Towards a Road Map for Mitigating the Rates and Occurrences of Long-Term Wellbore Leakage

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ABSTRACT

Wellbore leakage, the seepage of natural gas through cement channels, casing annuli and behind the outermost casing string, is a problem reported across Canada. Wellbore leakage is a threat to the environment and public safety because of potential groundwater quality deterioration, contributions to greenhouse gas emissions and explosion risks if methane gas accumulates in inadequately ventilated areas. Leakage rates remain poorly quantified and remedial workovers are often challenging. Subsequent costs attributed to remedial workovers are often significant and present an economic strain on the industry as well as lost profit, reduced exploration and production and, therefore, foregone royalties.

The purpose of this report has been to (1) identify persistent problems that result in wellbore leakage, (2) discuss potential approaches that appear to reduce the rates and occurrences of wellbore leakage, (3) describe methods for detecting and monitoring for wellbore leakage, and (4) discuss methods that have improved the efficiency of remedial workovers. Our motivation has been to outline the need for a Canadian Road Map for Wellbore Integrity that identifies future research and development (R&D) needs and identifies where the resources for such R&D might be found. Several key processes were identified that lead to the potential development of a leakage problem, working to either prevent the initial creation of an adequate cement seal or compromising the integrity of the cement sheath over time. The pathways produced by these processes include microannuli, channels and fractures due to poor mud removal, invasion by fluids during setting, stresses imposed by operations, cement shrinkage and casing corrosion. Intermediate-depth formations, i.e., non-commercial gas zones, are often found to be the source of the buoyant fugitive gases that migrate up these pathways.

'*Doing it right the first time*' – i.e., creating a robust seal during primary cementation – was uniformly agreed by industry and regulators to be the best approach for reducing leakage development over the operational and post-operational lifetime of a well. Even if an adequately sealed wellbore was achieved during primary cementation, there remains the possibility that a leakage problem may develop due to corrosion or cement shrinkage. Therefore, in addition to '*doing it right the first time*', new cement formulations, wellbore designs and abandonment approaches are needed. Wellbore monitoring needs to be improved by adopting the use of newer technologies and undergoing more thorough subsurface monitoring. Remedial workovers require advances in source identification (such as enhanced acoustic logging technology and isotopic fingerprinting) and alternative-sealing materials.

Wellbore leakage will likely only become worse with time as new wells are completed and old wells are abandoned. We recommend that a Canadian working group be established to develop a Road Map for Wellbore Integrity R&D to improve long-term wellbore integrity. Hydraulic fracturing is perceived as a threat by many in the public, however, we believe that this concern is misplaced. Because of the real issues associated with greenhouse gas emissions and possible groundwater quality deterioration, we believe the more significant issue affecting the social license of the oil and gas industry is long-term wellbore integrity.

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1 INTRODUCTION TO WELLBORE LEAKAGE

By 2013, in excess of 550,000 energy wellbores had been drilled in Canada, the great majority in the Western Canada Sedimentary Basin. These oil and gas wells are active (producing), suspended (not producing but not plugged), or abandoned (plugged and abandoned according to regulatory requirements). To meet our national demand for oil and gas, approximately 2.25 million barrels per day (MMbod) in 2013, and to supply clients in the United States, Canada produces a total of about 3.5 MMbod. Production is increasing, and projected to reach between 5 and 6 MMbod sometime in the period 2030 to 2040. Natural gas production is not increasing at present, but the advent of large exports of liquefied natural gas to countries seeking to replace coal-fired or nuclear power plants is likely to start at a commercial scale in 2020, and many more wells will be required annually to keep up with demand and depletion. Over the last 20 years, on average over 15,000 new wells have been added each year; this number may rise substantially as various jurisdictions in Canada seek to produce local oil and gas resources.

Despite the energy needs of our society, there is often significant public concern regarding potential environmental impacts of oil and gas production. In particular, hydraulic fracturing (HF) has received significant criticism because of perceived threats such as groundwater contamination; see Jackson et al. (2013a) for a discussion of this issue. Despite these concerns, recent assessments have suggested that these concerns are misplaced. Rather, wellbore leakage, a commonly overlooked problem relating to the long-term integrity of a wellbore, presents real risks to the environment and public safety (Dusseault and Jackson, 2013, 2014; Jackson and Dusseault, 2014). Wellbore leakage is known to have caused a number of documented cases of groundwater contamination and contributes to greenhouse gas (GHG) emissions and presents a significant economic burden for the industry (Chafin, 1994; Schmitz et al., 1996; Saponja, 1999; Komex International Ltd., 2002; Ravi et al., 2002; van Stempvoort et al., 2005; Bexte et al., 2008; Watson and Bachu, 2009; Jackson et al., 2013b; Karion et al., 2013; Miller et al., 2013). The frequency of groundwater contamination and GHG emissions and the quantities of natural gas involved are poorly understood and will remain so until quantitative measurements are conducted more frequently and publicly reported.

In this report, we use the term "wellbore leakage" throughout, although many other more-

specifically defined terms have been used, such as gas migration, gas seepage, behind-the-casing leakage, surface casing vent flow, and so on. The term "wellbore leakage" is intended to be inclusive: it refers to all processes whereby fluids (oil, gas, brine, fracturing fluids...) migrate from depth to the surface or near-surface during and after active operations.

The objectives of this report are to (1) identify persistent problems that have led to the development of leakage problems, (2) discuss methods that have the potential to reduce the rates and occurrences of wellbore leakage, (3) describe methods to improve monitoring and detection of wellbore leakage, and (4) discuss methods to improve the efficiency of remedial workovers. Identified sources, pathways, mechanisms and potential methods to reduce the rates and occurrences of wellbore leakage come from industry and experts in the field, usually service companies.

Overall, our motivation has been to outline the need for a Canadian Road Map for Wellbore Integrity that identifies future research and development (R&D) needs and locations where the resources for such R&D might be found. Such a Road Map would reflect *the inventory of possibilities for a particular field, thus stimulating more targeted investigations*". These words of Robert Galvin (1994), former Motorola chairman and pioneer of science and technology (S&T) Road Maps, illustrate how "*the roadmapping process provides a way to identify, evaluate and select strategic alternatives that can be used to achieve a desired S&T objective*" (Kostoff and Schaller, 2001). We tentatively state that S&T objective as comprising (a) minimizing gas emissions to the atmosphere and potable groundwater, while (b) reducing the cost of effective wellbore repair and abandonment and (c) improving primary wellbore completions in all terrains throughout Canada.

2 BACKGROUND

2.1 Oil and Gas Wellbore Completion, Design and Remedial Workovers

2.1.1 Drilling, Casing Installation and Primary Cementing Operations

Drilling and completion operations are relatively similar for all oil and gas wellbores. Before drilling begins, a conductor casing from 6 to 12 m deep is installed to prevent near-surface cohesionless soil and rock from caving into the borehole. Drilling begins with guiding a drill

bit fastened to the bottom of a pipe into the conductor pipe. The drill bit is advanced through rotation while fluids are circulated to clean the drill cuttings from the hole. Eventually, as the hole is deepened, a more complex bottomhole assembly (BHA) is used, comprising the drill bit, the downhole "mud motor" which rotates the bit, drill collars to apply weight to the drill bit, and stabilizers and reamers to maintain hole diameter and condition. A hollow pipe (referred to as a 'kelly') connected to the drilling fluid pumps is screwed into the uppermost joint of the drill pipe and is inserted into the kelly bushing on the floor of the drilling rig, which is used as the benchmark to measure borehole depths. Additional sections of drill pipe are added as the hole is deepened until the desired casing depth is reached. The entire system from the bit to the kelly bushing is called the "drill string" (Caenn et al., 2011; Varhaug, 2011).

As drilling proceeds, the drilling fluid ("mud") is circulated through the drill string and up through the annulus around the pipe. Drilling fluid typically consists of a clay-water mixture and other additives such as sodium hydroxide, polymers or some diesel fuel to control the properties. For the shallower part of the borehole, foams and air-entrained drilling fluids are often used to improve penetration rates, but for the deeper parts of the boreholes, it is necessary to have a carefully managed liquid system. As an alternative to a water-based drilling mud, a non-aqueous fluid such as an oil-based or an ester-based mud may be used to enhance borehole stability in shales and control formation damage in certain types of reservoir rocks. The drilling mud serves several purposes including lubricating, cleaning and cooling the drill bit, reducing friction between the drill string and the borehole wall, maintaining wellbore stability (i.e. preventing formation collapse), providing hydrostatic pressure to prevent the inflow of fluids and gases from permeable formations and carrying drill cuttings to the surface (Caenn et al., 2011; Varhaug, 2011).

Drilling fluids and the conductor casing are sufficient for sustaining wellbore stability up until a certain point, but since the conductor casing provides no capacity to control the wellbore if abnormal pressures are encountered, after some depth, stronger continuous steel casings must be installed and cemented in place. Casing strings are lowered into the borehole, guided with a bullet-shaped basal guide or float shoe. The shape helps guide the casing centrally, minimizing contact with the borehole wall, thus preventing damage to the casing and the borehole wall. Centralizers are placed at frequent intervals to prevent the casing from adhering to the borehole

wall while it is lowered into the well, as well as to keep the casing centralized within the borehole to ensure uniform cement placement during primary cementing operations (Varhaug, 2011; Nelson, 2012).

Depending on the location, type and depth of the wellbore, there may be several casing strings installed (Figure 2.1). These are commonly referred to as the surface casing and the intermediate and production casing strings. Surface casings are required for permanent isolation of soil and rock in the upper 150-300 m, and the steel casing is also important to provide wellbore control and to protect shallow groundwater resources, e.g., Alberta Energy Regulator (2009). Many jurisdictions will specify a minimum depth for the surface casing, with the requirements that the bottom of the surface casing string (the shoe) be placed a defined distance below potable groundwater, a depth known in Alberta as the base of the groundwater protection zone (BGWP).
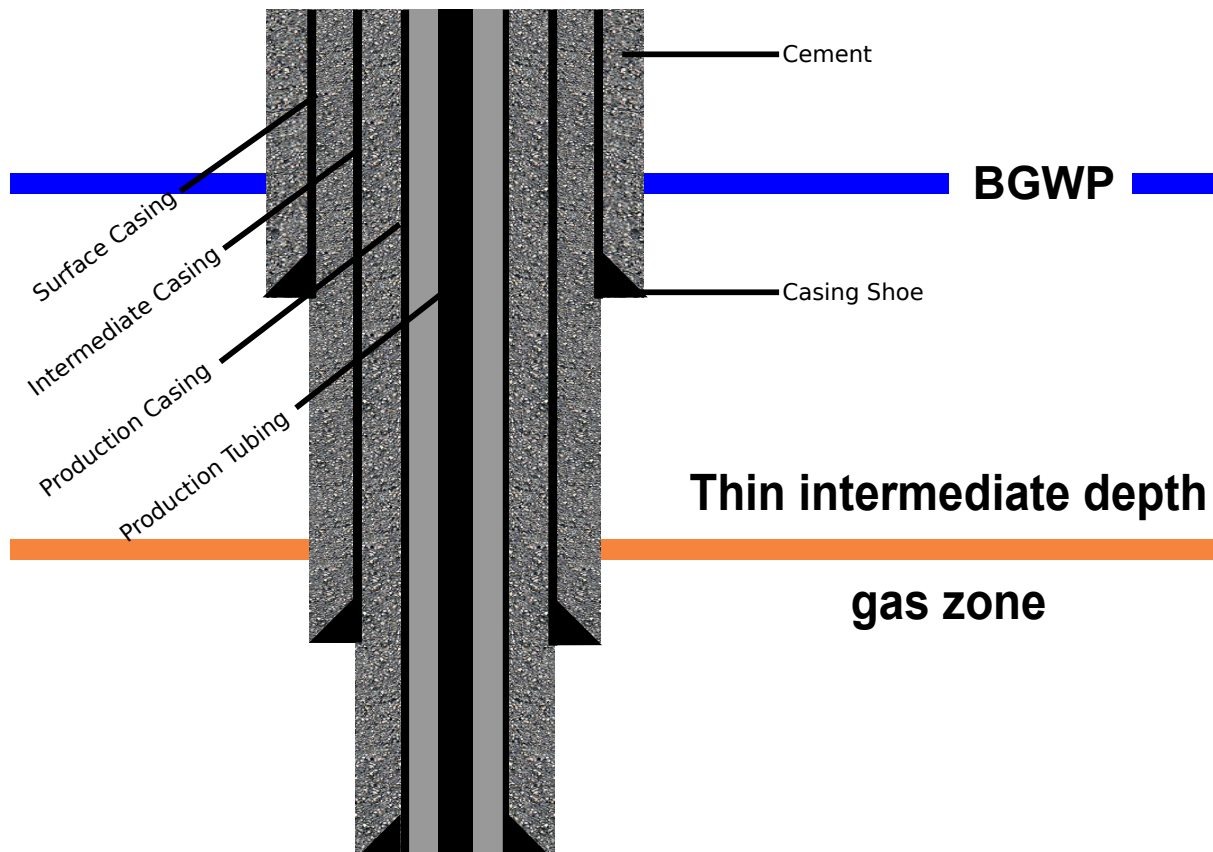
Figure 2.1. Schematic of a typical oil and gas wellbore structure

Intermediate casing strings are installed to provide protection of the wellbore against rock instability or the presence of excess pressures so that the drilling can continue unimpeded to the required "total depth" (TD). In the deeper parts of the Western Canada Sedimentary Basin, wells as deep as 4 to 5 km may be drilled, and usually have an intermediate casing to isolate the ductile

shales in the upper 2500 m so that they do not experience continued damage and impair the drilling operation. In regions where the hole is relatively shallow, the rocks are stable, and high pressures are not encountered, intermediate casing strings may not be installed. For example, in the heavy oil belt stretching from southwestern Saskatchewan to the north and northwest of Lloydminster in Alberta, vertical and inclined holes are drilled for non-thermal exploitation of heavy oil, and the hole is deepened from the surface casing shoe to TD. A single final casing string is installed, called the production casing.

Many shale gas and shale oil wells are drilled from the surface casing to the required depth, deviating the vertical borehole in the last few hundred meters so that it becomes horizontal. Then, a production casing is installed, and the horizontal well section, which can be up to 3 km long, is drilled from the shoe of the production well. Special hardware is installed in the horizontal section to facilitate hydraulic fracturing so that the well can be turned into an economically viable producing well. This is not referred to as a casing string, and in new approaches this special equipment is not cemented into place, rather it is anchored to the rock through the use of a series of expanding packers. This equipment is tied back into the end of the production casing and joined to the production tubing to form a contiguous protected pathway for produced fluids.

The production casing contains the components for completion and production (Alberta Energy Regulator, 2010), including the installation of a production tubing through which the produced fluids are carried to the surface. There may be various down-hole valves and equipment installed in special cases to allow the well to be better managed, and these expensive bits of downhole equipment are often referred to as "jewelry" (Varhaug, 2011).

Each casing installed requires a cementing operation, i.e., the placement of cement outside the casing in the exterior annulus, to anchor and support the casing string, protect the steel casing against corrosion, and to provide a hydraulic seal that will prevent fluid communication between zones (Drilling and Completion Committee, 1995; Nelson, 2012). Typically, a water-based Portland Class G cement slurry with a density of approximately 2.0 Mg/m^3 or slightly higher is used in primary cementing operations (Dusseault et al., 2000). Portland cements are finely ground anhydrous calcium silicate and calcium aluminate compounds that hydrate when added to water, generating a product that provides strength and low permeability (Nelson, 2012). Each wellbore presents varying conditions, such as downhole temperatures and adjacent geologic

media. Portland cements can be manufactured differently and used along with a number of additives to customize properties for a particular environment. Common additives include accelerators (to reduce set time and/or increase rate of compressive strength development), retarders (to delay set time, thus extending pumping times), extenders (to lower densities), weighting agents (to increase densities), fluid loss control additives (to control water expulsion from setting cement), lost circulation control agents (to limit flow of slurry into surrounding penetrable formations), dispersants (to reduce viscosity), inert fillers (to create thermally resistant cement) and other specialty additives. The cement slurry is pumped down the casing, and circulated up the annulus (Figure 2.2). The main objective is to uniformly place the cement slurry while adequately displacing the drilling mud from the annulus, which requires a properly mixed slurry and a suitable fluid displacement technique that achieves turbulent flow in the annulus (Smith, 1990; Ravi et al., 2002; Bellabarba et al., 2008; Nelson, 2012). The set cement is often referred to as the "cement sheath".
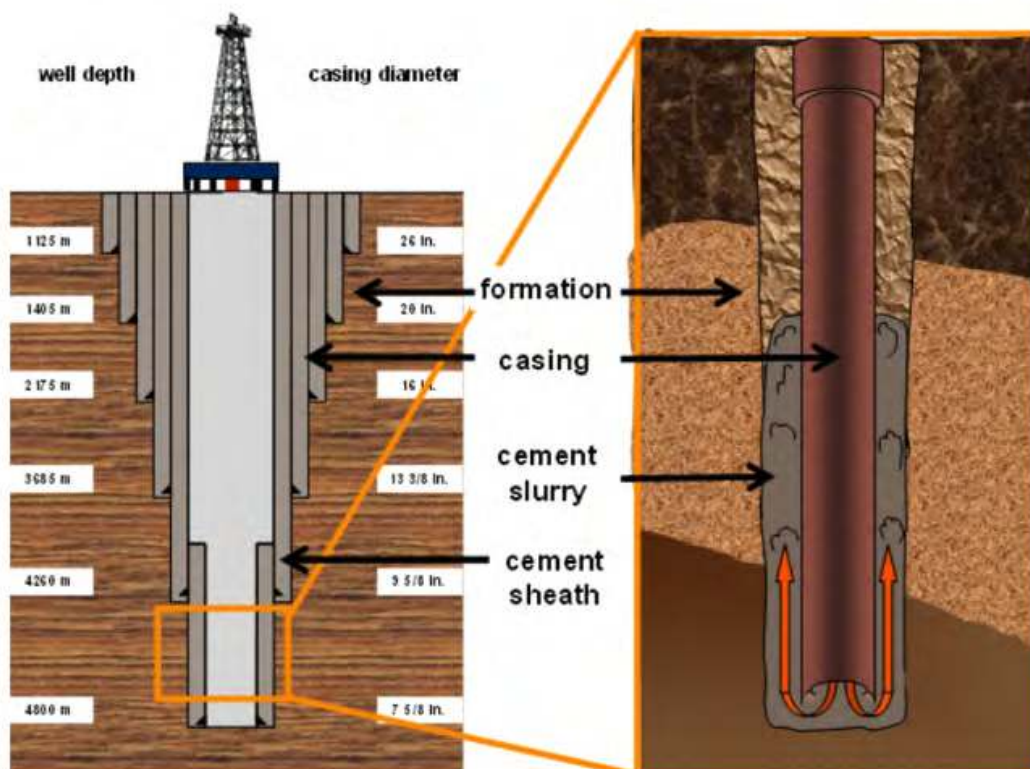
Figure 2.2. Primary cementing schematic (from Powerflex Cementers, Inc.)

2.1.2 Cement Sheath Evaluation

Cement bond logs (CBLs), a commonly used suite of tools to evaluate the cement-casing and cement-borehole wall 'bonds', use acoustic signals emitted by a transmitter installed in a wireline logging tool to produce waves that travel through a section of the casing to evaluate the condition of the cement (e.g., good, moderate or poor). A receiver, installed in the same tool below the transmitter, measures the arrival time and attenuation of the transmitted and reflected acoustic waves. Depending on the degree of the attenuation, the acoustic impedance of the reflected wave signals can provide semi-quantitative insight whether or not there is adequate bond development, good contact, or faults in the cement sheath that may require remedial attention. More recently, ultrasonic imaging tools have been developed that apply ultrasonic waves on the casing wall. The resulting resonance of the casing can provide insight on the material behind the casing (solid, liquid or gas) based on the acoustic impedance. Ultrasonic imaging tools typically complement acoustic logs (see Bellabarba et al., 2008; Chatellier et al., 2012; Nelson, 2012).

