* (2011) indicated that the low-end estimate of total leakage (3.6%) is consistent with the EPA methane leakage rate (2.2% of production) but that the high-end estimate (7.9%) is unreasonably large and misleading.

Other studies have also estimated shale gas loss from shale gas operations and have estimated lower emission rates for these activities. For example, Burnham, *et al.* (2011) estimated that 2.01% of the shale gas produced is lost during shale gas operations. This is principally based on data from US EPA.

However, the estimates by Howarth, *et al.* (2011) were recently supported by the results of a study led by researchers at the National Oceanic and Atmospheric Administration and the University of Colorado in Boulder where the loss of natural gas to the atmosphere from natural-gas operations were estimated on the basis of direct air sampling (Tollefson (2012)). Their study was located in the Denver-Julesburg Basin. They found that natural-gas producers lose approximately 2.3% to 7.7% (average of 4%) of their gas to the atmosphere. This range does not include losses in the pipeline and distribution system.

Using the lifetime production of a well of Howarth, *et al.* (2011), this corresponds to the emission of 805,000 to 16,170,000 m^3 methane per well (i.e. 28,400,000 cubic feet to 570,000,000 cubic feet per well).

TABLE 15: Fugitive Methane Emissions Associated with Development from Shale Formations (Expressed as the Percentage and Volumes of Methane Produced over the Life-Cycle of a Well)

Activities	Methane Emissions Related to the Total Annual Production (%)	Methane Equivalent Volumes, 1,000 Cubic feet (1,000 m^3)	
	Based on Howarth, *et al.* (2011)	Based on Howarth, *et al.* (2011)[1] (see Table 14)	Based on Cook and Charpentier (2010)[2]
Emissions During Well Completion	1.9	24,500 to 141,000 (665 to 3,990)	24,500 to 50,300 (665 to 1,425)
Routine Venting and Equipment Leaks at a Well Site	0.3 to 1.9	3,700 to 141.000 (105 to 3,990)	3,700 to 50,300 (105 to 1,425)
Emissions During Liquid Unloading	0 to 0.26	0 to 19,300 (0 to 546)	0 to 6,900 (0 to 195)
Emissions During Gas Processing	0 to 0.19	0 to 14,100 (0 to 399)	0 to 5,000 (0 to 142.5)
Emissions During Transport, Storage, and Distribution	1.4 to 3.6	17,300 to 270,000 (490 to 7,560)	17,300 to 95,000 (490 to 2,700)
TOTAL Methane Emissions	**3.6 to 7.9**	**45,000 to 590,000 (1,260 to 16,590)**	**45,000, to 209,000 (1,260 to 5,925)**

Based on: Howarth, *et al.* (2011), Cook and Charpentier (2010) and Lechtenböhmer, *et al.* (2011)

[1] According to Howarth, *et al.* (2011), the mean value for the life-time production per well ranges from 35,000,000 to 210,000,000 m^3 (1.2 billion to 7.4 billion cubic feet).

[2] According to Cook and Charpentier (2010) data, the mean value for the life-time production per well could range from 35,000,000 to 75,000,000 m^3 (1.2 billion to 2.7 billion cubic feet).

5.2.8 Applicability to the Canadian Situation

The contamination of ambient air related to shale gas exploration/exploitation activities may vary on a case-by-case basis depending on different parameters such as the laws and regulations applying in the province of concern, the technologies and practices used, as well as the mechanical equipment used. However, assuming that vehicles and engines as well as the different stages of the shale gas operations are similar in Canada and in the United States, it is reasonable to anticipate that the issues related to ambient air quality reported above and principally based on data from the United States should apply in Canada where few data are currently available. The health hazards related to air quality may vary with the regional situations (i.e. proximity of the population).

5.2.9 Summary of Health Hazards

During shale gas exploration/exploitation, various contaminants (e.g. nitrogen oxide, particulate matter, sulphur oxide, volatile organic compounds and methane) are emitted into the air. These contaminants might pose public health risks depending on their concentrations in the ambient air. A brief overview of the potential sources of air contamination is provided in Appendix E.

There are different types of potential air contaminants:

- Air pollutants originating from the vehicles and engines fuelled by diesel (nitrogen oxides, particulate matter, sulphur dioxides and carbon monoxide). These contaminants are emitted during all shale gas exploration/exploitation processes as vehicles and engines are always in use on the well pad;
- Volatile organic contaminants (VOCs) present in the fluids (e.g. drilling mud, hydraulic fracturing fluid, flowback water) during the different phases of the shale gas exploitation. Accidents (e.g. well blowouts and spills), shale gas flaring and venting and wastewater disposal (e.g. volatilization from the pits) are other sources of VOCs;
- Shale gas components (hydrocarbons and impurities) emitted during specific exploitation phases (e.g. well completion and shale gas production) and when accidents (e.g. well blowout) or venting occurs, and during gas transport storage and distribution;
- Naturally occurring contaminants present in the shale formation. Radioelements may be brought to the surface with the rock cuttings, the flowback water and shale gas, and emit radiation to the air.

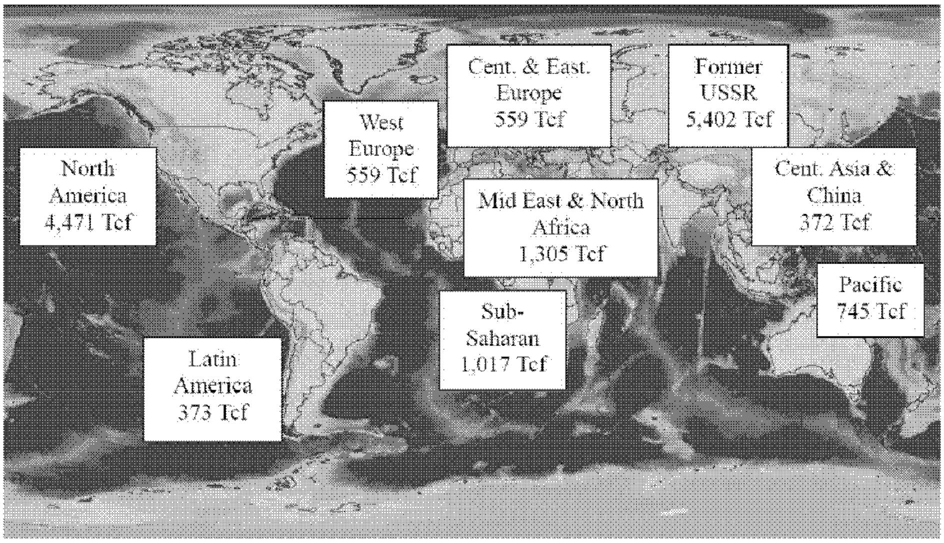
The quantification of the health impacts posed by all these chemicals was not part of this mandate. However, it can be concluded that air emissions related to the shale gas industry present health hazards since the air pollutants originating from the vehicles and engines fuelled by diesel are toxic to the respiratory and cardiovascular systems and can cause premature mortality, volatile organic compounds have been associated to neurotoxicity and some of these compounds (e.g. benzene) as well as NORMs are known or possible human carcinogens. Thus, exploration/exploitation of shale gas may pose risks to human health for local populations, depending on the ambient air quality.

The risk to public health may vary on a case-by-case basis since it depends on the sources of emissions (e.g. emission rates), on the atmospheric dispersion of the contaminants and on the distance between the population and the sources. Thus, for example, to evaluate the risks associated with air emissions from the diesel engines and vehicles used during a shale gas exploration and exploitation project, data concerning (i) the number and type of mechanical equipment used as well as their source of energy, (ii) the duration of the mechanical equipment activities, (iii) the emission rates from the mechanical equipment and (iv) the proximity of the population to the exploration/exploitation sites have to be available.

6. INTERNATIONAL ACTIVITIES RELATED TO SHALE GAS EXPLORATION AND EXPLOITATION

According to geologists, more than 688 shale deposits exist worldwide in 142 basins (a basin is a natural depression of strata containing stratified deposits). The global shale gas resource is currently estimated to be approximately 16,000 trillion cubic feet (Tcf) (450,000 km^3). The estimated worldwide shale gas resource potential is illustrated in Figure 12. In this Figure, the former USSR contains the largest shale gas estimate (36%), followed by North America (30%), Middle East and North Africa (9%), Sub-Saharan Africa (7%), Pacific (5%), West Europe as well as Central/East Europe (4% each), Latin America and Central Asia/China (3% each). These estimates could change significantly after a proper assessment is performed considering that, currently, only a few dozen of the shales have been explored for production capacities (World Energy Council (2010)).

Active shale gas production is currently occurring in the United States (see Section 6.2). In Canada, shale gas is produced in some provinces (see Section 7) but large-scale commercial production has not yet been achieved. Outside North America, shale gas has not yet been produced commercially because of a limited geological knowledge about shale gas and host reservoirs, and due to the higher technical and economic costs. However, large exploratory activities are being undertaken in some countries to establish the locations of viable shale gas reservoirs (e.g. Poland) (World Energy Council (2010)).



World Energy Council (2010) (Original source not clearly identified)

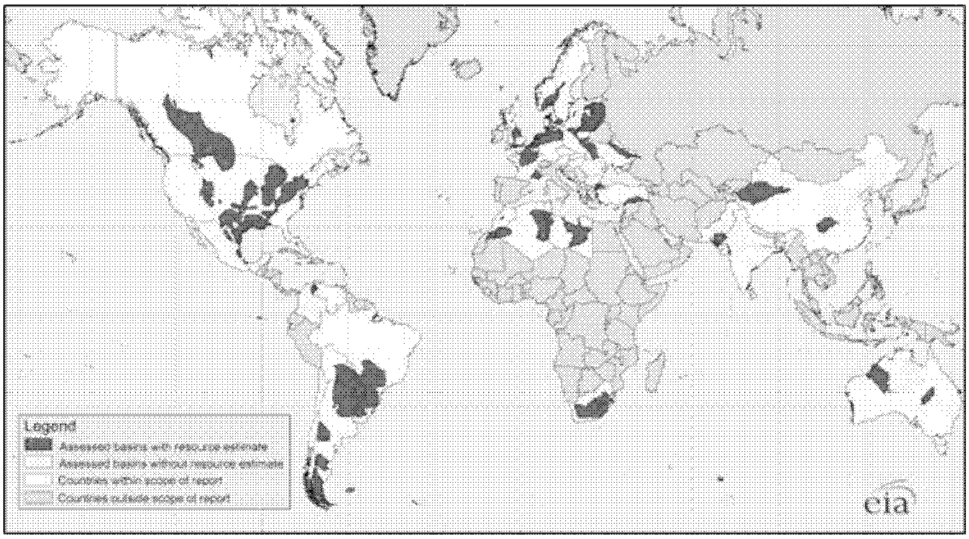
FIGURE 12: Estimated Worldwide Shale Gas Resource Potential (2010)

6.1 Overview of International Shale Gas Resources and Activities

International shale gas resources (i.e. potential reserves and shale formations) as well as international activities (exploration/exploitation) related to shale gas are summarized in Table 16.

This Table is principally based on the EIA (2011a) initial survey which assessed recoverable shale deposits in 32 countries located in 14 regions outside the United States. This initial survey estimated the gas in-place and the technically recoverable resource for 48 shale gas basins and 69 shale gas formations (see Figure 13). The survey covered the most prospective shale gas resources in countries that demonstrate some level of relatively near-term promise and for basins that have a sufficient amount of geologic data for resource analysis. The estimates are uncertain given the relatively sparse data that currently exists however they represent a moderately conservative 'risked' resource for the basins reviewed.

The survey reports a total technically recoverable resource estimate of 6,622 Tcf (190,000 km^3) for the United States and the other 32 countries assessed (important resources such as those located in former USSR were not accounted for).



Source: EIA (2011a)

Notes:
- Red colored areas represent the location of assessed shale gas basins for which estimates of the 'risked' gas-in-place and technically recoverable resources were provided;
- Yellow colored area represents the location of shale gas basins that were reviewed, but for which estimates were not provided, mainly due to the lack of data necessary to conduct the assessment;
- White colored countries are those for which at least one shale gas basin was considered for this report;
- Gray colored countries are those for which no shale gas basins were considered for this report.

FIGURE 13: Map of Shale Gas Basins in the United States and in 48 Major Shale Gas Basins in 32 Countries outside the United States

TABLE 16: Overview of the World Shale Gas Resource and Activities

CONTINENT	REGION[1]	BASIN	FORMATION	RISKED GAS IN-PLACE (TCF)	TECHNICALLY RECOVERABLE RESOURCE (TCF)	ACTIVITY
NORTH AMERICA	**Canada**	Appalachian Fold Belt	Utica	1,490	388	Large-scale commercial production of shale gas has not yet been achieved. Many companies are now exploring for and developing shale gas resources in basins. See Figure 15 for the shale gas formation locations in Canada.
		Windsor Basin	Horton Bluff			
		Horn River	Muskwa/Otter Park – Evie Klua			
		Cordova	Muskwa/Otter Park			
		Liard	Lower Besa River			
		Deep Basin	Montney Shale - Diog Phosphate			
		Colorado Group	2WS & Fish Scales			
	United States[2]	Fort Worth Basin	Barnett Shale		862	Presently, significant commercial shale gas production occurs in these formations which are the most active shale gas plays across the United States. Shale gas production in the United States increased from 0.39 Tcf in 2000 to 4.87 Tcf in 2010[2]. See Figure 14 for the shale gas formation locations in the United States.
		Texas-Louisiana Salt Basin	Haynesville/Bossier Shale			
		Michigan Basin	Antrim Shale			
		Arkoma Basin	Fayetteville Shale			
		Appalachian Basin	Marcellus Shale			
		Anadarko Basin	Woodford Shale			
		Illinois Basin	New Albany Shale			
	Mexico	Burgos Basin	Eagle Ford Shale – Titonian Shales	2,366	681	No shale gas leasing or exploration activity has been reported in the five basins. The national oil company is planning to begin exploration.
		Sabinas Basin	Eagle Ford Shale – Titonian La Casita			
		Tampico Basin	Pimienta			
		Tuxpan Platform	Tamaulipas – Pimienta			
		Veracruz Basin	U.K. Maltrata			

Continent	Region[1]	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)	Activity
South America	**Northern South America**	Maracaibo Basin	La Luna	120	30	Significant areas in these two basins are immature for gas generation and/or are excessively deep for exploration and production (over 5,000 meters).
		Catatumbo Sud-Basin	La Luna - Capacho			
	Southern South America	Neuquen Basin	Los Molles – Vaca Muerta	4,449	1,195	Initial shale gas exploration is underway in Argentina's Neuquen Basin. Shale gas exploration is planned in Uruguay.
		San Jorge Basin	Aguada Bandera – Pozo D-129			
		Austral-Magalianes Basin	L. Inoveramus – Magnas Verdes			
		Parana-Chaco Basin	San Alfredo			
Europe	**Poland**	Baltic Basin	Silurian Shales	792	187	Active levels of shale gas leasing and exploration are already underway.
		Lublin Basin	Silurian Shales			
		Podlasie Depression	Silurian Shales			
	Eastern Europe	Baltic Basin	Silurian Shales	290	65	The shale gas potential of Eastern Europe has not yet been widely explored but some exploration projects are underway.
		Dnieper- Donets Basin	Visean Shales			
		Lublin Basin	Silurian Shales			
	Western Europe	North Sea-German Basin	Posidonia Shale – Namurian Shale – Wealden Shale	1,505	372	Shales of Western Europe are being actively explored and evaluated by a host of small to large companies.
		Paris Basin	Permo-Carboniferous Shale			
		Scandinavia Region	Alum Shale			
		South-East French Basin	Terres Noires – Liassic Shale			
		N. U.K. Petroleum System	Bowland Shale			
		S. U.K. Petroleum System	Liassic Shale			

Continent	Region[1]	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)	Activity
Africa	**Central North Africa**	Ghadames Basin	Tannezuft Formation – Frasnian Formation	1,861	504	Considerable exploration activity is underway in the Ghadames Basin but no shale gas production has yet been reported.
		Sirt Basin	Sirt- Rachmat Formation – Etel Formation			There is no publically reported shale gas production or shale gas exploration activity underway in the Sirt Basin.
	Morocco	Tindouf Basin	Silurian Shales	267	53	Shale gas potential has been studied by the Moroccan national oil and gas company in the Tindouf Basin. Shale gas exploration is underway.
		Tadla Basin	Silurian Shales			There is no reported shale gas exploration activity underway in the Tadla Basin.
	South Africa	Karoo Basin	Prince Albert – Whitehill - Collingham	1,834	485	A number of major and independent companies are exploring shale gas resources in the Karoo Basin.
Asia	**China**	Sichouan Basin	Longmaxi – Qiongzhusi	5,101	1,275	Initial shale gas exploration is underway in the Sichouan Basin but no commercial shale gas production has been reported.
		Tarim Basin	O1/O2/O3 Shales – Cambrian Shales			To date no shale gas exploration or evaluation activity has been announced for the Tarim Basin.
	India/ Pakistan	Cambay Basin	Cambay Shale	496	114	No exploratory plans have been publically announced in the Cambay Basin.
		Damodar Valley Basin	Barren Measure			The Damodar Valley Basin is a priority basin for shale gas exploration by the Indian government. Exploratory wells have already been drilled.
		Krishna-Godavari Basin	Kommugudem Shale			Exploratory wells have been drilled into or through the Kommugudem Shale.
		Cauvery Basin	Andimadam Formation			
		Southern Indus Basin	Sembar Formation – Ranikot Formation			No publically available data was found on shale gas exploration or development in the Southern Indus Basin of Pakistan.

