EXECUTIVE SUMMARY

This report presents an assessment of atmospheric emission related to hydraulic fracturing activities, but does not address other potential environmental concerns associated with the use of this technology. Hydraulic fracturing is a stimulation treatment routinely performed on natural gas and oil wells in low-permeability reservoirs to achieve improved flow potential. The process has been used by industry for many years, but has gained increased public attention, most recently with respect to shale gas production.

Hydraulic fracturing involves pumping specially engineered fluids at high pressures into the target reservoir to produce fractures that extend radially outward into the reservoir from the well bore. Specially sized sand (or proppant) is mixed with the fracturing fluid to keep the fractures open once the treatment is completed. After the treatment has been completed, the fracturing fluids are back-flowed from the reservoir. During these back flow events, the fluids brought to the surface are separated into 4 streams: water, sand, hydrocarbon liquids, and natural gas. The hydrocarbon liquids are recovered and produced into storage tanks for eventual treatment and transport to refineries. The natural gas may be conserved if there is available access to a suitable gathering system, otherwise it is generally flared.

In this report, flaring and venting data associated with well-completions were identified for the 1579 well structures that contained one or more well legs (UWIs), which were drilled and fractured in Alberta in 2011. As shown in Figure ES.1, slightly less than one-quarter (371 of 1579, or 23.5%) of the well structures were not identifiable within the available volumetric data as discussed in Section 4.1.2 and were presumed to have been excluded by AER for confidentiality reasons. More than one-third (643 of 1579, or 40.7%) were identified as "green-completions" for which production data were reported that matched battery receipts, and no well-level flaring or venting were reported. Just over one-third (544 of 1579, or 34.5%) of well structures reported some degree of attributable flaring and venting during well-completion. Assuming that the breakdown of the non-confidential wells was consistent with the unknown breakdown of the confidential wells, these results imply that approximately half of all hydraulically fractured well-completions in Alberta in 2011 were green-completions based on zero reported flaring and venting.

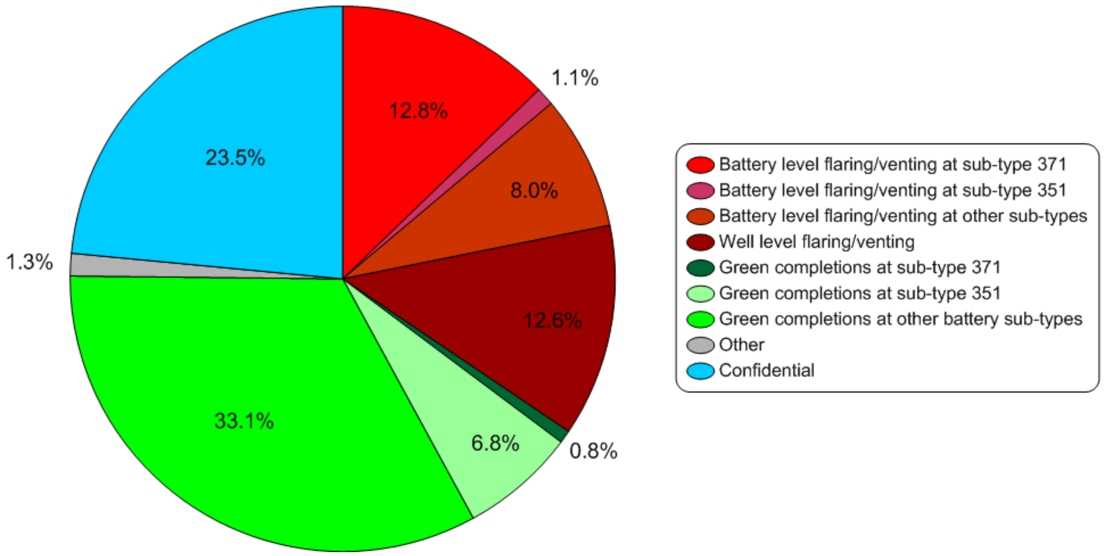

Figure ES.1: Percentage breakdown of how flaring and venting data associated with unconventional gas well-completions could be tracked within the confines of the available ERCB and PRA data for Alberta in 2011

