EVALUATION OF AIR EMISSIONS ASSOCIATED WITH HYDRAULIC FRACTURING:

Analysis of Emissions from Drilling, Completion, and Operation of Unconventional Gas Wells in Alberta

Project Report to Petroleum Technology Alliance of Canada and Natural Resources Canada

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Preface

This project was a collaborative venture between Carleton University and Clearstone Engineering Ltd. administered by Petroleum Technology Alliance of Canada (PTAC) with financial support of the Canadian Association of Petroleum Producers (CAPP), Natural Resources Canada CanmetENERGY-Devon, and Natural Sciences and Engineering Research Council (NSERC). Significant in-kind support was provided by Encana, Shell Canada, and the Alberta Energy Regulator (AER, formerly managed as the Energy Resources Conservation Board (ERCB)).

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LIST OF ACRONYMS

AAPG	American Association of Petroleum Geologists
AER	Alberta Energy Regulator; the name of the new Alberta regulatory body which officially took over all regulatory functions previously carried out by the Energy Resources Conservation Board (ERCB) as of June 17, 2013.
ANGA	American Natural Gas Alliance
API	American Petroleum Industry
CAC	Criteria Air Contaminant;
CAPP	Canadian Association of Petroleum Producers
CBM	Coal Bed Methane
DST	Drill Stem Test
ERCB	Energy Resources Conservation Board; this was the name of Alberta regulatory body previously responsible for the regulation of energy resources in Alberta. All regulatory functions of the ERCB were formally taken over by the Alberta Energy Regulator (AER) as of June 17, 2013. References to ERCB in this report are maintained where necessary to be consistent with the specific authorship of the source being referenced.
EUR	Estimated ultimate recovery
GENWELL	General well data file (See Section 3.1.1)
GAO	United States Government Accountability Office
GHG	Greenhouse Gas. Relevant GHGs in this report may include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O)
GHGRP	Greenhouse Gas Reporting Program within the US Code of Federal Regulations (40 CFR Part 98)
GRI	Gas Research Institute
GWP	Global warming potential
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
LDINJ	Load Injection

NEB	National Energy Board
NEMS	National Energy Modeling System
NGCC	Natural Gas Combined Cycle
NOx	Oxides of nitrogen which include both nitric oxide (NO) and nitrogen dioxide (NO_2)
$PM_{2.5}$	Particulate matter less than 2.5 microns in nominal size
PT code	Perforation treatment codes
PRA	Petroleum registry of Alberta
REC	Reduced emissions control
THC	Total hydrocarbons
US EPA	United States Environmental Protection Agency
UWI	Unique Well Identifier; a code used to identify each leg of a well where a well-structure may contain one or more UWIs
VOC	Volatile organic compounds

LIST OF UNITS

This report uses SI units, prefixes, and officially accepted symbols, except where alternate units are being quoted directly from cited sources. Volume units are calculated at standard conditions of 15°C and 101.325 kPa. A partial list of selected units and definitions is provided below:

t	tonne, equivalent to 1000 kg or 1 Mg
kt	kilotonne, equivalent to 10^6 kg or 1 Gg
Mt	megatonne, equivalent to 10^9 kg or 1 Tg
MJ	megajoule, equivalent to 10^6 J
kPa	kilopascal
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Tcf	trillion cubic feet

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.

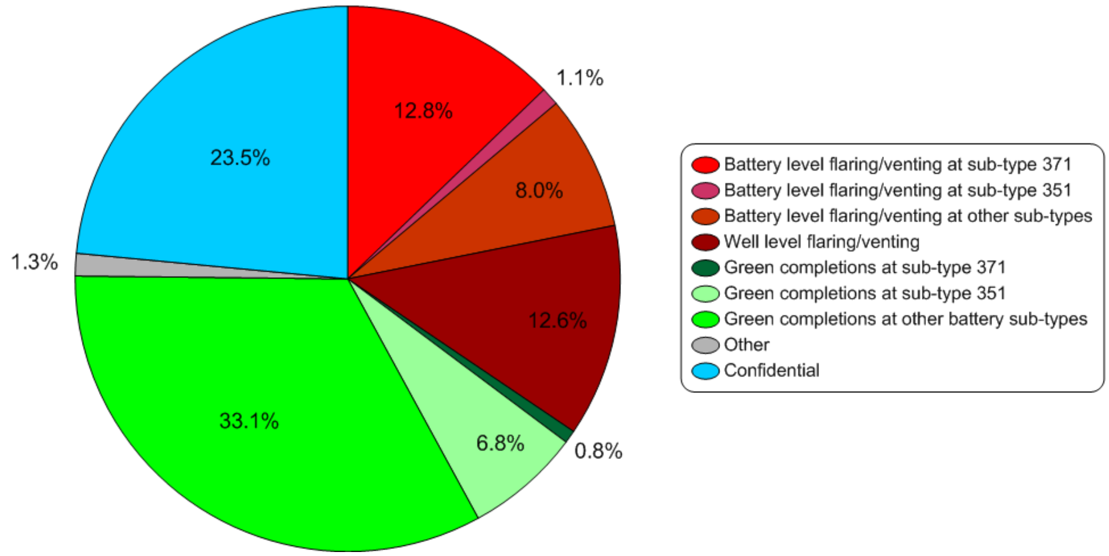

Figure ES.1: Percentage breakdown of how flaring and venting data associated with unconventional gas well-completions could be tracked within the confines of the available ERCB and PRA data for Alberta in 2011

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 performed. 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.

1 PROJECT OVERVIEW AND OBJECTIVES

The broad objectives of this study were to conduct a detailed analysis of unconventional natural gas well drilling, well completion, and well operational emissions in Alberta, based primarily on 2011 data. Specific components of this study included:

- A comprehensive literature review featuring an in depth analysis and comparison of input data sources used in frequently referenced unconventional well studies;
- A brief overview of key unconventional well processes and comparison of typical activities, sources, and emissions at conventional and unconventional wells;
- A detailed analysis of several recently published and highly-cited life-cycle analyses studies for unconventional gas production;
- 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.