Continent	Region[1]	Basin	Formation	Risked Gas In-Place (Tcf)	Technically Recoverable Resource (Tcf)	Activity
	Turkey	Thrace Basin	Hamitabat - Mezardere	64	15	The two basins are under active shale gas exploration by the national petroleum company and international exploration companies.
		Southeast Anatolian Basin	Dudas Shale			
AUSTRALIA	**Australia**	Cooper Basin	Roseneath- Epsilon- Murteree	1,381	396	Exploratory activities are underway in the four basins.
		Maryborough	Goodwood/Cherwell Mudstone			
		Perth Basin	Carynginia Shale – Kockatea Fm			
		Canning Basin	Goldwyer Fm			
				TOTAL	**6,622**	

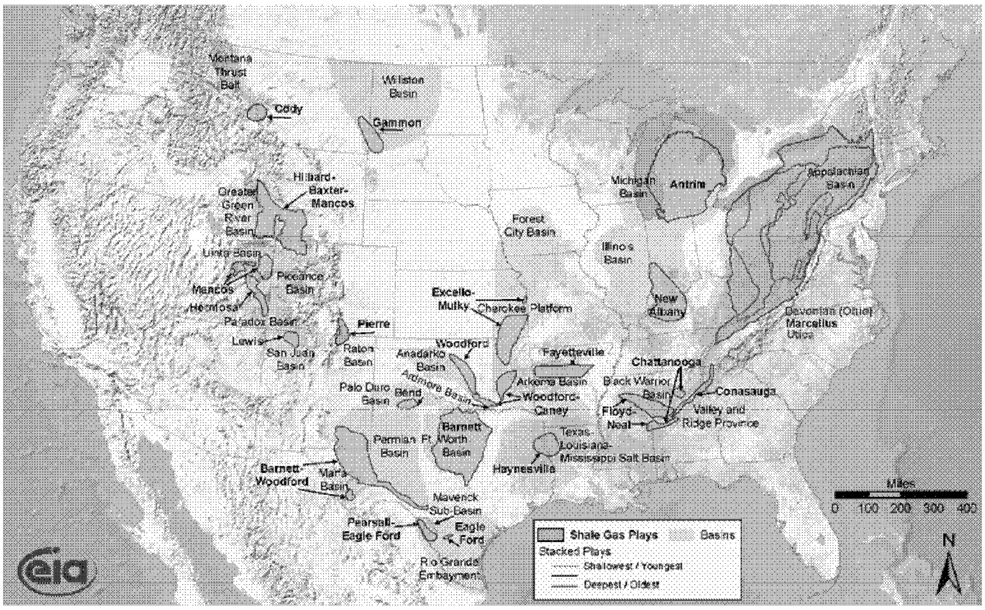
Based on: EIA (2011a)

[1] Northern South America (Colombia, Venezuela), Southern South America (Argentina, Chile, Uruguay, Paraguay, Bolivia, Brazil), Eastern Europe (Ukraine, Lithuania, and other Eastern Europe countries), Western Europe (including France, Germany, Netherlands, Norway, Denmark, Sweden, and United Kingdom), Central North Africa (Algeria, Tunisia, Libya), Western North Africa (Morocco, Mauritania, Western Sahara), Southern Africa (South Africa).

[2] Source: Ground Water Protection Council and ALL Consulting (2009). Only the most active shales are presented in this Table.

6.2 Overview of the Major Shale Gas Plays in the United States

In the United States, significant activities are underway to explore, produce and develop shale gas. Numerous shale gas basins exist (see Figure 14) and have a potential of hundreds to thousands of Tcfs. To date, the most active shales are the Marcellus Shale, the Barnett Shale, the Antrim Shale, the Haynesville/Bossier Shale, the Woodford Shale, the Fayetteville Shale and the New Albany Shale. Shale gas production in the United States increased from 0.39 Tcf in 2000 to 4.87 Tcf in 2010 (Ground Water Protection Council and ALL Consulting (2009)). By 2035, EIA estimates that shale gas production will rise to 13.6 Tcf, representing nearly half of all U.S. natural gas production.



Source: EIA (2011b)

FIGURE 14: Shale Gas Plays and Basins in the United States

A brief overview of each of the most active shale gas plays is presented below, followed by a Table summarizing the major shale characteristics (i.e. physical extent and resources). Estimates of the shale gas resources, especially the portion that is technically recoverable, will likely change over time.

The following data are based on Ground Water Protection Council and ALL Consulting (2009), and National Energy Laboratory (2010):

► The Marcellus Shale located within the Appalachian Basin is the most expansive shale gas play. It covers an area of 95,000 mi^2 (250,000 km^2). It extends over 6 states in the northeastern of the United States (New York, Pennsylvania, Ohio, West Virginia, Virginia and Maryland). In September 2008, a total of 518 wells were permitted in

Pennsylvania and 277 of the approved wells had been drilled. Horizontal and hydraulic fracturing techniques are used in this shale.

- The Barnett Shale is the most prominent shale gas play in the United States. It is located in the Fort Worth Basin of North-Central Texas, in an urban and suburban environment. It covers an area of 5,000 mi^2 (13,000 km^2). Currently, 2% of all the gas consumed in the United States is produced from this shale. Over 10,000 wells have already been drilled and it is estimated that production activity may continue for 20-30 years. Horizontal and hydraulic fracturing techniques are used in this shale.

- The Antrim Shale is located within the Michigan Basin, in the upper portion of the Lower Peninsula of Michigan. It covers an area of 12,000 mi^2 (31,000 km^2). The Antrim Shale has been one of the most actively developed shale gas plays in the United States, aside from the Barnett Shale. It is substantially different from the other shales because it has a shallow depth, a small stratigraphic thickness and large volumes of produced water. Over 9,000 predominantly vertical wells have already been drilled to shallow depths.

- The Haynesville Shale (or Haynesville/Bossier Shale) is located within the Texas-Louisiana Mississippi Salt Basin, in Northern Louisiana and Eastern Texas. It covers an area of 9,000 mi^2 (23,500 km^2). Its potential is thought to be many times larger than the Barnett Shale, with higher gas-in-place. However, the heterogeneous characteristics of the shale (e.g. high-depth, high-pressure, high lamination with significant lithologic changes over a few inches) may result in more rapid decline rates than the Barnett Shale as well as the increase of costs and technical challenges. Currently, the Haynesville Shale is near commercial production.

- The Woodford Shale is located within the Anadarko Basin, in South-Central Oklahoma. It covers an area of 11,000 mi^2 (28,500 km^2). It is more complex compared to the Barnett Shale and is thus more difficult to drill and fracture. However, promising results have been obtained for this shale in which horizontal and hydraulic fracturing techniques are used.

- The Fayetteville Shale is located within the Arkoma Basin of Northern Arkansas and Eastern Oklahoma. It covers a rural area of 9,000 mi^2 (23,500 km^2). Between 2004 and 2007, the number of gas wells annually drilled increased from 13 to more than 600. Currently, over 1,000 wells are in production and the Fayetteville Shale may become one of the most active plays in the United States.

- The New Albany Shale is located in the Illinois Basin in portions of Southeastern Illinois, Southwestern Indiana and Northwestern Kentucky. It covers an area of 43,500 mi^2 (110,000 km^2). The New Albany Shale is one of the largest shale gas plays in the United States. This shale is similar to the Antrim Shale as it is shallow and water-filled. It is principally in an exploratory stage with gas production occurring primarily in Western Indiana and Southwest Kentucky.

TABLE 17: Key Characteristics (i.e. Physical Extent and Resources) of the Most Active Shale Gas Plays in the United States

	Basin	Appalachian Basin (250,000 km^2)	Fort Worth Basin (13,000 km^2)	Michigan Basin (31,000 km^2)	Texas-Louisiana Mississippi Salt Basin (23,500 km^2)	Anadarko Basin (28,500 km^2)	Arkoma Basin (23,500 km^2)	Illinois Basin (110,000 km^2)
	Shale Formation	Marcellus	Barnett	Antrim	Haynesville/ Bossier	Woodford	Fayetteville	New Albany
Physical Extent	**Depth (m)**	1,220 – 2,600	2,000 – 2,600	180 - 670	3,200 – 4,100	1,800 – 3,300	300 – 2,100	150 - 600
	Net Thickness (m)	15 - 60	30 - 180	20 - 35	60 - 90	35 - 65	5 - 180	15 - 30
Resources	**Original Gas-in Place (Tcf)**	1,500	327	76	717	23	52	160
	Technically Recoverable Resources (Tcf)	262	44	20	251	11.4	41.6	19.2

Based on: Ground Water Protection Council and ALL Consulting (2009)

7. PROVINCIAL/TERRITORIAL ACTIVITIES RELATED TO SHALE GAS EXPLORATION AND EXPLOITATION

In Canada, there is a potential of approximately 1,500 Tcf (40,000 km^3) of shale gas, among which 20% could be recovered using the current technologies (EIA (2011a)). Shale plays (i.e. shale gas or oil areas in shale rocks) are located in Western Canada, in Southern Ontario and Southern Quebec as well as in the Atlantic Provinces. Figure 15 illustrates the North America shale plays and basins (natural depressions of strata containing stratified deposits). It should be noted that Canadian shale plays in Eastern Canada are generally located in regions with elevated population densities and that this proximity may be an issue of concern relative to potential impacts on human health (see Figure 16).

Large-scale commercial production of shale gas has not yet been achieved in Canada. However, many companies are now exploring and/or developing shale gas resources in Alberta, British Columbia, Quebec, Nova Scotia as well as New Brunswick.

The following sub-sections address the shale gas resources and related activities in the different Canadian provinces. A summary is presented in Section 7.3. For each province, the following data are reported when available:

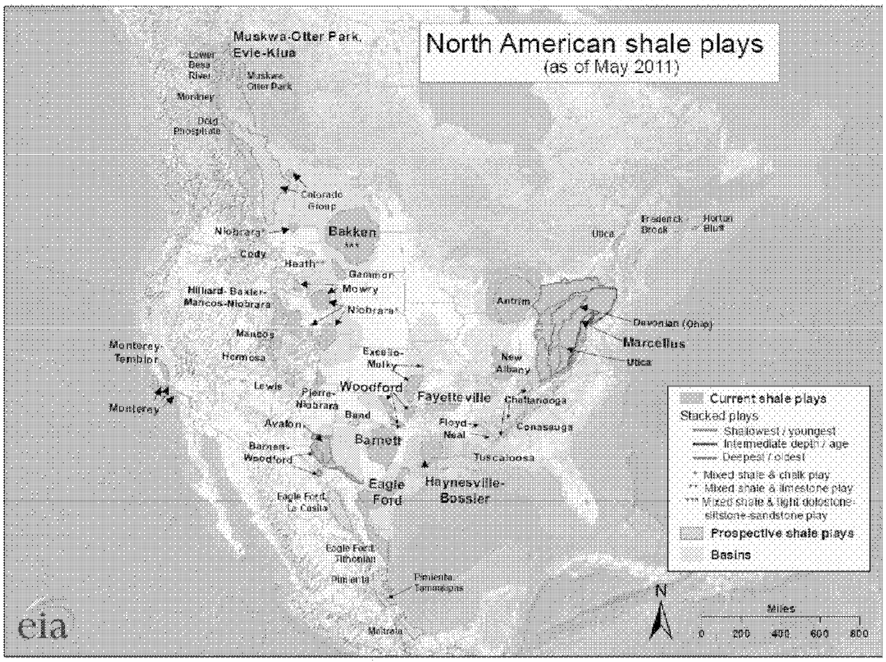
- The physical extent of the shale formation (e.g. prospective area, thickness and depth);
- The reservoir properties (e.g. pressure, average total organic content, thermal maturity and clay content);
- The resources (e.g. risked and technically recoverable gas in place);
- The activities related to shale gas (i.e. exploration or exploitation).

The potential of a shale formation to contain economic quantities of gas and thus, to have a ‘prospective’ value, is evaluated by identifying specific source rock parameters (i.e. physical extent of the shale formation and reservoir properties). For example:

- *Physical extent of the shale formation*: Prospective areas have a depth between 1,000 m to 5,000 m. Indeed, areas shallower than 1,000 m have a low pressure and low gas concentration, and the water content in their natural fracture systems may be high. In areas deeper than 5,000 m, reduced permeability may occur and there is a risk of much higher drilling and development costs;
- *Clay content (reservoir properties)*: Shales with a high clay content (i.e. shales deposited in non-marine settings) are more ductile and less responsive to hydraulic stimulation than shales with lower clay content (i.e. shales deposited in marine settings);

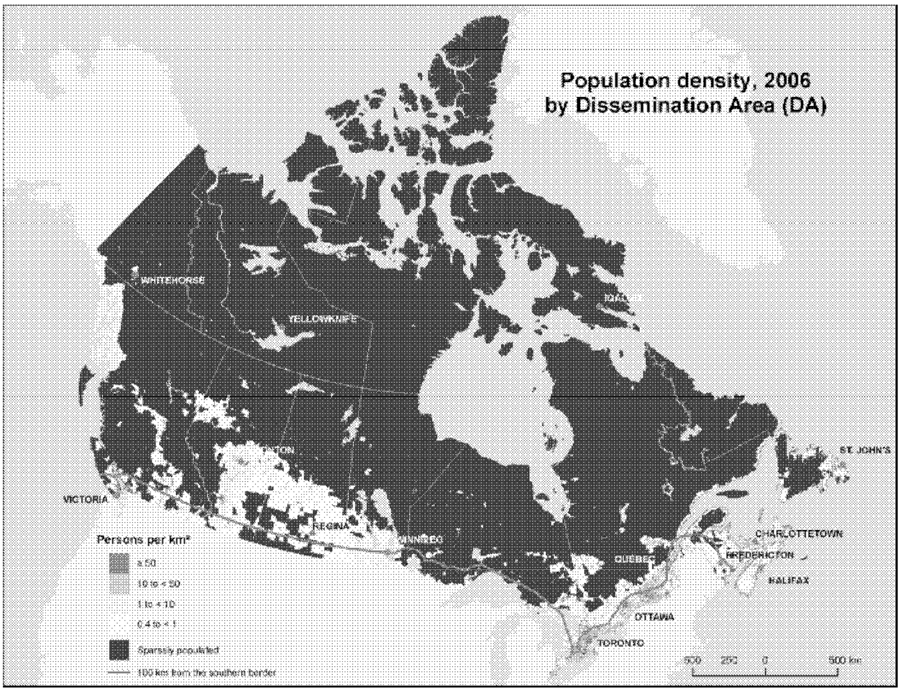
- Total organic content (TOC) (*reservoir properties)*: The TOC corresponds to the microorganism fossils and plant matter needed to create natural gas and oil. It is expressed as a percent by weight. An area with a TOC equal or greater than 2% has a prospective potential;
- *Thermal maturity (Ro) (reservoir properties)*: The thermal maturity measures the degree to which a formation has been exposed to high heat needed to break down organic matter into hydrocarbons. The thermal maturity of a prospective area needs to have a Ro greater than 1.0%. The zone of wet gas generation is in the 1.1-1.4% Ro range, whereas the zone of dry gas generation begins at a Ro of 1.4%. Dry gas is more thermally mature and consists primarily of methane, whereas wet gas is less thermally mature and may contain 'natural gas liquids' such as ethane, butane and propane. These natural gas liquids need to be separated from the methane. Wet gas is currently considered to be more valuable in the marketplace because the natural gas liquids have inherent value.

Several bibliographic resources (e.g. National Energy Board (2009), Ministère des Ressources Naturelles et de la Faune (2010)) provide estimates of some of these parameters. However, their methodology to obtain these data is not often reported and it may thus not be appropriate to compare the shale gas potential of the different provinces based on data coming from various bibliographic sources. Thus, to report the more updated and complete data for each province, all the quantitative data reported in Section 7 originate from a single source (EIA (2011a)) except for data from Ontario and New Brunswick because no or little information was presented by EIA for these provinces. It is important to note that the reservoir properties and the resource assessments are provided for the higher quality "prospective areas" of each shale gas basin and formation, and that data are estimates that will likely change as production methods and technologies improve.



Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

FIGURE 15: North American Shale Plays (May 2011)



Source: http://www12.statcan.ca/census-recensement/2006/as-sa/97-550/vignettes/m1-eng.htm

FIGURE 16: Canadian Population Density (2006)

7.1 Eastern Canada

Eastern Canada shows four potential shale gas plays (see Figure 15):

- The Utica and Lorraine Shales in the St. Lawrence Lowlands of the Appalachian Fold Belt of Quebec (limited data exist for the Lorraine shale);
- The Horton Bluff Shale in the Windsor Basin of Northern Nova Scotia;
- The Frederick Brook Shale in the Moncton Sub-Basin of the Maritimes Basin in New Brunswick.