Historically, wells were drilled vertically and only required a single stage of treatment in cases where fracturing was performed. In recent years, directional drilling has, for most types of production, become the predominant method of opening up and maximizing exposure to a reservoir; this is achieved through the creation of horizontal lateral sections designed to contact more of the productive portions of the formation. In particular, the average length of tight gas UWIs drilled in the year 2000 and actively reporting production in 2011 was 1034.7 m with roughly 2% having a horizontal orientation. By comparison, the average drilled length of tight gas UWIs drilled 2011 and subsequently fractured was nearly three times longer (2958.2 m) with approximately 30% being horizontal. These included 263 tight gas UWIs that extended to lengths in excess of 4000 m. To hydraulically fracture these lateral sections requires that the treatment be done in multiple stages. On average horizontal tight gas UWIs contain 1.8 times more fracture stages than vertical tight gas UWIs. Although horizontal UWIs tend to have a greater overall drilling length, as outlined in Section 5.2, there is no statically relevant correlation between the number of stages and the total well length in the reported data. Typically, it takes 1 to 2 hours to complete a stage of hydraulic fracturing, and up to 40 stages of fracturing may be performed on some natural gas wells.

The primary focus of this study has been to provide a critical review of the available literature, as well as present new data, on the potential amounts and types of atmospheric emissions associated with hydraulic fracturing operations. Emission contributions from unconventional natural gas well drilling, well completion, and well operations are considered and are based primarily on 2011 data. Specific components of this study included:

- A comprehensive technical analysis of available reported well activity and production data for Alberta in 2011 to track and identify flaring, venting, and diesel combustion emission volumes specifically linked to drilling, completion, and operation of hydraulically fractured natural gas wells;
- Development of a set of unconventional well drilling, well completion, and well operational emission factors pertaining to diesel combustion, flaring, venting, greenhouse gas emissions, and criteria air contaminants emissions representative of current operating practices in Alberta;
- An estimation of the total greenhouse gas and criteria air contaminants emission volumes resulting from well drilling , well completing, and operation of unconventional wells in Alberta for the year 2011; and
- A direct comparison of derived emission factors for unconventional Alberta natural gas wells with those outlined in the literature review as well as some key additional sources that were released during the revision of this report.

A summary of the derived emission factors is presented in Table ES.1, which includes cross-references for sections of the report containing relevant volume and criteria air contaminants (CACs) estimates. The results show that while the use of hydraulic fracturing is widespread among the various types of natural gas wells, the associated emissions potential varies dramatically.

Table ES.1: A comparison of emission sources associated with different types of hydraulically fractured gas wells in Alberta drilled in 2011, their emissions intensities, applicable controls, and future direction.

<table>
<tr><th>Source</th><th>Types of Pollutants</th><th>Duration</th><th>Emissions Factors (EFs)</th><th>Controls & future direction where applicable</th></tr>
<tr><td colspan="5">Drilling (See Section 4.3 for methodology for determining drilling lengths and diesel volume estimates; Section 5.2 for calculations of diesel-related CAC and GHG emission factor estimates; and Section 5.2.1 for calculation of estimated total CAC and GHG emission volumes)</td></tr>
<tr><td>Diesel and Dual-fuelled Rig Engines.</td><td>Diesel Engine Exhaust: CO_2, with trace amounts of SO_2, NO_X, CO, PM, & VOC.

CAC EFs are reported in Section 5.2 and Table 5.8</td><td>Drilling times directly related to well depth and can range from 24hrs for shallow wells to as long as several months for very deep wells.

Drilling lengths are reported in Section 4.3 and Table 4.12</td><td>Emission factors for diesel combustion during well drilling in Alberta 2011
<table>
<tr><th rowspan="2">Well type</th><th rowspan="2">Diesel rig fuel use [m^3/UWI]</th><th colspan="3">GHG EFs [t CO_2e /UWI] 100-year time horizon‡</th></tr>
<tr><th>Diesel rig</th><th>Dual-fuel rig</th><th>Prorated based on dual-fuel use in Alberta</th></tr>
<tr><td colspan="5">Analysis of Alberta Data for 2011 (see Table 5.11 in Section 5.2 for assumptions)</td></tr>
<tr><td>Tight gas</td><td>64.6</td><td>182.9</td><td>154.5</td><td>181.5</td></tr>
<tr><td>CBM hybrid</td><td>22.7</td><td>64.3</td><td>54.3</td><td>63.8</td></tr>
<tr><td>CBM</td><td>16.6</td><td>47.1</td><td>39.7</td><td>46.7</td></tr>
<tr><td>CBM shale other</td><td>23.6</td><td>66.8</td><td>56.4</td><td>66.3</td></tr>
<tr><td>Shale</td><td>47.5</td><td>134.3</td><td>113.5</td><td>133.3</td></tr>
<tr><td colspan="5">Estimates that can be derived from other sources (see Table 5.23 in Section 5.5.1 for assumptions)</td></tr>
<tr><td>CAPP</td><td>22.4</td><td>63.3</td><td>--</td><td>--</td></tr>
<tr><td>(Wood et al., 2011)</td><td>14.2-55</td><td>40.1-155.7</td><td>--</td><td>--</td></tr>
</table></td><td>Use of high-efficiency engines and low-sulphur diesel.