1.1 Overview of the Main Data Sources

In meeting the objectives of analyzing current practices for the development of unconventional gas wells, estimating associated emission volumes in Alberta for the year 2011, and developing new emission factor data, this study considered all available data sources of information including:

- Detailed well activity data for the Province of Alberta tracked by the Alberta Energy Resources Conservation Board (ERCB – recently reorganized as the Alberta Energy Regulator, AER);
- Alberta volumetric production activity data for 2011 (including reported gas production, flaring, venting, dispositions, receipts, and fuel usage) submitted by industry as part of regulatory requirements administered by the AER;
- CAPP technical reports detailing the development of the 2005 National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry;
- Interviews with industry representatives; and
- Further information and data gathered during a site visit to examine an in-progress unconventional well completion.

1.1.1 Unconventional Well Activity Data Reported to ERCB

Key sources of information were the Alberta Energy Resources Conservation Board's (ERCB) general well data file (GENWELL) and a customized 2011 volumetric facility activity report from the Petroleum registry of Alberta (PRA). The specific copy of the ERCB general well file used in this analysis was generated on January 31, 2012 and contained approximately 6.9 million entries, broken into 15 separate files, which collectively detailed all reportable activity data for individual well-segments (each identified by a unique well identifier, UWI) in Alberta. The PRA contains volumetric data from reporting facilities such as batteries, gas plants, gathering systems and metering stations that are connected to contributing batteries, other facilities, and/or wells. Volumetric data is reported by activity (i.e. flaring, venting, production, etc.) on monthly intervals at both the well and facility level as outlined in (ERCB, 2011b). The meticulous and complex procedures required to thoroughly analyze and correctly interpret these data are fully detailed in Chapter 3 and Chapter 4. For procedures and methods used to identify the set of fractured natural gas wells drilled and completed in 2011 from the physical well parameters within the GENWELL database, the reader is directed to Chapter 3. Chapter 4 contains complementary procedures and techniques for identifying flaring, venting, and load injection volumes within the PRA that could be linked to the set of fractured natural gas wells drilled and completed in Alberta in 2011 as identified in Chapter 3. Where the data permitted, these volumes were further segregated by natural gas well subtype, i.e. coalbed methane (CBM), CBM hybrid, tight gas, and shale gas, to investigate potential variations in emissions profiles and operating practices among different types of wells.

1.1.2 Site Visit and Interviews with Industry Representatives

Field visit to witness a hydraulically fractured well completion near Dawson Creek, BC:

A site visit to witness a well completion process at a Montney Shale well near Dawson Creek, BC, was organized by Filiz Onder of Encana for November 16, 2012. The site tour was led by Dean Jenkins (Completions Group Lead at Encana), and opportunities were provided to interview and pose technical question to Encana well site operators, other associated Encana personnel, as well as on-site personnel from a service provider handling the hydraulic fracturing operation. This exercise was particularly useful in clarifying key operating practices specific to the region and inventorying equipment used in the hydraulic fracturing process. As part of the site visit, an opportunity was also provided to remotely observe similar operations at a number of adjacent sites operated by other companies.

Shell Canada phone interview:

A technical interview was subsequently arranged with Ted Bergman (Well delivery manager at Shell Canada) on January 16, 2013. The interview focused on answering several technical questions pertaining to how and when process steps for hydraulically fractured tight gas wells in Alberta are reported to ERCB and recorded in the PRA. Mr. Bergman was also extremely helpful in answering questions pertaining to the specifics of flaring during well completion practices in Alberta and BC.

ERCB database contact:

In addition to the industry interviews noted above, Ian Curle of the Alberta ERCB was able to provide informed answers to a range of questions pertaining to the specifics of the general well data file (GENWELL) used in this inventory study. Mr. Curle was also able to confirm the accuracy of the methodology used in this report for grouping unique well identifiers (UWI) into well structures and the subsequent assignments of fluid type.

1.2 Report Organization and Key Contributions

Chapter 2 contains an in-depth literature review compiled from publically available academic, industrial, and governmental reports. In particular, the literature review addresses the variability among current unconventional natural gas well studies by focusing on emissions associated with:

- liquid unloading activity,
- well completion emissions,
- workover (re-completion) rates, and
- the use of emission mitigating practices (flaring, reduced emission controls/green completions (RECs), plunger lifts).

Within this context, Section 2.2 reviews the development and inherent assumptions behind the revised US EPA emission factors for unconventional gas wells (US EPA, 2010). Section 2.3 considers the industry response to these emission factors and, in particular, reviews implications and results from the recent American Petroleum Industry (API) and the American Natural Gas Alliance (ANGA) industry directed survey of key gas production activities and equipment emission sources (Shires and Lev-On, 2012). It is important to note that the activity data gathered by API/ANGA survey has had a direct impact on the recently published US EPA 2011 National Inventory (US EPA, 2013b) and that these changes have been included throughout this report were appropriate. Sections 2.4 and 2.5 review and contrast the methodologies and results of several frequently referenced lifecycle analyses aimed at estimating overall greenhouse gas emissions associated with unconventional gas development and production.

Chapter 3 details the analysis of the Alberta well activity and physical parameter data contained within the ERCB regulatory data GENWELL database. By reviewing individual status codes of every well in the database, a subset of all licensed well segments drilled in 2011 (each identified with a “unique well identifier”, UWI) was determined. In Section 3.2.2 these UWIs were further categorized into natural gas, crude oil/bitumen, oil sands evaluation and other by assigning fluid, LAHEE and other status codes. The distribution by fluid type was investigated along with the spatial representation of the surface-hole locations of each corresponding well structure. Fractured natural gas and fractured crude oil/bitumen UWIs were treated separately in Sections 3.2.3 and 3.2.4.