7.1.1 Quebec

► In Quebec, shale gas is principally present in the Utica Shale. The Utica Shale underlies portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia in the United States. It also extends under adjacent parts of Ontario and Quebec in Canada. In Quebec, the Utica Shale play focuses on an area south of the St. Lawrence River between Montreal and Quebec City (the St. Lawrence Lowlands); this is populated area (1 to >50 persons/km^2) (see Figure 16). The Utica Shale is a black calcareous shale of severe geologic complexity containing three major faults.

► The depth to the top of the shale prospective area ranges from 3,000 to over 11,000 feet (900 to 3,350 m) and its thickness ranges from 1,000 to 3,000 feet (300 to 900 m). The shale is shallower along the southwestern and northwestern boundaries and deeper along the eastern boundaries (see Table 18 for more details).

► The risked shale gas in place in the Utica Shale prospective area is 155 Tcf (4,300 km^3). The estimated risked technically recoverable shale gas resource is 31 Tcf (900 km^3) because the shale has a severe geologic complexity and a moderate clay content (EIA (2011a)).

► From 2006 through the end of 2010, 29 exploratory wells (18 vertical and 11 horizontal wells) were drilled in Quebec. The hydraulic fracturing process occurred in 9 vertical wells and 6 horizontal wells. The Ministère des Ressources Naturelles et de la Faune (2010) estimates that the shale gas development in Quebec will be progressive and may lead to the drilling of 250 horizontal wells per year in the St. Lawrence Lowlands.

► On February 2011, the province's *Bureau d'Audiences Publiques sur l'Environnement (BAPE)* released a report on sustainable development of the shale gas industry in Quebec. This report was generated in the process of a public consultation which occurred to the request of citizens and citizen associations which showed their concerns and opposition about the shale gas industry in Quebec (where it may develop in regions with a high density of population). Following the Quebec government's acceptance of the BAPE report, a strategic environmental assessment (SEA) began on the development of the shale gas industry in Quebec. Previously, all hydraulic activities were prohibited while this SEA was being carried out, except if they were required for the purpose of conducting the SEA. However, on April 3, 2012, the Committee performing the SEA indicated that it would not recommend the authorization of fracturing activities to acquire scientific and technical information. It will rather rely on laboratory experiments on fracking. Currently, Quebec is undertaking the development of a new regulatory framework for oil and gas production in the province (BAPE (2011), Quebec Government (2011), Quebec Government (2012b)) (see also Section 4.3).

7.1.2 New Brunswick

► In New Brunswick, shale gas is present in the Frederick Brook Shale located in the Moncton Sub-Basin of the larger Maritimes Basin, a populated area (1 to >50 persons/km^2). The shale is structurally complex with extensive faulting and deformation.

► The depth to the top of the shale prospective area ranges from 3,000 to over 15,000 feet (900 to 4,600 m). The TOC ranges from 1% to 10% and typically from 3% to 5%. The thermal maturity ranges from <1% to >2% (EIA (2011a)).

► New Brunswick's shale gas reserves are not currently proven but a petroleum consultant estimated that the Frederick Brooke Shale could contain 67.3 Tcf (1,900 km^3) of shale gas.

► The shale gas exploration is still in the very early stages in New Brunswick. It will determine whether or not there are sufficient deposits to warrant a full-scale development of the industry (New Brunswick Canada (2011)). Two vertical wells were drilled in New Brunswick and have flowed 0.15 million cubic feet (mmcf) per day after undergoing small fractures (National Energy Board (2009)).

► Fracking has been a controversial issue in New Brunswick, where numerous groups and communities have come forth to oppose shale gas exploration. This is why the provincial government launched an open dialogue on the subject of shale gas and developed a new website containing factual information about this industry.

Currently, the provincial government is developing a new environmental protection plan that will aim to identify immediate, intermediate and long-term actions to ensure New Brunswick is positioned to protect citizens and their property as well as the vital aspects of their environment. The first phase of this plan will be released in spring 2012. As part of this work, the government will review and update New Brunswick's guidelines, laws and regulations for the oil and gas industry (New Brunswick Canada (2011)) (see also Section 4.3).

7.1.3 Nova Scotia

► In Nova Scotia, shale gas is found in the Horton Bluff Shale which is located in a populated area (1 to >50 persons/km^2). The Horton Bluff Shale is a complex and faulted shale.

► The depth of the prospective area ranges from 3,000 to 5,000 feet (900 to 1,500 m) and its thickness ranges from 500 to 1,000 feet (150 to 300 m) (see Table 18 for more details).

► The risked shale gas-in place in the Horton Bluff Shale prospective area is 9 Tcf (250 km^3). The estimated risked technically recoverable shale gas resource is 2 Tcf (56 km^3) because the shale has a severe geologic complexity (EIA (2011a)).

► As in New Brunswick, the shale gas exploration is still in the very early stages (National Energy Board (2009)).

► The Government of Nova Scotia (Departments of Energy and Environment) is presently reviewing the potential environmental impacts of hydraulic fracturing in onshore petroleum exploration. It also aims to determine how the environmental issues are managed in other jurisdictions and to identify the industries best practices. The scope of this review is primarily focused on issues about water. It is anticipated to be complete by early 2012. Hydraulic fracturing has been a controversial issue in Nova Scotia, where numerous groups and communities have come forth to oppose shale gas exploration (Nova Scotia Government (2012)) (see also Section 4.3).

7.1.4 Ontario

► In Ontario, shale gas deposits are located in three major zones (Carter*, et al.* (2009)) that are densely populated (1 to >50 persons/km^2):

- The Kettle Point Formation, known as the Antrim Shale in the United States. It is approximately 105 m thick and contains 3% to 15% of TOCs;
- The Collingwood/Blue Mountain formations known as the Utica Shale (also present in Quebec). It is about 50 m thick and contains 1% to 11% of TOCs;
- The northernmost limit of the Marcellus Shale that extends up from Pennsylvania and New York State (United States). It is about 12 m thick and contains 1% to 11% of TOCs.

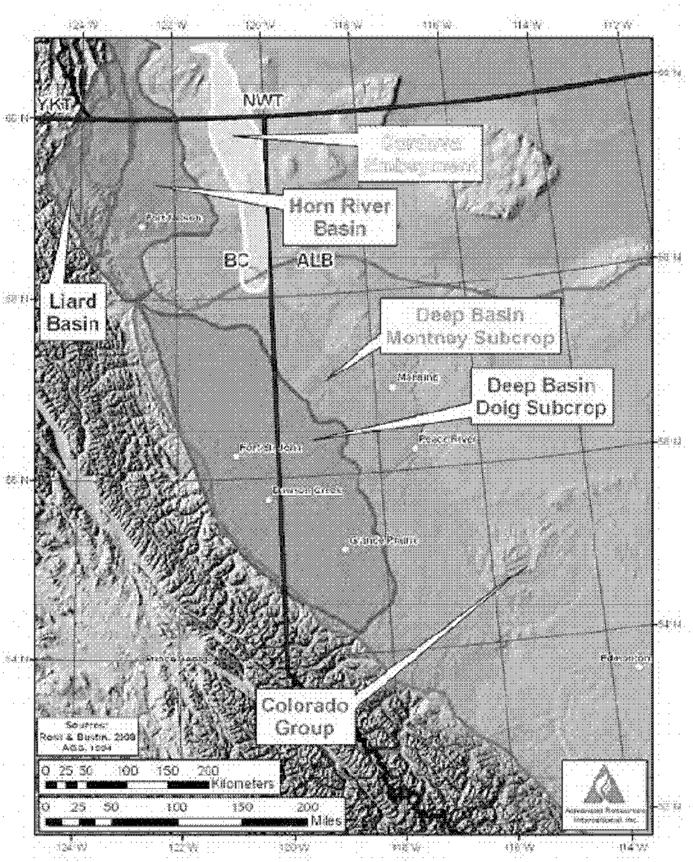
► Currently, there is no indication that Ontario hosts economic reserves of shale gas, and there are no proposals for shale gas drilling or exploration (Klose (2012)).

► The Oil, Gas and Salt Resources Act (OGSRA) administered by the Ministry of Natural Resources (MNR) was amended in 2010 to include shale gas extraction (Ontario Ministry of Natural Resources (2011)) (see also Section 4.3).

7.2 Western Canada

Western Canada presents five large sedimentary basins (Figure 17) that contain thick and organic-rich shales (EIA (2011a)):

- The Horn River, Cordova Embayment and Liard in Northern British Columbia and the Northwest Territory;
- The Deep Basin/Montney in Central Alberta and British Columbia;
- The Colorado Group in Central and Southern Alberta.



Source: EIA (2011a)

FIGURE 17: Shale Gas Basins of Western Canada

7.2.1 British Columbia

Most shale gas exploration activity in British Columbia has been in the Horn River Basin and the Cordova Embayment as well as in the Upper Montney play region (National Energy

Board (2009)). Currently, shale gas production principally occurs in the Cordova Embayment as well as in the Upper Montney play region.

British Columbia's Oil and Gas Activities Act (OGAA) came into effect in October 2010 to respond to increased pressures on its regulatory system as well as to better regulate the new technologies employed in modern oil and gas production (British Columbia Government (2012)) (see also Section 4.3).

7.2.1.1 Horn River Basin

► The Horn River Basin contains a stack of organic shales, with the Muskwa/Otter Park and the Evie/Klua Shales being the most prominent. It extends into the Northwest Territories. This Basin is located on a sparsely populated area.

► The depths to the top of the prospective shale areas range from 6,300 to 10,700 feet (1,900 to 3,300 m) and the thicknesses range from 110 to 730 feet (30 to 220 m). The average TOC is 3.5%. The shales contain very mature rocks that have been heated into the thermogenic gas window (thermogenic gas is formed when organic matter or oil is compressed at high temperatures and high pressures for a long period of time, see Section 2.1). The thermal maturity averages 3.8% (dry gas window with the potential for the presence of CO_2) (see Table 18 for more details).

► The risked shale gas in place in the Muskwa/Otter Park Shale prospective area is 378 Tcf (10,700 km^3). The estimated risked technically recoverable shale gas resource is 132 Tcf (3,700 km^3).

► The risked shale gas in place in the Evie/Klua Shale prospective area is 110 Tcf (3,100 km^3). The estimated risked technically recoverable shale gas resource is 33 Tcf (930 km^3) (EIA (2011a)).

► In the Horn River Basin, testing is still in the preliminary stage; approximately 20 horizontal wells were already drilled, hydraulically fractured and flowing into pipelines. Horn River Basin wells are very prolific and produce up to 16 mmcf per day on startup. Currently, production data from the Horn River Basin is confidential and estimating total shale-gas production is not possible (National Energy Board (2009)).

7.2.1.2 Cordova Embayment

► The Cordova Embayment is associated with the Horn River Basin. It extends into the Northwest Territories and is located in a sparsely populated area. Its dominant shale gas formation is the Muskwa/Otter Park Shale containing a moderately high quartz content favorable for hydraulic fracturing.

► The depth to the top of the shale prospective area averages 6,000 feet (1,800 m) and the thickness is approximately 230 feet (70 m) (see Table 18 for more details).

► The risked shale gas in place in the Muskwa/Otter Park Shale prospective area is 83 Tcf (2,350 km^3). The estimated risked technically recoverable shale gas resource is 29 Tcf (820 km^3) (EIA (2011a)).

► The Cordova Embayment has shale gas potential, although it is at an early stage of evaluation by the industry (National Energy Board (2009)).

7.2.1.3 Liard Basin

► The Liard Basin is separated from the Horton River Basin by a fault. Its northern boundary is currently defined by the British Columbia and the Yukon-Northwest Territories border. This Basin is located in a sparsely populated area. Its dominant shale gas formation is the Lower Besa River Shale.

► The depths to the top of the shale prospective area range from 6,600 to 12,300 feet (2,000 to 3,800 m) and the thickness is about 630 feet (190 m) (see Table 18 for more details).

► The risked shale gas-in place in the Lower Besa River Shale prospective area is 125 Tcf (3,500 km^3). The estimated risked technically recoverable shale gas resource is 31 Tcf (900 km^3).

► Shale gas exploration is underway in the Liard Basin. Three exploration wells have been completed and are in production (EIA (2011a)).

7.2.1.4 Deep Basin

► The Deep Basin of Alberta and British Columbia contains the Montney and Doig Phosphate Resource plays. These plays contain natural gas in conventional gas formations, tight gas and shale gas. They are located on sparsely to populated areas (0 to >50 persons/km^2).

► The depth to the top of the Montney Shale prospective area averages 6,000 feet (1,800 m) and its thickness is about 400 feet (120 m). The interval from the top of the Upper Montney to the base of the Lower Montney encompasses up to 1,000 feet (300 m) with an interval between the two units of up to 500 feet (150 m). Thus, some operators are planning to pursue stacked horizontal wells (i.e. horizontal wells at two elevations). The shale contains mature rock heated into the thermogenic gas window (see Table 18 for more details).

- The risked shale gas in place in the Montney Shale prospective area is 141 Tcf (4,000 km^3). The estimated risked technically recoverable shale gas resource is 49 Tcf (1,400 km^3).

- The depth to the top of the Doig Phosphate prospective area averages 9,250 feet (2,800 m) and the thickness ranges from 70 to 220 feet (20 to 67 m) (see Table 18 for more details).

- The risked shale gas in place in the Doig Phosphate Shale prospective area is 81 Tcf (2,300 km^3). The estimated risked technically recoverable shale gas resource is 20 Tcf (570 km^3) (EIA (2011a)).

- A significant number of wells have been drilled in the Montney and Doig resource plays. Since 2005, production of shale gas from horizontal wells from the Montney Formation has risen from 0 to 376 mmcf per day and is expected to continue to rise. As of July 2009, 234 horizontal wells were producing from the Montney Shale. It is often considered to be the most significant unconventional gas resource play in North America (National Energy Board (2009)).

7.2.2 Alberta

- In Alberta, the Colorado Group contains two shale formations of interest for natural gas development: the Fish Scale Shale Formation and the Second White Speckled (2WS). These shales are located in sparsely to densely populated areas (0 to >50 persons/km^2).

- In the prospective area, the depths to the top of these two shales range from 5,000 to 10,000 feet (1520 to 3,000 m). The Fish Scale Shale is generally about 200 feet (60 m) deeper than the 2WS (see 18 for more details) (EIA (2011a)). Shale gas has biogenic (gas formed at shallow depths and low temperatures by anaerobic bacteria, see Section 2.1) rather than thermogenic origins. Thus, it is suggested that the Colorado Group has a very low potential for natural gas liquids. Moreover, it has an under pressured reservoir which is more difficult to hydraulically fracture. Consequently, operators are pursuing the use of nitrogen or mixtures of propane and butane as fracturing fluid instead of hydraulic fracturing fluid (National Energy Board (2009)).

- The risked shale gas in place in the prospective area is 408 Tcf (11,500 km^3). The estimated risked technically recoverable shale gas resource is 61 Tcf (1,700 km^3) (EIA (2011a)).

- Because of poor rock conditions and the risk of caving in the wellbore, only vertical wells are planned in the Colorado Group. Currently, more than 3 mmcf per day (85,000 m^3

per day) is being produced out of a few dozen shallow wells (National Energy Board (2009)).

► In 2009, the Energy Resources Conservation Board (ERCB) embarked on the vision to 'be the best non-conventional regulator in the world by 2013'. In 2011, the ERCB initiated a corporate-wide Unconventional Gas Regulatory Framework Project to develop and implement a new regulatory framework for the development of Alberta's coal bed, shale gas, and tight gas (Government of Alberta (2012a)) (see also Section 4.3).

7.3 Summary of Canadian Shale Gas Potential and Activities

The following Table summarizes the shale gas reservoir properties and resources in the Canadian provinces for which detailed information is available (i.e. Quebec, Nova Scotia, Alberta and British Columbia). No data for Ontario and New Brunswick is presented in this Table since for these provinces, shale gas exploration is in the early stages and the risked gas-in place has not been estimated yet.

As can be seen in Table 18, shale gas exploitation only occurs in Western Canada but exploration is largely underway in Eastern Canada. The Muskwa/Otter Park shale located in the Horn River Basin (British Columbia/Northwest Territories) is the shale having the largest risked recoverable gas. This shale is situated in a sparsely populated area contrarily to the Colorado Group in Alberta (including populated cities such as Calgary and Edmonton), the Utica Shale in Quebec (including very populated areas between Montreal and Quebec) and the Horton Bluff Shale in Nova Scotia.