It is estimated that roughly 5 to 6 percent of the drilling rig fleet is equipped with dual-fuel engines (i.e., natural gas and diesel) and these are estimated to use natural gas fuel 80 percent of the time. Typical dual fuel rigs can achieve 40-60% substitution of natural gas for diesel.</td></tr>
<tr><td>Flaring or venting of dissolved / entrained gas released from the drilling mud returned to the surface for recirc-ulation.</td><td rowspan="2">Flaring emissions: CO_2, CH_4, VOC and potentially SO_2 and H_2S, as well as trace amounts of CO, PM, & NO_x</td><td>Same as drill period</td><td>n/a – Available data did not permit emission estimates. Although amounts are assumed to be small with negligible GHG and CAC emission relative to other sources</td><td>Disposal of the gases by venting at a safe location if they are sweet, or by thermal oxidation using a continuously-ignited flare if they are malo-dourous or toxic.</td></tr>
<tr><td>Drill stem testing</td><td>n/a</td><td>Emission in 2011 are shown to be negligible in Section 5.5.1 and Figure 5.5</td><td>Gas produced to the atmosphere for a period of time >10 minutes must be flared (Province of Alberta, 2013).</td></tr>
</table>

Table ES.1: A comparison of emission sources associated with different types of hydraulically fractured gas wells in Alberta drilled in 2011, their emissions intensities, applicable controls, and future direction. ***(cont.)***

<table>
<tr><th>Source</th><th>Types of Pollutants</th><th>Duration</th><th>Emissions Factors (EFs)</th><th>Controls & future direction where applicable</th></tr>
<tr><td colspan="5">Completions (See Section 4 for methodology to determine flaring and venting volumes, green completion rates, and reporting modes; Sections 5.1 and 5.1.1 for calculation of flaring and venting CAC and GHG emission factors; Section 5.1.2 for determination of total CAC and GHG estimates)</td></tr>
<tr><td>Transport of hydraulic fracturing fluids to site and subsequent disposal of the fluids.</td><td>Diesel Engine Exhaust: CO_2 & trace amounts of SO_2, NO_X, CO, PM, & VOC.</td><td>Days to several weeks depending on transport distances.</td><td>Available data did not permit emission estimates specific to Alberta. However, transportation greenhouse gas emissions are estimated by (Wood et al., 2011), see Section 2.4.5.</td><td>Industry is moving toward using field-based treatment processes to reuse water and/or use lower quality water sources.</td></tr>
<tr><td>Hydraulic Fracturing of stages – emissions from diesel fuel use by the pump trucks used to pressurize the fracturing fluids used.

Note that moderate amounts of fuel used may be associated with the hauling the fluids to and from the site (i.e., if it is a multi-stage fracturing event, and/or the site is remote) as well as on site equipment, see Section 2.1.1 and Table 2.2</td><td>Diesel Engine Exhaust: CO_2, with trace amounts of SO_2, NO_X, CO, PM, & VOC.</td><td>Varies with the number of stages from several hours to a full day

Although horizontal wells tend to have a greater overall drilling length as outlined in Sections 4.3 and 5.2, there is no correlation between the number of stages and total drilling length in the reported data.

Typical numbers of stages are reported in Section 3.2.3 and Table 3.13 and Table 3.14</td><td>Emission factors for diesel combustion during hydraulically fractured well-completions
<table>
<tr><th>Well type</th><th>Diesel consumption [m^3/UWI]</th><th>GHG EFs [t CO2e /UWI] 100-year time horizon‡</th></tr>
<tr><td colspan="3">Analysis of Alberta Data for 2011</td></tr>
<tr><td>Tight gas</td><td>30.1</td><td>85.3</td></tr>
<tr><td>Shale</td><td>4.6</td><td>13.1</td></tr>
<tr><td colspan="3">Available estimates that can be derived from other sources (see Table 5.24 in Section 5.5.2 for assumptions)</td></tr>
<tr><td>Tight gas Dawson Creek, BC</td><td>36</td><td>101.9</td></tr>
<tr><td>(Wood et al., 2011)</td><td>13.7</td><td>38.8</td></tr>
</table></td><td>Use of high-efficiency engines and low-sulphur diesel.</td></tr>
</table>