Chapter 4 describes the procedures required to attribute flaring, venting, and diesel combustion volumes, where appropriate, to well drilling, well completion, and operation of hydraulically fractured natural gas wells. A detailed methodology for determining well completion specific flaring and venting volumes from the 2011 PRA date is presented in Section 4.2. In the subsequent sections the distributions and overall totals of these volumes are systematically presented in relevant figures and tables. The consumption of diesel during well drilling and well completion (i.e. for pumping of fracturing fluids; operation of sand and blender trucks; wireline equipment; heaters for fracturing fluids; light towers; office trailers; and other on-site equipment) is not tracked as part of the upstream oil and gas regulatory system. However, in Sections 4.3 and 4.4 novel procedures for estimating diesel combustion volumes from well drilling and well completion are developed which enables computation of greenhouse gas (GHG) and criteria air contaminant (CAC) air emissions, as detailed in Chapter 5. Finally identifiable trends in monthly flaring, venting, and fuel (natural gas) volumes, reported in the PRA outside of the well completion interval, are discussed for fractured wells that have been completed in the past 10-years.

In Chapter 5 the derived flaring, venting, and diesel volumes of Chapter 4 are used to calculate well-type specific flaring, venting, and diesel emission/intensity factors on a UWI basis for unconventional natural gas well drilling, completion, and operation in Alberta for the year 2011. For each emission/intensity factor, corresponding greenhouse gas (GHG) and criteria air contaminant (CAC) emission factors are derived. Additionally, these data are used to calculate the total estimated GHG and CAC contributions from each activity at unconventional natural gas wells in Alberta in 2011.

In the final section of Chapter 5 (Section 5.5), the newly developed flaring, venting, and diesel intensity factors for unconventional Alberta gas wells are separately compared to a range of emission factor data that can be derived from sources described in the literature review of Chapter 2. Comparable emission factor data were calculated using available information from CAPP (See Section 2.4.4), US EPA (See Section 2.2), API/ANGA (See Section 2.3), the Tyndall Center (Wood et al., 2011), as well as from the recently published measurement study conducted by (Allen et al., 2013b).

The successful development of a range of new emission factors based directly on reported production, flaring, venting, and activity data in Alberta is a significant achievement that provides much needed insight into many of the controversial data issues raised in the literature review presented in Chapter 2. In future work, assessments of overall air emissions associated with Canadian unconventional natural gas production using these new data should also incorporate knowledge of estimated ultimate recoverable volumes for each contributing UWI. While these data were not available for the present analysis, the specific procedures developed and detailed in this report could be readily extended to address this by tracking subsets of fractured UWIs in past and future volumetric reporting to create a robust, data-backed inventory estimate for unconventional gas production in Alberta.

2 LITERATURE REVIEW

Broadly speaking, unconventional gas sources refer to natural gas contained in porous geological formations with low permeability. The extraction of this gas requires well stimulation, in the form of hydraulic fracturing, to open a network of pathways within the formation. Unconventional sources of natural gas such as shale gas, tight gas and coalbed methane have an ever increasing role in North American energy production. The United States Energy Information Administration estimates that there are 482 trillion cubic feet (Tcf) of "unproved technically recoverable" unconventional gas resources in the Unites States (U.S. EIA, 2012). In Canada the current total unconventional gas reserves are not as well-known since potential shale resources in Alberta (Duvernay and Exshaw plays), Quebec (Utica shale), and New Brunswick (Horton Bluff shale) are yet to be developed. For Western Canada, as of 2010, the National Energy Board estimates that there is 78 Tcf of "marketable" shale gas in the Horn River basin of British Columbia (BC MEM/NEB, 2011) and 2.4 Tcf of coalbed methane in Alberta (National Energy Board, 2011a). The remaining "marketable" tight gas is estimated to be 170 Tcf of which 108 Tcf is attributed to the Alberta/British Columbia Montney gas play (National Energy Board, 2011b). Other tight gas areas include Deep Basin BC/AB, Milk River AB, Medicine Hat AB and the Second White Specks formation in southern Alberta and Saskatchewan. The National Energy Board (NEB) provides a tentative estimate of 314 Tcf of remaining "marketable" unconventional gas from Canadian shale, tight gas, and coalbed methane formations as of 2010 (National Energy Board, 2011b).

By 2035 shale gas production in Canada is set to increase from the 2011 rate of 0.473 billion cubic feet per day (Bcf/d) to 4 Bcf/d, and consist of 22% of total natural gas production (National Energy Board, 2011a). Furthermore, Canadian tight gas is predicted to reverse the current overall decline in gas production by 2016, surpass conventional sources by 2014, and in combination with shale, makeup 71% of total gas production in Canada by 2035 (National Energy Board, 2011a).

With increased production, there has been increased attention on the lifecycle emissions of unconventional gas sources. In 2011 the United States Environmental Protection Agency (US EPA) released their revised emission factors for methane venting from natural gas production systems. In updating these emissions factors, the US EPA for the first time made a distinction between conventional and unconventional natural gas wells (US EPA, 2010). Following the publication of the US EPA's emission factors for unconventional gas wells, several governmental (Skone et al., 2011; (S&T)2 Consultants Inc., 2011), industrial (Wood et al., 2011; Fulton et al., 2011; Barcella et al., 2011; Shires and Lev-On, 2012), and academic (e.g. Howarth et al., 2011; Jiang et al., 2011b) reports emerged, which focused on the lifecycle greenhouse gas (GHG) and/or methane emissions of hydraulically fractured natural gas wells. As summarized in Table 2.1, the majority of these reports used the US EPA's emission factors, applying them with differing assumptions to estimate emissions from various unconventional natural gas basins in the United States.