2.1.3 Remedial Cementing

Remedial (secondary) cementing operations take place following primary cementing should completion evaluation tools, surface casing vent flow measurements, or evidence of behind-the-casing gas migration indicate there are violations of regulated issues such as casing corrosion or gas leakage (Nelson, 2012). Such indications may be detected immediately following placement of the cement sheath or later in the life of the well such as at the time of abandonment. Problem areas behind casings may be sections of the cement sheath where void spaces exist or where no cement has been injected. Usually, a "squeeze" operation is performed to fill the void space with a sealing material, typically cement, to achieve a suitable seal.

A typical cement squeeze procedure is outlined by Van Dyke (1997). The problem (defective) interval is first detected by wireline tools (cement bond logs and noise and temperature logs) and isotopes measured in fugitive gases. The casing is perforated using a perforation gun, which effectively blasts a hole through the casing, the cement, and into the adjacent formation rock. A plug (a cement plug or a mechanical packer) is placed in the well below the problem area and cement slurry is pumped down a tube filling the perforated area with cement. The casing is then sealed off with a valve or a packer to induce elevated pressures by continuing to pump cement

down the tube in the isolated region. The induced pressures squeeze the cement through the perforations into the annular region. Ideally, the cement or sealing agent creates a successful seal that isolates the formations behind the casing, resulting in appropriate zonal isolation between shallower and deeper formations (see Figure 2.3) (Bradford and Reiners, 1985; Van Dyke, 1997; Nelson, 2012; von Flatern, 2012). After the initial cement squeeze, the wellbore should be re-evaluated to ensure that the problem was resolved. A number of cement squeezes may be performed to eventually achieve a successful seal. We discuss this further in section 6.2.2.
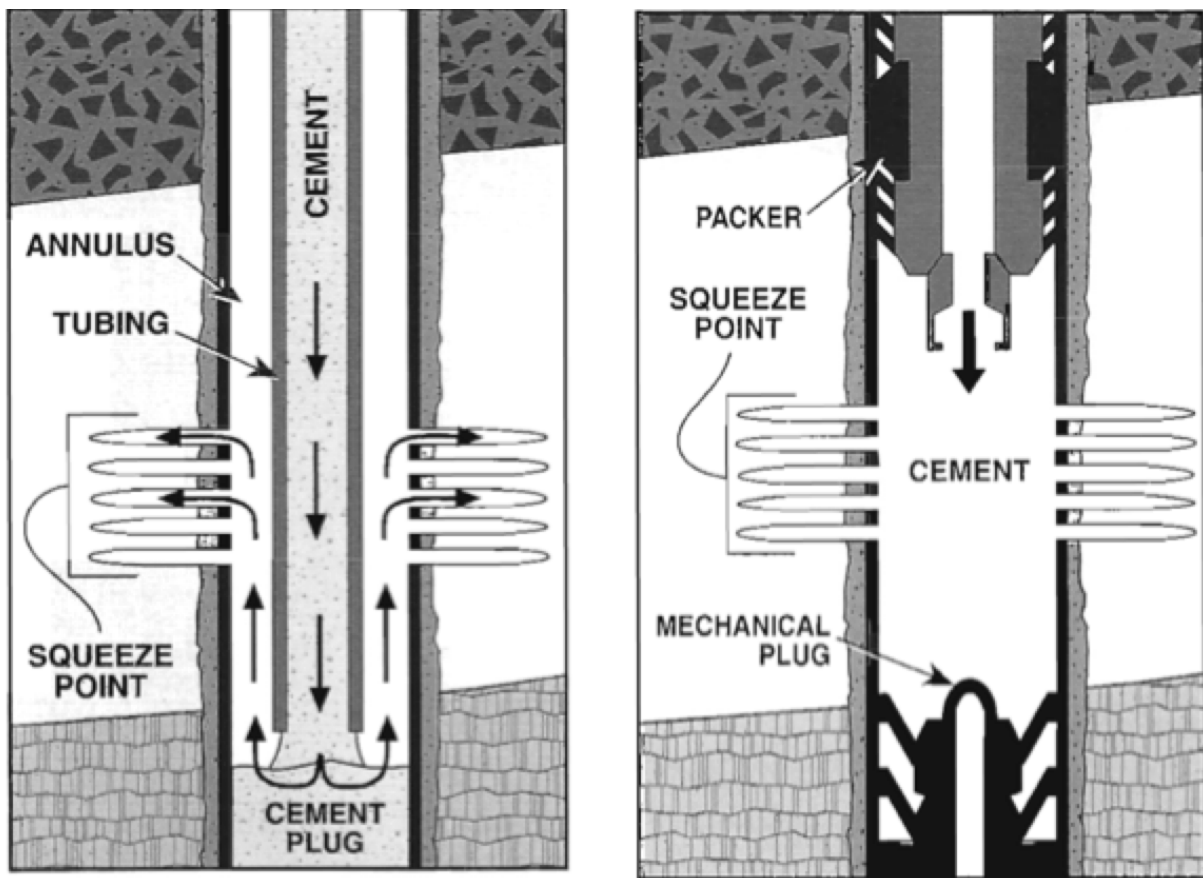
Figure 2.3. Schematic of a bradenhead squeeze (left) and a packer squeeze (right) (from Van Dyke, 1997)

2.2 Wellbore Abandonment

At the end of the wellbore's active life, when the reservoir has been depleted, or in some cases when regulators require the well be abandoned due to structural issues, the wellbore must be plugged and abandoned (P&A). The main objective of abandonment is to isolate the depleted reservoir as well as any fluid bearing formation penetrated by the wellbore to prevent any subsurface-surface interactions (Barclay et al., 2001; Diller, 2011). Typically, this includes covering non-saline groundwater ($<$4000 mg/L total dissolved salts) to the BGWP and isolating

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deep, intermediate and shallow depth fluid (liquid and gas hydrocarbons and saline water) formations with a cement plug.

An ideal abandonment operation follows several main steps, as outlined by Barclay et al. (2001):

1. The production tubing is cleaned;

2. Production perforations are filled with cement;

3. Tubing above the production packer is perforated; cement is circulated between the casing and the tubing. At shallower depths, multiwall perforations are made, and open annular region is completely filled with cement;

4. A surface plug is placed;

5. All plug locations are confirmed and pressure tested; and

6. The wellhead and casing stump is removed; casing is cut and capped.

Generally, successful abandonment operations require knowledge of the surrounding geology, location of fluid bearing formations, wellbore geometry and accessibility and reservoir pressures and temperatures (Barclay et al., 2001).

In practice, abandonment operations are often not straightforward, rather are frequently very complex procedures. Even with careful planning and workmanship, unforeseeable issues may be encountered and may require alternative or additional action than originally planned. Diller (2011) outlines the planning and workover of an improperly abandoned wellbore in the Peace River region of Alberta. This example illustrates the need for diligent planning for approaching a problem and demonstrates the need for contingency plans if unforeseen issues are encountered along the way. Each abandonment operation is unique to the wellbore and requires collaboration with regulators to achieve an effectively abandoned wellbore.

2.3 Wellbore Leakage Problem

Fugitive emissions, i.e., uncontrolled leakage of natural gas from oil and gas wells is a commonplace problem in oil and gas producing areas. Watson (2004) pointed out that such emissions reflect the presence of a gas source that has sufficient fluid pressure for the gas to accumulate and then begin to migrate upwards along a permeable pathway adjacent to or within

a wellbore. Wellbore leakage is observed across Canada; some preliminary data for provinces with active oil and gas activities are reported in Table 2.1.

Table 2.1. Reported wellbore leakage in active onshore drilling provinces across Canada

Province	Wellbore Leakage Frequency	Source of Information
British Columbia	10% of all active and suspended oil and gas wells leak	BC Oil & Gas Commission, 2014
Alberta	27,000 leakage reports since 1971	Cases listed in Alberta Public Reports (2013)
Saskatchewan	20% of wells have vent flows, gas migration, or some combination of both	Regional Manager Lloydminster, Petroleum Development Branch, Ministry of Economy
Ontario	20% of all oil and gas wells have minor vent flows	Petroleum Operations, Ontario Ministry of Natural Resources
Québec	18 of 28 shale-gas wells have minor leaks	Ministère du Développement durable, de l'Environnement, de la Faune et des Parcs du Québec
New Brunswick	2 of 29 producing wells in the McCully gas field have measurable vent flows	Corridor Resources, 2013
The information presented in this table is not a reliable quantification of the leakage frequencies across Canada. The values are best estimates of leakage in the corresponding areas and are meant to illustrate that leakage occurs nationwide.		

Reviews of atmospheric emissions during natural gas gathering and processing, such as those by Alvarez et al. (2012), Allen et al. (2013), and Brandt et al. (2014), conclude that a few "superemitters", i.e., individual tanks, valves and other components, are likely responsible for much of the measured natural gas leakage. From discussions held during the preparation of this report, it appears likely that this conclusion applies also to wellbore leakage of natural gas. Shell Appalachia indicated that 90% of their leaks measured by mass-flow meters were < 100 scf/day, i.e., < 700 kg CH_4/yr. Kevin Parsonage of British Columbia Oil & Gas Commission estimated a typical (median) SCVF rate of just 0.5 m^3/day, which is equivalent to ~ 100 kg CH_4/yr, while average SCVF emissions in B.C. are 9.6 m^3/day or over 2,000 kg/yr [1]. The difference between these median and average values indicates that a few leaky wells are indeed "superemitters".

Leakage rate distributions from wells in Alberta and British Columbia are shown in Figures

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[1]To put this into context, a typical pneumatic device operating under field conditions near Fort St. John in northeastern B.C. emits ~ 0.2 m^3/hr of fuel gas or, assuming this is only methane, $\sim 1,000$ kg CH_4/yr (The Prasino Group, Final Report for Determining Bleed Rates for Pneumatic Devices in British Columbia, December 18, 2013, Calgary, Alberta). We may estimate the average ruminant cattle emission to be 250-500 L/day according to Johnson and Johnson (1995). Therefore taking an average value of 375 L/day, ruminant cattle emits ~ 100 kg/yr per animal.

2.4 and 2.5, respectively. These figures illustrate that majority of wells leaking in these regions fall below what is considered a severe leak, a mandated criteria where immediate remedial workovers are required (see section 6.1.1).
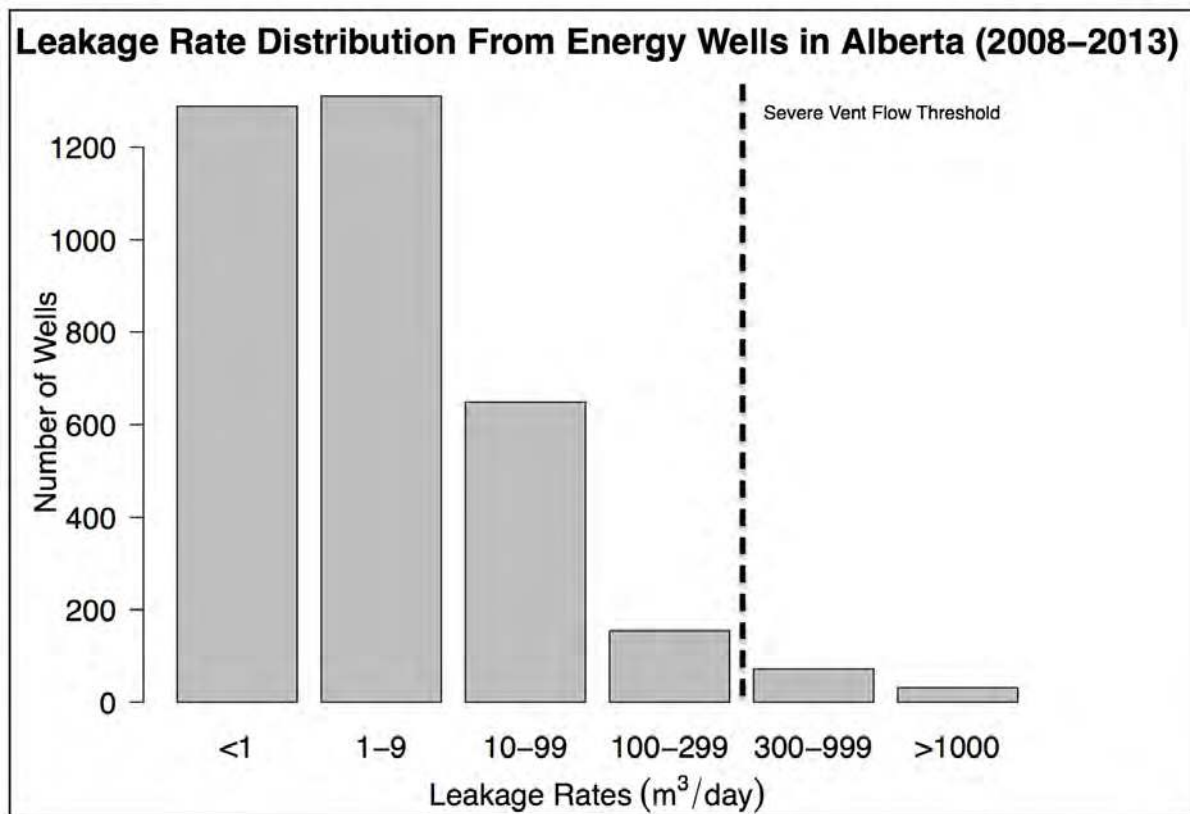
Figure 2.4. Distribution of wellbore leakage frequency in Alberta from 2008 to 2013. Data obtained from Alberta Energy Regulator (2013b)
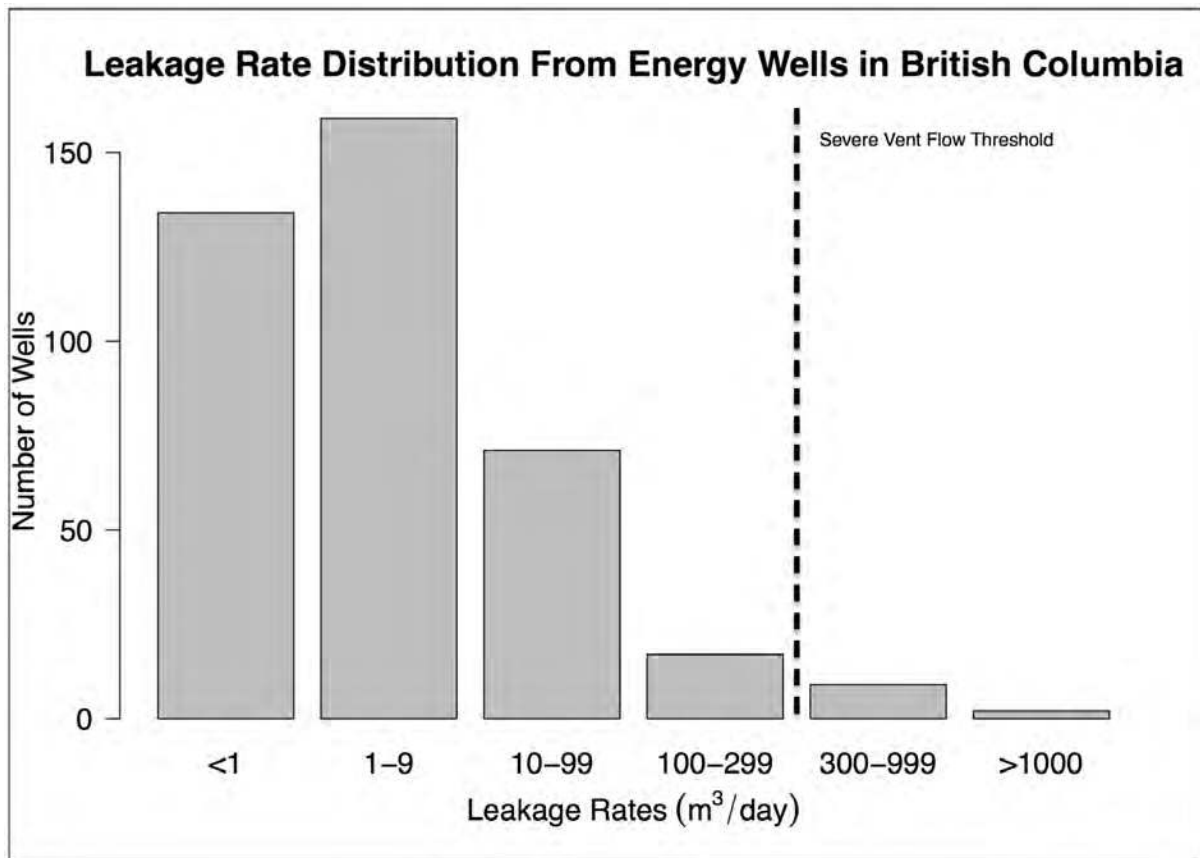
Figure 2.5. Distribution of wellbore leakage frequency in British Columbia. Data obtained from BC Oil and Gas Commission's SCVF Wellbore Database, retrieved in Checkai (2012)

The uncontrolled migration of liquids and gases may manifest itself as either surface casing vent flow or behind-the-casing gas migration (collectively referred to as wellbore leakage in this report). A surface casing vent flow (SCVF), defined by the Alberta Energy Regulator (2003) as "*the flow of gas and/or liquid or any combination out of the surface casing/casing annulus*", may develop where there is no cement present or when a poorly cemented/damaged cement sheath fails to provide a continuous impermeable barrier to migrating gases. Chafin (1994) showed an example of the absence of an annular cement sheath allowing gas leakage into overlying strata in Figure 2.6. An uncemented exterior annulus will not intercept and isolate formations fluids and further increases the casing's susceptibility to corrosion (see section 3.3.3.6). Leakage pathways through poorly cemented or damaged casing/hole annuli include circumferential microannuli, i.e., discontinuities with aperture dimensions on the order of microns, and channels with aperture dimensions on the order of millimeters to centimeters (see Figure 2.7). Microannuli as small as 10-15 micrometers are sufficient to provide a pathway for gas migration to the surface, provided the conduit is continuous from the source to the surface casing shoe (Saponja, 1999; Zhang