Table ES.1: A comparison of emission sources associated with different types of hydraulically fractured gas wells in Alberta drilled in 2011, their emissions intensities, applicable controls, and future direction. ***(cont.)***

<table>
<tr><th>Source</th><th>Types of Pollutants</th><th>Duration</th><th>Emissions Factors (EFs)</th><th>Controls & future direction where applicable</th></tr>
<tr>
<td>Well cleanup and flowback to remove hydraulic fluids -</td>
<td>Flaring emissions: CO_2, CH_4, VOC and potentially SO_2 and H_2S, as well as trace amounts of CO, PM, & NO_x</td>
<td>Highly variable and gas formation dependent

Can range from 24 hours to potentially 30 days. Typically time scales are, 7 to 10 days</td>
<td rowspan="2">Emission factors for flaring and venting during well-completion
<table>
<tr><th rowspan="2">Well type</th><th rowspan="2">Flaring [1000 m^3 / UWI]</th><th rowspan="2">Venting [1000 m^3 / UWI]</th><th colspan="2">GHG EFs 100 time horizon‡ [t CO_2e /UWI]</th></tr>
<tr><th>Flaring</th><th>Venting</th></tr>
<tr><td colspan="5">Analysis of Alberta Data for 2011</td></tr>
<tr><td>Tight gas</td><td>113.2</td><td>0.6</td><td>271.6</td><td>8.9</td></tr>
<tr><td>CBM hybrid</td><td>0.9</td><td>n/a</td><td>2.1</td><td>n/a</td></tr>
<tr><td>CBM</td><td>2.7</td><td>n/a</td><td>6.5</td><td>n/a</td></tr>
<tr><td colspan="5">Available estimates that can be derived from other sources (see Table 5.24 in Section 5.5.2 for assumptions)</td></tr>
<tr><td>CAPP (CAPP, 2004a)</td><td>18.8</td><td>0.4</td><td>43.4</td><td>5.3</td></tr>
<tr><td>US EPA unconventional (US EPA, 2013a)</td><td>296.1</td><td>1.6[g]</td><td>710.8</td><td>23.1</td></tr>
<tr><td>US EPA conventional (US EPA, 2010)</td><td>1.2</td><td>0.006</td><td>2.9</td><td>0.1</td></tr>
<tr><td>(Allen et al., 2013a)</td><td>270</td><td>1.4</td><td>633.3</td><td>20.8</td></tr>
</table>
</td>
<td>Currently the majority of emissions that are not captured are flared. In Alberta in 2011, 99.5% of reported flowback volumes from tight gas wells were flared.

Best practice is to separate the gas and hydrocarbon liquids from the water and solids that flow back from the well, and produce the gas into a gathering system (referred to as a “Green Completion”). This requires that the gathering system be completed before the well is completed

In Alberta in 2011, ~50% of natural gas wells used green completions, see Section 4.2.6.</td>
</tr>
<tr>
<td>Well Tests</td>
<td>Flaring emissions: CO_2, CH_4, VOC & potentially SO_2 and H_2S, as well as trace CO, PM, & NO_x</td>
<td>Shallow Gas Well in new reservoirs: usually 24hrs if a test is per-formed. Deep Gas Wells: typically 48-72 hrs.</td>
<td>Best practice is to test the wells by producing them into an existing gathering system wherever possible,</td>
</tr>
</table>

Table ES.1: A comparison of emission sources associated with different types of hydraulically fractured gas wells in Alberta drilled in 2011, their emissions intensities, applicable controls, and future direction. ***(cont.)***

<table>
<tr><th>Source</th><th>Types of Pollutants</th><th>Duration</th><th>Emissions Factors (EFs)</th><th>Controls & future direction where applicable</th></tr>
<tr><td colspan="5">Liquid Unloading (See Section 5.4 for methodology to derive venting emission factor estimates; Table 5.21 for estimated totalGHG from liquid unloading; and Table 5.22 for estimated total GHG from liquid unloading using API/ANGA emission factors and activity data)</td></tr>
<tr><td>Some shallow wells with high water production may have a coiled tubing string installed for use in periodically removing accumulated water from the well-bore.