While all of the cited authors agree that unconventional wells have a larger GHG footprint than conventional wells, the estimated magnitudes of the difference vary widely. Perhaps the most well-known and controversial of these reports is the "Howarth Study", as further detailed in section 2.4.1, which considered wells based in Louisiana, Texas, Utah, and Colorado (Howarth et al., 2011). Although their conclusion,

> *"Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal"*,

has been largely dismissed, it has brought significant attention and scrutiny to the US EPA emission factors and the methodologies with which they are used (Barcella et al., 2011).

Estimates of additional life-cycle emissions from unconventional gas wells are heavily influenced by parameters such as:

- liquid unloading activity;
- well-completion emissions;
- workover (re-completion) rates;
- the use of emission mitigating practices (flaring, reduced emission controls/green-completions (RECs), plunger lifts); and
- the estimated ultimate recovery (EUR) of the well.

Thus, although the studies summarized in Table 2.1 mostly draw from the same source emission factor data, they differ in a number of critical ways with respect to the assumptions made and the system boundaries of their analyses. For example, the analysis of Wood et al. (2011) does not include vented well-completion emissions or liquid unloading emissions and focuses mainly on the additional combustion emissions associated with drilling and hydraulic fracturing; Howarth et al. (2011) assume much higher rates of venting than might be expected based on more recent analysis including the results of the present report. The studies in Table 2.1 are critiqued in greater detail in Section 2.4.

Table 2.1: Comparison of recent lifecycle analysis studies on GHG emissions associated with hydraulic fracturing

		Howarth et al., 2011 ("Howarth Study")[a]	Skone et al., 2011 ("NETL Report")[b]	Jiang et al., 2011 ("Carnegie Mellon Study")[c]	S&T consultants, 2011 ("NRCan Report")[d]	Fulton et al. 2011 (Deutsche Bank Report)[e]	Wood et al. 2011 (Tyndall Centre Report)[f]
Additional emissions over conventional		≥30%	NA	3%	3.8%	11%	0.2-2.9%
Methane global warming potential (GWP)	20 years	105	72	NA	NA	72-105	NA
	100 years	33	25	25	NA	25	NA
Comparison units		gCO2e/ unit of energy	gCO2e/ unit of electricity	gCO2e/ unit of electricity	gCO2e/ unit of electricity	gCO2e/ unit of electricity	gCO2e/ unit of energy
Emissions compared to Coal	20 years	≥20%	-39%	NA	NA	≤-27%	-37% to -39%
	100 years	-18% to 15%	-52%	-40.5% to -47%	NA	-47%	

[a] See Section 2.4.1; See Section 2.4.2; See section 2.4.3; See Section 2.4.4; See Section 2.4; See Section 2.4.5

Prior to 2013, there was very little consensus on the application of liquid unloading emission factors to unconventional hydraulic gas wells. Both the US EPA (US EPA, 2010) and the National Energy Technology Laboratory (Skone et al., 2011) suggested that liquid unloading was negligible for unconventional wells and stated, respectively:

- *"… many of those basins contain unconventional wells which will not require liquid unloading"* and;
- *"Liquid unloading is necessary for conventional gas wells –it is not necessary for unconventional wells".*

Conversely, recently published industry survey data collected by the American Petroleum Industry (API) and the American Natural Gas Alliance (ANGA) (Shires and Lev-On, 2012, as further detailed in Section 2.3.1), suggest liquid unloading at unconventional wells may be significant. Compiled responses representing both conventional and unconventional wells sets revealed that 49.4% of natural gas wells were equipped with mechanical lifts for liquid unloading and an additional 9.3% performed liquid unloading by venting to atmosphere. Data analysis suggested that vented emissions associated with liquid unloading ranged from 590 m^3 gas/well-month to 1150 m^3 gas/well-month for unconventional wells (Shires and Lev-On, 2012, Table C3 and Table C4). During the finalization of this report, the US EPA released an updated US National Inventory (US EPA, 2013b), which now includes liquid unloading emissions from unconventional wells. This update was a direct consequence of the API/ANGA survey data, and the updated EPA values are considered in Section 5.5 when comparing results of the current analysis to available information from other sources. As well, relevant field measurement data from the very recently published study of (Allen et al., 2013b) are also included in results comparisons in Section 5.5.

A further complication in comparing various lifecycle analyses is inconsistency in the definition of unconventional wells as the language used to classify hydraulically fractured wells has evolved since the release of the US EPA emission factor updates in 2010. One example is the classification of tight gas wells, where variations in definition can be found even within the same organizations. The Canadian National Energy Board (NEB) considers tight gas a subset of conventional gas in Canada’s future energy projections (National Energy Board, 2011b), but as an unconventional gas source in a report estimating the ultimate resource potential of the Horn River area in British Columbia (BC MEM/NEB, 2011). Quite notably, in an effort to be more precise, the US EPA is dropping the use of the word “unconventional” in favor of using “hydraulically fractured” in inventory calculations (US EPA, 2012c).

The range of assumptions and emissions presented in the literature highlights the difficultly of a “one size fits all” emission factor. A common theme throughout the literature is a request for more data on operator/industrial practices and equipment, as well as activity data at well-level resolution. This is in part due to the speed at which hydraulically fractured wells are becoming the dominant production mode and the rate at which industrial practices are changing.

For example, the US EPA flaring rate of 51% for unconventional completions and workovers (See Section 2.2) was based on legislative requirements across different states, which operators claim lags the current best practices (Barcella et al., 2011). From a legislative point of view, this issue should be at least partially addressed by the recently passed US EPA Code of Federal Regulations, 40 CFR Part 60 and 63, effective October 15, 2012, relating to national emission standards for the oil and natural gas sector (US EPA, 2012a). According to this legislation, by January 1, 2015, essentially all hydraulically fractured gas wells must route flowback emissions to a reduced emissions completion (REC) system used in combination with a well-completion combustion device.