and Bachu, 2011). Gas migration, i.e., "*the flow of gas that is detectable at surface outside the outermost casing string*" (Alberta Energy Regulator, 2003), may develop if there are adjacent permeable formations, a drilling-damaged zone from the drilling process, or discontinuities between the outermost cement sheath and the borehole rock wall.
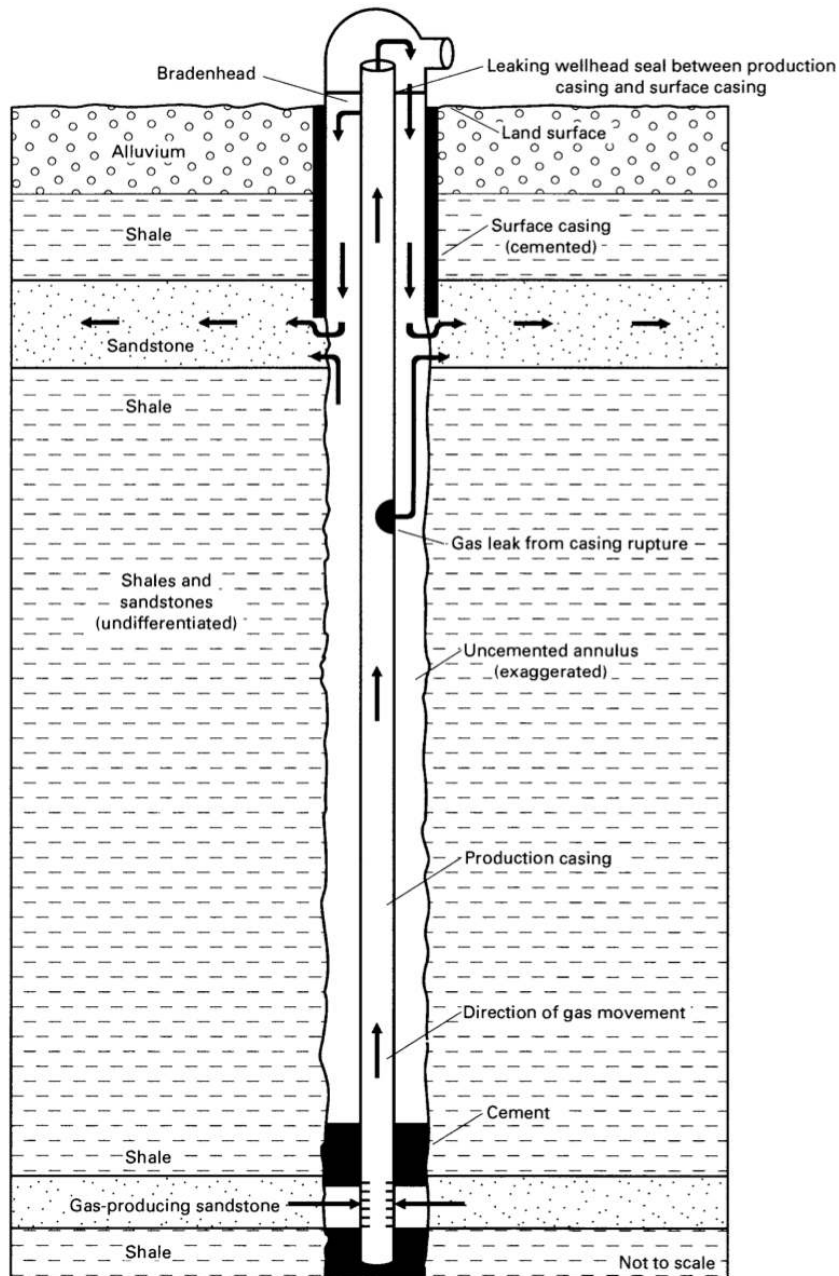
Figure 2.6. Uncemented annuli of gas wells documented by Chafin (1994, Fig. 23) in the Animas River Valley, New Mexico and Colorado.)
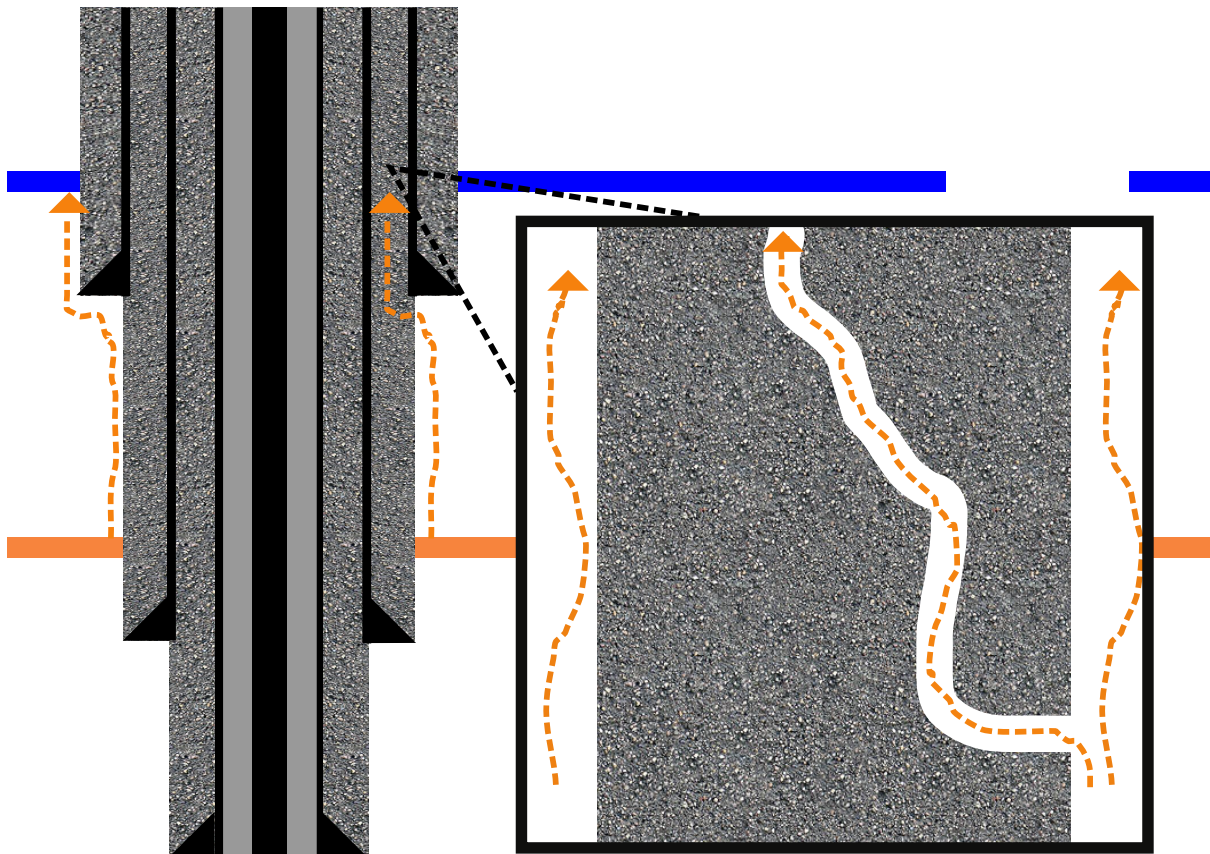
Figure 2.7. Schematic of gas migration (left side of wellbore) and surface casing vent flow (right side of wellbore), originating from a thin, intermediate source depth zone

2.4 Wellbore Leakage Consequences

Wellbore leakage is of an environmental concern because of greenhouse gas emissions and possible groundwater quality deterioration. The principal component of commercial natural gas is methane (Hunt, 1979). The Intergovernmental Panel on Climate Change (2013) in their most recent report indicate that global average methane concentrations have risen to 1803 ± 2 ppb as of 2011 from 722 ± 25 ppb in 1750 "…*due predominately to changes in anthropogenic related methane*". Miller et al. (2013) suggest that anthropogenic methane emissions now account for 50-65% of the global methane budget. Although there are a number of natural sources of methane, fugitive emissions from natural gas production has been identified as one of the leading five sources in the U.S. in a recent report by the U.S. Environmental Protection Agency (2013). Potential leakage pathways attributed to shale gas and other unconventional gas development are shown in Figure 2.8. Storage tanks and facilities, transportation accidents, drilling and surface casing issues, leakage from offset and legacy wellbores, and leakage from the immediate vicinity of a wellbore (i.e., wellbore leakage) collectively contribute to methane emissions. The

short-term (20-year) impact of CH_4 as a greenhouse gas is so powerful (over 60 times larger than the impact of CO_2 – although CO_2 is more persistent), that small amounts of methane have a disproportionate effect on greenhouse effects and short-term warming.
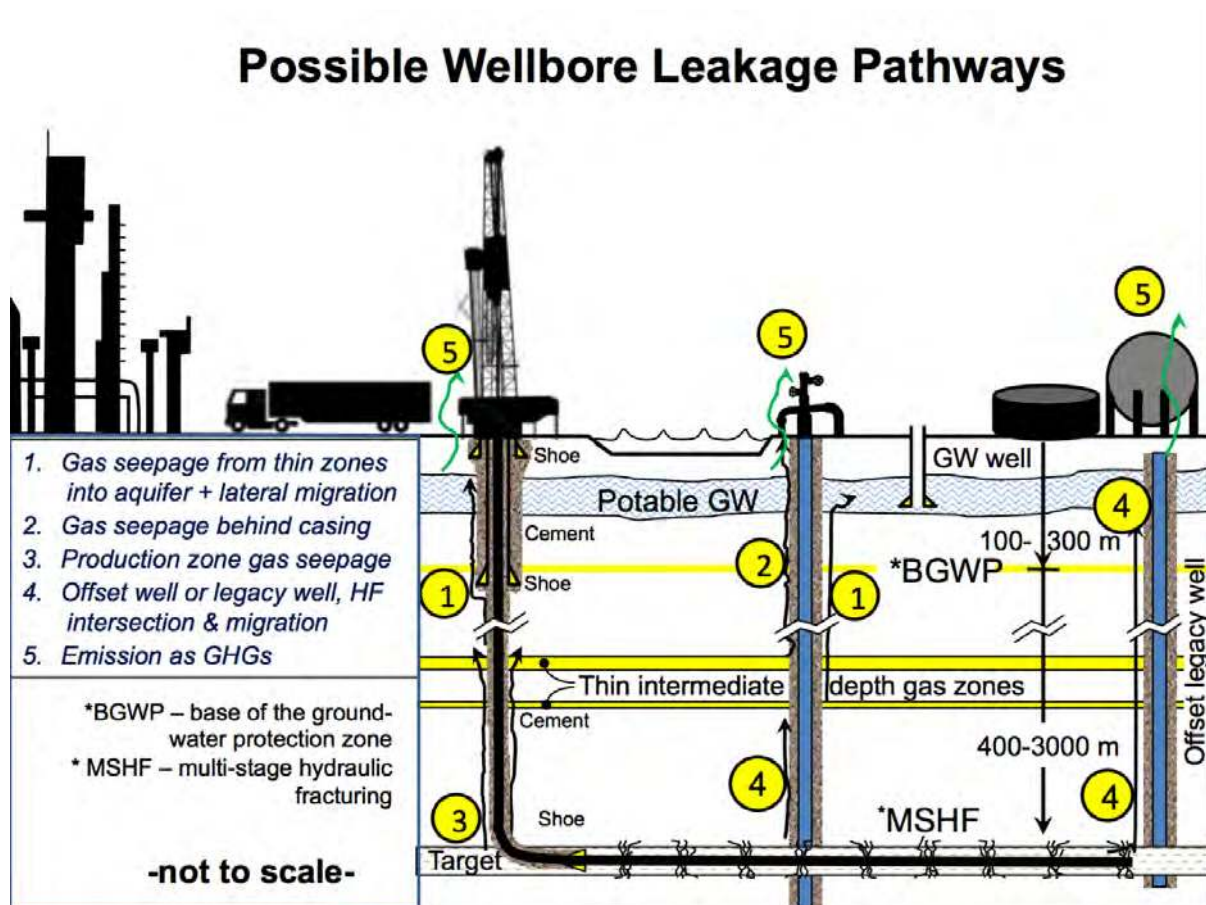
Figure 2.8. Outline of potential leakage pathways during shale gas development

Wellbore leakage may also lead to the deterioration of the quality of potable groundwater. Water quality deterioration because of microbially catalyzed hydrocarbon oxidation has been described by both American and Canadian hydrogeologists. Kelly et al. (1985) described conditions in groundwaters near a well blowout in Ohio in which the natural oxidants (e.g., O_2, NO_3, SO_4) in the aquifer were replaced by iron and manganese, which had dissolved from the reduction of the oxides within the aquifer. Furthermore, the total dissolved solids (TDS) increased in concentration and sulphate reduction of the methane produced hydrogen sulphide. The study by Chafin (1994) in the San Juan basin in New Mexico and Colorado also indicated a strong association between methane and hydrogen sulfide. This association was substantiated by van Stempvoort et al. (2005) in the Lloydminster heavy oil belt, who showed by isotopic characterization that in-situ microbially-catalyzed methane oxidation was

associated with sulphate reduction in groundwaters adjacent to the leaky oil well. Thus we can expect that natural-gas contamination of freshwater aquifers will result in the oxidized methane being replaced by H_2S and the net effect of the oxidation-reduction reactions will be a groundwater elevated in terms of TDS, thus causing a pronounced deterioration in the quality of the groundwater. Furthermore, these processes are not uniquely associated with CH_4; other hydrocarbon gases (C_2H_6, C_3H_8) that may comprise part of the gas seeping will experience similar reactions in shallow groundwater.

In addition to the environmental concerns of wellbore leakage, there are also safety concerns. A leaking wellbore may lead to the accumulation of methane in enclosed spaces in one of two ways: de-gassing of dissolved methane from groundwater that slowly invaded the aquifer overtime and seepage of free-phase gas through soils after migration along the wellbore annulus (van Stempvoort et al., 2005; Bair et al., 2010; Tilley and Muehlenbachs, 2011; Gorody, 2012). Methane solubility is controlled by temperature, pressure and salinity. Generally, methane solubility decreases with increasing temperatures and decreasing pressures (Duan et al., 1992). If the water is subjected to a decrease in pressure or an increase in temperature, degassing may occur. This gas, along with gases percolating through soils, may accumulate in an enclosed area. When methane accumulates to significant concentrations (5-15% by volume of air), such as in basements, well pits, etc., it becomes both an asphyxiation and explosive hazard (Komex International Ltd., 2002; Révész et al., 2012; Jackson et al., 2013b).

Finally, wellbore leakage leads to substantial costs to the industry through the need for remediation of leaky wellbores. Because of both the remediation costs and the loss of production, wellbore leakage in some circumstances is costing the industry an average of $150,000 per well (in the Lloydminster area, remediation costs for one corporation are $600,000 per well). In some extreme cases, remedial costs have been cited at millions of dollars per well, with one remote well reaching costs of $8 million (Hull, 2013; discussions with BC O&GC, Shell Canada and Husky Energy, 2013).

3 WELLBORE LEAKAGE

3.1 Sources of Gas

Hydrocarbon fluids leaking from a wellbore, generally gases, may be from several potential sources, depending on the geological stratification and wellbore location. The sources of the fluid may be of deep thermogenic origin, which we define as the general reservoir depth, or from one of potentially several shallow to intermediate depth hydrocarbon-bearing formations in which the gases may be either of biogenic or thermogenic origin, or a combination of both (see Figure 3.1).

Most often, leaks are found to be originating from a shallow to intermediate depth source, rather than from the reservoir itself. Evidence comes from isotopic analyses of approximately 300 wells in Alberta and British Columbia. The isotopic signature of hydrocarbons is reflective of its source, maturity and its origin (Rich et al., 1995; Slater, 2010). In the Western Canada Sedimentary Basin, gases in formations associated with heavy oil deposits within the Mannville Group in the Alberta-Saskatchewan border area have distinctive geological histories compared to shales in the overlying Colorado Group. These differences are reflected in their isotopic fingerprints and were utilized to determine that the gases found in three-quarters of the sampled wells in a study must have originated from a gas-bearing interval located above the heavy oil production zone (see section 6.2.3.2) (Rowe and Muehlenbachs, 1999a; Muehlenbachs, 2012; Tilley and Muehlenbachs, 2013).

Producing formations are often not the source of a leak because, as pointed out by Watson and Bachu (2009) and Dusseault and Jackson (2013), these regions are often sealed with the highest quality cement in a wellbore. During placement, the cement at the bottom interval is subjected to high hydrostatic pressure. Since the hydrostatic pressure of the cement slurry when it is fully liquid is significantly higher than the surrounding pore pressure (large Δp), significant amounts of water are lost to adjacent strata that may be somewhat permeable, resulting in a dense cement with a good seal (Dusseault and Jackson, 2013). Conversely, intermediate and shallow depth intervals are often sealed with lower quality cement with a number of filler additives, which do not always generate good primary wellbore seals (Watson and Bachu, 2008).

Intermediate and shallow depth sources are typically thin, non-commercial hydrocarbon-

bearing formations found in low permeability sandstones and silts, high permeability sand seams, or even in coals. These formations often have pressures at or slightly above regional pore pressure because gases slowly generated by biogenic processes or travelling from a deeper source become trapped in these regions. These formations present a significant risk for leakage because if the adjacent cement quality is poor, gas can seep into the exterior wellbore annulus (rock-casing annulus) and accumulate through the displacement of water (Saponja, 1999). In contrast, reservoir depth sources become zones of low regional pressures because they are depleted as a result of production. As stated by Dusseault and Jackson (2013), "...*depleted shale gas formations become a zone of low regional pressure and are more likely to induce brine flow into it than to allow gas flow to escape*".
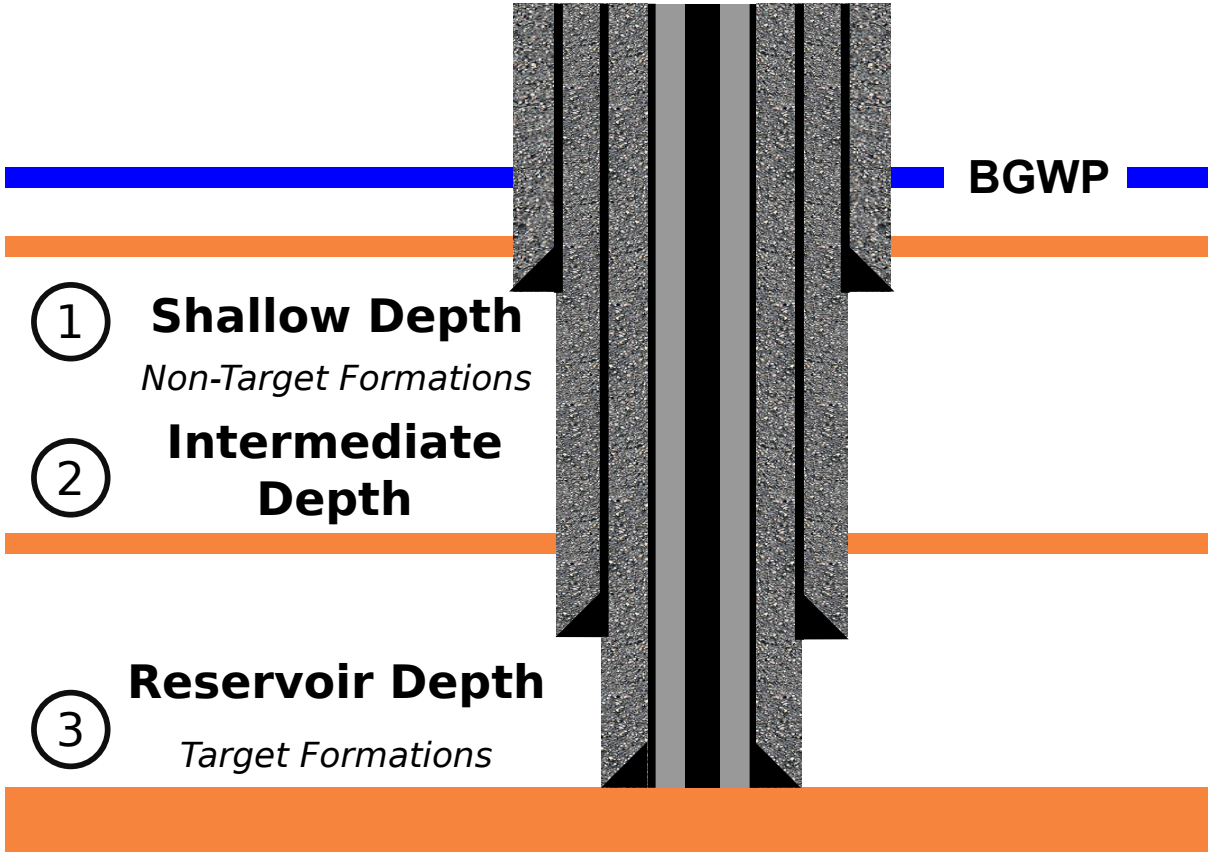
Figure 3.1. Potential source of gas for a typical oil and gas well. Shallow to intermediate depth non-target formations are often found to be the source of fugitive gas

3.2 Gas Migration

At the wellhead, the annular space between the outermost casing string (the surface casing) and the next inner casing string is partially or, in many jurisdictions, completely filled with cement to the surface. This annulus is closed to the atmosphere by the steel assembly of the

wellhead, except for the surface casing vent. The surface casing vent is controlled by a valve, which may be opened to allow gas to vent to the atmosphere (a vented surface casing assembly) or closed to prevent venting (a non-vented surface casing assembly).