TABLE 18: Shale Gas Reservoir Properties and Resources Determined in the Prospective Shale Gas Areas in Quebec, Nova Scotia, Alberta and British Columbia

	BASIN	APPALACHIAN FOLD BELT (9,000 KM^2)	WINDSOR BASIN (1,700 KM^2)	HORN RIVER (21,000 KM^2)		CORDOVA (11,100 KM^2)	LIARD (11,100 KM^2)	DEEP BASIN (6,800 KM^2)		COLORADO GROUP (320,000 KM^2)
	SHALE FORMATION	UTICA	HORTON BLUFF	MUSKWA/ OTTER PARK	EVIE/KLUA	MUSKWA/ OTTER PARK	LOWER BESA RIVER	MONTNEY SHALE	DOIG PHOSPHATE	2WS AND FISH SCALES
Localization	Provinces/ Territories	Quebec	Nova Scotia	British Columbia, Northwest Territories	British Columbia, Northwest Territories	British Columbia, Northwest Territories	British Columbia, Yukon-Northwest Territories	British Columbia, Alberta	British Columbia, Alberta	Alberta
	Population Density[1] (persons/km^2)	Populated (1 to >50)	Populated (1 to >50)	Sparsely populated	Sparsely populated	Sparsely populated	Sparsely populated	Sparse to Populated (0 to >50)	Sparse to Populated (0 to >50)	Sparse to Populated (0 to >50)
Physical Extent	Prospective Area (km^2)	7,500	1,350	8,600	8,600	7,400	5,000	4,900	7,800	126,000
	Interval Thickness (m)	300 - 900	150 - 300	76 - 220	30 - 62	45 - 105	150 - 335	60 - 335	20 - 67	90 - 600
	Average Depth (m)	2,400	1,200	2,400	2,500	1,800	2,700	1,800	2,800	2,100
Reservoir Properties	Reservoir Pressure	Slightly Overpressured	Normal	Moderately Overpressured	Moderately Overpressured	Normal	Moderately Overpressured	Overpressured	Moderately Overpressured	Underpressured
	Average TOC (wt. %)	2.0%	5.0%	3.5%	3.5%	2.0%	3.5%	3.0%	5.0%	2.4%
	Thermal Maturity (Ro)	2.0%	2.0%	3.8%	3.8%	2.5%	3.8%	1.5%	1.1%	0.61%
	Clay Content	Low	Unknown	Low	Low	Low	Low	Low	Low	Low
Resources	Risked Gas-in-place (Tcf)	155	9	378	110	83	125	141	81	408
	Risked Recoverable Gas (Tcf)	31	2	132	33	29	31	49	20	61
Activities	Exploration/ Exploitation	Exploration	Exploration	Exploration and Exploitation		Exploration	Exploration	Exploration and Exploitation in the Upper Montney		Exploitation (vertical wells only)

Source: EIA (2011a)

[1] Based on Statistics Canada (2006): http://www12.statcan.ca/census-recensement/2006/as-sa/97-550/vignettes/m1-eng.htm

8. SUMMARY OF DATA GAPS

During shale gas exploration and exploitation, all processes including drilling, hydraulic fracturing, shale gas production, transport, wastewater disposal and treatment as well as venting and flaring, are potential sources of air and/or water contamination. To adequately identify all potential health hazards related to air and/or water contamination by shale gas exploration and exploitation, and to allow further quantification of the health impacts, a large amount of data should be collected and documented, mostly on a case-by-case basis. The main data gaps are listed below.

Drilling, Well Completion and Shale Gas Production:

- Complete list of chemicals used during fracturing and drilling;
- Quantity of each chemical additive used during hydraulic fracturing;
- Identification of the by-products possibly resulting from the degradation of the chemicals injected or from reactions between injected chemicals and compounds naturally present underground. No data about the occurrence and identity of such by-products is currently available;
- Quantity of fracturing fluid remaining in the formation;
- Data concerning the fracture behaviour during and after hydraulic fracturing and shale gas exploration;
- Chemical fate and transport over time of hydraulic fracturing fluids remaining underground;
- Data concerning well integrity during its lifetime;
- Estimates of the time for fluids to migrate through the fractures in the rock up to the water table;
- Data concerning the venting and flaring of shale gas during all exploration and exploitation stages (e.g. frequency and duration).
- Water quality data before, during and after shale gas exploitation (short-term, intermediate and long-term monitoring);
- Air quality data before, during and after shale gas exploitation;
- Radioactivity data in the cuttings and on the well pad (air).

Wastewater:

- Data concerning the disposal of wastewater such as rates of disposal, volumes generated and disposal methods (e.g. treatment, injection);
- Data concerning the pits (e.g. membrane integrity, storage installations and duration of wastewater storage);

- Complete characterization of wastewater (e.g. organic and inorganic chemicals, radioelements, salinity and pH) with monitoring over time;
- Data concerning the ability of the plant designated to treat wastewaters originating from the shale gas industry (potentially salted and contaminated with radioactive elements and various organic and inorganic chemicals) and to deal with increased volumes of wastewater, especially during specific events (e.g. high amount of stormwater);
- Data concerning the quality of the water and the sludge after treatment (complete characterization and monitoring);
- Estimates of the time for injected wastewater to migrate through the fractures in the rock up to the water table;
- Data concerning the quality of groundwater in the area potentially affected by the underground injections of wastewater (long-term monitoring).

The risks to human health depend on both the impacts of shale gas exploration and exploitation, and on the levels of human exposure. The level of human exposure depends on several parameters, the most important being the proximity to the source of contamination (i.e. the wells, the well pads as well as the entire area that may be affected by the shale gas operations (underground water and air contamination)) and the source of drinking water. These factors are both an issue of concern in many cases. For instance, in Quebec, the Utica Shale is located in an area south of the St. Lawrence River between Montreal and Quebec City where the population density is elevated and the agricultural resources are important.

To characterize the risks to public health associated with potential contamination of air and drinking water related to shale gas exploration and exploitation, both generic, site-specific and project-specific information must be documented (in addition to the data gaps identified previously):

- Identity and quantity of the contaminants used, created and released during all exploration and exploitation phases;
- Toxicological data regarding the chemicals and compounds used, created and released during all exploration and exploitation phases;
- Data concerning the intensity and the duration of the population exposure (i.e. characterization of the sources of emissions, thorough description of the project, estimates of migration to groundwater and monitoring data);
- Characteristics of the exposed population (e.g. distance between the population and the emissions sources, age and sensitivity).

9. CONCLUSION

The present review led to the identification of potential sources of water and air contamination related to shale gas exploration/exploitation. The main findings can be summarized as follows:

- ► Any step of shale gas exploration/exploitation may represent a potential source of drinking water and air contamination;
- ► Hydraulic fracturing and wastewater disposal were identified as the main potential sources of risk.
  - Although the risks related to hydraulic fracturing itself (creation of multiple cracks underground) and to further injection of chemicals are currently unknown (lack of monitoring data and lack of information on migration through the cracks in the long-term), it is anticipated that this practice could potentially contaminate the groundwater after several years or decades.
  - Wastewater disposal appeared to be amongst the most potent sources of water contamination, due to either the risk of leakage from the pits, the possible inadequacy/inefficiency of the treatment before release into the environment or the possibility of migration into the groundwater when wastewater is disposed of by injection underground.
  - The contaminants of interest potentially released into surface or groundwater by all sources may include:
    - Compounds naturally present underground, such as metals, salts and naturally occurring radioactive materials (NORMs);
    - Compounds intentionally added during the processes to facilitate drilling or for hydraulic fracturing (organic and inorganic additives such as methanol, ethylene glycol, naphthalene, benzene, ethylbenzene, copper or lead);
    - By-products possibly resulting from the degradation of the fracturing chemicals or from reactions between fracturing chemicals and compounds naturally present underground. No data about the occurrence and identity of such by-products is currently available.
- ► Air contaminants are principally the same as those encountered in each conventional natural gas exploitation process since the sources are similar. However, there may be additional contaminants specific to shale gas operations, such as the volatile chemicals

potentially present in wastewater. The whole set of pollutants potentially emitted into the air by shale gas exploration/exploitation includes:

- Air pollutants originating from vehicles and engines fuelled by diesel: nitrogen oxides (NOx), particulate matter (PM), sulphur dioxides (SOx) and carbon monoxide (CO);
- Volatile organic compounds (VOCs) potentially emitted by leaks from equipment, wells, gas transport, venting or volatilization from wastewater;
- Other shale gas constituents, such as methane (main constituent) and heavier hydrocarbons (e.g. ethane, propane and butane) and impurities (e.g. H_2S, CO_2 and N_2);
- Naturally occurring contaminants including NORMs (e.g. radon gas).

The toxicity of some chemicals potentially released or emitted by the shale gas industry into water resources and ambient air is documented. Data indicate that chemicals used, emitted and/or released during shale gas exploration/exploitation include chemicals known for their carcinogenicity to human and/or animals, for their acute/chronic toxicity (e.g. adverse effects on the respiratory tract, the central nervous system, the skin, eye and sensory organs, etc.) and for their potential for endocrine disruption. It should be reiterated that carcinogenic compounds are thought to present a risk at any dose and that endocrine disruptors usually act at very low doses.

Thus, although quantitative data are lacking, the qualitative data available indicate that potential contamination of water and atmospheric emissions related to the shale gas industry may present hazards to public health, especially for the local population. The potential hazards to water and air are directly related to:

► The processes used for exploration/exploitation, including (not limited to) the method used for fracturing (e.g. hydraulic fracturing) and the type of wells (horizontal, vertical, stacked);

► Well-specific characteristics, such as well depth or composition of the hydraulic fluid (specific to each well and to each injection);

► Well pad-specific characteristics, including (not limited to) the management of wastewater (e.g. storage in pits, treatment, underground injection), the management of stormwater runoff, venting and flaring;

- Site-specific characteristics, especially those related to the geological and hydrogeological context, such as shale depth, water tables depths and permeability of the soil between the shale and the water tables;
- The regulatory framework and the conformity to all regulations, standards and good practices by the exploiting company and its subcontractors.

Considering that the risk of hazards to water and air are mainly specific to the project, it may be difficult to assess the impacts of the shale gas industry to human health on a generic basis. Rather, impacts to human health should be estimated on a case-by-case basis. However, the present review revealed that to conduct a reliable assessment, many data gaps should be filled. A detailed list of the data gaps was provided in the report.

The United States are currently the only country where large scale shale gas exploitation is already active. In Canada, exploration is taking place in several provinces and shale gas is currently produced in Western Canada, however large-scale commercial production has not yet been achieved. Outside North America, shale gas has not yet been produced commercially however exploratory activities are being undertaken in some countries such as Poland. Although there is a large increase of interest for this resource, shale gas exploration/exploitation has raised a lot of concerns in several countries (e.g. France and Canada) due to their potential impacts on the water resources and air quality.

The regulatory framework is relatively similar in the United States and in Canada, although its development in Canada is less mature.

- In the United States, the development and production of oil and gas (including shale gas) are regulated under a complex set of federal, state and local laws;
- In Canada, oil and gas drilling and production fall under provincial jurisdiction except on federal land, and under territorial jurisdiction in the Yukon. Regulations of the oil and gas sector vary between provincial jurisdictions. Regulations related to exploitation currently exist in Alberta and British Columbia, where shale gas exploitation already occurs. There are also some regulations in other provinces, and further regulations are expected in the future. Some governments are currently working to document the issues related to shale gas exploitation; reviews conducted by the governments of Quebec and New Brunswick are expected in 2012-2013.

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APPENDIX A

List of the Chemical Components of Hydraulic Fracturing Products Used between 2005 and 2009 by 14 Oil and Gas Leading Companies in the United States (Waxman*, et al.* (2011))

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
1	1-(1-naphthylmethyl)quinolinium chloride	65322-65-8	1
2	1,2,3-propanetricarboxylic acid, 2-hydroxy-, trisodium salt, dihydrate	6132-04-3	1
3	1,2,3-trimethylbenzene	526-73-8	1
4	1,2,4-trimethylbenzene	95-63-6	21
5	1,2-benzisothiazol-3	2634-33-5	1
6	1,2-dibromo-2,4-dicyanobutane	35691-65-7	1
7	1,2-ethanediaminium, N, N'-bis[2-[bis(2-hydroxyethyl)methylammonio]ethyl]-N,N'-		
	bis(2-hydroxyethyl)-N,N'-dimethyl-,tetrachloride	138879-94-4	2
8	1,3,5-trimethylbenzene	108-67-8	3
9	1,6-hexanediamine dihydrochloride	6055-52-3	1
10	1,8-diamino-3,6-dioxaoctane	929-59-9	1
11	1-hexanol	111-27-3	1
12	1-methoxy-2-propanol	107-98-2	3
13	2,2`-azobis (2-amidopropane) dihydrochloride	2997-92-4	1
14	2,2-dibromo-3-nitrilopropionamide	10222-01-2	27
15	2-acrylamido-2-methylpropanesulphonic acid sodium salt polymer	*	1
16	2-bromo-2-nitropropane-1,3-diol	52-51-7	4
17	2-butanone oxime	96-29-7	1
18	2-hydroxypropionic acid	79-33-4	2
19	2-mercaptoethanol (Thioglycol)	60-24-2	13
20	2-methyl-4-isothiazolin-3-one	2682-20-4	4
21	2-monobromo-3-nitrilopropionamide	1113-55-9	1
22	2-phosphonobutane-1,2,4-tricarboxylic acid	37971-36-1	2
23	2-phosphonobutane-1,2,4-tricarboxylic acid, potassium salt	93858-78-7	1
24	2-substituted aromatic amine salt	*	1
25	4,4'-diaminodiphenyl sulfone	80-08-0	3
26	5-chloro-2-methyl-4-isothiazolin-3-one	26172-55-4	5
27	Acetaldehyde	75-07-0	1
28	Acetic acid	64-19-7	56
29	Acetic anhydride	108-24-7	7
30	Acetone	67-64-1	3
31	Acetophenone	98-86-2	1
32	Acetylenic alcohol	*	1
33	Acetyltriethyl citrate	77-89-4	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
34	Acrylamide	79-06-1	2
35	Acrylamide copolymer	*	1
36	Acrylamide copolymer	38193-60-1	1
37	Acrylate copolymer	*	1
38	Acrylic acid, 2-hydroxyethyl ester	818-61-1	1
39	Acrylic acid/2-acrylamido-methylpropylsulfonic acid copolymer	37350-42-8	1
40	Acrylic copolymer	403730-32-5	1
41	Acrylic polymers	*	1
42	Acrylic polymers	26006-22-4	2
43	Acyclic hydrocarbon blend	*	1
44	Adipic acid	124-04-9	6
45	Alcohol alkoxylate	*	5
46	Alcohol ethoxylates	*	2
47	Alcohols	*	9
48	Alcohols, C11-15-secondary, ethoxylated	68131-40-8	1
49	Alcohols, C12-14-secondary	126950-60-5	4
50	Alcohols, C12-14-secondary, ethoxylated	84133-50-6	19
51	Alcohols, C12-15, ethoxylated	68131-39-5	2
52	Alcohols, C12-16, ethoxylated	103331-86-8	1
53	Alcohols, C12-16, ethoxylated	68551-12-2	3
54	Alcohols, C14-15, ethoxylated	68951-67-7	5
55	Alcohols, C9-11-iso-, C10-rich, ethoxylated	78330-20-8	4
56	Alcohols, C9-C22	*	1
57	Aldehyde	*	4
58	Aldol	107-89-1	1
59	Alfa-Alumina	*	5
60	Aliphatic acid	*	1
61	Aliphatic alcohol polyglycol ether	68015-67-8	1
62	Aliphatic amine derivative	120086-58-0	2
63	Alkaline bromide salts	*	2
64	Alkanes, C10-14	93924-07-3	2
65	Alkanes, C13-16-iso	68551-20-2	2
66	Alkanolamine	150-25-4	3
67	Alkanolamine chelate of zirconium alkoxide (Zirconium complex)	197980-53-3	4
68	Alkanolamine/aldehyde condensate	*	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
69	Alkenes	*	1
70	Alkenes, C>10 alpha-	64743-02-8	3
71	Alkenes, C>8	68411-00-7	2
72	Alkoxylated alcohols	*	1
73	Alkoxylated amines	*	6
74	Alkoxylated phenol formaldehyde resin	63428-92-2	1
75	Alkyaryl sulfonate	*	1
76	Alkyl (C12-16) dimethyl benzyl ammonium chloride	68424-85-1	7
77	Alkyl (C6-C12) alcohol, ethoxylated	68439-45-2	2
78	Alkyl (C9-11) alcohol, ethoxylated	68439-46-3	1
79	Alkyl alkoxylate	*	9
80	Alkyl amine	*	2
81	Alkyl amine blend in a metal salt solution	*	1
82	Alkyl aryl amine sulfonate	255043-08-04	1
83	Alkyl benzenesulfonic acid	68584-22-5	2
84	Alkyl esters	*	2
85	Alkyl hexanol	*	1
86	Alkyl ortho phosphate ester	*	1
87	Alkyl phosphate ester	*	3
88	Alkyl quaternary ammonium chlorides	*	4
89	Alkylaryl sulfonate	*	1
90	Alkylaryl sulphonic acid	27176-93-9	1
91	Alkylated quaternary chloride	*	5
92	Alkylbenzenesulfonic acid	*	1
93	Alkylethoammonium sulfates	*	1
94	Alkylphenol ethoxylates	*	1
95	Almandite and pyrope garnet	1302-62-1	1
96	Aluminium isopropoxide	555-31-7	1
97	Aluminum	7429-90-5	2
98	Aluminum chloride	*	3
99	Aluminum chloride	1327-41-9	2
100	Aluminum oxide (alpha-Alumina)	1344-28-1	24
101	Aluminum oxide silicate	12068-56-3	1
102	Aluminum silicate (mullite)	1302-76-7	38
103	Aluminum sulfate hydrate	10043-01-3	1
104	Amides, tallow, n-[3-(dimethylamino)propyl],n-oxides	68647-77-8	4