2.1 Brief Overview of Key Processes Involved in Unconventional Gas Production

Prior to discussing details of various published emissions factors and life-cycle analyses, it is instructive to briefly review key processes involved in the development and production of unconventional gas wells. As shown in Figure 2.1, the general workflow for hydraulically fractured wells may be divided into three categories: well drilling and completion; production and maintenance; and on-site gas processing. Within these categories, there are several key processes that influence lifecycle emissions. These are separately outlined below.

Well Drilling: Vertical and horizontal wells share the same initial steps during the drilling process. As indicated in Figure 2.2, the first stage involves drilling through the surface material into which a well (conductor) casing is inserted and affixed with cement. The conductor casing acts as a barrier between high pressure well fluids/gas and the surrounding surface layers of sand, gravel and other unconsolidated material. The wellbore is then drilled to a depth below the base groundwater aquifers, and a second steel (surface) casing is cemented into place to prevent groundwater and well fluid interaction. The subsequent step involves drilling the wellbore to production depth (CSUG, 2011; IEA, 2012).

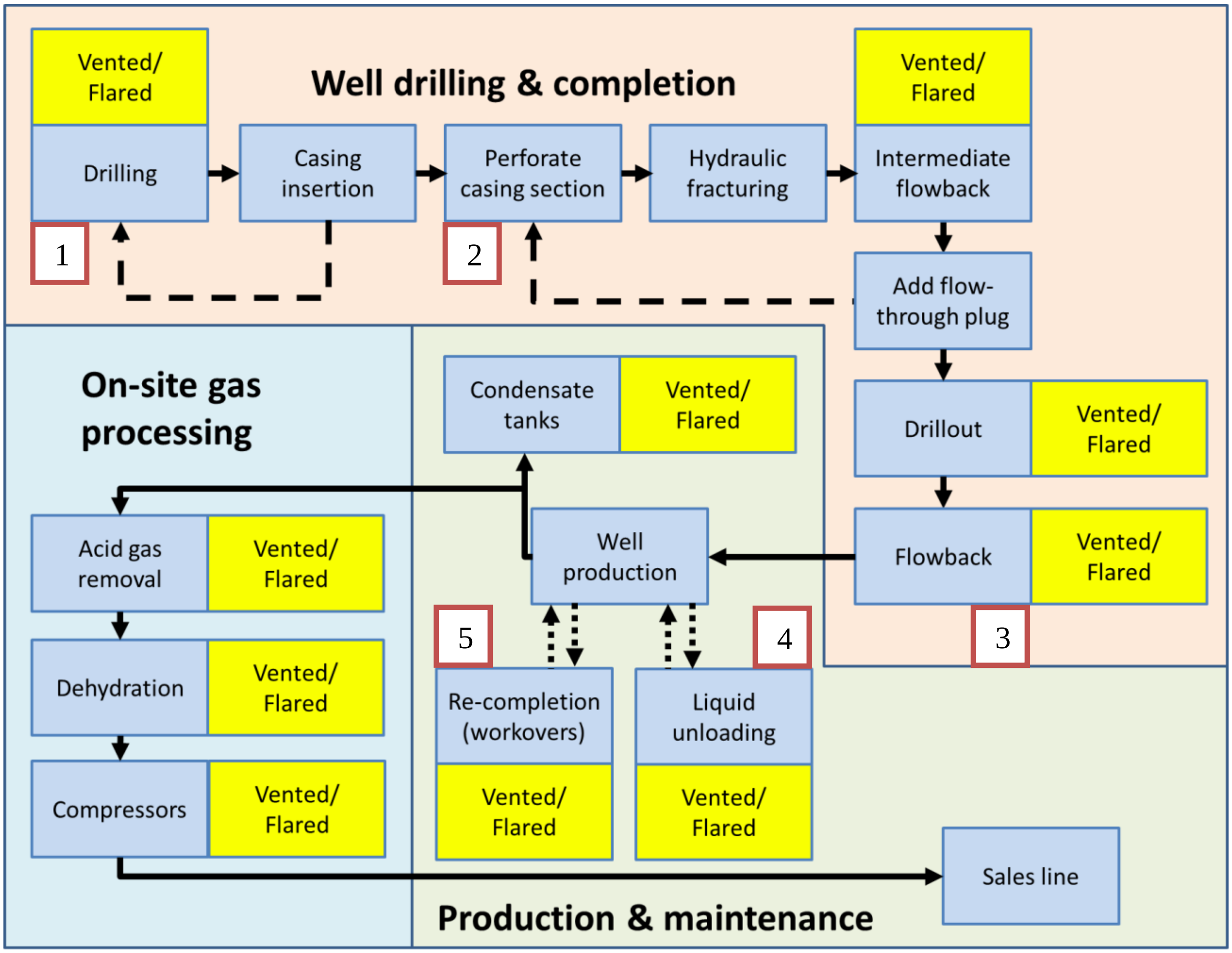

Figure 2.1: Schematic of key processes involved in well drilling & completion; production & maintenance; and on-site processing of hydraulic fractured unconventional gas

For vertical wells, the production depth passes vertically through the target rock and a final steel (production) casing is cemented into place to the bottom of the wellbore. In the case of "open hole" wells, the final steel casing ends above the target rock (CSUG, 2011).

For horizontal wells, the vertical component is drilled to a level within the gas-bearing rock. The horizontal component of the well is then drilled outward through the gas-bearing rock (shale) layer. The length of the horizontal well component may vary between well pads; for example, in the Horn River Basin the horizontal well sections may vary between 1176 m and 2727 m in length (BC Oil & Gas Commission, 2012). In the final drilling step, a steel casing is inserted from "heel to toe" into the horizontal well section and secured by cement to the surrounding rock formation (CSUG, 2011). Excluding well pad and site infrastructure a vertical well may cost as much as $800,000 USD to drill and $2.5 million USD for a horizontal well (Ground Water Protection Council and ALL Consulting, 2009).