A non-vented surface casing annulus (or any other annulus) has the potential to exacerbate gas seepage behind the surface casing (i.e., gas migration). A free gas column may develop below the surface casing shoe behind the exterior casing, and if sufficient pressure develops, gas can migrate upward along the outside of the surface casing. If any casing vent valve is kept closed, there may be no other pathway for the pressurized gases to follow than to leak outside the casing into the adjacent formations. This gas may enter a permeable zone or an aquifer if the gas pressure exceeds the pore pressure and the capillary entry pressure as shown in Figure 3.2 (Penoyer, 2013). Nevertheless, there is no assurance that surface casing vent flow of gas comprises all or even a significant fraction of the gas seeping up along the outside of the casing: if the annulus is well-sealed, gas migration up this annulus, perhaps 150-300 m in length, will be greatly suppressed, leaving only the exterior pathway for gas pressure to be relieved.

Gas migration from annular gas pressure build up behind exterior casings is likely to be somewhat more common in the U.S., where casing-head valves are often non-vented (Dusseault and Jackson, 2014). Although the likelihood of gas migration is somewhat reduced as a result of vented surface casing assemblies, it is probable that gas migration is still occurring outside the surface casing.
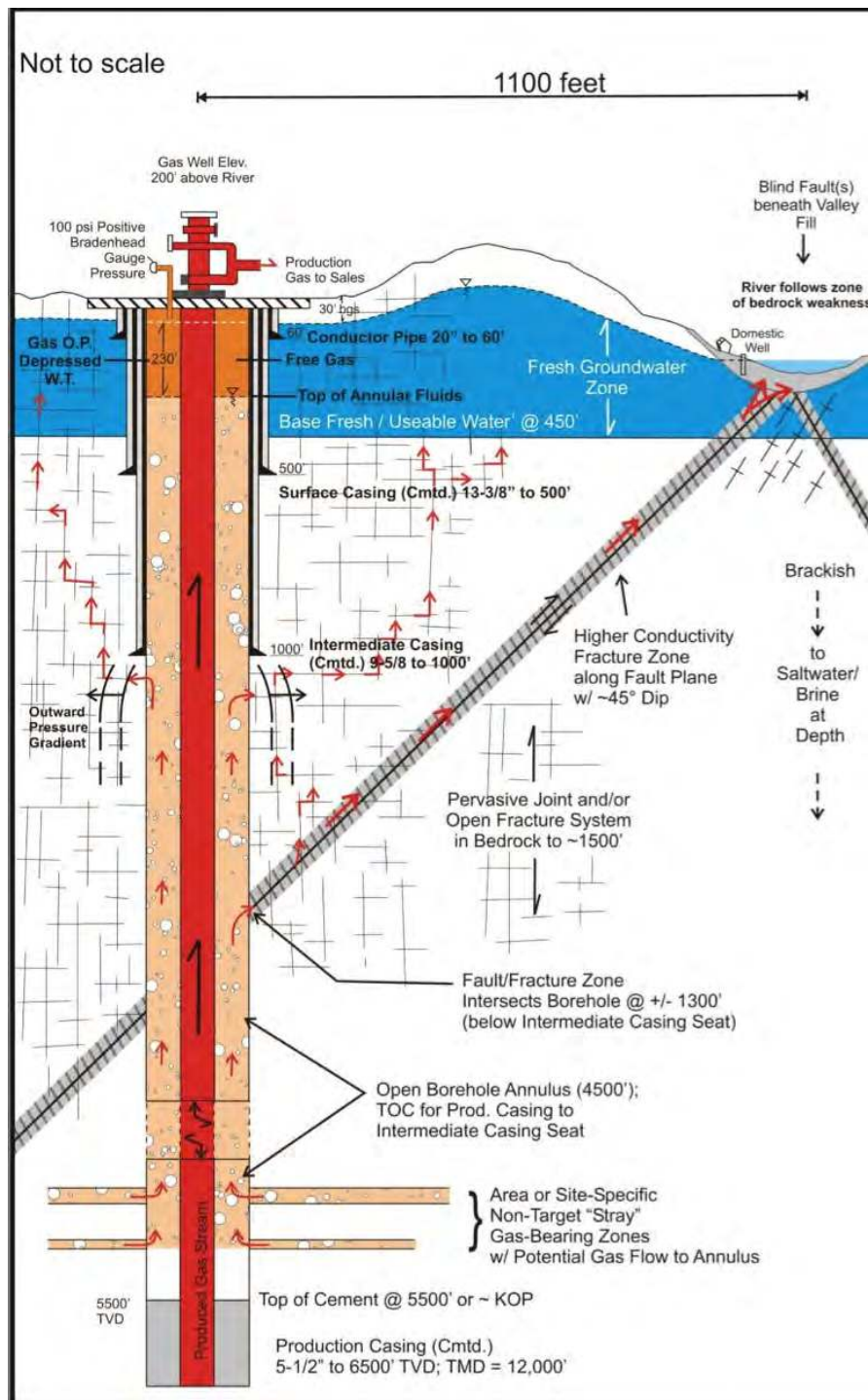
Figure 3.2. Shut-in casing head valves promote gas build up beneath surface casing shoe causing gas migration into bedrock in a Marcellus shale gas well, NE Pennsylvania. Note absence of cement annulus over a distance of 4500 ft. (1500 m) (Courtesy: Pete Penoyer, 2013, US NPS, Ft Collins, CO)

3.3 Surface Casing Vent Flows - Short-Term and Long-Term Mechanisms and Other Important Factors

Surface casing vent flows may develop if a leakage pathway, i.e., a channel or microannulus,

forms in the cement sheath between the surface and next interior casing strings. These leakage

pathways may form either during the initial drilling and completion of the wellbore (short-term mechanisms) or later during the active life of the wellbore (i.e., after completion and before abandonment), or even in the decades following plugging and abandonment of the wellbore (long-term mechanisms). We define short-term mechanisms as those that work to prevent or inhibit the formation of an adequate initial seal during primary cementation, and long-term mechanisms as those processes that adversely affect the cement sheath over the life of the well, before and after abandonment.

3.3.1 Short-Term Mechanisms

3.3.1.1 Improper Drilling Mud and Cement Slurry Design

In order to ensure safe and rapid drilling, the drilling fluid (i.e., air, foam, or aqueous-based or oil-based fluid) must be properly chosen to meet the geological and wellbore conditions. In particular, engineers must pay attention to the density and viscosity of the drilling fluid to ensure adequate drill cutting displacement and low frictional forces, and to avoid blowouts or massive borehole instability while remaining below the fracture gradient. If the viscosity of the drilling fluid is insufficient, cuttings may not be properly cleaned, and if the density is too low, the hydrostatic pressure (the force exerted by the setting cement) within the borehole may be insufficient to prevent the influx of formation fluids and gases, i.e., the fluid column of the wellbore is less than the fluid pressure in a pore volume (Baker, 2001). On the other hand, if the drilling fluid is too viscous or too dense, the pressure of the fluid column may be too large, and this will severely slow down drilling, induce washed out areas, and lead to formation fracturing if the lateral stresses in formations near the previous casing shoe are below the equivalent drilling fluid density. Ultimately, drilling engineers generally seek to minimize the density and viscosity of the drilling fluid to drill more rapidly, without losing the ability to transport cuttings, control borehole instability and formation pore pressures, while avoiding fracturing (Brufatto et al., 2003).

The cement slurry must also be properly designed to ensure adequate cement sheath placement. Potential consequences of an improperly designed cement slurry include the development of leakage pathways through the annular region and a final cement product with undesirable properties. For example, a common historic problem was failure to design the cement slurry for

the appropriate temperatures encountered in the wellbore. As Watson (2004) discussed, cement used in oil wells in the Lloydminster area of Alberta and Saskatchewan were first tested in the lab at around 20°C. However, placement conditions did not reflect lab temperatures; in the Lloydminster area, temperatures near the surface can be substantially cooler than 20°C. As a result, the surface casing cement slurry did not set as originally intended. The cooler temperatures prolonged the transition time, which increased the time the cement slurry was vulnerable to the invasion of formation fluids. As further discussed in section 3.3.1.3, invading fluids can result in the development of fluid cut channels in the cement sheath. The cooler temperatures also allowed the development of undesirable products such as Thaumasite, a mineral that reduces the compressive strength of the set cement. Unexpected high temperatures (generally not an issue in Canada) can lead to premature set so that the cement slurry is not fully displaced (an expensive problem). Overall, the principal consequence of an improperly designed cement slurry is the inability of the cement to provide an adequate seal between casing and rock, regardless of quality control during placement (Watson et al., 2002; Watson, 2004; Macedo et al., 2012).

3.3.1.2 Inadequate Mud Removal

Failure to adequately displace drilling mud during the initial construction of the wellbore may result in the development of microannuli, channels and generally poor cement quality (see Figure 3.3). Microannuli develop as a result of poor cement bonding with the adjacent rock (Watson, 2004). Cement requires water-wet clean surfaces for good cohesive bond development, and will not form a bond with particular materials such as salt, oil-rich beds such as oil sands, high porosity shale and drilling mud filter cake (Dusseault et al., 2000; Watson et al., 2002). Therefore, if residual mud remains on the casing or borehole wall, a stable long-lasting cement bond will not form (Zhang and Bachu, 2011). Washed-out areas of the wellbore wall present a particular problem, because drilling mud typically accumulates within such voids and is often hard to remove because scraping is ineffective, and it is difficult to generate good turbulent flow displacement in deep washouts (i.e., low velocity because of a large area) (Bellabarba et al., 2008; Macedo et al., 2012).

In addition to displacing drilling mud during the initial construction of the wellbore, sufficient isolation between the cement slurry and the drilling fluid must be maintained to ensure

drilling mud does not become embedded within the cement. If the drilling mud is water-based and dominated by sodium ions, contact with the calcium-rich cement fluids causes massive flocculation and virtual solidification of the mud, making it difficult to dislodge or further mobilize. The mud cake and any embedded drilling mud dehydrates over time because of the ionic exchange reactions that cause collapse of the hydrated sheath around the clay minerals, leaving behind a void space to act as a pathway for fluid and gas migration (Watson, 2004; Zhang and Bachu, 2011). Generally, mixing may occur if the density contrast between the drilling mud and the cement slurry is low (in cases where high density drilling mud was necessary to control high formation fluid pressures) and no wash fluids and spacers are used (Watson, 2004; Bellabarba et al., 2008).

So, mud-contaminated cement slurry may result in undesirable behavior; Bittleson and Dominique (1991) point out, "*if drilling mud and cement come into contact, chemical reaction between the two can produce an unpumpable mass*". Watson (2004) further states that embedded mud may reduce the compressive strength of the set cement or even prevent slurry gelation from occurring. In summary, regardless if the cement slurry was designed properly or not, residual drilling muds generally interfere with adequate seal development (Dousett et al., 1997).

Figure 3.3. Cement and drilling fluid channels resulting from incomplete drilling mud displacement. Note that because of the eccentric casing, the severity of the problem on the thinner annulus is much greater (from Watson, 2004)

Eccentric casing placement, as illustrated in Figure 3.4, is a critical factor contributing to

inadequate mud removal in deviated wellbores. A difference in annular space thickness on the two sides of the casing makes displacing the drilling mud and placing the cement slurry more difficult, especially when the interior casing is in direct contact with the exterior casing or the rock wall over a considerable distance. Residual mud may be left behind in the thinner annulus (contact zone) because turbulent displacement will be inhibited and the cement slurry will preferentially flow up the wider side of the annulus (Bellabarba et al., 2008; Roth et al., 2008). In Figure 3.3, the effects of an eccentric casing are observed to be particularly detrimental to full mud removal in the deviated part of the borehole. Note on the thinner side of the annulus, the microannulus is much more significant than on the wider side of the annulus.
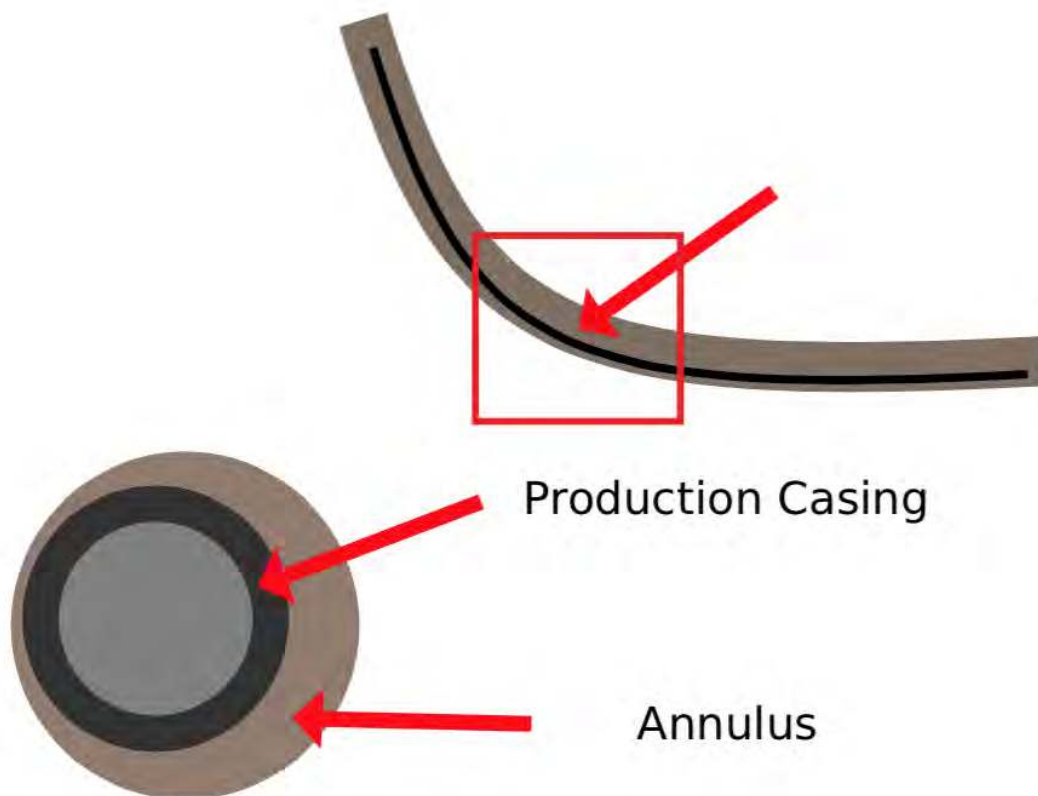
Figure 3.4. Schematic of an eccentric casing

3.3.1.3 Invasion of Liquids and Gases

In order for the cement slurry to resist the invasion of formation fluids, the cement must maintain sufficient hydrostatic pressure until the slurry has developed adequate strength. Depending on the conditions of the wellbore and the slurry design, the slurry may require several hours to develop sufficient strength following placement. If the cement slurry does not maintain sufficient

hydrostatic pressure, then the pressure in the cement can drop below the pore pressure in the surrounding rocks, and invading formation fluids may result in the development of channels and gas pockets (as shown in Figure 3.5). The time period when the cement slurry remains most susceptible to the invasion of fluids and gases is often referred to as the critical phase (Brufatto et al., 2003; Stein et al., 2003; Macedo et al., 2012).

Thus fluid invasion into the cement slurry is generally attributed to a loss in the slurry's hydrostatic pressure. Cement shrinkage, early or uneven gelation, sedimentation and the bridging of particles in the annulus may all contribute to this loss. Cement shrinkage during the period when it is fluid occurs as a result of slurry dehydration because of the pressure difference with the pore fluids, leading to expulsion of liberated water into permeable formations surrounding the wellbore. Autogenous shrinkage is the bulk shrinkage that arises during and after cement set because the volume of the products is smaller than that of the reactants, and perhaps also because of osmotic dewatering (Ravi et al., 2002; Stein et al., 2003) (see also Brufatto et al., 2003; Dousett et al., 1997; Zhang and Bachu, 2011).

Figure 3.5. Channels and gas pockets formed as a result of gas invasion during cementing set (from Watson, 2004)

3.3.2 Long-Term Mechanisms

3.3.2.1 Operating Stresses

During the well's active life, the wellbore is subjected to production, injection, stimulation, and other operations that impose occasional or cyclic pressure and/or thermal stresses, depending on the type of the well. The pressure changes or elevated temperatures cause casing expansion and subsequent compression of the cement sheath, i.e., an increase in the radial stress. When the pressure or temperature increase ends, the reverse occurs, the radial stress drops. However, the process is seldom fully reversible, and the radial stress may even drop below the pore pressure in the strata outside the casing. The term 'bond' as used to describe the cement-to-rock interface is misleading, as bond implies one form of cohesive bonding, but in reality the 'bond' as measured in acoustic tools is a measure of the intergranular contact at this interface maintained by the radial effective stress. Continuous cyclic activity will likely result in de-bonding, and therefore the development of a microannulus at this interface when the radial stress drops below the pore pressure (Dusseault et al., 2000; Zhang and Bachu, 2011; Dusseault and Jackson, 2014).

Casing expansion has also been observed to induce radial stress cracks in the cement sheath as shown in Figure 3.6, where the casing expansion leads to an increase in radial compressive stress (Goodwin and Crook, 1992; Ravi et al., 2002) and a drop in the tangential stress. When the tangential total stress in the cement drops below the pore pressure in the annular space, the cement will crack under the induced tensile effective stresses.

Wellbores used for enhanced oil recovery operations are particularly vulnerable to leakage problems. Considering cyclic steam and steam injection wells, these wells are subjected to significant temperatures, i.e., 'thermal shock' (Bour, 2005). Likewise, hydraulically fractured wells where the exterior casing is exposed to the fracturing fluids are subjected to high pressures. Due to the magnitude of stresses imposed on the wellbores using such stimulation techniques, the likelihood of developing microannuli and stress fractures is significantly increased (Watson and Bachu, 2008). The use of a suspended production tubing string through which hydraulic fracturing fluids are introduced to the stimulation zone has the effect of eliminating the cyclic high pressures acting on the exterior casing.

Figure 3.6. Cement sheath failure and crack development as a result of pressure cycling (Watson, 2004)

3.3.2.2 Cement Shrinkage

Another potential mechanism responsible for the development of a microannulus is cement shrinkage. Cement shrinkage is the result of volume losses such as those described previously in section 3.3.1.3, exacerbated by the presence of dissolved gases, high curing temperatures, and early set (Dousett et al., 1997; Dusseault et al., 2000). Autogenous shrinkage alone can result in a volume loss of around 4-6% (Ravi et al., 2002; Stein et al., 2003), far greater than is needed for a massive loss of radial stress.

Dusseault et al. (2000) discuss the development of a microannulus as a result of cement shrinkage. Initially, a small volume reduction (0.1-0.2%) reduces the radial total stress between the cement and the rock to less than the pore pressure. This consequently leads to the development of circumferential fractures that grow vertically because of differences between lateral stress gradients and fluid pressure gradients. The vertical growth is much greater if the fluid is gas rather than a liquid, because the difference in the gradients is significantly higher. The upward driving displacement pressure (P_d), i.e., $P_d = zg(\rho_w - \rho_g)$ where z is the height of the gas slug, g is the gravitational constant, and ρ_w and ρ_g are the densities of water (brine) and gas, respectively, becomes greater as the height of the gas-filled fracture grows, and the more gas-filled it becomes.

Pathway development as a result of cement shrinkage is a slow process. Diffusion rates of gas into the fractures and the size of the apertures limit the ability to transmit gas. As a result, the effects of cement shrinkage may not be detectable until abandonment or even decades following the plugging and abandonment of the wellbore (Dusseault et al., 2000).

3.3.2.3   Corrosion and Cement Degradation

Casing corrosion is a significant problem for industry because corrosion negatively affects the mechanical properties of the casing, and may also lead to the development of leakage problems. Steel casing corrosion is a natural phenomenon, an issue encountered with every engineered steel structure worldwide (King and King, 2013). However, there are a number of particularly corrosive agents found in natural gas, such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S). Dissolved in water, CO_2 forms weak carbonic acid and H_2S forms sulfurous acid, both yielding a low aqueous pH, and hence corrosive to iron. Other corrosive agents contained in drilling fluids include dissolved oxygen and treatment acids that are not fully reacted and subsequently can accelerate casing corrosion.