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
105	Amidoamine	*	1
106	Amine	*	7
107	Amine bisulfite	13427-63-9	1
108	Amine oxides	*	1
109	Amine phosphonate	*	3
110	Amine salt	*	2
111	Amines, C14-18; C16-18-unsaturated, alkyl, ethoxylated	68155-39-5	1
112	Amines, coco alkyl, acetate	61790-57-6	3
113	Amines, polyethylenepoly-, ethoxylated, phosphonomethylated	68966-36-9	1
114	Amines, tallow alkyl, ethoxylated	61791-26-2	2
115	Amino compounds	*	1
116	Amino methylene phosphonic acid salt	*	1
117	Amino trimethylene phosphonic acid	6419-19-8	2
118	Ammonia	7664-41-7	7
119	Ammonium acetate	631-61-8	4
120	Ammonium alcohol ether sulfate	68037-05-8	1
121	Ammonium bicarbonate	1066-33-7	1
122	Ammonium bifluoride (Ammonium hydrogen difluoride)	1341-49-7	10
123	Ammonium bisulfate	7783-20-2	3
124	Ammonium bisulfite	10192-30-0	15
125	Ammonium C6-C10 alcohol ethoxysulfate	68187-17-7	4
126	Ammonium C8-C10 alkyl ether sulfate	68891-29-2	4
127	Ammonium chloride	12125-02-9	29
128	Ammonium fluoride	12125-01-8	9
129	Ammonium hydroxide	1336-21-6	4
130	Ammonium nitrate	6484-52-2	2
131	Ammonium persulfate (Diammonium peroxidisulfate)	7727-54-0	37
132	Ammonium salt	*	1
133	Ammonium salt of ethoxylated alcohol sulfate	*	1
134	Amorphous silica	99439-28-8	1
135	Amphoteric alkyl amine	61789-39-7	1
136	Anionic copolymer	*	3
137	Anionic polyacrylamide	*	1
138	Anionic polyacrylamide	25085-02-3	6
139	Anionic polyacrylamide copolymer	*	3

	Chemical Component	CAS Number	Number of Products Containing the Chemical (n=750 chemicals)
140	Anionic polymer	*	2
141	Anionic polymer in solution	*	1
142	Anionic polymer, sodium salt	9003-04-7	1
143	Anionic water-soluble polymer	*	2
144	Antifoulant	*	1
145	Antimonate salt	*	1
146	Antimony pentoxide	1314-60-9	2
147	Antimony potassium oxide	29638-69-5	4
148	Antimony trichloride	10025-91-9	2
149	a-organic surfactants	61790-29-8	1
150	Aromatic alcohol glycol ether	*	2
151	Aromatic aldehyde	*	2
152	Aromatic ketones	224635-63-6	2
153	Aromatic polyglycol ether	*	1
154	Barium sulfate	7727-43-7	3
155	Bauxite	1318-16-7	16
156	Bentonite	1302-78-9	2
157	Benzene	71-43-2	3
158	Benzene, C10-16, alkyl derivatives	68648-87-3	1
159	Benzenecarboperoxoic acid, 1,1-dimethylethyl ester	614-45-9	1
160	Benzenemethanaminium	3844-45-9	1
161	Benzenesulfonic acid, C10-16-alkyl derivs., potassium salts	68584-27-0	1
162	Benzoic acid	65-85-0	11
163	Benzyl chloride	100-44-7	8
164	Biocide component	*	3
165	Bis(1-methylethyl)naphthalenesulfonic acid, cyclohexylamine salt	68425-61-6	1
166	Bishexamethylenetriamine penta methylene phosphonic acid	35657-77-3	1
167	Bisphenol A/Epichlorohydrin resin	25068-38-6	5
168	Bisphenol A/Novolac epoxy resin	28906-96-9	1
169	Borate	12280-03-4	2
170	Borate salts	*	5
171	Boric acid	10043-35-3	18
172	Boric acid, potassium salt	20786-60-1	1
173	Boric acid, sodium salt	1333-73-9	2
174	Boric oxide	1303-86-2	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
175	b-tricalcium phosphate	7758-87-4	1
176	Butanedioic acid	2373-38-8	4
177	Butanol	71-36-3	3
178	Butyl glycidyl ether	2426-08-6	5
179	Butyl lactate	138-22-7	4
180	C10-C16 ethoxylated alcohol	68002-97-1	4
181	C-11 to C-14 n-alkanes, mixed	*	1
182	C12-C14 alcohol, ethoxylated	68439-50-9	3
183	Calcium carbonate	471-34-1	1
184	Calcium carbonate (Limestone)	1317-65-3	9
185	Calcium chloride	10043-52-4	17
186	Calcium chloride, dihydrate	10035-04-8	1
187	Calcium fluoride	7789-75-5	2
188	Calcium hydroxide	1305-62-0	9
189	Calcium hypochlorite	7778-54-3	1
190	Calcium oxide	1305-78-8	6
191	Calcium peroxide	1305-79-9	5
192	Carbohydrates	*	3
193	Carbon dioxide	124-38-9	4
194	Carboxymethyl guar gum, sodium salt	39346-76-4	7
195	Carboxymethyl hydroxypropyl guar	68130-15-4	11
196	Cellophane	9005-81-6	2
197	Cellulase	9012-54-8	7
198	Cellulase enzyme	*	1
199	Cellulose	9004-34-6	1
200	Cellulose derivative	*	2
201	Chloromethylnaphthalene quinoline quaternary amine	15619-48-4	3
202	Chlorous ion solution	*	2
203	Choline chloride	67-48-1	3
204	Chromates	*	1
205	Chromium (iii) acetate	1066-30-4	1
206	Cinnamaldehyde (3-phenyl-2-propenal)	104-55-2	5
207	Citric acid (2-hydroxy-1,2,3 propanetricarboxylic acid)	77-92-9	29
208	Citrus terpenes	94266-47-4	11
209	Coal, granular	50815-10-6	1
210	Cobalt acetate	71-48-7	1

	Chemical Component	CAS Number	Number of Products containing the Chemical (n=750 chemicals)
211	Cocaidopropyl betaine	61789-40-0	2
212	Cocamidopropylamine oxide	68155-09-9	1
213	Coco bis-(2-hydroxyethyl) amine oxide	61791-47-7	1
214	Cocoamidopropyl betaine	70851-07-9	1
215	Cocomidopropyl dimethylamine	68140-01-2	1
216	Coconut fatty acid diethanolamide	68603-42-9	1
217	Collagen (Gelatin)	9000-70-8	6
218	Complex alkylaryl polyo-ester	*	1
219	Complex aluminum salt	*	2
220	Complex organometallic salt	*	2
221	Complex substituted keto-amine	143106-84-7	1
222	Complex substituted keto-amine hydrochloride	*	1
223	Copolymer of acrylamide and sodium acrylate	25987-30-8	1
224	Copper	7440-50-8	1
225	Copper iodide	7681-65-4	1
226	Copper sulfate	7758-98-7	3
227	Corundum (Aluminum oxide)	1302-74-5	48
228	Crotonaldehyde	123-73-9	1
229	Crystalline silica - cristobalite	14464-46-1	44
230	Crystalline silica - quartz (SiO2)	14808-60-7	207
231	Crystalline silica, tridymite	15468-32-3	2
232	Cumene	98-82-8	6
233	Cupric chloride	7447-39-4	10
234	Cupric chloride dihydrate	10125-13-0	7
235	Cuprous chloride	7758-89-6	1
236	Cured acrylic resin	*	7
237	Cured resin	*	4
238	Cured silicone rubber-polydimethylsiloxane	63148-62-9	1
239	Cured urethane resin	*	3
240	Cyclic alkanes	*	1
241	Cyclohexane	110-82-7	1
242	Cyclohexanone	108-94-1	1
243	Decanol	112-30-1	2
244	Decyl-dimethyl amine oxide	2605-79-0	4
245	Dextrose monohydrate	50-99-7	1
246	D-Glucitol	50-70-4	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
247	Di (2-ethylhexyl) phthalate	117-81-7	3
248	Di (ethylene glycol) ethyl ether acetate	112-15-2	4
249	Diatomaceous earth	61790-53-2	3
250	Diatomaceous earth, calcined	91053-39-3	7
251	Dibromoacetonitrile	3252-43-5	1
252	Dibutylaminoethanol (2-dibutylaminoethanol)	102-81-8	4
253	Di-calcium silicate	10034-77-2	1
254	Dicarboxylic acid	*	1
255	Didecyl dimethyl ammonium chloride	7173-51-5	1
256	Diesel	*	1
257	Diesel	68334-30-5	3
258	Diesel	68476-30-2	4
259	Diesel	68476-34-6	43
260	Diethanolamine (2,2-iminodiethanol)	111-42-2	14
261	Diethylbenzene	25340-17-4	1
262	Diethylene glycol	111-46-6	8
263	Diethylene glycol monomethyl ether	111-77-3	4
264	Diethylene triaminepenta (methylene phosphonic acid)	15827-60-8	1
265	Diethylenetriamine	111-40-0	2
266	Diethylenetriamine, tall oil fatty acids reaction product	61790-69-0	1
267	Diisopropylnaphthalenesulfonic acid	28757-00-8	2
268	Dimethyl formamide	68-12-2	5
269	Dimethyl glutarate	1119-40-0	1
270	Dimethyl silicone	*	2
271	Dioctyl sodium sulfosuccinate	577-11-7	1
272	Dipropylene glycol	25265-71-8	1
273	Dipropylene glycol monomethyl ether (2-methoxymethylethoxy propanol)	34590-94-8	12
274	Di-secondary-butylphenol	53964-94-6	3
275	Disodium EDTA	139-33-3	1
276	Disodium ethylenediaminediacetate	38011-25-5	1
277	Disodium ethylenediaminetetraacetate dihydrate	6381-92-6	1
278	Disodium octaborate tetrahydrate	12008-41-2	1
279	Dispersing agent	*	1
280	d-Limonene	5989-27-5	11
281	Dodecyl alcohol ammonium sulfate	32612-48-9	2
282	Dodecylbenzene sulfonic acid	27176-87-0	14

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
283	Dodecylbenzene sulfonic acid salts	42615-29-2	2
284	Dodecylbenzene sulfonic acid salts	68648-81-7	7
285	Dodecylbenzene sulfonic acid salts	90218-35-2	1
286	Dodecylbenzenesulfonate isopropanolamine	42504-46-1	1
287	Dodecylbenzenesulfonic acid, monoethanolamine salt	26836-07-7	1
288	Dodecylbenzenesulphonic acid, morpholine salt	12068-08-5	1
289	EDTA/Copper chelate	*	2
290	EO-C7-9-iso-, C8-rich alcohols	78330-19-5	5
291	Epichlorohydrin	25085-99-8	5
292	Epoxy resin	*	5
293	Erucic amidopropyl dimethyl betaine	149879-98-1	3
294	Erythorbic acid	89-65-6	2
295	Essential oils	*	6
296	Ethanaminium, n,n,n-trimethyl-2-[(1-oxo-2-propenyl)oxy]-,chloride, polymer with		
297	2-propenamide	69418-26-4	4
298	Ethanol (Ethyl alcohol)	64-17-5	36
299	Ethanol, 2-(hydroxymethylamino)-	34375-28-5	1
300	Ethanoldiglycine disodium salt	135-37-5	1
301	Ether salt	25446-78-0	2
302	Ethoxylated 4-nonylphenol (Nonyl phenol ethoxylate)	26027-38-3	9
303	Ethoxylated alcohol	104780-82-7	1
304	Ethoxylated alcohol	78330-21-9	2
305	Ethoxylated alcohols	*	3
306	Ethoxylated alkyl amines	*	1
307	Ethoxylated amine	*	1
308	Ethoxylated amines	61791-44-4	1
309	*Ethoxylated fatty acid ester*	*	1
310	Ethoxylated nonionic surfactant	*	1
311	Ethoxylated nonyl phenol	*	8
312	*Ethoxylated nonyl phenol*	68412-54-4	10
313	Ethoxylated nonyl phenol	9016-45-9	38
314	Ethoxylated octyl phenol	68987-90-6	1
315	Ethoxylated octyl phenol	*9002-93-1*	1
316	Ethoxylated octyl phenol	9036-19-5	3
317	Ethoxylated oleyl amine	13127-82-7	2
318	Ethoxylated oleyl amine	26635-93-8	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
319	Ethoxylated sorbitol esters	*	1
320	Ethoxylated tridecyl alcohol phosphate	9046-01-9	2
321	Ethoxylated undecyl alcohol	127036-24-2	2
322	Ethyl acetate	141-78-6	4
323	Ethyl acetoacetate	141-97-9	1
324	Ethyl octynol (1-octyn-3-ol,4-ethyl-)	5877-42-9	5
325	Ethylbenzene	100-41-4	28
326	Ethylene glycol (1,2-ethanediol)	107-21-1	119
327	Ethylene glycol monobutyl ether (2-butoxyethanol)	111-76-2	126
328	Ethylene oxide	75-21-8	1
329	Ethylene oxide-nonylphenol polymer	*	1
330	Ethylenediaminetetraacetic acid	60-00-4	1
331	Ethylene-vinyl acetate copolymer	24937-78-8	1
332	Ethylhexanol (2-ethylhexanol)	104-76-7	18
333	Fatty acid ester	*	1
334	Fatty acid, tall oil, hexa esters with sorbitol, ethoxylated	61790-90-7	1
335	Fatty acids	*	1
336	Fatty alcohol alkoxylate	*	1
337	Fatty alkyl amine salt	*	1
338	Fatty amine carboxylates	*	1
339	Fatty quaternary ammonium chloride	61789-68-2	1
340	Ferric chloride	7705-08-0	3
341	Ferric sulfate	10028-22-5	7
342	Ferrous sulfate, heptahydrate	7782-63-0	4
343	Fluoroaliphatic polymeric esters	*	1
344	Formaldehyde	50-00-0	12
345	Formaldehyde polymer	*	2
346	Formaldehyde, polymer with 4-(1,1-dimethyl)phenol, methyloxirane and oxirane	30704-64-4	3
347	Formaldehyde, polymer with 4-nonylphenol and oxirane	30846-35-6	1
348	Formaldehyde, polymer with ammonia and phenol	35297-54-2	2
349	Formamide	75-12-7	5
350	Formic acid	64-18-6	24
351	Fumaric acid	110-17-8	8
352	Furfural	98-01-1	1
353	Furfuryl alcohol	98-00-0	3

	Chemical Component	CAS Number	Number of Products Containing the Chemical (n=750 chemicals)
354	Glass fiber	65997-17-3	3
355	Gluconic acid	526-95-4	1
356	Glutaraldehyde	111-30-8	20
357	Glycerol (1,2,3-Propanetriol, Glycerine)	56-81-5	16
358	Glycol ethers	*	9
359	Glycol ethers	9004-77-7	4
360	Glyoxal	107-22-2	3
361	Glyoxylic acid	298-12-4	1
362	Guar gum	9000-30-0	41
363	Guar gum derivative	*	12
364	Haloalkyl heteropolycycle salt	*	6
365	Heavy aromatic distillate	68132-00-3	1
366	Heavy aromatic petroleum naphtha	64742-94-5	45
367	Heavy catalytic reformed petroleum naphtha	64741-68-0	10
368	Hematite	*	5
369	Hemicellulase	9025-56-3	2
370	Hexahydro-1,3,5-tris(2-hydroxyethyl)-s-triazine (Triazine)	4719-04-4	4
371	Hexamethylenetetramine	100-97-0	37
372	Hexanediamine	124-09-4	1
373	Hexanes	*	1
374	*Hexylene glycol*	107-41-5	5
375	Hydrated aluminum silicate	1332-58-7	4
376	Hydrocarbon mixtures	8002-05-9	1
377	Hydrocarbons	*	3
378	Hydrodesulfurized kerosine (petroleum)	64742-81-0	3
379	Hydrodesulfurized light catalytic cracked distillate (petroleum)	68333-25-5	1
380	Hydrodesulfurized middle distillate (petroleum)	64742-80-9	1
381	Hydrogen chloride (Hydrochloric acid)	7647-01-0	42
382	Hydrogen fluoride (Hydrofluoric acid)	7664-39-3	2
383	Hydrogen peroxide	7722-84-1	4
384	Hydrogen sulfide	7783-06-4	1
385	Hydrotreated and hydrocracked base oil	*	2
386	Hydrotreated heavy naphthenic distillate	64742-52-5	3
387	Hydrotreated heavy paraffinic petroleum distillates	64742-54-7	1
388	Hydrotreated heavy petroleum naphtha	64742-48-9	7