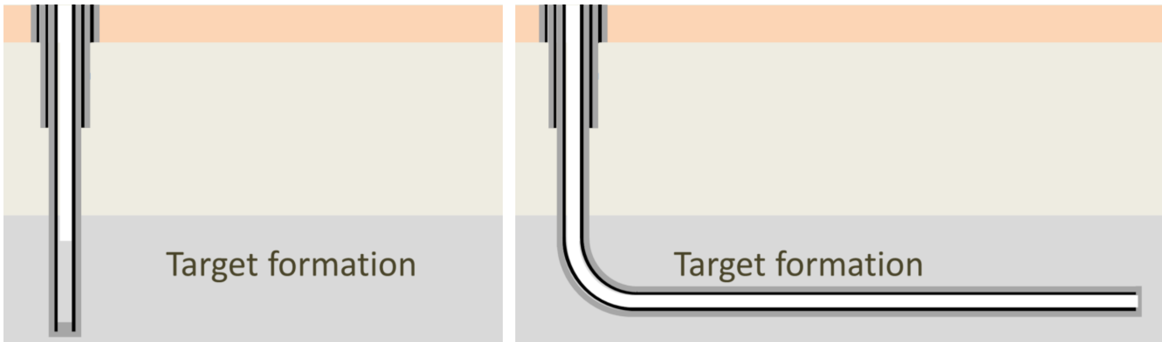

Figure 2.2: Cased vertical and horizontal wellbores

Shut-in period: Depending on the availability of equipment and gathering systems, a well may be "shut-in" or turned off for a period of time. An operator may also shut in a well, before the hydraulic fracturing process, to provide the appropriate time for the wellbore cement to harden.

Casing perforation: To allow the high pressure fracturing fluid access to the target rock, the steel production casing is perforated using small electrically-fired (jet) charges. These charges create small shallow holes through the casing and into the target formation (Devold, 2010). Once perforated, the flow of gas/hydrocarbons in shale and tight gas wells will be low due to the low permeability of the rock (Ground Water Protection Council and ALL Consulting, 2009).

Hydraulic Fracturing: To produce commercially viable gas production rates in shale and tight gas wells, the permeability of the target rock is increased by a fracturing process which is illustrated schematically in Figure 2.3. The fracturing process involves pumping high pressure fracturing fluid (a mixture of water, proppant (sand, resin coated sand, or ceramic particles) and proprietary combinations of "fracking chemicals") down the wellbore where it enters the rock formation through the perforations in the production casing. With a fluid pressure higher than the formation pressure, a network of fissures is created that extends tens to hundreds of meters from the wellbore through the formation. The ultimate length of the fissures depends on the brittleness of the rock, the proximity of cap rock barriers, and the capability of the pumping equipment (IEA, 2012). The network of fissures is kept open by the proppant, which is left behind by the fracturing fluid after flowback. This allows faster gas flow and hence increased production rates.

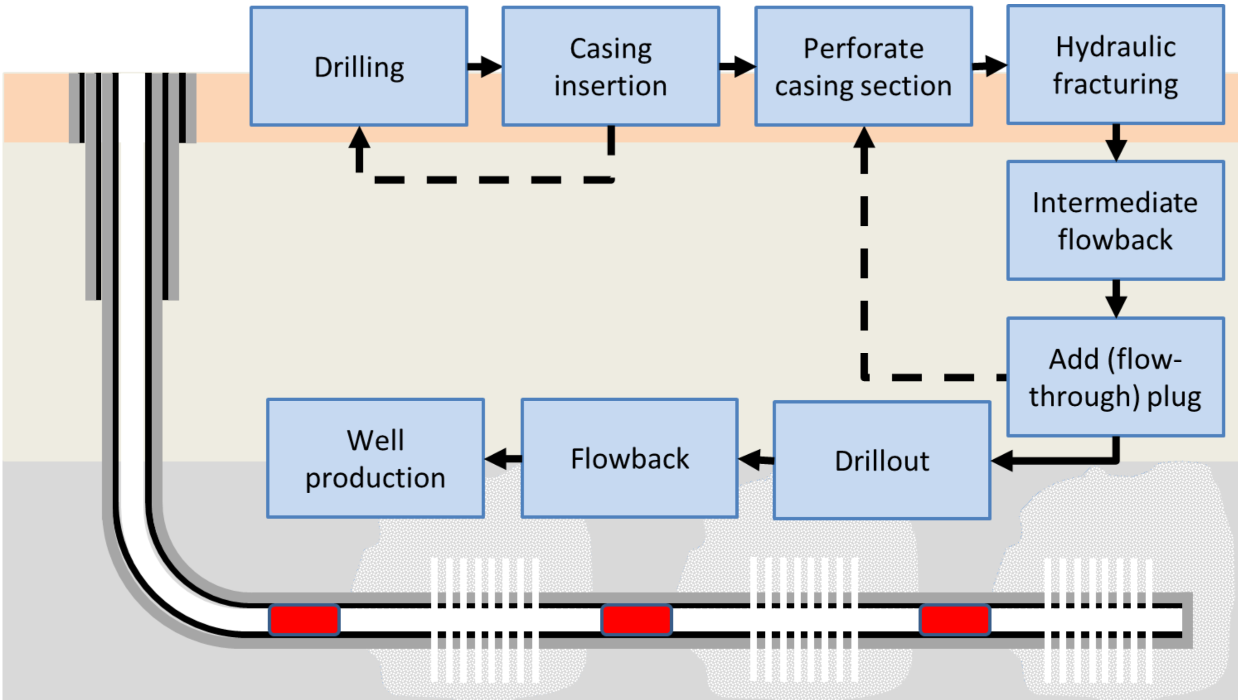

Figure 2.3: Schematic well-completion diagram and depiction of a fractured horizontal well with plugs before drillout

Flowback: Based on the design and fracturing schedule of a well, an operator may permit intermediate flowback after each fracturing stage. During flowback the fracturing fluid is pushed to the surface by reservoir gas pressure and is directed through a series of pressurized tanks where fluids are separated from produced reservoir gases. These gases are then flared, vented, or directed into a pipeline tie-in system, depending on the quantity and composition of the gas returned, the availability of infrastructure, and economic and regulatory considerations.