There are a number of potential reactions that may be involved in casing corrosion. These reactions include electrochemical corrosion (galvanic corrosion, crevice corrosion, and stray-current corrosion), chemical corrosion (H_2S corrosion, CO_2 corrosion, strong acids, concentrated brines, and biological effects), and mechanical corrosion (cavitation, erosion, erosion corrosion, corrosion fatigue, sulfide stress corrosion, chloride stress cracking and stress corrosion cracking) (see Brondel et al., 1994; Abdallah et al., 2013; Popoola et al., 2013).

Degradation of the cement sheath over time may exacerbate pre-existing pathways that have arisen from corrosion or rock damage during drilling. Filler additives e.g., bentonite and gypsum, are often used in cements to reduce cementing costs across non-completed intervals in shallower areas. These filler additives are often susceptible to acid attack from CO_2 and H_2S. In the context of carbon dioxide sequestration, this has been a particular concern because carbonation reactions of the CO_2 being stored exacerbates leakage pathways in the wellbore by deteriorating the cement. For the same reason, acid treatments and acid gas may also promote cement degradation because cement is vulnerable to acid attack (Watson and Bachu, 2008).

3.3.3 Other Important Factors Contributing to Leakage Problems

Watson and Bachu (2009) evaluated wellbore leakage in Alberta in the context of the potential for CO_2 from wellbores that may penetrate or be close to the injection well for carbon dioxide capture and storage. They identified six factors 'showing major impact':

1. Geographic area
2. Wellbore deviation
3. Well type
4. Abandonment method
5. Oil price, regulatory changes and SCVF/GM testing
6. Uncemented casing/hole annulus

3.3.3.1   Geographic Area

The occurrence of leakage problems, although not limited to a particular area, is often found to be more likely in some geographic areas. A review of leakage reports in Alberta by Watson and Bachu (2009), for example, found that the 'Test Area' (an area designated for special testing requirements for leakage, shown in Figure 3.7) had higher occurrences of leakage problems than the rest of the province. Although the authors speculated that the greater percentage of reported leakage may be reflective of the testing requirements, they presumed that the testing requirements in the test area were designated based on historical problems in the area.

Geographically-identified problem areas may reflect problematic geological conditions or particular activities occurring in the area. Saponja (1999) discussed how typical formations found in the Lloydminster area – the presence of shallow gravel beds, swelling clays and thin non-commercial hydrocarbon-bearing formations – make both obtaining and maintaining an adequate seal much more difficult in the Test Area. Furthermore, areas where enhanced oil recovery and other stress-inducing operations are performed have significantly increased potential for leakage development in the area (section 3.3.2.1).
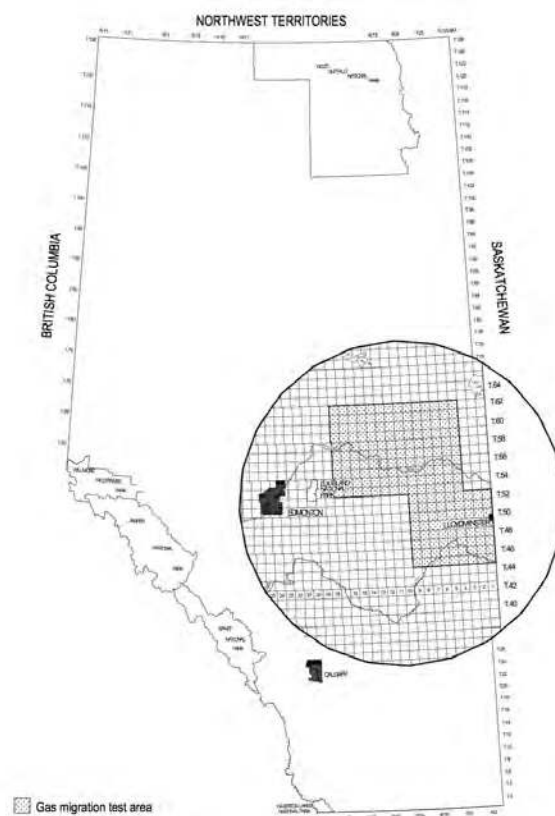
Figure 3.7. Gas migration Test Area in Alberta (AER, 2010)

3.3.3.2 Wellbore Deviation

Watson and Bachu (2009) found that a deviated wellbore (i.e., any wellbore where the total length is greater than the true vertical depth) is a major factor in the development of a leakage. The authors observed that deviated wellbores in the Test Area had higher occurrences of leakage than other wells in the Test Area (see Figure 3.8). Poor casing centralization was suspected as the main contributing factor to this finding. An eccentric casing results in issues with adequate displacement of drilling mud and uniform placement of the cement slurry, therefore increasing the probability of leakage issues (section 3.3.1.2).
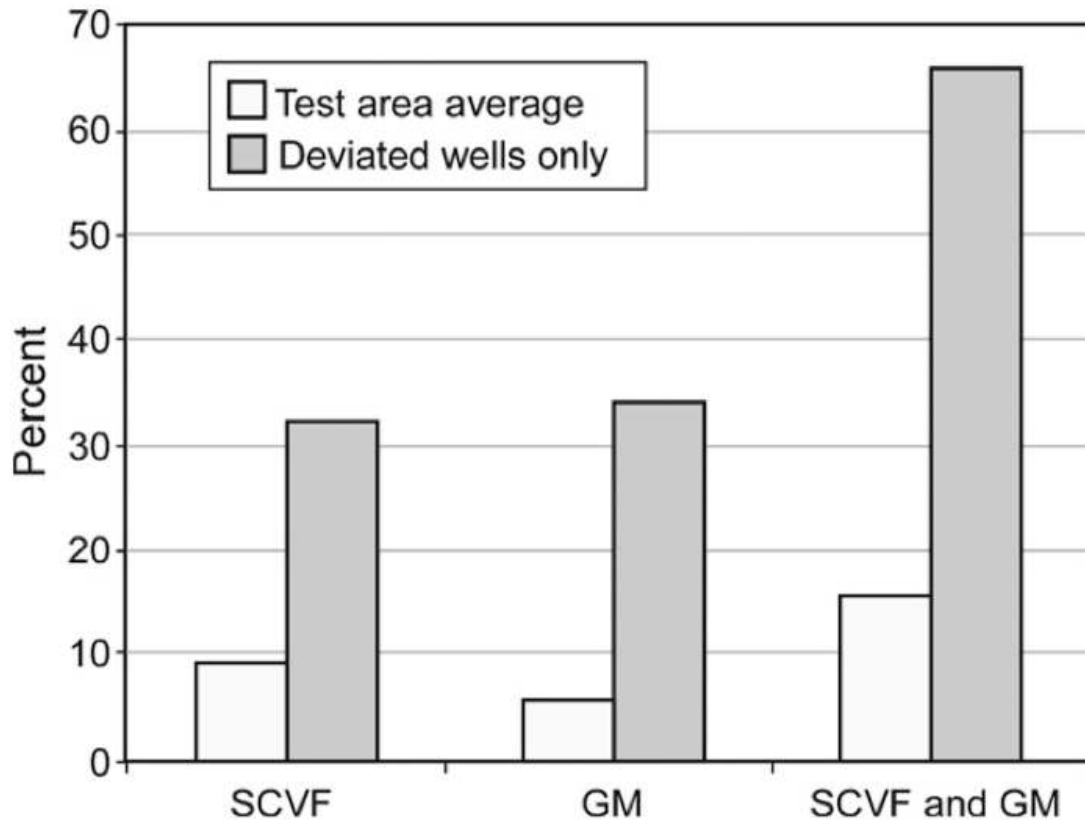
Figure 3.8. Comparison of the occurrences of SCVF/GM in all the wells in the Test Area of Alberta and in deviated wells only in the same region (from Watson and Bachu, 2009)

3.3.3.3 Well Type

Watson and Bachu (2009) noted that the occurrences of leakage varied between wells that were drilled and abandoned, versus wells that were drilled, cased and abandoned. The authors found that within the study area, wells that were cased and abandoned accounted for 98% of all leakage cases reported. The authors speculated this may be related to historically more stringent abandonment requirements for drilled and abandoned wellbores. It may simply be that the presence of a steel casing with exterior cement subjected to a long operating life span is likely to develop a behind-the-casing pathway, whereas a well that is immediately abandoned, and plugged with a number of long cement plugs, does not have such a potential for pathway development.

3.3.3.4 Well Abandonment Method

Well abandonment method plays a role in leakage development. Providing an adequate seal for many years requires that a competent abandonment approach be correctly used. The use of bridge plugs capped with cement is the predominant abandonment method in Alberta (Watson and Bachu, 2009). The authors determined that this method may not be adequate for providing an adequate seal for the long term. Bridge plugs are composed of mechanical plugging devices made of cast iron and nitrile elastomers, which are susceptible to corrosion by formation and injected fluids, in particular in the presence of dissolved CO_2. Furthermore, the cement used to cap bridge plugs is often placed using dump-bailer systems. Experience has shown that the dump-bailer approach is often unsatisfactory in providing an adequate seal (T.L. Watson, personal communication, 31 October, 2013, Calgary workshop).

A small subset of wellbores was re-entered to evaluate the efficiency of the bridge plug abandonment approach. Investigators found that the bridge plugs, over a 5-30 year period, underwent significant degradation. The cement plug placed on top of the bridge plug was near nonexistent in some cases. Due to corrosion of bridge plugs, and the inefficiency of placement observed for dump-bail cement caps, the authors suggested that over a long period of time (hundreds of years), approximately 10% of these abandonment methods will fail and allow formation gases to enter the wellbore (see Figure 3.9). When compared to other abandonment approaches, such as placing cement across completed intervals using a balanced plug method or setting a retainer and performing a cement squeeze, "*the bridge plug abandonment method will have a shorter life than other methods due to mechanical failure...*" (Watson, 2009; Watson and Bachu, 2009).
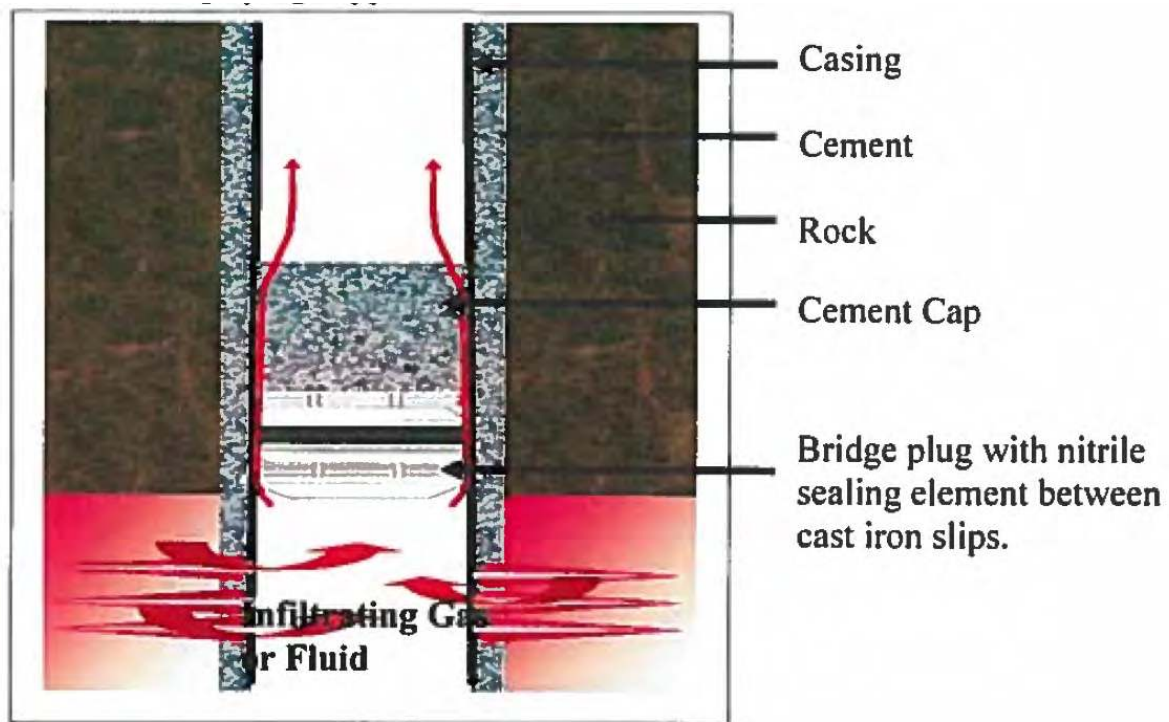
Figure 3.9. Bridge plugs capped with cement (from Watson, 2009)

3.3.3.5   Oil Price, Regulatory Changes and SCVF/GM Testing

Watson and Bachu (2009) observed a strong correlation between historical oil prices and SCVF/GM occurrences (Figure 3.10). When oil prices were high, there was an increase in drilling activity; during these times, the authors noted that there were elevated occurrences of vent flows and gas migration. They suggested that with larger financial incentives to drill many wells rapidly, combined with limits on equipment availability, i.e., "*pressure to do more with less*", wellbore construction practices were negatively impacted, which may explain the elevated occurrences of leakage problems. The authors further suggested that higher prices lead to an economic incentive to develop heavy oilfields. Heavy oilfield development consists of developing high-density well spacings (as tight as 10 acres per well in some areas), which increase the risk of offset well interaction, the use of directional drilling (multiwell pads), and enhanced recovery processes involving steam injection, all of which raise issues with eccentric casings and elevated stresses.
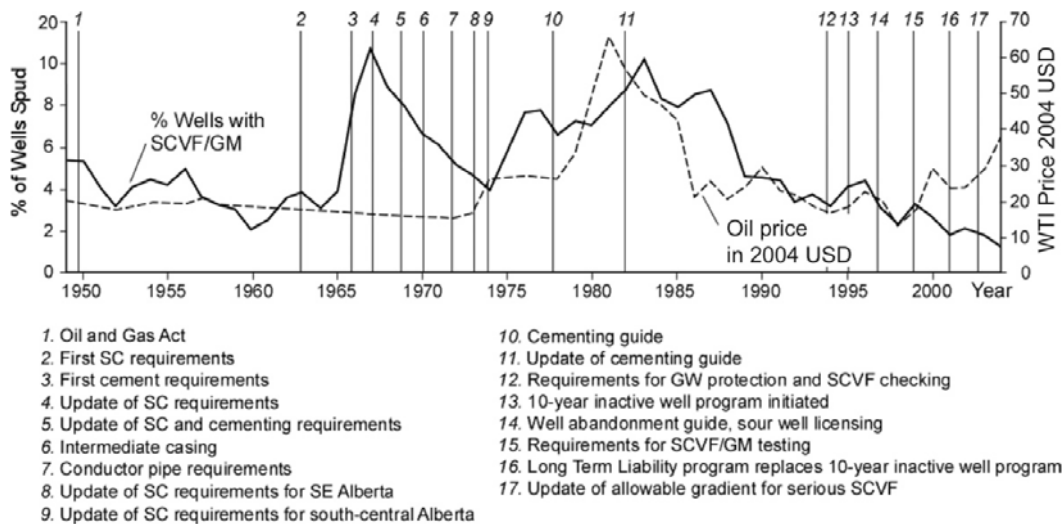
Figure 3.10. Occurrence of SCVF/GM in Alberta in relation to oil price and regulatory changes (from Watson and Bachu, 2009)

3.3.3.6   Uncemented Casing/Hole Annulus

Watson and Bachu (2009) found that exposed casing was the most important indicator for surface casing vent flow and gas migration. In a study by the authors, approximately 150 well casings and cement bond logs were analyzed, which led to 3 important conclusions: 1) the majority of significant corrosion occurs on the external wall of the casing; 2) a large proportion of the wellbore length is uncemented; 3) external corrosion is most likely to occur in areas where there is no or poor cement. Although all wellbore casings have some potential to degrade over time, the potential for corrosion is significantly elevated if the cement sheath quality is poor or inexistent. Also, exterior steel casing corrosion is known to be more frequent at the contact between glacial (Pleistocene) and older (Tertiary or Cretaceous) sediments in Alberta and Saskatchewan because the geochemistry of the groundwater changes from chloride-based (Cretaceous strata) to bicarbonate/sulfate-based in the surficial cover. These differing but adjacent chemistries lead to the development of weak electrolytic cells that corrode the casing from the outside.

4 ADDRESSING SHORT-TERM ISSUES

In discussions held in Calgary, Pittsburgh and Houston with the energy industry and its service companies during preparation of this report (2013-2014), there was clear evidence that learning-by-doing had led to much lower rates of SCVF and GM as each new field was developed.

'*Doing it right the first time*' is obviously the best practice to reduce long-term problems with emission rates (SCVF or GM) and to reduce the costs of workovers and abandonment. But just what constitutes '*doing it right the first time*'? We consider issues of casing properties, primary cementing over the full casing length and cement evaluation logging; all of these, if done well, will reduce the incidence of SCVF and GM.

4.1 Casing Properties

Casing design in Canada is specified by regulations such as AER's Directive 010 that identifies burst strength and other parameters necessary to achieve satisfactory results. We did hear, however, of concerns about the quality assurance (QA) of casing manufactured outside North America. It is unclear to the authors if this matter of QA is a genuine matter to be addressed by importers of the casing or if it is an issue that the buyer – i.e., the operator – must address upon receipt of the casing.

Importantly, Muehlenbachs (2012, 2013) has presented evidence of SCVF gases that originate in the production zones in the Montney and Horn River Basin shale gas plays. This was puzzling because one expects that the cement quality at the heel of the production casing would be of the highest quality, given that it was emplaced at very high pressure heads arising from the entire vertical column of cement in its fluid state. Apparently the problem – at least in the Montney shale – has been due to casing couplings and threads that were suitable for vertical wells, but not for use in the horizontal sections of newer wells (BC Oil & Gas Commission, 2014, personal communication). More stringent standards may have to be applied for deep oil and gas well couplings and threads, which is a matter for industry and regulators to define.

4.2 Primary Cementing

From our discussions with industry and service companies, the greatest reductions in SCVF and GM rates are those associated with improvements in the primary cementing operations, i.e., '*doing it right the first time*'. Reducing the rates and occurrences of wellbore leakage by improving wellbore construction practices began to be emphasized after a number of mechanisms were identified in the 1970s (see Cooke et al., 1983 and references therein) as leading to the development of leakage pathways (Watson et al., 2002):

- inadequate drilling mud removal;

- cement sheath failure leading to sheath cracking;

- gas migration into the setting cement; and

- absence of cement protecting the casing, i.e., low cement top

There are a number of methods that have been used to improve drilling mud removal (see Figure 4.1). As an example, reduction of washed-out zones in the Celtic field in Saskatchewan has been successfully achieved by using specially designed drilling fluids, such as silicate based muds (Macedo et al., 2012). To help reduce the risk of fluid mixing (i.e. between drilling fluid and cement slurry), the cement slurry is placed with a significantly larger density than the drilling mud, and mud-removal spacers provide a buffer volume between the drilling mud and the cement slurry. Removal of residual mud on the borehole wall is accomplished by rotating and reciprocating the casing along with the use of chemical washes, scrapers and wipers (Watson et al., 2002; Watson, 2004; Holt and Lahoti, 2012). Improvements have also been attributed to the use of software packages that allow the completions engineer to design better displacement systems (Brufatto et al., 2003). All these methods are well established and may work better in some fields than others.

Ensuring adequate casing centralization is particularly important and perhaps produces the most cost-effective improvement in reducing wellbore leakage. The casing needs to be centralized so that there is room for the spacer and wash fluids to displace the filter cake and drilling fluid and to ensure that the cement slurry completely fills the annulus (Ravi et al., 1992; Roth et al., 2008). Casing centralization is accomplished by the placement of centralizers on casing joints, typically one centralizer per 100 linear meters, although the interval varies by wellbore and company (Dousett et al., 1997; Zhang and Bachu, 2011). Shell Canada has been using one centralizer per casing joint (i.e., a 13 m spacing interval) in vertical sections of its wells in the Montney and Duvernay shale gas and shale oil plays in Alberta and British Columbia, and one centralizer every third casing joint in the horizontal sections (from which leakage would not be expected in any case). This increased centralizer frequency has resulted in improved quality primary completions.