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
389	Hydrotreated light petroleum distillates	64742-47-8	89
390	Hydrotreated middle petroleum distillates	64742-46-7	3
391	Hydroxyacetic acid (Glycolic acid)	79-14-1	6
392	Hydroxyethylcellulose	9004-62-0	1
393	Hydroxyethylethylenediaminetriacetic acid, trisodium salt	139-89-9	1
394	Hydroxylamine hydrochloride	5470-11-1	1
395	Hydroxypropyl guar gum	39421-75-5	2
396	Hydroxysultaine	*	1
397	Inner salt of alkyl amines	*	2
398	Inorganic borate	*	3
399	Inorganic particulate	*	1
400	Inorganic salt	*	1
401	Inorganic salt	533-96-0	1
402	Inorganic salt	7446-70-0	1
403	Instant coffee purchased off the shelf	*	1
404	Inulin, carboxymethyl ether, sodium salt	430439-54-6	1
405	Iron oxide	1332-37-2	2
406	Iron oxide (Ferric oxide)	1309-37-1	18
407	Iso amyl alcohol	123-51-3	1
408	Iso-alkanes/n-alkanes	*	10
409	Isobutanol (Isobutyl alcohol)	78-83-1	4
410	Isomeric aromatic ammonium salt	*	1
411	Isooctanol	26952-21-6	1
412	Isooctyl alcohol	68526-88-0	1
413	Isooctyl alcohol bottoms	68526-88-5	1
414	Isopropanol (Isopropyl alcohol, Propan-2-ol)	67-63-0	274
415	Isopropylamine	75-31-0	1
416	Isotridecanol, ethoxylated	9043-30-5	1
417	Kerosene	8008-20-6	13
418	Lactic acid	10326-41-7	1
419	Lactic acid	50-21-5	1
420	L-Dilactide	4511-42-6	1
421	Lead	7439-92-1	1
422	Light aromatic solvent naphtha	64742-95-6	11
423	Light catalytic cracked petroleum distillates	64741-59-9	1
424	Light naphtha distillate, hydrotreated	64742-53-6	1

	Chemical Component	CAS Number	Number of Products Containing the Chemical (n=750 chemicals)
425	Low toxicity base oils	*	1
426	Maghemite	*	2
427	Magnesium carbonate	546-93-0	1
428	Magnesium chloride	7786-30-3	4
429	Magnesium hydroxide	1309-42-8	4
430	Magnesium iron silicate	1317-71-1	3
431	Magnesium nitrate	10377-60-3	5
432	Magnesium oxide	1309-48-4	18
433	Magnesium peroxide	1335-26-8	2
434	*Magnesium peroxide*	*14452-57-4*	*4*
435	Magnesium phosphide	12057-74-8	1
436	Magnesium silicate	1343-88-0	3
437	Magnesium silicate hydrate (talc)	14807-96-6	2
438	Magnetite	*	3
439	Medium aliphatic solvent petroleum naphtha	64742-88-7	10
440	Metal salt	*	2
441	*Metal salt solution*	*	*1*
442	Methanol (Methyl alcohol)	67-56-1	342
443	Methyl isobutyl carbinol (Methyl amyl alcohol)	108-11-2	3
444	Methyl salicylate	119-36-8	6
445	Methyl vinyl ketone	78-94-4	2
446	Methylcyclohexane	108-87-2	1
447	Mica	12001-26-2	3
448	*Microcrystalline silica*	1317-95-9	1
449	Mineral	*	1
450	Mineral Filler	*	1
451	Mineral spirits (stoddard solvent)	8052-41-3	2
452	Mixed titanium ortho ester complexes	*	1
453	Modified alkane	*	1
454	Modified cycloaliphatic amine adduct	*	3
455	*Modified lignosulfonate*	*	1
456	Monoethanolamine (Ethanolamine)	141-43-5	17
457	Monoethanolamine borate	26038-87-9	1
458	Morpholine	110-91-8	2
459	Mullite	1302-93-8	55
460	n,n-dibutylthiourea	109-46-6	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
461	N,N-dimethyl-1-octadecanamine-HCl	*	1
462	N,N-dimethyloctadecylamine	124-28-7	3
463	N,N-dimethyloctadecylamine hydrochloride	1613-17-8	2
464	n,n'-Methylenebisacrylamide	110-26-9	1
465	n-alkyl dimethyl benzyl ammonium chloride	139-08-2	1
466	Naphthalene	91-20-3	44
467	Naphthalene derivatives	*	1
468	Naphthalenesulphonic acid, bis (1-methylethyl)-methyl derivatives	99811-86-6	1
469	Natural asphalt	12002-43-6	1
470	n-cocoamidopropyl-n,n-dimethyl-n-2-hydroxypropylsulfobetaine	68139-30-0	1
471	n-dodecyl-2-pyrrolidone	2687-96-9	1
472	N-heptane	142-82-5	1
473	Nickel sulfate hexahydrate	10101-97-0	2
474	Nitrilotriacetamide	4862-18-4	4
475	Nitrilotriacetic acid	139-13-9	6
476	Nitrilotriacetonitrile	7327-60-8	3
477	Nitrogen	7727-37-9	9
478	n-Methylpyrrolidone	872-50-4	1
479	Nonane, all isomers	*	1
480	Non-hazardous salt	*	1
481	Nonionic surfactant	*	1
482	Nonyl phenol ethoxylate	*	2
483	Nonyl phenol ethoxylate	9016-45-6	2
484	Nonyl phenol ethoxylate	9018-45-9	1
485	Nonylphenol	25154-52-3	1
486	Nonylphenol, ethoxylated and sulfated	9081-17-8	1
487	N-propyl zirconate	*	1
488	N-tallowalkyltrimethylenediamines	*	1
489	Nuisance particulates	*	2
490	Nylon fibers	25038-54-4	2
491	Octanol	111-87-5	2
492	Octyltrimethylammonium bromide	57-09-0	1
493	Olefinic sulfonate	*	1
494	Olefins	*	1
495	Organic acid salt	*	3

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
496	Organic acids	*	1
497	Organic phosphonate	*	1
498	Organic phosphonate salts	*	1
499	Organic phosphonic acid salts	*	6
500	Organic salt	*	1
501	Organic sulphur compound	*	2
502	Organic titanate	*	2
503	Organiophilic clay	*	2
504	Organo-metallic ammonium complex	*	1
505	Other inorganic compounds	*	1
506	Oxirane, methyl-, polymer with oxirane, mono-C10-16-alkyl ethers, phosphates	68649-29-6	1
507	Oxyalkylated alcohol	*	6
508	Oxyalkylated alcohols	228414-35-5	1
509	Oxyalkylated alkyl alcohol	*	1
510	Oxyalkylated alkylphenol	*	1
511	Oxyalkylated fatty acid	*	2
512	Oxyalkylated phenol	*	1
513	Oxyalkylated polyamine	*	1
514	Oxylated alcohol	*	1
515	Paraffin wax	8002-74-2	1
516	Paraffinic naphthenic solvent	*	1
517	Paraffinic solvent	*	5
518	Paraffins	*	1
519	Perlite	93763-70-3	1
520	Petroleum distillates	*	26
521	Petroleum distillates	64742-65-0	1
522	Petroleum distillates	64742-97-5	1
523	Petroleum distillates	68477-31-6	3
524	Petroleum gas oils	*	1
525	Petroleum gas oils	64741-43-1	1
526	Phenol	108-95-2	5
527	Phenol-formaldehyde resin	9003-35-4	32
528	Phosphate ester	*	6
529	Phosphate esters of alkyl phenyl ethoxylate	68412-53-3	1
530	Phosphine	*	1
531	Phosphonic acid	*	1

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
532	Phosphonic acid	129828-36-0	1
533	Phosphonic acid	13598-36-2	3
534	Phosphonic acid (dimethlamino(methylene))	29712-30-9	1
535	Phosphonic acid, [nitrilotris(methylene)]tris-, pentasodium salt	2235-43-0	1
536	Phosphoric acid	7664-38-2	7
537	Phosphoric acid ammonium salt	*	1
538	Phosphoric acid, mixed decyl, octyl and ethyl esters	68412-60-2	3
539	Phosphorous acid	10294-56-1	1
540	Phthalic anhydride	85-44-9	2
541	Pine oil	8002-09-3	5
542	Plasticizer	*	1
543	Poly(oxy-1,2-ethanediyl)	24938-91-8	1
544	Poly(oxy-1,2-ethanediyl), alpha-(4-nonylphenyl)-omega-hydroxy-, branched		
	(Nonylphenol ethoxylate)	127087-87-0	3
545	Poly(oxy-1,2-ethanediyl), alpha-hydro-omega-hydroxy	65545-80-4	1
546	Poly(oxy-1,2-ethanediyl), alpha-sulfo-omega-(hexyloxy)-, ammonium salt	63428-86-4	3
547	Poly(oxy-1,2-ethanediyl),a-(nonylphenyl)-w-hydroxy-, phosphate	51811-79-1	1
548	Poly-(oxy-1,2-ethanediyl)-alpha-undecyl-omega-hydroxy	34398-01-1	6
549	Poly(sodium-p-styrenesulfonate)	25704-18-1	1
550	Poly(vinyl alcohol)	25213-24-5	2
551	Polyacrylamides	9003-05-8	2
552	Polyacrylamides	*	1
553	Polyacrylate	*	1
554	Polyamine	*	2
555	Polyanionic cellulose	*	2
556	Polyepichlorohydrin, trimethylamine quaternized	51838-31-4	1
557	Polyetheramine	9046-10-0	3
558	Polyether-modified trisiloxane	27306-78-1	1
559	Polyethylene glycol	25322-68-3	20
560	Polyethylene glycol ester with tall oil fatty acid	9005-02-1	1
561	Polyethylene polyammonium salt	68603-67-8	2
562	Polyethylene-polypropylene glycol	9003-11-6	5
563	Polylactide resin	*	3
564	Polyoxyalkylenes	*	1

	Chemical Component	CAS Number	Number of Products Containing the Chemical (n=750 chemicals)
565	Polyoxyethylene castor oil	61791-12-6	1
566	Polyphosphoric acid, esters with triethanolamine, sodium salts	68131-72-6	1
567	Polypropylene glycol	25322-69-4	1
568	Polysaccharide	*	20
569	Polyvinyl alcohol	*	1
570	Polyvinyl alcohol	9002-89-5	2
571	Polyvinyl alcohol/polyvinylacetate copolymer	*	1
572	Potassium acetate	127-08-2	1
573	Potassium carbonate	584-08-7	12
574	Potassium chloride	7447-40-7	29
575	Potassium formate	590-29-4	3
576	Potassium hydroxide	1310-58-3	25
577	Potassium iodide	7681-11-0	6
578	Potassium metaborate	13709-94-9	3
579	Potassium metaborate	16481-66-6	3
580	Potassium oxide	12136-45-7	1
581	Potassium pentaborate	*	1
582	Potassium persulfate	7727-21-1	9
583	Propanol (Propyl alcohol)	71-23-8	18
584	Propanol, [2(2-methoxy-methylethoxy) methylethoxyl]	20324-33-8	1
585	Propargyl alcohol (2-propyn-1-ol)	107-19-7	46
586	Propylene carbonate (1,3-dioxolan-2-one, methyl-)	108-32-7	2
587	Propylene glycol (1,2-propanediol)	57-55-6	18
588	Propylene oxide	75-56-9	1
589	Propylene pentamer	15220-87-8	1
590	p-Xylene	106-42-3	1
591	Pyridinium, 1-(phenylmethyl)-, ethyl methyl derivatives, chlorides	68909-18-2	9
592	Pyrogenic silica	112945-52-5	3
593	Quaternary amine compounds	*	3
594	Quaternary amine compounds	61789-18-2	1
595	Quaternary ammonium compounds	*	9
596	Quaternary ammonium compounds	19277-88-4	1
597	Quaternary ammonium compounds	68989-00-4	1
598	Quaternary ammonium compounds	8030-78-2	1
599	Quaternary ammonium compounds, dicoco alkyldimethyl, chlorides	61789-77-3	2

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
600	Quaternary ammonium salts	*	2
601	Quaternary compound	*	1
602	Quaternary salt	*	2
603	Quaternized alkyl nitrogenated compound	68391-11-7	2
604	Rafinnates (petroleum), sorption process	64741-85-1	2
605	Residues (petroleum), catalytic reformer fractionator	64741-67-9	10
606	Resin	8050-09-7	2
607	Rutile	1317-80-2	2
608	Salt of phosphate ester	*	3
609	Salt of phosphono-methylated diamine	*	1
610	Salts of oxyalkylated fatty amines	68551-33-7	1
611	Secondary alcohol	*	7
612	Silica (Silicon dioxide)	7631-86-9	47
613	Silica, amorphous	*	3
614	Silica, amorphous precipitated	67762-90-7	1
615	Silicon carboxylate	681-84-5	1
616	Silicon dioxide (Fused silica)	60676-86-0	7
617	Silicone emulsion	*	1
618	Sodium (C14-16) olefin sulfonate	68439-57-6	4
619	Sodium 2-ethylhexyl sulfate	126-92-1	1
620	Sodium acetate	127-09-3	6
621	Sodium acid pyrophosphate	7758-16-9	5
622	Sodium alkyl diphenyl oxide sulfonate	28519-02-0	1
623	Sodium aluminate	1302-42-7	1
624	Sodium aluminum phosphate	7785-88-8	1
625	Sodium bicarbonate (Sodium hydrogen carbonate)	144-55-8	10
626	Sodium bisulfite	7631-90-5	6
627	Sodium bromate	7789-38-0	10
628	Sodium bromide	7647-15-6	1
629	Sodium carbonate	497-19-8	14
630	Sodium chlorate	7775-09-9	1
631	Sodium chloride	7647-14-5	48
632	Sodium chlorite	7758-19-2	8
633	Sodium cocaminopropionate	68608-68-4	2
634	Sodium diacetate	126-96-5	2
635	Sodium erythorbate	6381-77-7	4

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
636	Sodium glycolate	2836-32-0	2
637	Sodium hydroxide (Caustic soda)	1310-73-2	80
638	Sodium hypochlorite	7681-52-9	14
639	Sodium lauryl-ether sulfate	68891-38-3	3
640	Sodium metabisulfite	7681-57-4	1
641	Sodium metaborate	7775-19-1	2
642	Sodium metaborate tetrahydrate	35585-58-1	6
643	Sodium metasilicate, anhydrous	6834-92-0	2
644	Sodium nitrite	7632-00-0	1
645	Sodium oxide (Na2O)	1313-59-3	1
646	Sodium perborate	1113-47-9	1
647	Sodium perborate	7632-04-4	1
648	Sodium perborate tetrahydrate	10486-00-7	4
649	Sodium persulfate	7775-27-1	6
650	Sodium phosphate	*	2
651	Sodium polyphosphate	68915-31-1	1
652	Sodium salicylate	54-21-7	1
653	Sodium silicate	1344-09-8	2
654	Sodium sulfate	7757-82-6	7
655	Sodium tetraborate	1330-43-4	7
656	Sodium tetraborate decahydrate	1303-96-4	10
657	Sodium thiosulfate	7772-98-7	10
658	Sodium thiosulfate pentahydrate	10102-17-7	3
659	Sodium trichloroacetate	650-51-1	1
660	Sodium tripolyphosphate	7758-29-4	2
661	Sodium xylene sulfonate	1300-72-7	3
662	Sodium zirconium lactate	174206-15-6	1
663	Solvent refined heavy naphthenic petroleum distillates	64741-96-4	1
664	Sorbitan monooleate	1338-43-8	1
665	Stabilized aqueous chlorine dioxide	10049-04-4	1
666	Stannous chloride	7772-99-8	1
667	Stannous chloride dihydrate	10025-69-1	6
668	Starch	9005-25-8	5
669	Steam cracked distillate, cyclodiene dimer, dicyclopentadiene polymer 68131-87-3		1
670	Steam-cracked petroleum distillates	64742-91-2	6
671	Straight run middle petroleum distillates	64741-44-2	5

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
672	Substituted alcohol	*	2
673	Substituted alkene	*	1
674	Substituted alkylamine	*	2
675	Sucrose	57-50-1	1
676	Sulfamic acid	5329-14-6	6
677	Sulfate	*	1
678	Sulfonate acids	*	1
679	Sulfonate surfactants	*	1
680	Sulfonic acid salts	*	1
681	Sulfonic acids, petroleum	61789-85-3	1
682	Sulfur compound	*	1
683	Sulfuric acid	7664-93-9	9
684	Sulfuric acid, monodecyl ester, sodium salt	142-87-0	2
685	Sulfuric acid, monooctyl ester, sodium salt	142-31-4	2
686	Surfactants	*	13
687	Sweetened middle distillate	64741-86-2	1
688	Synthetic organic polymer	9051-89-2	2
689	Tall oil (Fatty acids)	61790-12-3	4
690	Tall oil, compound with diethanolamine	68092-28-4	1
691	Tallow soap	*	2
692	Tar bases, quinoline derivatives, benzyl chloride-quaternized	72480-70-7	5
693	Tergitol	68439-51-0	1
694	Terpene hydrocarbon byproducts	68956-56-9	3
695	Terpenes	*	1
696	Terpenes and terpenoids, sweet orange-oil	68647-72-3	2
697	Terpineol	8000-41-7	1
698	Tert-butyl hydroperoxide	75-91-2	6
699	Tetra-calcium-alumino-ferrite	12068-35-8	1
700	Tetraethylene glycol	112-60-7	1
701	Tetraethylenepentamine	112-57-2	2
702	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (Dazomet)	533-74-4	13
703	Tetrakis (hydroxymethyl) phosphonium sulfate	55566-30-8	12
704	Tetramethyl ammonium chloride	75-57-0	14
705	Tetrasodium 1-hydroxyethylidene-1,1-diphosphonic acid	3794-83-0	1
706	Tetrasodium ethylenediaminetetraacetate	64-02-8	10