Minimizing emissions during flowback may be accomplished using reduced emission completion (REC) equipment. The REC equipment accommodates the high flow rates of returning fluids mixed with formation hydrocarbons using specialized sand traps, liquid/gas separators, and tie-in piping to the nearest gas gathering system (or other end use device) (US EPA, 2011a; Smith, 2011). RECs may also be used in conjunction with flaring during well-completion. REC equipment can be costly but it has the potential for a short payback period, depending on the market value of the gas/hydrocarbons captured during flowback (US EPA, 2011a). During a 2011 US EPA Natural Gas STAR Program workshop, British Petroleum reported an average gas recovery of 3.3 MMcf per well during 106 well-completions. The value of the gas at the time of completion set British Petroleum's RECs payback period at 1.5 years (US EPA, 2011b).

Stage plugs: Hydraulic fracturing may be performed in multiple stages, where each gas producing zone is separated by stage plugs. These plugs can be set by wirelines, coiled tubing, or threaded tubing. Depending on the type of plugs used, flowback may occur between stages or only after the final stage is fractured and the plugs are subsequently drilled out. Some operators use flow through plugs with internal check valves that allow the one way flow of fluids from below the plug. In this configuration the gas well is able to produce until a workover drill rig is available to drill out the plugs (US EPA, 2007). Alternatively, as is the case in Horn River British Columbia, the typical procedure involves the use of bridge plugs which have a solid core that holds pressure from both directions to prevent flowback ((S&T)2 Consultants Inc., 2011). The number of fracturing stages per well in Horn River typically ranges from as few as 5 to as many as 27 (BC Oil & Gas Commission, 2012).

Drillout: Stage plugs are drilled out allowing flow back (or further flowback when check-valve type plugs are used) of natural gas to the surface. In Horn River, coil tubing is typically employed to drillout the bridge plugs so that flowback may be captured and any produced gas can be flared or sent for processing depending on the quality and flow rate consistency ((S&T)2 Consultants Inc., 2011).

Final Flowback: The volumes of natural gas produced during flowback as well as the volumes of recovered formation and fracturing liquids vary significantly among different formations. Estimating recovered gas volumes during completion and flowback based on Alberta operational data was a key objective of this project. In terms of proportions of recovered liquids, King (2012) reports that the Haynesville shale may return as little as 5% while the Barnett and Marcellus shales return as much as 50%. The proportion of gas in the produced fluids increases over the flowback period, which can occur for as long as 2 to 3 weeks for multi-stage fracturing (IEA, 2012).

Liquid unloading: Over the lifetime of a gas well, the accumulation of fluids can significantly reduce gas production. The removal of these fluids is achieved using well cleanup procedures that may include beam lifts, plunger lifts, or well blowdowns (US EPA, 2006). Analysis of the American Petroleum Institute and America's Natural Gas Alliance's (API/ANGA) survey data (Shires and Lev-On, 2012, see Section 2.3.1) suggests that approximately 58.7% of natural gas wells require liquid unloading. Frequently, liquids are separated inline and gas is delivered to the sales pipeline resulting in zero flaring or venting emissions. However, venting can occur at older wells where the down-hole pressure has decreased to the point where there is an insufficient pressure drop to drive liquids to the surface at gathering system pressure. In these cases, sufficient pressure drop is obtained by relieving the well into an atmospheric vessel where liquids/gases are separated, and gas is directed to a flare or vent. The API/ANGA data (Shires and Lev-On, 2012) suggest that 9.3% of natural gas wells vent to atmosphere during liquid loading. Liquid unloading emissions for Canadian conventional wells are grouped under the heading of "Well Servicing" by the Canadian Association of Petroleum Producers (CAPP), (CAPP, 2004b), and are estimated separately from reported flaring and venting volumes as further discussed in Section 4.5.

Re-completion (workovers): Over time, well pressure and production decline in tight gas and shale gas wells. To improve production, the well may be re-hydraulically fractured. The frequency with which workovers may occur directly affects the lifecycle emissions of the well.

Condensate tanks: Condensate tanks collect any produced liquid hydrocarbons that reach the surface. These tanks are typically vented to atmosphere.

On-site gas processing: Well pad gas processing may include the separation of liquids and other gases, metering, dehydration, sweetening (H_2S removal), compression, and liquid storage equipment to produce sales line quality natural gas. Emissions from these components are expected to be equivalent between conventional and unconventional wells.

2.1.1 Comparison of Typical Activities, Sources, and Emissions at Conventional and Unconventional (Hydraulically Fractured) Wells

While many of the processes involved in well drilling, completion, and testing are similar between conventional and unconventional wells, there are several important distinctions. Table 2.2 provides a summary comparison of potential activities/equipment and emissions/sources at conventional and unconventional wells. This report is primarily focused on quantifying and constraining estimates of sources and activities that are specific to unconventional wells.