Gas migration into the setting cement requires that the transition time of the cement – the duration required for the slurry to progress through the gel stage to set cement – be minimized. During this period, the slurry is vulnerable to the invasion of gases from adjacent formations.

Once the cement slurry has reached a static gel strength of 240 Pa, it is believed that the cement is impermeable to gas invasion and subsequent channeling (see Sabins et al., 1982; Rogers et al., 2004).
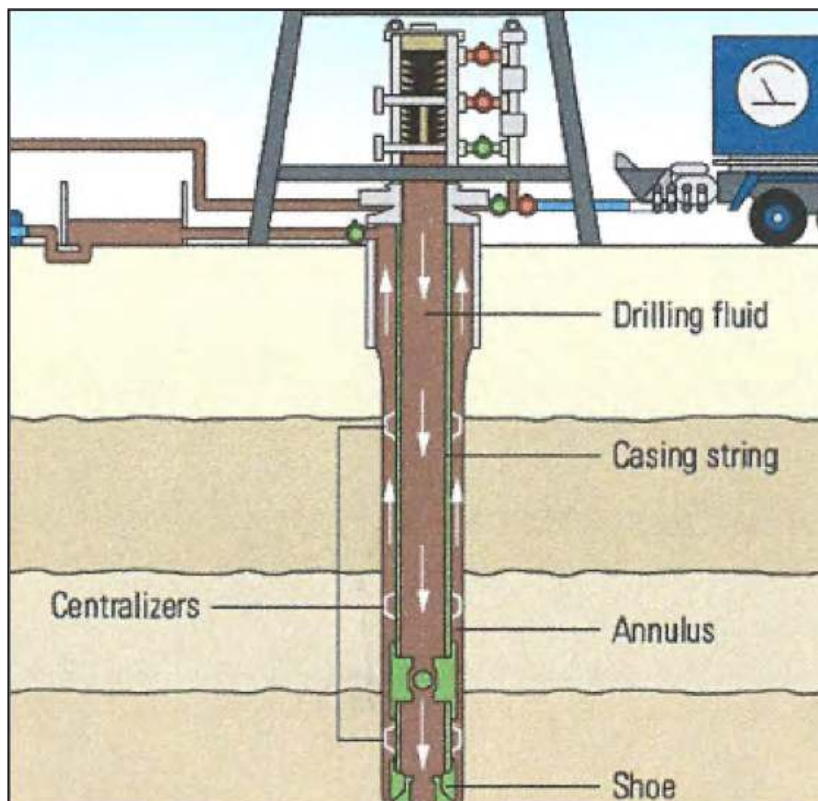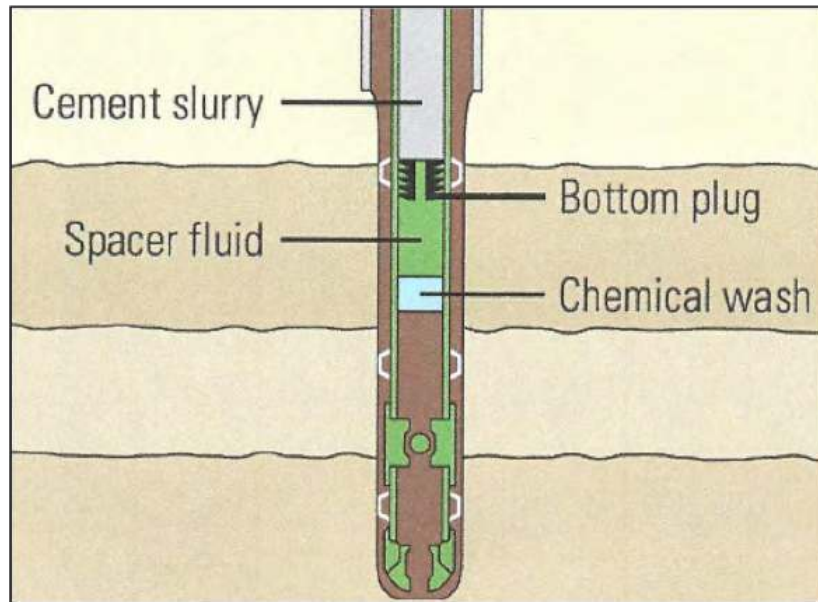
Figure 4.1. Improving drilling mud displacement by using centralizers (top), and (bottom) conditioning the wellbore and ensuring adequate separation between different fluids, from Nelson (2012).

The authors found no consensus on choice of cement systems to meet this goal. On the basis of improved cement bond logs, Nexen believed that it had dispensed with many wellbore issues in the Horn River Basin by using foam cement [2]. Husky indicated that it had measurably reduced its wellbore completion problems by using silica sand to remove filter cake and thermal cement to establish the seal. Shell Appalachia recommended that whatever cement was used, a sample should be archived to allow subsequent testing when needed.

For long-term integrity of new wells, the full cementation of each annulus is most desirable. Thus the production casing is cemented a distance of $\sim$200 m into the intermediate casing, which is cemented to the surface as is the surface casing. In this manner, there will be no exposed casing that might corrode over time or promote the accumulation of a large amount of head-space gas. This would appear to be the best solution to the prevention of corrosion over the life of the well. It is also the preferred solution to minimize SCVF and GM that are predominantly associated with non-commercial intermediate zones that should be sealed off (Watson and Bachu, 2009): "*the vast majority of SCVF/GM originates from formations not isolated by cement*".

We noticed that in the US (as in older Canadian wells) there were many cases in which the cement tops did not reach the next casing shoe leaving considerable lengths of exposed casing. Figure 3.2 shows a particular example from the Marcellus with very large lengths of uncemented casing exposed to the formation fluids. In such cases, Shell Appalachia employs inhibited brine to protect the exterior of the casing. The longevity of such a measure is uncertain as the development of a head-space buoyant gas may displace the inhibited brine, thus full cementation seems to be the preferred solution.

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[2]Foam completions are not without problems and require careful design and implementation similar to all other cement completions. The investigation by the US National Academy of Engineering and the US National Research Council into the Macondo Well-Deepwater Horizon blowout in April 2010 in the Gulf of Mexico raised concerns about the efficacy of the primary foam cement emplacement. The NAE/NRC study demonstrated the likelihood that the foam cement may have inadvertently become mixed with the high-density tail cement resulting in an gravitationally unstable system at the base of the production casing. This scenario would have led to a much lower compressive strength cement than was intended and may have played a major role in the blowout. This conclusion is based on the photographic evidence of hydrocarbon flow inside the casing resulting in the blowout and destruction of the rig. (NAE/NRC, 2012, Macondo Well-Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety. The National Academies Press, Washington D.C.).

4.3 Cement Evaluation Logging

Improvements in cement bond logging (CBL) have been continuous over the last decades, and where the cost ($30,000 to $100,000) of the CBL is considered small compared with the benefit, there is increasing likelihood that residual mud and discontinuities in the cement sheath will be identified. The current generation of cement evaluation tools is impressive. For example, Schlumberger's Isolation Scanner combines traditional acoustic tools with ultrasonic imaging to identify zones of incomplete cement sheath or residual mud. It is sensitive to lightweight cements but has some weaknesses detecting a wet microannulus (i.e.,<200 μm) and when imaging unconsolidated formations. In such cases the pulse-echo technique yields a weak acoustic impedance measurement; the user will need to refer to other CBL tools such as the variable density log.

What is of concern is the lack of mandated third-party testing of performance assessment (PA) of such tools, noting as well that these tools may also be run by the same company that performed the cement job. In the absence of such independent PA studies and third-party interpretation, the operator and the regulator must retain a healthy skepticism of the claims of commercial CBL providers. For example, CBLs should never be relied upon if they were run at excess borehole pressure because this expands the casing against the cement sheath and may close any microannuli at the cement-rock interface. Furthermore, we have not been able to identify standardized methods of CBL interpretation that will provide more confidence in their analysis. Again, there is a need for independent studies to ensure consistency in interpretation.

4.4 Accountability

Finally, we are concerned that practices in the field do not necessarily match those specified in work plans, which are always "recommended best practices". Because of time constraints, best practices may not be used, particularly at times of high oil and gas prices, where as pointed out by Watson and Bachu (2009), there are "*pressures to do more with less*" (see figure 3.10). Field crews may not be directly supervised by company engineers and the results may be far from optimal. If the corporate cementing engineer is not on site during primary cementing, then the service companies will have no oversight. The authors have heard several complaints that this leads to a lack of accountability, although the service company will likely be paid regardless.

These PA matters require regulatory attention; at this time, it seems reasonable to stipulate that cement jobs be supervised by a responsible engineer with authority to request rectification of issues. The sign-off by this responsible engineer should indicate his/her confidence in the completion and the likelihood of no significant wellbore failure prior to abandonment.

5 ADDRESSING LONG-TERM ISSUES

5.1 The Need to Address Long-Term Issues

Casing properties, primary cement jobs, cement evaluation logging and accountability are important considerations for reducing the incidence of SCVF and GM. In addition, long-term mechanisms of pathway development must also be addressed because even an adequately completed wellbore with a good initial seal may be compromised over time.

Wellbores need to be designed to be able to withstand mechanical and thermal loading. Regardless of how well the cement sheath is placed, if the wellbore is not both durable and adaptive to changing conditions, the wellbore may not be able to withstand large changes in stress (Ravi et al., 2002; Bellabarba et al., 2008). The use of enhanced recovery methods (steam injection, hydraulic fracturing, etc.) elevates the mechanical and thermal loading on wellbores, and significantly increases the probability of leakage problem development during the operational lifetime of the wellbore, before final abandonment.

Cement shrinkage must be addressed, as simply improving completion practices will not resolve the problem if the cement slurry is inherently susceptible to appreciable shrinkage. Regardless of any efforts to properly design the cement slurry, neat Portland-based cements are vulnerable to cement shrinkage. The development of a microannulus as a result of cement shrinkage is a slow process, and may not manifest itself until decades following P&A (plug and abandonment) of the wellbore because increasing pressure arising as the result of development of a free gas column may take place.

The slow deterioration and corrosion of a wellbore, both the cement and the steel, also presents an issue for long-term wellbore integrity (>100 years). Although improved primary cement jobs may reduce the occurrence of poorly cemented intervals, cement remains vulnerable to deterioration over long times, especially if exposed to acidic fluids, potentially leading to the development or exacerbation of slow leakage problems. A particular concern has been

expressed by some experts in the field concerning failure of abandonment methods related to failure of the plugging procedure within the casing. More specifically, because cast iron and nitrile elastomers are susceptible to corrosion, the use of bridge plugs for abandonment is in question for extended periods of time. Then the capping cement placed on top of the bridge plug may be inadequate of itself for providing an adequate seal (inadequate length, having experienced shrinkage, inadequate placement method, or cement deterioration). Evidence suggests that within a short period of time (decades), leakage as the result of abandonment failure will significantly increase and with it gas leakage problems.

5.2 New Cement Formulations

Many cement additives have been introduced to try to 'counter' the mechanisms of leakage development. For example, volume losses, which consequently contribute to the invasion of liquids and gases and the development of microannuli, have been said to be addressed by using a number of additives such as fluid loss additives, nitrogen and hydrogen gas, surfactants and liquid latex (Dousett et al., 1997). However, the success of such additives is uncertain as there is little third party testing of these products. As Dusseault et al. (2000) point out, "*additives may enhance some properties; however, they may induce negative impacts on other properties, or lose effectiveness at elevated temperatures, pressures, or in the presence of certain geochemical species*". In other words, it is not clear whether or not additives will always provide the desired effect. Third party PA is needed to determine the limitations of proposed additives, and in general there is no industry agreed-upon third party verifications of the claims of companies promoting the use of these additives. Often, no independent research whatsoever can be found to substantiate broad claims of efficacy.

Although we found no consensus on choice of cement system, we believe that the use of a ductile cement slurry will provide the most promising resistence to leakage development. Both Goodwin and Crook (1992) and Bour (2005) found that low compressive strength cements, which are inherently more ductile or require greater extensional strain to generate tensile cracks, were most likely to withstand stress cycling. Modeling studies showed that with increasing compressive strength, there was a corresponding increase in the cement's susceptibility to cracking and the cement's elastic modulus, i.e., the cement became more brittle.

It is widely accepted, although not discussed in as much detail as one might expect, that

formulating a cement slurry that does not exhibit shrinkage is highly desirable. Of course, as suggested above, such proposed formulations should undergo vigorous third party PA because of the long-term consequences of cement shrinkage. We believe, furthermore, that although laboratory tests following specified standards are appropriate, field verification is necessary to demonstrate the claims in practice. This will not be required for each wellbore, but for a sufficient number under varying conditions to give credence to marketing claims.

Overall, the conditions of each wellbore vary, therefore there is almost certainly no universal cement formulation based on Portland cement powders that can be applied irrespective of wellbore conditions, rock stresses and planned use. Rather, the cement should be formulated based on experience and demonstrated previous successful practice to determine what works best.

5.3 New Abandonment Approaches and Wellbore Designs

'*Doing it right the first time*' and formulating ductile cement slurries that do not exhibit shrinkage may reduce occurrences of wellbore leakage. It may also be possible to further reduce the occurrences of wellbore leakage, or at least mitigate the impacts, by manipulating abandonment methods and wellbore design.

Abandoning a wellbore in such a manner that high security against leakage can be assured for many decades is no easy task. Also, the wellbore needs to be robust enough to be accessible for future remedial workovers, if necessary. The bridge plug abandonment technique appears not to provide long-term isolation guarantees because of its potential for corrosion, and it is therefore not a recommended abandonment method unless improvements are made in the materials used. Watson and Bachu (2009) recommend placing cement across completed intervals using a balanced plug method or setting a retainer and performing a cement squeeze, because then there are no corrodible components used, other than the cement itself.

It is well to remember that for engineering work, the concept of risk includes both the probability and the consequences of an "incident" or "occurrence". Reducing one or the other each lead to risk reduction. Proactively planning for the potential development of leakages in appropriate environments may lead to designs that can mitigate the consequences of leakage[3].

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[3]This raised the critical issue of what constitutes an acceptable leakage rate, how to determine it, and how to regulate such a guideline in practice, especially with abandoned wellbores. These, and related regulatory issues, are worthy of careful thought and discussion on an across-Canada basis.

Most often, preventative measures are taken to reduce the occurrences of wellbore leakage in the primary cementation, and this reduces the probability of incidents, a fundamentally sound approach. Preventative measures attempt to prevent wellbore leakage from developing, for example, is directly achieved by improving completion practices or manipulating the slurry formulation to be more resilient to changing stress conditions. However, how confident can one be that the wellbore will maintain its integrity for many decades? Not only does the wellbore need to be resilient, but there may also be contingencies in place in order to mitigate (reduce) the consequences of potential leakage problems. Simply put, if techniques can be developed to reduce the volumetric leakage rate of future leakage incidents to a few liters per day, then the risk has been greatly reduced (at least in non-urbanized areas).

Inducing leak off of fugitive gas into natural containment structures, natural conveyance pathways, or into regions with appropriate lithostratigraphic conditions can reduce risk. For example, there are myriad gas impermeable structures that might serve as traps, or there may well be a permeable formation presenting a desirable flow path that is also penetrated by the wellbore. This presents a promising opportunity to mitigate the impacts of wellbore leakage. Such containment structures and formations are geologically dependent and therefore require thorough analyses of potential structures and formations at the particular site or in the adjacent regions. Dusseault et al. (2000) outlines how permeable formations may be utilized to induce leak off of fugitive gas, illustrated in Figure 5.1: a section of the annular region behind the casing is deliberately left uncemented adjacent to a sufficiently permeable formation below the BGWP. Packers are placed in the annular region directly above the uncemented section to ensure a gas tight seal. In this section, fugitive gases will accumulate and invade the permeable zone once excess pressures develop and overcome capillary exclusion forces.

Typical abandonment approaches primarily focus on in-casing abandonment and completed intervals, without much attention paid to leakage behind the casing. The benefit of forcing a leak off behavior is that gases migrating behind the casing, i.e., gas migration, are less likely to invade higher formations such as shallow aquifers or be emitted to the atmosphere. The packers may be permanent inflatable packers (pumped full of cement or resin under pressure after the annular cement has been placed and is still liquid), or chemical hydrating and thus expanding packers that can retain long-term integrity. Other methods can be suggested and these will have

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to be demonstrated in practice.
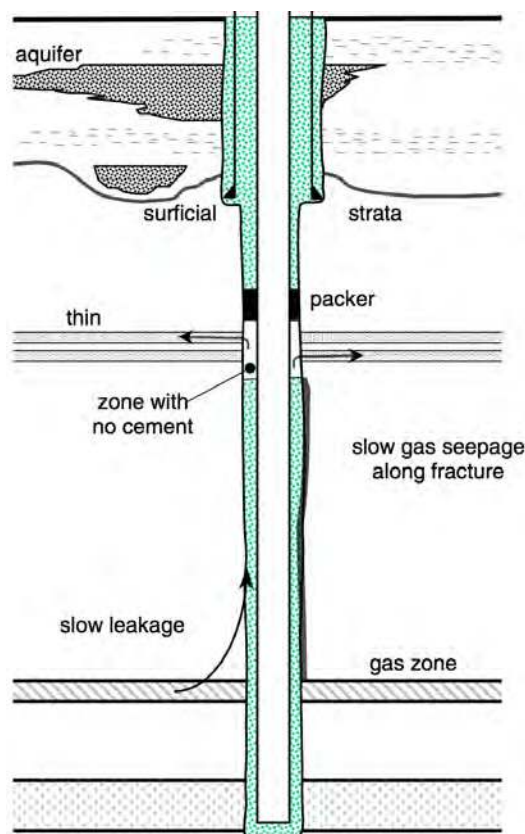
Figure 5.1. Leaving a leak-off zone to arrest gas migration (from Dusseault et al., 2000)

6 DETECTION AND REMEDIATION OF WELLBORE LEAKAGE

6.1 Monitoring Wellbore Leakage

6.1.1 Monitoring Requirements in Canada

Monitoring requirements that industry must adhere to in Canada are outlined by their corresponding provincial regulatory body. The more senior and by far the largest regulator in Canada is the AER – the Alberta Energy Regulator (formerly the ERCB - Energy Resources Conservation Board, and the EUB – Energy Utilities Board). Other regulatory bodies are smaller and less experienced merely by virtue of the dominance of Canadian oil and gas production from Alberta. In many cases, smaller provincial regulatory bodies look to the AER and often adopt the guidelines published on the AER website with minor modifications as may be considered valuable.

Generally, regulators in Canada require SCVF testing shortly after construction of the wellbore (usually within 90 days of drilling rig release) and at the time of abandonment. Some

places (e.g., British Columbia and New Brunswick) are somewhat more stringent, and further require annual testing throughout the active life of the wellbore. For GM, typically testing is not required, except if there is no surface casing assembly, or if there are obvious physical signs that gas migration is occurring.

If a leak is detected during a test, the severity of the leak must then be quantified and classified as either severe or non-severe. The Alberta Energy Regulator outlines a severe vent flow, which has been adopted by many provinces across Canada, as the following:

1. Vent flow adjacent to unprotected (i.e., uncemented) surface casing, and/or next casing string,

2. Vent flow ≥ 300 m^3/day and/or equal to a surface casing vent stabilized shut-in pressure $>$ one-half the formation leak-off pressure at the surface casing shoe, or 11 kPa/m times the surface casing setting depth,

3. Vent flow with H$_2$S present,

4. Hydrocarbon liquid (oil) vent flow,

5. Saline water ($>$4000mg/l) vent flow,

6. Usable water flow where surface shut-in pressure is as in (2),

7. Vent flow due to a wellhead seal failure or casing failure, or

8. Vent flow that constitutes a fire, public safety, or environmental hazard.

A vent flow that meets the preceding conditions is considered severe, and it must be remediated immediately (section 6.2) as such conditions present significant risks to the environment and to public safety. A vent flow that does not meet any of the preceding conditions is considered non-severe. Non-severe vent flows must be monitored annually for a minimum of 5 years, or until the leak dissipates, to ensure the leak does not become more severe (Alberta Energy Regulator, 2003).