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
707	Thiocyanate sodium	540-72-7	1
708	Thioglycolic acid	68-11-1	6
709	Thiourea	62-56-6	9
710	Thiourea polymer	68527-49-1	3
711	Titanium complex	*	1
712	Titanium oxide	13463-67-7	19
713	Titanium, isopropoxy (triethanolaminate)	74665-17-1	2
714	Toluene	108-88-3	29
715	Treated ammonium chloride (with anti-caking agent a or b)	12125-02-9	1
716	Tributyl tetradecyl phosphonium chloride	81741-28-8	5
717	Tri-calcium silicate	12168-85-3	1
718	Tridecyl alcohol	112-70-9	1
719	Triethanolamine (2,2,2-nitrilotriethanol)	102-71-6	21
720	Triethanolamine polyphosphate ester	68131-71-5	3
721	Triethanolamine titanate	36673-16-2	1
722	Triethanolamine zirconate	101033-44-7	6
723	Triethanolamine zirconium chelate	*	1
724	Triethyl citrate	77-93-0	1
725	Triethyl phosphate	78-40-0	1
726	Triethylene glycol	112-27-6	3
727	Triisopropanolamine	122-20-3	5
728	Trimethylammonium chloride	593-81-7	1
729	Trimethylbenzene	25551-13-7	5
730	Trimethyloctadecylammonium (1-octadecanaminium, N,N,N-trimethyl-, chloride)	112-03-8	6
731	Tris(hydroxymethyl)aminomethane	77-86-1	1
732	Trisodium ethylenediaminetetraacetate	150-38-9	1
733	Trisodium ethylenediaminetriacetate	19019-43-3	1
734	Trisodium nitrilotriacetate	18662-53-8	8
735	Trisodium nitrilotriacetate (Nitrilotriacetic acid, trisodium salt monohydrate)	5064-31-3	9
736	Trisodium ortho phosphate	7601-54-9	1
737	Trisodium phosphate dodecahydrate	10101-89-0	1
738	Ulexite	1319-33-1	1
739	Urea	57-13-6	3
740	Wall material	*	1
741	Walnut hulls	*	2

	CHEMICAL COMPONENT	CAS NUMBER	NUMBER OF PRODUCTS CONTAINING THE CHEMICAL (n=750 chemicals)
742	White mineral oil	8042-47-5	8
743	Xanthan gum	11138-66-2	6
744	Xylene	1330-20-7	44
745	Zinc chloride	7646-85-7	1
746	Zinc oxide	1314-13-2	2
747	Zirconium complex	*	10
748	Zirconium dichloride oxide	7699-43-6	1
749	Zirconium oxide sulfate	62010-10-0	2
750	Zirconium sodium hydroxy lactate complex (Sodium zirconium lactate)	113184-20-6	2

* Appearance of the components on at least one Material Safety Data Sheet (MSDS) without an identifying CAS number. The MSDSs in these cases marked the CAS as proprietary, noted that the CAS was not available, or left the CAS field blank. Components marked with an asterisk may be duplicative of other components on this list, but Committee staffs had no way of identifying such duplicates without the identifying CAS number.

APPENDIX B

List of the Chemical Components Used During the Hydraulic Fracturing Process, Analysed by the Tyndall Centre and Giving Rise to Concern for Human Health and the Environment (Wood, *et al.* (2011))

CAS NUMBER	SUBSTANCES	PRIORITY LIST[1]	PBT OR LISTED ON FIRST PRIORITY LIST (1st PL)	AQUATIC TOXICITY (CHRONIC AND/OR ACUTE)	ACUTE TOXICITY	CARCINOGEN[2]	MUTAGEN[3]	REPRO[4]
2634-33-5	1,2 Benzisothiazolin-2-one or 1,2-benzisothiazolin-3-one			Yes	Yes			
95-63-6	1,2,4 trimethylbenzene			Yes	Yes			
123-91-1	1,4 Dioxane	2				Carc 2		
52-51-7	2-Bromo-2-nitro-1,3-propanediol			Yes	Yes			
111-76-2	2-Butoxy ethanol	4			Yes			
107-19-7	2-Propyn-1-ol /Progargyl Alcohol			Yes	Yes			
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-			Yes	Yes			
108-24-7	Acetic Anhydride				Yes			
79-06-1	Acrylamide	1			Yes	Carc 1B	Muta 1B	Repr 2
1336-21-6	Ammonia			Yes				
12125-02-9	Ammonium Chloride				Yes			
1341-49-7	Ammonium hydrogen-difluoride				Yes			
7727-54-0	Ammonium Persulfate /Diammonium peroxidisulphate				Yes			
7664-41-7	Aqueous ammonia			Yes	yes			
71-43-2	Benzene	1	1st PL			Carc 1A	Muta 1B	
10043-35-3	Boric acid	4						
71-36-3	Butan-1-ol				Yes			
10049-04-4	Chlorine Dioxide			Yes	Yes			
10049-04-5	Chlorine Dioxide			Yes	Yes			
7758-98-7	Copper (II) Sulfate			Yes	Yes			
111-46-6	Diethylene Glycol				Yes			
107-21-1	Ethane-1,2-diol /Ethylene Glycol				Yes			
100-41-4	Ethyl Benzene	1			Yes			
9003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-,polymerwithoxirane)							
75-21-8	Ethylene oxide				Yes	Carc 1B	Muta 1B	
50-00-0	Formaldehyde				Yes	Carc 2		

CAS Number	Substances	Priority List[1]	PBT or Listed on First Priority List (1st PL)	Aquatic Toxicity (Chronic and/or Acute)	Acute Toxicity	Carcinogen[2]	Mutagen[3]	Repro[4]
75-12-7	Formamide							Repr 1B
111-30-8	Glutaraldehyde			Yes	Yes			
7647-01-0	Hydrochloric Acid /Hydrogen Chloride /muriatic acid				Yes			
7722-84-1	Hydrogen Peroxide	2			Yes			
5470-11-1	Hydroxylamine hydrochloride			Yes	Yes	Carc 2		
98-82-8	Isopropylbenzene (cumene)	1						
64742-95-6	Light aromatic solvent naphtha					Carc 1B	Muta 1B	
67-56-1	Methanol				Yes			
8052-41-3	Mineral spirits /Stoddard Solvent					Carc 1B	Muta 1B	
141-43-5	Monoethanolamine				Yes			
64742-48-9	Naphtha (petroleum),hydrotreated heavy					Carc 1B	Muta 1B	
91-20-3	Naphthalene	1	1st PL	Yes	Yes	Carc 2		
38640-62-9	Naphthalene bis(1-methylethyl)		PBT					
64742-65-0	Petroleum Base Oil					Carc 1B		
64741-68-0	Petroleum naphtha					Carc 1B	Muta 1B	
1310-58-3	Potassium Hydroxide				Yes			
107-98-2	Propylene glycol monomethyl ether	4						
7631-90-5	Sodium bisulfate				Yes			
3926-62-3	Sodium Chloroacetate			Yes	Yes			
1310-73-2	Sodium Hydroxide	4						
7681-52-9	Sodium hypochlorite	2			Yes			
1303-96-4	Sodium tetraborate decahydrate							Repr 1B
5329-14-6	Sulfamic acid			Yes				
533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)			Yes	Yes			
64-02-8	Tetrasodium Ethylenediaminetetraacetate	1			Yes			
68-11-1	Thioglycolic acid				Yes			

CAS NUMBER	SUBSTANCES	PRIORITY LIST[1]	PBT OR LISTED ON FIRST PRIORITY LIST (1st PL)	AQUATIC TOXICICY (CHRONIC AND/OR ACUTE)	ACUTE TOXICITY	CARCINOGEN[2]	MUTAGEN[3]	REPRO[4]
62-56-6	Thiourea			Yes	Yes	Carc 2		Repr 2
108-88-3	Toluene	2						Repr 2
5064-31-3	Trisodium Nitrilotriacetate	3			Yes	Carc 2		
1330-20-7	Xylene				Yes			

PBT: Persistent, bioaccumulative and toxic

Summary of Hazard categories (European Parliament and the Council of the European Union (2008)):

1. Since 1994, the European Commission has published four lists of substances requiring immediate attention because of their potential effects to man or the environment. There are 141 substances on the lists.

2. **Carcinogenicity:**

Category 1: Known or presumed human carcinogens. A substance is classified in Category 1 for carcinogenicity on the basis of epidemiological and/or animal data. A substance may be further distinguished as:

- Category 1A: known to have carcinogenic potential for humans, classification largely based on human evidence, or
- Category 1B: presumed to have carcinogenic potential for humans, classification largely based on animal evidence.

Category 2: Suspected human carcinogens.

1. **Mutagenicity** :

Category 1: Substances known to induce heritable mutations or to be regarded as if they induce heritable mutations in the germ cells of humans. Substances known to induce heritable mutations in the germ cells of humans.

- Category 1A: based on positive evidence from human epidemiological studies. Substances to be regarded as if they induce heritable mutations in the germ cells of humans.
- Category 1B: based on:
  - ✓ positive result(s) from in vivo heritable germ cell mutagenicity tests in mammals; or
  - ✓ positive result(s) from in vivo somatic cell mutagenicity tests in mammals, in combination with some evidence that the substance has potential to cause mutations to germ cells. It is possible to derive this supporting evidence from mutagenicity/genotoxicity tests in germ cells in vivo, or by demonstrating the ability of the substance or its metabolite(s) to interact with the genetic material of germ cells; or
  - ✓ positive results from tests showing mutagenic effects in the germ cells of humans, without demonstration of transmission to progeny; for example, an increase in the frequency of aneuploidy in sperm cells of exposed people.

Category 2: Substances which cause concern for humans owing to the possibility that they may induce heritable mutations in the germ cells of humans

2. **Reproductive toxicants** :

Category 1: Known or presumed human reproductive toxicant. Substances are classified in Category 1 for reproductive toxicity when they are known to have produced an adverse effect on sexual function and fertility, or on development in humans or when there is evidence from animal studies, possibly supplemented with other information, to provide a strong presumption that the substance has the capacity to interfere with reproduction in humans. The classification of a substance is further distinguished on the basis of whether the evidence for classification is primarily from human data (Category 1A) or from animal data (Category 1B).

- Category 1A: known human reproductive toxicant. The classification of a substance in Category 1A is largely based on evidence from humans.
- Category 1B: presumed human reproductive toxicant

Category 2: Suspected human reproductive toxicant.

APPENDIX C

Composition of Flowback in a Limited Number of Samples from Pennsylvania and West Virginia (NYSDEC (2011))

CAS #	PARAMETER	TOTAL NUMBER OF SAMPLES	NUMBER OF DETECTS	MIN	MEDIAN	MAX	UNITS
Inorganic compounds							
07439-90-5	Aluminum	43	12	0.02	0.07	1.2	mg/L
	Aluminum (dissolved)	22	1	1.37	1.37	1.37	mg/L
07440-36-0	Antimony	34	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	48	45	11.3	44.8	382	mg/L
07440-38-2	Arsenic	43	7	0.015	0.09	0.123	mg/L
07440-39-3	Barium	48	47	0.553	1450	15,700	mg/L
	Barium (dissolved)	22	22	0.313	212	19,200	mg/L
	Barium Strontium P.S.	145	145	17	1320	6,400	mg/L
07440-41-7	Beryllium	43	1	422	422	422	mg/L
	Bicarbonates	150	150	0	183	17,08	mg/L
07440-42-8	Boron	23	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	15	15	11.3	607	3,070	mg/L
07440-43-9	Cadmium	43	6	0.007	0.025	1.2	mg/L
	Cadmium (dissolved)	22	2	0.017	0.026	0.035	mg/L
07440-70-2	Calcium	187	186	29.9	4,241	123,000	mg/L
	Calcium (dissolved)	3	3	2,360	22,300	31,500	mg/L
	Carbon Dioxide	5	5	193	232	294	mg/L
	Chloride	193	193	287	56,900	228,000	mg/L
07440-47-3	Chromium	43	9	0.009	0.082	760	mg/L
	Chromium (dissolved)	22	2	0.058	0.075	0.092	mg/L
	Chromium (VI) (dissolved)	19	10	0.0126	0.539	7.81	mg/L
07440-48-4	Cobalt	30	6	0.03	0.3975	0.62	mg/L
	Cobalt (dissolved)	19	1	0.489	0.489	0.489	mg/L
07440-50-8	Copper	43	8	0.01	0.0245	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
07439-89-6	Iron	193	168	0	29.2	810	mg/L
	Iron (dissolved)	34	26	6.75	63.25	196	mg/L
07439-92-1	Lead	43	6	0.008	0.035	27.4	mg/L
	Lithium	13	13	34.4	90.4	297	mg/L
	Lithium (dissolved)	4	4	24.5	61.35	144	mg/L
07439-95-4	Magnesium	193	180	9	177	3,190	mg/L
	Magnesium (dissolved)	3	3	218	2170	3,160	mg/L
07439-96-5	Manganese	43	29	0.15	1.89	97.6	mg/L
	Manganese (dissolved)	22	12	0.401	2.975	18	mg/L

CAS #	PARAMETER	TOTAL NUMBER OF SAMPLES	NUMBER OF DETECTS	MIN	MEDIAN	MAX	UNITS
07439-97-6	Mercury	30	2	0.0006	0.295	0.59	mg/L
	Mg as $CaCO_3$	145	145	36	547	8,208	mg/L
07439-98-7	Molybdenum	34	12	0.16	0.44	1.08	mg/L
07440-02-0	Nickel	43	15	0.01	0.03	0.137	mg/L
	Nickel (dissolved)	22	2	0.03	0.0715	0.113	mg/L
	Nitrate (as N)	1	1	0.025	0.025	0.025	mg/L
	Nitrogen (total as N)	1	1	13.4	13.4	13.4	mg/L
	Nitrogen (total Kjeldahl)	25	25	37.5	122	585	mg/L
57723-14-0	Phosphorus. as P	3	3	0.89	1.85	4.46	mg/L
07440-09-7	Potassium	33	17	15.5	125	7,810	mg/L
	Potassium (dissolved)	3	3	84.2	327	7,080	mg/L
07782-49-2	Selenium	34	1	0.058	0.058	0.058	mg/L
	Selenium (dissolved)	22	1	1.06	1.06	1.06	mg/L
07440-22-4	Silver	43	3	0.129	0.204	6.3	mg/L
	Silver (dissolved)	22	2	0.056	0.0825	0.109	mg/L
07440-23-5	Sodium	42	41	83.1	23,500	96,700	mg/L
	Sodium (dissolved)	3	3	9,290	54,800	77,400	mg/L
07440-24-6	Strontium	36	36	0.501	1,115	5,841	mg/L
	Strontium (dissolved)	22	21	8.47	629	7,290	mg/L
14808-79-8	Sulfate (as SO_4)	193	169	0	1	1270	mg/L
	Sulfide (as S)	8	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO_3)	3	3	2.56	64	64	mg/L
07440-28-0	Thallium	34	2	0.1	0.18	0.26	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
07440-62-2	Vanadium	24	1	40.4	40.4	40.4	mg/L
07440-66-6	Zinc	43	18	0.011	0.036	8,570	mg/L
	Zinc (dissolved)	22	1	0.07	0.07	0.07	mg/L
	Zirconium	19	1	0.054	0.054	0.054	mg/L
Organic compounds							
00067-64-1	Acetone	3	1	681	681	681	µg/L
00071-43-2	Benzene	35	14	15.7	479.5	19,50	µg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	20	2	10.3	15.9	21.5	µg/L
00075-25-2	Bromoform	26	2	34.8	36.65	38.5	µg/L
00124-48-1	Chlorodibromomethane	26	2	3.28	3.67	4.06	µg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	µg/L
00100-41-4	Ethyl Benzene	38	14	3.3	53.6	164	µg/L

CAS #	PARAMETER	TOTAL NUMBER OF SAMPLES	NUMBER OF DETECTS	MIN	MEDIAN	MAX	UNITS
00074-83-9	Methyl Bromide	26	1	2.04	2.04	2.04	µg/L
00074-87-3	Methyl Chloride	26	1	15.6	15.6	15.6	µg/L
00091-20-3	Naphthalene	23	1	11.3	11.3	11.3	µg/L
	Oil and Grease	39	9	5	17	1470	mg/L
	Petroleum hydrocarbons	1	1	0.21	0.21	0.21	mg/L
00108-95-2	Phenol	20	1	459	459	459	µg/L
	Phenols	35	5	0.05	0.191	0.44	mg/L
00127-18-4	Tetrachloroethylene	26	1	5.01	5.01	5.01	µg/L
00108-88-3	Toluene	38	15	2.3	833	3,190	µg/L
	Xylenes	38	15	15.3	444	2,670	µg/L
Radioelements							
	Cesium 137	16	2	9.9	10.2	10.5	pCi/L
Microorganisms							
	Coliform (total)	5	2	1	42	83	Col/100 mL
	Heterotrophic plate count	5	3	25	50	565	CFU/mL
Other parameters							
	Acidity (total)	4	4	101	240	874	mg/L
	Alkalinity	155	155	0	153	384	mg/L
	Total Alkalinity	5	5	28	91	94	mg/L
	Alkalinity. Carbonate (as $CaCO_3$)	164	163	0	9485	48,336	mg/L
	Hardness by Calculation	170	170	203	11,354	98,000	mg $CaCO_3$/L
	Biochemical Oxygen Demand	38	37	3	200	4,450	mg/L
	Chemical Oxygen Demand	38	38	223	5,645	33,300	mg/L
	Colour	3	3	200	1,000	1,250	PCU
	Fluid Density	145	145	8.39004	8.7	9.2	lb/gal
	pH	191	191	0	6.6	8.58	S.U.
	Salt %	145	145	0.9	5.8	13.9	%
	Scale Inhibitor	145	145	315	744	1,346	mg/L
	Specific Conductivity	15	15	1,030	110,000	165,000	pmhos/cm
	Specific Gravity	150	154	0	1.04	1.201	
	Surfactants	12	12	0.1	0.21	0.61	mg/L
	Temperature	31	31	0	15.3	32	°C
	Temperature	145	145	24.9	68	76.1	°F

CAS #	PARAMETER	TOTAL NUMBER OF SAMPLES	NUMBER OF DETECTS	MIN	MEDIAN	MAX	UNITS
	Total Dissolved Solids	193	193	1530	63,800	337,000	mg/L
	Total Suspended Solids	43	43	16	129	2080	mg/L
	Total Organic Carbon	28	23	69.2	449	1,080	mg/L

Analysis based on limited data from Pennsylvania and West Virginia. The analytical methods and detection levels used were not uniform across all parameters and the reports indicate that the composition of the flowback water from a single well changes within a few days of the well being fractured. .