See Section 5.4 for methodology</td><td>Venting of gas may occur (typically, in proportion to the well pressure)</td><td>Typically less than 1 day. See Section 5.4for activity factors</td><td>A comparison of estimated monthly venting emission factors for liquid unloading of hydraulically fractured wells
<table>
<tr><th>Unconventional wells</th><th>Vented Gas Volume [1000 m^3 / well-month]</th><th>GHG EFs 100-year time horizon‡ [t CO_2e /well-month]</th></tr>
<tr><td colspan="3">Current Analysis</td></tr>
<tr><td>Estimate for Alberta tight gas</td><td>0.009-0.026</td><td>0.13-0.38</td></tr>
<tr><td colspan="3">Estimates of that can be derived from other sources (see Table 5.25in Section 5.5.3 for assumptions)</td></tr>
<tr><td rowspan="2">US EPA 2011 Inventory (US EPA, 2013a)</td><td>0.23-6</td><td>3.4-87.5</td></tr>
<tr><td>0.009-3.53 (plunger lift)</td><td>0.1-51.4</td></tr>
<tr><td rowspan="2">API/ANGA (Shires and Lev-On, 2012)</td><td>1.15</td><td>16.7</td></tr>
<tr><td>0.59 (plunger lift)</td><td>8.61</td></tr>
<tr><td>(Allen et al., 2013a)</td><td>0.0048-3.29</td><td>0.07-47.9</td></tr>
</table>
See Section 5.5.3 and Table 5.25 for a full comparison of conventional and unconventional liquid unloading emission factors</td><td>Typically, the volumes of gas involved are too small for flaring or recovery of the gas to be practical and may fall under the reporting minimum in directive 60. However, over the lifetime of a well these emissions have the potential to be the primary GHG contributor, see Section 5.4, Table 5.21 and Table 5.22.</td></tr>
<tr><td colspan="5">Production (See Section 4.5 for gas production, fuel use ,and production flaring and venting statistics)</td></tr>
<tr><td>Compressor engines and possibly line heaters or dehydrators.</td><td>Natural Gas-Fuelled Engine and Heater Exhaust: CO_2 with CO, NO_x, THC and trace amounts of PM.</td><td>Highly variable & formation dependent

Shallow Gas Wells: From a few to 20yrs or more. Some wells may produce for up to 40yrs.

Deep Gas Wells: often 20yrs or more</td><td>The analysis of monthly reported volumes (excluding volumes attributable to well-completions) from tight gas wells tied to single-well gas batteries, which had fracture dates between January 1, 2000 and December 31, 2011 revealed that 56% of these wells reported nature gas fuel usage data. The calculated nature gas fuel usage rate of 2200 m^3/UWI per month was found and the total nature gas fuel volume use as fuel was equivalent to 0.7% of production of their production.

See Section 4.5 and Table 4.15</td><td>Use of high-efficiency. standards for NO_x control have been increasing in recent years.

Fuel use per unit of production tends to increase as the well matures, due to decline in reservoir pressures and increasing water production.</td></tr>
</table>

Table ES.1: A comparison of emission sources associated with different types of hydraulically fractured gas wells in Alberta drilled in 2011, their emissions intensities, applicable controls, and future direction. ***(cont.)***

Source	Types of Pollutants	Duration	Emissions Factors (EFs)	Controls & future direction where applicable
Venting by pneumatic devices (e.g., instrument control loops and chemical injection pumps), where natural gas is used as the supply medium.	Venting Emissions: CH_4 and lesser amounts of CO_2 and VOCs.	Highly variable & formation dependent Shallow Gas Wells: From a few to 20yrs or more. Some wells may produce for up to 40yrs. Deep Gas Wells: often 20yrs or more	n/a – see National inventory for list of emission factors	Current practice is to use low-bleed pneumatics. Also, there is a trend towards using electric power (if available) to operate chemical injection pumps. Conversion to compressed air may be a practicable option if the well is located on the site of a larger production facility.
Fugitive Equipment Leaks	Leakage: CH_4, CO_2, VOCs and potentially H_2S if the gas is sour.		n/a – Available data did not permit emission estimates. Note that unless there is more than a wellhead and basic separation equipment at the site, there are relatively few potential leakage points, and these generally have low leak potentials.	These emissions are managed through regulated directed inspection and maintenance programs.

‡ Calculated using data from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007), which specifies 100- time horizon GWP values for methane of 25 and for N_2O of 298 respectively.