6.1.2 Typical Methods for Detecting Wellbore Leakage

There is often visual evidence at the surface when a wellbore develops a leakage problem. Most commonly, the presence of dead vegetation and bubbling of standing water surrounding the wellhead (Figures 6.1 & 6.2) and wellhead corrosion suggest there may be a problem (Watson, 2004). When there is visual evidence that there may be a leakage problem, or when testing is required by the regulator, bubble tests and gas migration surveys are performed to test for SCVF and GM, respectively.

The bubble test, shown in Figure 6.3, has a methodology outlined by the Alberta Energy Regulator (2010). A small hose is placed beneath the water level of a water-filled container for a 10-minute interval (minimum). The formation of any bubbles during the test is indicative of a surface casing vent flow. The rate of flow or the stabilized shut-in surface casing annular pressure is required to determine whether the leak is severe. The flow rate is determined using positive dis-

Figure 6.1. Dead vegetation surrounding a natural gas wellhead in Pennsylvania (Emily Grubet)

placement meters for low flow rates, and orifice well testers for higher flow rates. The stabilized shut-in pressure is determined using pressure gauges and pressure relief valves that are attached to the annular space between the surface casing and the next interior casing string, whether this space is filled entirely with cement or not.

Figure 6.2. Bubbling of standing water surrounding a wellhead, from Ingraffea (2011)

A standard method for a gas migration survey is outlined by Doull Site Assessment Ltd., in Watson (2009). An array of shallow boreholes (50-60 cm) are drilled radially outwards from a wellbore at distances of 1, 2, 4, and 6 m. The gas from the boreholes is measured by directing gas flow into an instrument capable of detecting hydrocarbons at 1% of the lower explosive limit (%LEL)[4],

while ensuring the sample is isolated from atmospheric gas. Also, as pointed out by Slater (2010), sampling should occur only during frost-free periods and not immediately following a precipitation event. If gas flow is detected, the procedure is repeated with test points installed at depths of 2 m at a radial distance of 2 m from the well. At this point, if no gas flow is detected, the survey is complete. However, if gas flow is detected, then further testing is undertaken to

[4]The lower explosive limit for methane is approximately 6% uniformly mixed with air.

obtain as much information as possible from such shallow testing.

6.1.3 Improving Leakage Detection

Typical methods of detecting wellbore leakage raise several concerns as to whether or not leakage is effectively detected and reasonably quantified. First, evidence has shown that gas leakage from depth is not a continuous phenomenon; rather, it is quite variable over time. As shown in Figure 6.4 and observed at water wells (Gorody, 2012), gas is often noted to flow in pulses. There is therefore good reason to believe that bubble tests and gas surveys will not adequately characterize the leakage problem because these tests are short and only provide a snapshot of the leakage problem at the time of testing.
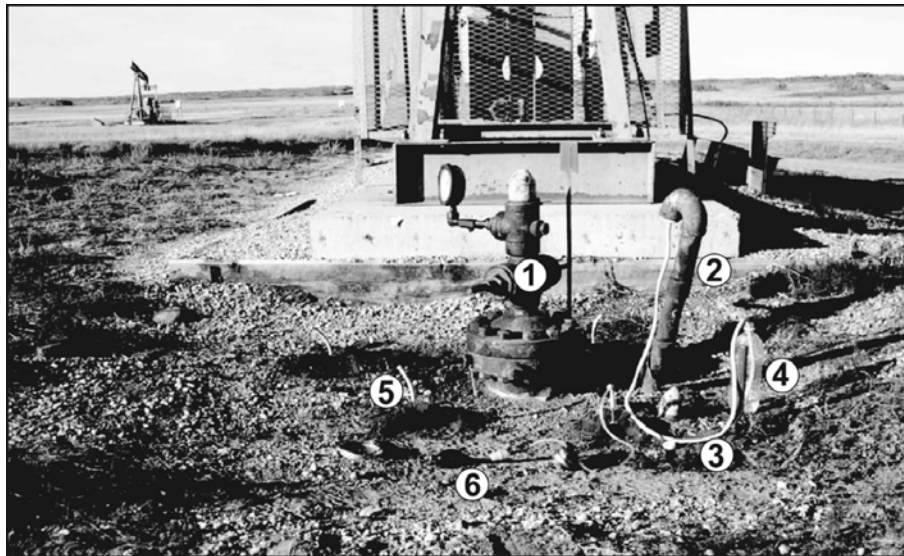
Figure 6.3. Wellhead with bubble-test apparatus installed on surface-casing vent, and GM test holes surrounding the wellhead. The numbers are the following: 1-wellhead; 2-surface-casing vent; 3-hose connected to surface casing vent to direct flow; 4-container with water to observe gas bubbles; 5-GM-test holes; 6-hand pump to direct the accumulated gas to the lower-explosion-limit meter (from Watson and Bachu, 2009).
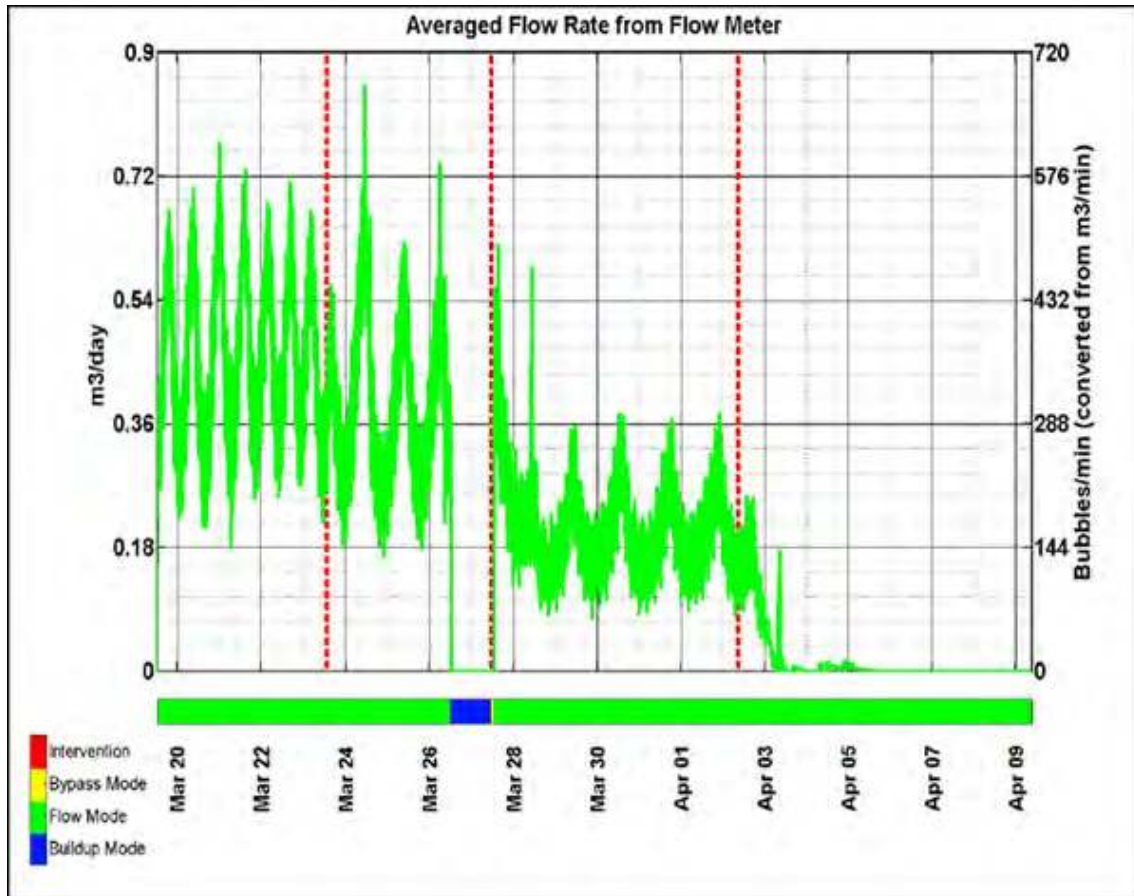
Figure 6.4. Pulsed flow in m³/day measured as surface casing vent flow by a VentMeter™ (courtesy John Hull, Hifi Engineering Ltd., Calgary, Alberta). Casing perforations and cement squeeze injections are shown as dotted vertical red lines; the third remediation was successful in stopping gas flow.

Another concern with typical leakage detection methods is that subsurface seepage is neglected. Subsurface seepage refers to the leakage of gas that does not manifest itself at the surface. As pointed out by Dusseault and Jackson (2013), "*...documented natural gas emissions to the atmosphere strongly suggest that the emitted gas is a fraction of that which is migrating uncontrolled in and adjacent to the annulus of production wells*". Bubble tests and gas migration surveys measure gas leakage that is detectable at the surface. Consequently, if only bubble tests and gas migration surveys are performed, latent leakage of gas that may be invading a shallow aquifer may go unnoticed.

There is therefore a need to improve the methods for detecting wellbore leakage. Fortunately, many of these concerns may be addressed by utilizing existing technology. For example, Figure 6.4 illustrates the vent flow measurements made during the remediation of a wellbore made using a VentMeter™ (Figure 6.5), a tool developed by Hifi Engineering Ltd. in Calgary in

collaboration with Doull Site Assessments, which is designed to measure gas leakage in real time. During the remediation of the wellbore, the continuous measurements of the vent flow provided important clues, which aided in stopping the leak. For instance, after the first two squeeze attempts were made on the wellbore, the Ventmeter^{TM} clearly showed that the leakage rate of the vent flow was reduced. Conversely, the bubble test only indicated that a vent flow still existed with "*too many bubbles to count*" (Hull, 2013). We believe that such devices or similar instruments will provide means by which SCVF and GM fluxes can be quantified reliably.

For GM measurements, because of such a diffuse source around each energy well, it would be most appropriate to attempt to capture emissions by the use of tent-like structures that permit diversion of the gas flow into a measurement probe, e.g., a Ventmeter^{TM}. It would further be revealing to determine how gas flux varies with depth beneath the ground surface around the well and compare such measurements with the test-point measurements made with surface gas migration surveys.

Figure 6.5. Ventmeter^{TM} installed at a wellbore

Due to the potential seepage of gas into shallow formations with or without any indication of leakage at the surface, installing a multi-level groundwater monitoring wells designed and periodically sampled by a trained hydrogeologist will help to ensure no significant groundwater quality deterioration is occurring. Because a single monitoring well is only a point-sample in each productive aquifer horizon, it cannot provide assurance that there is no leakage whatsoever, as the methane flux could be in a direction away from the monitor well and remain undetected. In any case, if a monitoring well is installed before drilling takes place and is properly sampled and analyzed, it provides useful baseline water quality information for comparison later in time if concerns are raised that the energy wellbore is having adverse affects on the groundwater in the surrounding area. It is worth repeating that having baseline data and monitoring data from a purpose-installed groundwater well provides a good level of assurance, but is not a guarantee

that leakage can be detected.

6.2 Remedial Workovers

6.2.1 Remedial Workover Requirements in Canada

When a wellbore develops a leakage problem or violates another integrity regulation, such as severe casing corrosion, a remedial workover is required. A remedial workover is a process that (1) identifies the source depth or formation of gas origin using an approved method (e.g., gas analysis or wireline tools such as noise/temperature logs and CBLs) and (2) stops any leakage by successfully squeezing a sealing material, generally cement, into a set of perforations appropriately placed, while meeting minimum cementing requirements. If a wellbore develops a leakage problem that is defined as severe, remediation of the severe vent flow must begin immediately following detection, and all leaks, including non-severe leaks, must be repaired at the time of abandonment (Alberta Energy Regulator, 2003).

6.2.2 Issues with Remedial Workovers

The authors were informed on several occasions in discussions with service companies and operators that remedial efforts are often quite unsatisfactory. Success rates of less than 50% were frequently reported, with on average three interventions required to successfully arrest gas migration (Chmilowski and Kondratoff, 1992; Saponja, 1999; Chatellier et al., 2012; Hull, 2013). In addition, there have also been reports of successfully remediated wellbores developing leakage problems later in the life of the well (Watson et al., 2002). As a result, remedial costs can be quite significant. On average, remedial costs are $150,000 per well, with an exceptional workover described to us that cost close to $8 million. Schmitz et al. (1996) point out that in many cases, it is more economical to renew a lease than to attempt remedial action. Here, we discuss methods, limitations and potential approaches that may improve the success rates of remedial workovers.

6.2.3 Determining the Origin of the Problem

Following the detection of a leakage problem, one of the most critical steps in preparing a remedial workover is to identify the origin of the problem, i.e., the source of the gas and the leakage pathways. This is commonly achieved by analyzing existing information pertaining to the wellbore including background analyses such as mud gas logs, re-examination of geophysical

logs to help identify potential thin gas zones, isotope analyses of the escaping gas, and running a series of wireline tools such as CBLs and noise and temperature logs to try and pinpoint the source.

6.2.3.1 Background Analyses

Potentially valuable information that may help in identifying and understanding the nature and source of fugitive gas may be found in existing information pertaining to the wellbore and surrounding area. Valuable information sources include the following:

1. Drilling and completion information;
2. Past cement bond logs;
3. Geological disposition of the region;
4. Individual well logs for the intermediate depth zone; and,
5. History of past remedial work (of both the wellbore requiring remediation and other wellbores in the area)

Locations where problems were previously encountered during drilling and completion are more likely to be future areas susceptible to leakage problems. For example, histories of lost circulation problems, improperly placed plugs and blowouts may be attributed to zones of low cement tops, washed-out areas, or void spaces and channels in the cement sheath (Ness and Gatti, 1995; Watson, 2004). This information is often available in drilling records, well logs and any existing CBLs, and can be used to identify potential formations or zones in a well where leakage may be occurring (Watson and Bachu, 2008; Slater, 2010). In order to properly interpret and utilize this information, an understanding of hole preparation, cement types and additives is needed (Arthur, 2012).

An understanding of the formation properties in an area is important for identifying potential sources of gas as well as for considering slurry design for the sealing material. Depending on the location of the wellbore, there may be several potential sources of gas. These sources may be at reservoir depth or at a shallow depth such as the shallow Belly River Formation above the Cardium reservoir in the Pembina oilfield south east of Edmonton. Knowing the location of these potential sources will help in identifying the problem zone and where a squeeze should be performed (Arthur, 2012). Furthermore, since formation porosity and permeability influence the

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success of cement squeeze operations, knowledge of these petrophysical properties is needed for calculating appropriate circulation rates and slurry densities.

Last, information regarding past remedial workovers on the leaking well and on any offset wellbores may help in designing a workover plan. Engineers need to consider the success, challenges and failures of previous attempts in the area when designing a remedial program, and careful statistics must be kept and updated.

6.2.3.2 Isotope Analyses

Stable isotope analysis is a useful approach to aid in fugitive gas source identification, although it is not a panacea that can be relied upon exclusively in the absence of all other data. As introduced in section 3.1, the isotope composition of gas is usually distinct between formations of different age (maturity), source rock and origin making their use a beneficial tool for discriminating between sources of gas (Rich et al., 1995; Slater, 2010). In the case of remedial workovers, stable isotopes are used to fingerprint the source of fugitive gas where an isotopic depth profile is well developed through experience and the implementation of mud gas logging and development of isotopic fingerprints with depth.

Figure 6.6. Isotopic signatures of Mannville and Colorado Group formations in the heavy oil region. Note the distinctive isotope signature transition at the Mannville-Colorado Group Boundary (from Rowe and Muehlenbachs, 1999b)

Isotopic depth profiles are the isotopic characterization of hydrocarbon bearing formations vertically penetrated by the wellbore. These profiles are generally established by analyzing the gases contained in drilling mud during the initial construction of the wellbore. Essentially, as the drill bit breaks apart pieces of rock at the bottom of the hole, gas embedded within the rock fragments is released and dissolves into the mud because of the high pressure, and this is

circulated to the surface with the drilling mud without serious dilution or mixing. A mud gas sample can be extracted at the surface and its depth of origin can be calculated based on drilling fluid circulation rate and drill bit depth. Analysis of the isotope composition of the sample compared to the calculated depth of extraction provides an isotopic depth profile (Rich et al., 1995; Rowe and Muehlenbachs, 1999a; Taylor et al., 2000). Generally, depth is plotted against $\delta^{13}C$ of CH_4, C_2H_6, C_3H_8, and C_4H_{10}, as shown in Figure 6.6.

Once an isotopic depth profile is established, it may later serve as a catalogue or fingerprint to help narrow down the origin of fugitive gases leaking from a wellbore. This is accomplished by analyzing the isotopic composition of the fugitive gas and comparing the results to the isotopic depth profile. Rowe and Muehlenbachs (1999a) provides an exemplary outline for the use of this tool in the Western Canada Sedimentary Basin (WCSB). The isotopic depth profile was used to fingerprint the origin of fugitive gas from a leaking wellbore to a depth of ~350 m, shown in Figure 6.7.
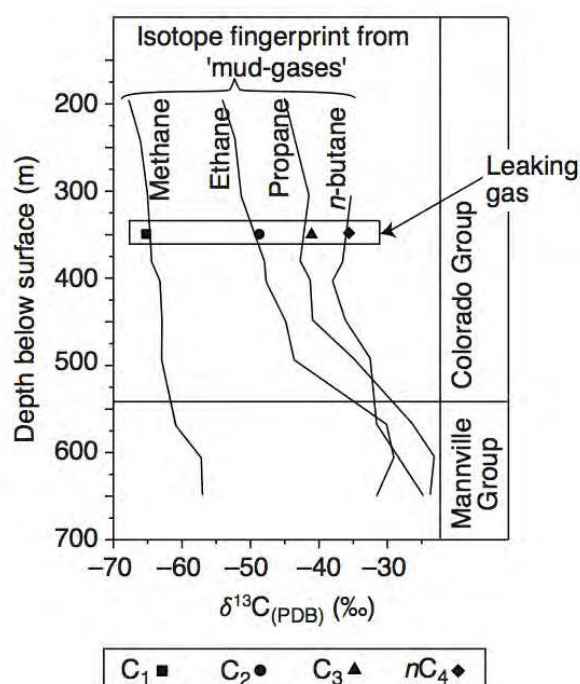
Figure 6.7. Isotopic composition of a fugitive gas sample superimposed on an isotopic depth profile for the region (from Rowe and Muehlenbachs, 1999b)

This was possible because the Mannville Group had a distinctive isotopic fingerprint compared to the overlying Colorado Group. The higher chained hydrocarbons, e.g., ethane (C_2), propane (C_3) and normal butane ($_nC_4$) were distinctively enriched, i.e., more positive, $\delta^{13}C$ than the Colorado Group. In some regions, ethane signatures alone appear to be definitive of sources (see Taylor et al., 2000; Szatkowski et al., 2001). Furthermore, the Mannville Group exhibited isotopic reversals where $\delta^{13}C_3$ was more enriched than $\delta^{13}C_4$ (typically $C_1 < C_2 < C_3 < C_4$) (Rich et al., 1995; Rowe and Muehlenbachs, 1999a) similar to the reversals found in Talisman's wells in Québec (Chatellier et al., 2012), a characteristic not observed in the Colorado Group.

The use of isotopes for remedial workover decision aids requires proper sample collection, analysis and interpretation. There have been reported issues, in Québec for example, where the importance of closely-spaced samples to identify possible isotopic reversals and anomalies was made clear (Chatellier et al., 2012). Samples must also be collected carefully to prevent contamination. Furthermore, although the isotope composition of natural gas is thought to be "*negligibly affected by migration through the subsurface*" (Rich et al., 1995), mixing of gases and biodegradation can alter the isotope composition. Careful treatment of samples and careful interpretation of the data are essential to prevent costly mistakes.