APPENDIX D

Water Contamination Related to Shale Gas Exploration/Exploitation – Overview of the Potential Sources, Contaminants, Risk Probabilities and Mitigation, Preventive and Regulatory Actions

EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]	SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
Part I : Direct Sources of Potential Impacts on Water Resources				
1 **Drilling**	- Improper drilling operations; - Fluids migration from the borehole; - Well blowouts; - Drilling fluids spills.	- Drilling mud containing chemical additives; - Rock cuttings containing contaminants naturally present underground (radioelements (NORM) and metals).	A large number of drinking resource contamination is associated with drilling activities. As the causes of the reported accidents are not often established, it is not possible to determine if the contamination events were specifically associated with the drilling process. See Part II of the Table for indirect sources of potential impacts.	Preventive and Regulatory Actions *United States:* several preventive and regulatory actions associated with well drilling and construction exist (see activity no. 6 below: Well and Rock Integrity). *Canada:* some provinces (e.g. Alberta) have developed directives relative to well development. In Quebec, any drilling work to explore/produce oil/shale gas must obtain a certificate of authorization. *Europe:* drilling has been suspended since February 2011 in France, pending assessment of the environmental impact.
2 **Hydraulic Fracturing**	- Accidents and spills by truck transport; - Leaks from waste water ponds, storage containers, compressors; - Spills from on-site accidents (e.g. blowout); - Damages to the cementation and casing; - Migration through artificial or natural cracks of formations; - 'Communication' events between wells.	- Hydraulic fracturing fluid containing chemical additives; - Flowback water containing chemical additives, contaminants naturally present underground (NORM, metals, salts) and contaminants formed by the reactions between different chemicals and compounds; - Production brine containing native minerals from the formation, (salts, metals, NORM).	A large number of drinking resource contamination is associated with hydraulic fracturing. As the causes of the reported accidents are not often established, it is not possible to determine if the contamination events were specifically associated with the hydraulic fracturing process. The risk probability relative to NORM depends on the concordance of the regulation, standards and practices related to production brine (e.g. monitoring, treatment efficiency) and on the actual application of these administrative/technical rules. See Part II of the Table for indirect sources of potential	Preventive and Regulatory Actions *United States:* • Series of tests to be performed on the well and the equipment to ensure a safe hydraulic fracturing process; • Monitoring of the hydraulic fracturing process; • Fees imposed when a violation occurs; • Water quality testing before and after hydraulic fracturing required before permit issuance (State of New York); • Regulation of the hydraulic fracturing process (injection) under the SDWA (Alabama); • Public disclosure of the chemical additives present in the hydraulic fracturing fluid (some states); • Each state producing oil and gas is responsible for promulgating and administering regulations to control the re-use and disposal of NORM-contaminated equipment, produced water, and oil-field wastes.

Exploration/ Exploitation Related Activities[1]	Sources of Potential Impacts	Contaminants[2]	Risk Probabilities	Mitigation, Preventive Actions and Regulatory Actions
			impacts.	• In the State New York, it is proposed to require, via permit condition and/or regulation, that radiation surveys be conducted at specific time intervals for the wells using hydraulic fracturing on all accessible well piping, tanks, or other equipment that could contain NORM. These surveys should be required for as long as the facility remains in active use. *Canada:* • Respect of a minimal distance between water wells and shallow fracturing operations (Alberta); • Public disclosure of the chemical additives present in the hydraulic fracturing fluid (British Columbia); • All hydraulic activities are prohibited while the Strategic Environmental Assessment (SEA), which begins in 2011, is being carried out, except if they are required for the purpose of conducting this SEA (Quebec). *Europe and European Countries*: • Moratorium pledged on hydraulic fracturing (Germany); • Hydraulic fracturing allowed in small scales and for scientific reasons only (France); • Moratorium pledged for 6 months on exploration of shale gas reserves using hydraulic fracturing (Bulgaria); • Best practices should be enforced through adequate supervision (European Parliament); • Radioactivity should be evaluated for each individual shale and tight basin, and the composition of a core sample of specific shale should be disclosed before any production (European Parliament).

	EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]	SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
3	**Shale Gas Production**	Accidents such as leaks, spills, well blowouts	- Natural gas primarily containing methane; - Production brine containing native minerals from the formation (salts, metals and NORM).	Risk probability ranges from 1.2 % to 1.9%, and could be higher (5.7%) for new construction. A large number of drinking resource contamination is associated with shale gas exploitation. As the causes of the reported accidents are not often established, it is not possible to determine if the contamination events were specifically associated with the exploitation process. See Part II of the Table for indirect sources of potential impacts.	US EPA launched a research program to improve understanding of the surface and ground water contamination risks associated with shale gas extraction (initial results expected toward the end of 2012).
Part II : Indirect Sources of Potential Impacts on Water Resources					
4	**Wastewater Treatment and Disposal**	- Deep injection of production brine underground; - Water treatment plants not designed or intended to deal with the contaminants present in the wastewater; - Criminal disposal; - Leaks of the containment and transport systems.	- Drilling mud containing chemical additives; - Rock cuttings containing contaminants naturally present underground (NORM, metals); - Flowback water containing chemical additives, contaminants naturally present underground (NORM, metals, salts) and contaminants formed by the reactions between different chemicals and compounds;	The risk related to wastewater disposal is several orders of magnitude larger than the risk related to the other sources (i.e. transportation spills, well casing leaks, leaks through fractured rock and drilling site discharge). A large number of criminal disposals have been reported in the United States. Moreover, several cases of drinking water contamination have been linked with inefficient wastewater treatment plants and underground injection wells. It was very likely than an individual well would release at	<u>Preventive and regulatory actions</u> *United States:* • Regulation of the underground injection of fluids (SDWA); • Authorization required for the use of a pit (State level); • Conditions and restrictions may apply at the state level (e.g. requirement of a liner, respect of a minimum distance between the pit and water plans or water tables). *Canada:* • Conditions and restrictions apply at the level of the province (e.g. unlined storage pits and reintroduction of treated water into waterways are strictly forbidden in Alberta).

EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]		SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
			- Production brine containing minerals native from the formation (salts, metals, NORM); - Contaminants formed by the reactions between different chemicals and compounds.	least 200 m^3 of contaminated fluids into the environment.	*Europe:* a strict handling of the wastewater disposal should be applied (European Parliament).
5	**Spills and Releases**	- Drilling operations, hydraulic fracturing; shale gas production; - Wastewater disposal; - Truck traffic; - Fuelling tank and refilling activities; - Materials and chemical storage; - Chemical mixing, material handling, loading/unloading areas; - Bulk chemical/fluid storage tanks; - Equipment cleaning; - Vehicle and equipment storage/maintenance areas; - Lumber storage and/or processing areas.	- Hydrocarbons; - Products used in the maintenance of mechanical equipment; - Drilling mud, hydraulic fracturing fluid, production brine.	Thousands of spills and releases are reported in the literature. For example, on average, one incident occurred every two days in Colorado (1,549 spills and leaks within January 2003-March 2008); 20% of the spills involved water contamination. In Colorado, spills represent 0.05% (i.e. 2 million gallons) of the total volume of fluid handled by the shale gas industry. As the oil and gas industry operates on a large scale, spills and releases will always exist.	Preventive and regulatory actions *United States:* • Regulations impose a variety of requirements (e.g. maintenance and inspections, secondary containment on all storage tanks) to prevent spills and releases from occurring); • Some States also have specific cleanup standards related to spills. *Canada:* • Conditions and restrictions apply at the level of the province (e.g. a containment system plan is required in New Brunswick).

EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]		SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
6	**Well and Rock Integrity**	- Gas migration along the well; - Leaks along the casing wells; - Contaminants migration from the fractured zone through the aquifer by the presence of cracks.	- Natural gas; - Hydraulic fracturing fluid; - Production brine.	A large number of cases of well casing and cementing failures are reported. Risks occur during and after the well production life. The estimates of risk of well failure range from 1.5% to 19%, and may reach 50% for 15 year-aged wells. There is currently no consensus concerning the probabilities that contaminants can reach the aquifers through cracks caused by hydraulic fracturing: • On one hand, it is stated that the probability at short or long term may be elevated since the rock between the aquifer and the shale formation is not totally impermeable (e.g. presence of faults, cracks and fractures), the hydraulic fracturing process is not still fully controlled and migration of contaminants takes time; • On the other hand, it is stated that the probability may be low considering that the distance between the fractured zone and the aquifer should be sufficient to prevent the propagation of the cracks to the aquifers.	Mitigation Various techniques (modelling, microseismic fracture mapping and use of tilt-meters) can be used to accomplish fracture stimulations and decrease the risk of crack propagation beyond the target formation into the aquifer. However, monitoring the hydraulic fracturing process does not control it. Preventive and regulatory actions *United States:* • Regulatory requirements for well construction and operation; • Standards exist for well construction (e.g. thickness, composition of the casing); • Some states require to perform checks to ensure the quality of the casing and cementing; • After the well productive life, operators must plug the wells and reclaim the site; • In the State of New York, financial security is required before the accordance of the drilling permit to ensure funds for well plugging.

EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]	SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
7 **Well Blowout and Stormwater Runoff**	All the phases of shale gas development	- Natural gas; - Contaminants present on the shale gas exploitation site (e.g. hydraulic fluid and fuel)	Several cases of blowouts are reported in the literature. Blowouts are mostly related to incorrect handling, either by untrained personnel or through incorrect behaviour. All phases of natural gas well development have the potential to impact water resources during rain and snow melt events if stormwater is not properly managed.	Mitigation • Appropriate planning development (e.g. avoiding steep slopes and maintaining sufficient separation from environmentally sensitive features, such as streams and wetlands), diverting uncontaminated water away from excavated or disturbed areas, rapidly stabilizing disturbed areas, following equipment maintenance and rapid spill cleanup,; • Installation of blowout preventers. Preventive and regulatory actions *United States:* • Requirement of blow preventer in some states; • Requirement of the development of a Stormwater Prevention Plan. *Europe:* strict regulation and monitoring are recommended (European Parliament).

[1]: See Figure 7 and Section 5.1 for more details.

[2]: Potential health effects related to these contaminants (NORM, chemical additives, metals) include cancer and other adverse effects (e.g. acute/chronic toxicity, endocrine disruption, etc.).

APPENDIX E

Air Contamination Related to Shale Gas Exploration/Exploitation – Overview of the Potential Sources, Contaminants, Risk Probabilities and Mitigation, Preventive and Regulatory Actions

Exploration/ Exploitation Related Activities[1]	Sources of Potential Impacts	Contaminants[2]	Risk Probabilities	Mitigation, Preventive Actions and Regulatory Actions
Part I : Indirect Sources of Potential Impacts on Ambient Air				
1 **Transport, Equipment, Storage and Distribution**	- Vehicles and engines fuelled by diesel; - Dust or soil entering the air pad construction; - Fugitive methane emissions during activities; - Leaks of the equipment (e.g. compressor and condensers).	- Nitrogen oxides; - Particulate matter; - Sulphur oxides; - Volatile organic compounds; - Carbon monoxide; - Methane; - Hydrogen sulfide - Ozone (formed *in situ*).	Contaminants are emitted during all the shale gas exploration/ exploitation stages. High levels of contaminants have been reported in several locations near shale gas exploitation. 1.4% to 3.6% of the total production of gas (shale gas principally composed of methane) is emitted during transport, equipment, storage and distribution.	Preventive and regulatory actions *United States:* • Standards and enforcement programs exist to control air emissions; • Several voluntary programs have been established (e.g. Natural Gas STAR program) to encompass avoidance, minimization and mitigation strategies applicable to the shale gas industry; • New federal standards will soon be required to reduce air emissions from the oil and gas industry. *Canada:* • Standards and enforcement programs exist to control air emissions; • Conditions and restrictions apply at the level of the province. *Europe*: it is recommended to restrict and monitor emissions from gas processing and transportation.
2 **Well Blowouts and Spills**	Accidents during all shale gas exploration/exploitation activities (volatilization from fluids)	- Hydrocarbons; - Products used in the maintenance of mechanical equipment; - Drilling mud, hydraulic fracturing fluid, flowback water components; - Production brine compounds (e.g. NORM).	As the oil and gas industry operates on a large scale, spills and releases will always exist. Thousands of accidents (e.g. spills, blowouts) are reported in the literature. Most are related to incorrect handling, either by untrained personnel or through incorrect behaviour.	Preventive and regulatory actions *United States:* there is a variety of regulatory requirements to prevent spills and releases from occurring. *Canada:* regulatory requirements to prevent spills and releases vary depending on the province. *Europe*: • Strict regulations are recommended to minimize the risks of accidents; • Companies with negative track records could be excluded from further exploration or production rights.

EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]	SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
3 **Flaring and Venting**	Flaring and venting during all shale gas exploration/ exploitation activities	- Carbon monoxide; - Methane; - Volatile organic compounds; - Nitrogen oxides; - Ozone.	Flaring and venting always occur during shale gas operations. The frequency and duration of these operations vary depending on the technologies and practices used on the well pad.	Regulatory actions *United States:* voluntary programs have been established (e.g. Natural Gas STAR program) to improve operational efficiency and reduce methane emissions. *Canada:* Conditions and restrictions apply at the level of the province.
4 **Wastewater Disposal**	Evaporative emissions of chemicals	- Chemicals originally present in the fluids (e.g. drilling mud, flowback water, production brine); - Chemicals resulting from chemical mixing.	Emission rates depend on the chemical volatility, the area of wastewater, in contact with air and the temperature. Air concentrations further depends on atmospheric dispersion (e.g. wind and distance to the source).	No information.
Part II : Direct Sources of Potential Impacts on Ambient Air				
5 **Well Completion**	- Drill-out stage; - Flowback process. - Indirect sources have potential impacts during all shale gas exploitation stages (see Part I of this Table).	- Fugitive methane emissions; - Radiations.	Fugitive methane emissions always occur during well completion, with estimates ranging from 1.1 to 9% of the total life-time production of gas during the well completion gas (flowback period). During the drill out, emissions may represent about 0.3% of the total production. If radioactive elements are present in the shale formations, radiations may be emitted in the air when NORM are brought to the surface with flowback water. See Part I of the Table for indirect sources of potential impacts.	Methane emissions could be largely reduced by using green technologies during well completion.
6 **Shale Gas Production and**	- Flowback process; - Gas processing;	- Fugitive methane emissions;	If radioactive elements are present in the shale formations, radiations may be emitted in the	In the United States, employers are required to evaluate radiation hazards, post caution signs and provide personal protection

EXPLORATION/ EXPLOITATION RELATED ACTIVITIES[1]	SOURCES OF POTENTIAL IMPACTS	CONTAMINANTS[2]	RISK PROBABILITIES	MITIGATION, PREVENTIVE ACTIONS AND REGULATORY ACTIONS
Processing	- Indirect sources have potential impacts during all the shale gas exploitation stages (see Part I of this Table).	- Radiations.	air when NORM are brought to the surface with flowback water. During shale gas processing (if any), methane may be emitted, at an estimated rate of 0.19% of the total gas. See Part I of the Table for indirect sources of potential impacts.	equipment when radiation doses could exceed regulatory standards, in order to protect workers.

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[1]: See Figure 11 and Section 5.2 for more details.

[2]: Potential health effects related to these contaminants (e.g. air pollutants (e.g. NOx, VOCs, hydrocarbons and particulate matter) and radiations), include cancer and other adverse effects (e.g. acute/chronic toxicity, respiratory effects, asthma).