The use of hydraulic fracturing to stimulate production is not currently as prevalent in tight oil developments relative natural gas developments. The fracturing rate of oil UWIs drilled in Alberta in 2011 was 37%, which was roughly 2.5 times less than the fracturing rate of natural gas UWIs. The majority of fractured oil wells (99%) were classified by AER as crude oil; in general heavy oil UWIs were not fractured. In 2011, roughly 70% of fractured crude oil UWIs were horizontal. The challenge in many of the tight oil developments has been the lack of existing gas gathering pipelines to allow conservation of the gas. Indeed, the duration of emissions from fractured crude oil and fractured natural gas wells are fundamentally different, based on distinct trends observed in the reported volumetric data for Alberta in 2011. For fractured natural gas wells, major flaring and venting events are confined to a 1-month period from the fracture date, and therefore are directly attributable to well-completion operations. By contrast, flaring and venting occurs on a nearly continuous basis with oil production for fractured crude oil wells, with nearly 70% reporting flaring and/or venting in every month of production. Current regulations in Alberta, Canada specify that "venting is not an acceptable alternative to conservation or flaring", and require that combustible waste gas volumes from flowback in excess of 2000 m^3 be flared rather than vented. In addition, flared and vented volumes in excess of 100 m^3/month from must be reported, except in cases where "production submissions are not routinely submitted for a facility, as is sometimes the case for well completions", in which case all volumes in excess of 500 m^3/month must still be reported (see Section 10.3 of AER Directive 60, (ERCB, 2011a)). Once production commences, any waste associated gas volumes at oil wells in excess of 900 m^3/d must be conserved except where this is more than marginally uneconomical to do (see Section 2.8 of AER Directive 60). Current regulatory direction is toward requiring the development of natural gas gathering infrastructure to keep pace with rate of development of the oilfield.

In accordance with the Clean Air Act, the United States (US) Environment Protection Agency (EPA), has implemented federal air standards (Code of Federal Regulations, 40 CFR Part 60 and 63, effective October 15, 2012) specifically targeting emissions from hydraulically fractured natural gas well completions, plus new performance standards for storage tanks, pneumatic controllers, and small dehydrators used in upstream oil and natural gas production (US EPA, 2012a). The well completion regulations are expected to dramatically reduced volatile organic compounds (VOCs) emission, and are currently in phase one of a two phase transitional period The VOC emissions will primarily be achieved through a proven process known as "reduced emissions completions" or "green completions". In a green completion, special separation equipment is used to direct natural gas and hydrocarbon liquids from the flowback fluids to inline gathering systems or storage tanks. Phase one mandates that, prior to January 1, 2015, all flowback emissions from a natural gas well completion must be collected and either flared using a "completion combustion device (unless combustion is a safety hazard or is prohibited by state or local regulations)", or conserved (i.e., through a green completion). After this date, phase two allows only green well completions, except in the following cases (US EPA, 2012b):

- New exploratory ("wildcat") wells or delineation wells (used to define the borders of a natural gas reservoir), because they are not near a pipeline to bring the gas to market;
- Hydraulically fractured low-pressure wells, where natural gas cannot be routed to the gathering line. Operators may use a simple formula based on well depth and well pressure to determine whether a well is a low-pressure well; or
- Owners/operators must reduce emissions from these wells using combustion during the well-completion process, unless combustion is a safety hazard or is prohibited by state or local regulations.

These regulations apply to both new and existing natural gas wells that are re-fractured to stimulate production and/or to produce natural gas from a different production zone within the formation. To comply with these rules companies will need to ensure that gas gathering lines are installed up to the well sites prior to the well completions being performed. Such requirements do not currently exist in Canada.

Overall, as conventional sources of oil and gas decline there will be increased development of unconventional oil and natural gas, particularly tight oil and natural gas reserves. The emissions contributions from completions will increase in importance as this occurs. This will place increasing pressure on industry to not only apply green completions but to find more efficient means of performing completions (for example, through the reuse of fracking fluids). The derivation of the new emission factor data presented in this report represents a significant accomplishment that should help clarify many of the controversial data issues raised in the detailed literature review presented in Chapter 2. However, it is also noted that a fair assessment of the significance of Canadian unconventional gas production emissions using these data will ultimately require knowledge of estimated ultimate recoverable volumes of natural gas for each contributing UWI. This knowledge of total recoverable volumes is important if emissions are to be compared on a unit of delivered energy basis factored over the lifetime production and emissions of a well. Although estimated ultimate recovery data are not presently available, the specific procedures developed and detailed in this report could be readily extended in future work to estimate the necessary production decline curves by tracking these UWI in past and future volumetric reporting, enabling the creation of a robust, data-backed, specific inventory estimate for unconventional gas production in Alberta.