Although there are benefits to using isotopes, there are limitations to their use that need to be considered. First, in order to use the isotopic information of fugitive gas, there needs to be a well-developed isotopic depth profile. Unfortunately, in many regions isotopic depth profiles are often not available or they are poorly defined. For this reason, the British Columbia Oil and Gas Commission consider that using well logs combined with drilling reports and geological data is much more effective for SCVF/GM repair, because lack of reliable information (poorly characterized shallow formations) and contradictory findings have led to poor results (BCO&GC, personal communications, January 14, 2014). There is therefore a need to develop robust isotope depth profiles across Canada that can be used in remedial workovers.

A second limitation with isotopic profiling is that isotope analyses provide no insight about a leakage pathway. In areas where an isotopic profile exists, the information obtained may only constrain the leak to a particular interval that may still be a few hundred meters long. Whether the gas is flowing through a microannulus, a channel or fracture, or even coming from inside the production casing through crossed-threads, and where exactly remediation is required cannot be deduced from isotopes. Therefore, isotopes are not a replacement of wireline tools, but work best in conjunction with them. It is always important to have a trained geoscientist go back to the original geophysical logs and cement bond logs to see if zones can be identified that are more likely to be sources of gas than others, and see how that correlates with the isotopic signature for the region and the wireline logs for the wellbore.

6.2.3.3 Cement Bond Logs

Since isotopes may provide no insight as to where specific problems exist in the cement sheath (i.e. what kind of problem and where it is), CBLs are important in remedial workovers for identifying such problems before mitigation steps are undertaken. Ideally, information obtained from background and isotopic analyses would have identified the most likely stratum candidates sourcing a leakage problem, therefore CBLs can generally be run on selected intervals, rather than the entire length of the wellbore. It is important to run new CBLs because significant changes in the condition of the wellbore may have occurred since the last log, and because CBL technology has improved.

Cement bond logs are widely used, have been improving, and give a reasonable likelihood that a problem area will be correctly identified; they should also be used as part of an array of tools, not used in isolation. Nevertheless, these tools still have their limitations and occasionally produce ambiguous results. Cement bond logs and other sonic tools are limited in that oftentimes they cannot differentiate between contaminated cement, microannuli or an eccentric tool. Ultrasonic tools have low signal-to-noise ratios, and are therefore constricted to the region directly adjacent to the casing and also struggle with differentiating between mud contaminated cements and lightweight cements. Logging tools are also incapable of detecting defects in cement beyond one casing string in the radial direction, so that the presence of an intermediate casing string outside the cemented-in production casing string shields the CBLs from detection of microannular spaces and other problems in the rock-cement system outside the outermost casing. Hence, there are conditions and circumstances when logging tools are not successful at detecting problem areas behind the outermost casing (Saponja, 1999; Stein et al., 2003; Bellabarba et al., 2008). Albert et al. (1988) suggests field performance for a properly run and calibrated CBL of $\sim 90\%$ and $\sim 10\%$ for identifying channels and total annular space, respectively. Clearly, channels are generally macroscopic, millimeters to even centimeters in size, whereas microannular space may be on the order of a few microns. Given these challenges, if CBLs are improperly run or interpreted, costly remedial work may take place in an incorrect location (King and King, 2013), and even when all is done properly there remains a substantial level of uncertainty.

In addition to the need for third party PA, it is critical that these tools are properly used: they

must first be calibrated appropriately and run in the wellbore after or within an appropriate time frame, ensuring excess pressure is not acting on the inside of the casing. Excess pressure helps close microannular spaces and gives a far better bond response than an unpressured casing (i.e., under operational pressures). Knowing the limitations of each device will help in determining which tool is most appropriate to use in each case. Ambiguity of CBLs may be reduced if isotopes and noise and temperature logs are used in addition for comparison.

6.2.3.4 Noise and Temperature Logs

Noise and temperature logs are commonly conducted during remedial workovers to provide additional information about the possible source depth of a leak. Noise logs are often conducted to attempt to detect gas leakage behind the casing. As outlined by Slater (2010), sound measurements are made by a highly sensitive microphone at particular intervals in the wellbore. Gas in the annular region may produce noise at a diagnostic frequency identified by McKinley et al. (1973) that can indicate the nature of gas flow (see also Arthur, 2012). In conjunction with noise logs, temperature logs are often conducted to measure downhole temperatures and compare these measurements to the downhole temperature gradient to detect unexpected variations possibly attributable to gas flow (see Slater, 2010).

The effectiveness of noise and temperature logs remains a controversial topic. Some experts feel that traditional noise logs are relatively unreliable, while others claim the tools are an important aid in identifying the location of leaks (see Arthur, 2012). If the background noise is louder than that of the annular gas flow, then the noise anomaly may not be observed (i.e., low signal-to-noise ratio), therefore the frequency structure of the background noise (<100Hz) and the gas flow should be monitored to discriminate between them. Some newer noise logging techniques, such as that developed by Hifi Engineering of Calgary, are omnidirectional and thus overcome many of the handicaps of traditional noise workovers.

6.2.3.5 Pressure Testing

Monitoring the pressure build-up in annular zones or 'pressure build-up testing' is a standard requirement for each new oil and gas well (see Alberta Energy Regulator, 2013a and American Petroleum Institute, 2010). Arthur (2012) indicates that such tests may be used to evaluate

overall wellbore integrity or to check the integrity of sealed perforations. He recommends testing of all annnular volumes – surface, intermediate and production annuli – and the employment of transducers and data loggers to record a continuous time series of annular pressure. Such continuous time series of annular pressure permit discrimination between potential sources of gas leakage.

6.2.4 Squeeze Operations

Successful cement squeeze operations require controlled and accurate placement of the cement slurry. Under suitable conditions, cement squeeze operations are said to be "...*a routine and highly predictable procedure*" (Chmilowski and Kondratoff, 1992). However, in many circumstances, formation conditions and fracture aperture limit control of the remedial operation. Extremely permeable formations or formations containing large vugs and natural fractures may not be able to support a cement column, as cement slurries may flow unconstrained into the formation. On the other hand, particular geological materials, such as swelling clays and media with low permeability, limit feed rates that can lead to hydration immediately at perforations, consequently blocking passage for cement to enter the void space (Chmilowski and Kondratoff, 1992; Saponja, 1999; Watson et al., 2002). The cement may also undergo shrinkage and deterioration, which may compromise a seal over time.

A concern about casing perforation and cement squeeze operations in stiff naturally fractured rock is that as the grout is forced into the formation at fracturing pressures, the grout fails to penetrate fully into the crack that has been forced open by the high pressures. Thus, even though one pathway may be sealed, cracks as large as 20-50 microns can be opened up from the squeezing operation (Figure 6.8).
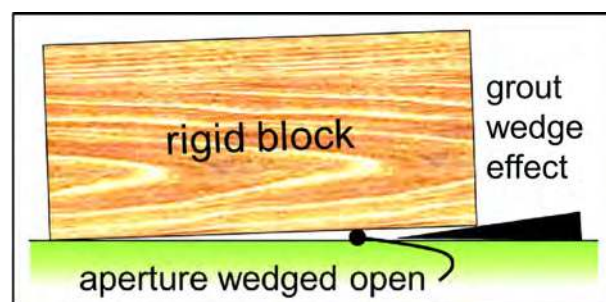
Figure 6.8. When a cement grout is pumped into a stiff naturally fractured rock at fracturing pressures, additional pathways may be opened as others are sealed

Because of repeated issues related to poor perf-and-squeeze control, shrinkage and deterioration, and failure to seal attributed to the use of traditional cements as the sealing material for remedial workovers, there have been a number of additives and alternative sealing materials

that have been developed to offer improved (deeper) penetration and better control. Some of the commonly recommended materials include gel polymers, resins, synthetic cements, sodium silicates and foamed cement (Chmilowski and Kondratoff, 1992; Saponja, 1999; Watson et al., 2002). There have also been suggestions for cement-free sealing alternatives such as melted metals and asphalt that claim to offer a better seal with more resilience than typical cement. To the best of our knowledge, these have never undergone independent performance assessments.

Overall, we found no consensus on what sealing material offers the greatest probability of achieving an adequate seal on the first attempt and providing the seal for many years. Many additives and alternative sealing materials have been successfully used on a case-by-case basis, but a general collection of successes and failures, carefully documented and permitting of independent statistical assessment, has never been compiled.

Whether the use of alternative sealing materials offers an improved seal is unknown, as independent, third-party performance assessments have not investigated their limitations. It would seem that suitable sealing agents for high porosity sandstone and ductile shale sequences (e.g., Upper Mannville and Colorado Group in Eastern Alberta and Western Saskatchewan) should be radically different from the formulations used for low-porosity, naturally fractured rock masses (e.g., Waterton AB region or shale gas in the Horn River Basin, BC). For example, to seal cracks in a stiff rock mass, a grouting agent should not be granular; it should be miscible with the formation fluids, wetting of the rock surface, of low viscosity before setting, and of indefinite chemical stability after set. Agents that meet reasonable general specifications and recommended for use in the field should be independently tested and assessed, both in the laboratory and in the field.

Experts emphasize that each remedial workover job is unique and should be treated as such. In other words, there is no universal sealing material because the sealant must be designed to meet the conditions of the wellbore. However, it is reasonable to expect that certain approaches may work well in some sequence of formation but not in others. Experience in the WCSB should be a useful guide to what has worked well and what has not. This information would be of great benefit for improving remedial workovers across Canada.

However, there remains a reluctance to describe failures in great detail, and certainly these are seldom discussed outside of individual companies. Because the purpose of a remediation

is to eliminate or reduce leakage to acceptable levels, an intervention or remedial operation generally continues with repeated episodes until the goal is reached, and success is declared. Therefore such an operation is not treated as a failure, despite high costs and many attempts before success is achieved. These challenges to collecting information of high enough quality to warrant detailed analysis should be addressed and overcome to the degree possible.

6.3 Other Concerns Regarding Wellbore Leakage Detection and Remediation

6.3.1 Leakage from Abandoned Wellbores

6.3.1.1 Monitoring

There are hundreds of thousands of known abandoned wellbores across Canada. In Alberta alone, there are approximately 151,000 abandoned wellbores, making up 35% of the province's well population (Alberta Energy Regulator, 2014), and of course this number will increase, especially with the aggressive redevelopment that is taking place using horizontal wells in various fields, and with the gradual shut down of SAGD and CHOPS pads (although CHOPS wells are generally placed on inactive status for decades before a final abandonment is considered).

Processes related to cement shrinkage and corrosion result in the possibility of leakage development decades following shut in or abandonment. Depending on the abandonment approach, such as the bridge plug and cement bailer dump abandonment method, or if abandonment took place prior to modern abandonment requirements, the probability of leakage development may be significantly elevated (Watson and Bachu, 2009). Regulatory requirements across Canada typically require a wellbore be checked for leakage at the time of abandonment. However, if the well is not monitored following abandonment, potential development of leakage may not be detected unless the consequences are readily apparent. To our knowledge, there is no monitoring regulation in Canada that requires operators to test wellbores for leakage following final abandonment. The leakage occurrences and rates from abandoned wellbores across Canada are therefore unknown.

6.3.1.2 Remediation

Ideally, energy wells should remain free of leaks for many decades to come following the abandonment of the wellbore, and if any leaks eventually develop, they should be minor,

but this is by no means always the case. Following identification of a leakage issue and approval by the regulator, wells occasionally need to be re-entered to repair a leakage problem. Costs for re-entering a wellbore can be substantial. Furthermore, the well may be difficult to access, particularly in old oilfields that have since been re-developed, or if urbanization or other infrastructure development has taken place. Taking as an example the leaking well in Calmar, Alberta, several houses had to be demolished to make room for a rig to reseal a leaking abandoned wellbore that neither the town nor the developer knew existed.

In addition, there is also a risk that remedial work will be unsuccessful. With very low rates of leakage, there is a potential that remedial activities may only exacerbate the leakage problem. This suggests again that a minimum acceptable rate of leakage has to be considered for different conditions, and perhaps a venting technology for slow gas seepage cases should be considered, rather than a full remediation. These issues will become more important as more and more energy wells are abandoned, and as urbanization or increased density rural development occurs.

There needs to be a serious discussion of what is an acceptable rate of gas emission from a wellbore, given the likelihood that gas emissions will remain a fact-of-life for the foreseeable future. At present, remediation of active wellbores throughout Canada is required if SCVF is found to exceed 300 m^3 CH$_4$/day, i.e., over 70,000 kg CH$_4$/yr, during the active operational life of the well. This flux, if unremediated, is equivalent to $\sim$ 1.6 million tons of CO$_2$ equivalent if a Global Warming Potential of 23 kg CO$_2$ per kg CH$_4$ (IPCC, 3rd Assessment, 2001) is used[5]. We must therefore ask the question: if one cow can emit $\sim$ 100 kg CH$_4$/yr and individual pneumatic devices at natural gas gathering stations in remote areas of B.C. can emit $\sim$ 1,000 kg CH$_4$/yr, what then should be the maximum annual emission rate from SCVF and GM for any Canadian oil or gas well?

In addition, there is no lower leakage limit defined as being an acceptable rate of flow. At the time of abandonment, a wellbore must be leak-free, regardless of rate of flow, type of leak or location. Some experts feel this requirement is too stringent, and suggest that each well should be considered on a case-by-case basis by evaluating the risk the leak presents. The reasoning behind this is that a risk comprises both the probability of an event occurring and

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[5]The more recent IPCC equivalent effects for methane over a short time period (twenty years) recommend numbers as high as 70, rather than 23, indicating that the short-term contribution of methane to the greenhouse effect is startlingly large. This is driving concern in USA in particular to reduce the magnitude of fugitive methane emissions.

the consequence. Depending on the location of the well and the type of leak, there may be cases where small leaks present relatively small consequences compared to others. There may be many cases where some new technology permitting slow bleed off of a minor methane leak is implemented, at a cost of thousands of dollars rather than hundreds of thousands for a remediation operation. Whether or not there should be an acceptable limit and what this limit should be requires regulatory attention.

7 TOWARDS A CANADIAN ROAD MAP FOR IMPROVING LONG-TERM WELLBORE INTEGRITY

Constructing a wellbore capable of maintaining integrity for many years has been a challenge for the oil and gas industry. The loss of integrity and consequently the development of gas leakage in the form of GM or a SCVF has been observed nationwide. Although the majority of public concern has been attributed to the potential environmental impacts of hydraulic fracturing, the concerns raised by long-term wellbore integrity are seemingly of greater importance.

The objectives of this report were to account for the persistence of wellbore leakage in the oil and gas industry, identify approaches that appear to reduce the rates and occurrences of wellbore leakage, describe methods for detecting and monitoring for wellbore leakage and discuss methods that have improved the efficiency of remedial workovers. Our overall motive was to use these findings to outline a Canadian Road Map for Wellbore Integrity that identifies future R&D needs and where the resources for such R&D activities might be found. This may be used as a guide to the identification, evaluation and selection of "*strategic alternatives that can be used to achieve a desired S&T objective*" (Kostoff and Schaller, 2001); i.e., improved long-term wellbore integrity. The objectives of a road mapping exercise must include:

1. minimizing gas emissions to the atmosphere and potable groundwater, while
2. reducing the cost of effective wellbore repair and abandonment and
3. improving primary wellbore completions in all terrains throughout Canada.

We have encountered many specific issues that need to be addressed by industry and regulators across Canada in order to improve wellbore integrity. A number of these issues are summarized here.

- Cementing companies recommend excellent cementing programs and such best practices are invariably included in work plans. However, best practices are not necessarily followed in terms of using a sufficient number of casing centralizers, use of scrapers, and providing sufficient time and casing reciprocation for full mudcake removal because of time constraints and unexpected events in the field.

- Quality control of the cement formulation in the field is often less than perfect; as one example, cement slugs of lower-than-expected density can be displaced downhole because of temporary mixing problems. Because rectification of a poor cement job is both a time-consuming nuisance and expensive, poor cement jobs may be tolerated.

- Over the years, all kinds of additives and special formulations have been promoted by vendors. In general, these have not been widely adopted, and there is little or no third-party verification that these additives are substantially more effective in achieving a superior-quality primary cement job. Without this independent verification, regulatory agencies are hampered in the development of guidelines.

- Usually, there is no direct supervision of the cementing operations by an engineer from the cementing company who wrote the well completion program; rather, it is executed by field crews without senior technical supervision. Drilling engineers from the oil company may not be present on site to ensure adherence to work plans.

- Cement bond logs should not be run solely with excess pressure in the casing (beyond hydrostatic) because this flexes the casing outward slightly, reducing any microannular space that may have developed and giving falsely optimistic data. Furthermore, there are no standardized and regulated methods of interpreting cement evaluation logs in a consistent manner for quality assurance. Uniform ways of interpreting the cement quality logs are needed (wavelet decomposition and related transform methods).

- The development of microannuli and fractures following wellbore completion is mainly attributed to the cement's susceptibility to changing stress conditions and cement shrinkage. Better primary cement that does not shrink or become cracked from flexure is needed. In addition, to collect real time casing-cement stress condition data, the development

of robust and long-lived easy-to-run behind-the-casing pressure measurement systems are needed. Such tools would indicate when pressures exceed the cement's compressive strength.

- The slow development of a continuous gas path behind the casing is not well-recognized or acknowledged by the cementing companies and the oil companies. Perf-and-squeeze remediation of behind-the-casing seal failure has a poor track record, likely even poorer than has been noted in the technical literature because of persistent under-reporting of negative results. Methods for improving the success rates and costs of well work-overs are needed. Alternative sealing materials have been suggested to overcome obstacles presented by the use of cement, however, the limitations of such sealants are unknown. Performance assessments of various sealants is required. Furthermore, improvements for source identification is needed. This will require the use of a number of tools (e.g., background analyses of well information, past CBLs, geology and past remedial work, isotope fingerprinting, pressure build-up testing, new CBLs and noise and temperature logging) in conjunction with one another.

- Well abandonment is critical for ensuring isolation for many years. Plugs need to be properly placed and resistant to corrosion. An abandoned wellbore must remain accessible for future remediation if necessary.

- The methods of gas emission measurement from a wellbore – in particular GM – require review, testing and advancement. The frequency of groundwater contamination by GM is not known nor is the volume of emission of greenhouse gases quantified.

- One senior U.S. industry executive told us that groundwater contamination was preferable to gas emission to the atmosphere. This comment may reflect the widespread tendency in the US to shut in casing-head valves rather than allow, at least for the surface casing valve, the Canadian practice of venting. Informed sources in the USA indicate that this practice has contributed to groundwater contamination and, in our opinion, to the erosion of the social license that permits the functioning of the upstream hydrocarbon industry.

- There needs to be a serious discussion of what is an acceptable rate of gas emission

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from a wellbore given the likelihood that gas emissions will remain a fact-of-life for the foreseeable future. The answer to this question will determine many of the details of the proposed Road Map.

8 CLOSURE

The oil and gas industry is an anchor of the Canadian economy, and has been the main reason that the great majority of new employment opportunities in Canada over the last 10 years have been generated in the Western Canada Sedimentary Basin. The importance of this sector is likely to continue and even grow as oil exports continue and as liquefied natural gas exports from Alberta and British Columbia begin in the years to come (likely starting in 2020). While not appreciated as such by Canadians, it is also a high-tech sector for the economy.

The oil and gas industry is active because it is developing resources that are owned by the citizens of the Provinces across Canada, as the resources are largely communally owned, rather than privately owned. As such, a social contract exists to permit this, and respect of this social contract is an important part of the operating philosophy of the Canadian oil and gas industry, as well as the governments and the citizenry.

Protecting the environment and the well-being of personnel is fundamental to the social contract and the oil and gas industry has a reasonable to good record in Canada, far better than in most other jurisdictions in the world. The preservation and improvement of this approach is commendable, and understanding and addressing issues related to wellbore leakage is part of this proactive process. Continuous improvement in wellbore integrity is the goal, and this is technically feasible at reasonable cost if the processes are well-understood and addressed in planning. A Canadian Road Map for improved understanding and addressing wellbore integrity issues is needed.

9 ACKNOWLEDGEMENTS

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