Table 2.2: Summary and comparison of typical activities, sources, and emissions at conventional and hydraulically fractured wells

Activity and Associated Equipment	Emissions & Sources	Conventional wells	Fractured wells	Notes and relevant information gather during a fractured well site visit in Dawson Creek, BC.
Pad construction • Earthmoving/grading and road building equipment	**CAC and GHG emissions from:** *Diesel combustion:* Heavy vehicles used for: • equipment delivery • debris / solids removal • geotextile delivery • compaction/berms/drainage • road construction	Y	Y	• Well pad areas for fractured wells will be typically bigger to accommodate required fracture equipment. • Additional earth moving maybe require for fractured wells to build temporary water storage pits. • Dawson Creek single wellhead pad area: roughly 100m x 100m
Well pad building and lights • Office trailers and skids: ○ command center ○ outbuildings for personnel ○ equipment storage skids ○ light stands	**CAC and GHG emissions from:** *Diesel combustion* • equipment delivery & setup • electrical power generation • heating of buildings • site lighting	Y	Y	• Fractured well sites will have an additional data monitoring trailer for down-hole measurements, pump rates, fluid density etc. during fracturing. • Light stands run during night operations that occur during: drilling, fracturing, cleanup and testing. • Dawson Creek: 10 light stands using approximately 100 L diesel/day
Drilling and casing • drill rig, incl.mud system: pumps, water/mud tanks • separator equipment for returning mud • flare stack • casing & cementing equip-ment –pumps for casing pressure test, • well head -installation • trucks for removal of rock cuttings & drill mud	**CAC and GHG emissions from:** *Diesel combustion (Section 5.2)* • equipment delivery & setup; • powering pumps and heavy vehicles *Flaring and/or venting* • gas returned with drill mud • well kicks flared • openhole precasing drill stem tests	Y	Y	• Drilling durations will vary depending on the depth, orientation of the well and the target formation. • Current fractured wells with deep vertical/horizontal legs require larger drill rigs. • Dawson Creek: 2000m horizontal leg drill off a 2200m deep vertical surface hole • Drill stem test are not required by regulation and initial pressure testing may be performed during well testing (refer to ERCB Directive 40)

Table 2.2: Summary and comparison of typical activities, sources, and emissions at conventional and hydraulically fractured wells (*continued*)

Activity and Associated Equipment	Emissions & Sources	Conventional wells	Fractured wells	Notes and relevant information gather during a fractured well site visit in Dawson Creek, BC.
Hydraulic fracturing setup and operations • water tanks/ heaters • water transportation trucks • sand trucks/towers • sand conveyors • blender trucks • fracture fluid pump trucks • additives(acid, breaker, friction reducer, gelling agents, scaling inhibitor, etc) trucks • manifold trailer –transfer point for all mixed fluids to wellhead • wireline truck – raising & lowering measurement equipment and tools (plugs, perf gun etc) • wellhead crane unit • motorized personnel lifts & plaforms • gas/flowback fluid separators • outbuilding/skids to housing site metering • line heaters, prevents condensate during production, warms separators • waste water storage tanks	**CAC and GHG emissions from:** *Diesel combustion (See Section 5.3):* • equipment delivery & setup; • daily personnel transportation • fracturing pumps, sand conveyors, blender trucks etc. • heating of fracturing fluids • diesel fuel & water delivered by trucks • waste water removal *Propane combustion:* • line heaters to prevent hydrate formation down-stream of the separators if applicable • flare igniter if applicable *Flaring and/or venting:* • flowback gases flared downstream of liquid/gas separators (4-10 days) (See Section 5.1)	N	Y	Dawson Creek site included/involved: • single horizontal leg with 13 fracture stages • estimated 12000 L diesel/day for 3 day fracture job • 38 insulated and heated water tanks filled by trucks delivering water, pumped in. • sand towers (solar powered) • sand conveyor trucks • 1 gel truck with pumps • chemical trucks with pumps • 1 blender truck • 2 crane units (wellhead and smaller truck mounted unit) • 8 pump trucks for fracturing (2100 hp)- 2.5 hours per stage • 2 pump trucks for wireline and proppant delivery • 1 wireline truck • 1 manifold trailer • sand delivered by train to Grande Prairie and then by truck to Dawson Creek • 1 line heater (2 propane tanks) • 1 methanol (hydrate inhibitor) tank • >10 light trucks on site • 1 60 ft flare stack
Drillout • coil tubing rig for drilling out stage plugs • pumps- mill head run by circulating fluid downhole	**CAC and GHG emissions from:** *Diesel combustion:* • equipment delivery & setup; • running pumps and tubing rig *Flaring:* • drillout emissions are flared	N	Y	Typical duration is 2-3 days.
Well testing • flaring, venting, & fugitive emissions	**CAC and GHG emissions from:** *Flaring during pressure and productivity testing. (See Section 5.1)*	Y	Y	• Conventional and unconventional gas wells are govern same the directives: • Directive 040: Pressure and Deliverability Testing Oil and Gas Wells • Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting

2.1.2 *Relevant Regulatory Developments and Framework for Hydraulically Fractured Wells*

Hydraulically fractured gas wells in Canada are primarily regulated under Provincial oil and gas development laws which vary somewhat among provinces. In recent years provincial regulators and industry partners have moved to access the regulatory change opportunities specific to hydraulically fractured wells in an effort to address landowner and public concerns. Specifically, work supported by the Petroleum Technology Alliance Canada, compiled by All Consulting, provides an overview of the Canadian regulatory framework and provincial comparisons with regard to groundwater protection and hydraulic fracturing operations (All Consulting, 2012). In Alberta, ERCB conducted a jurisdictional review to access, identify and learn from unconventional gas development in both Canada and the United States. The review includes survey feedback that highlights development issues and regulations within different jurisdictional frameworks (ERCB, 2011c). Within the survey, common regulatory challenges included:

- Well spacing: gas recovery from low permeable target zones requires higher well densities to ensure economically viable gas recovery. There are risks of interaction between an adjacent producing wellbore and one that is being completed.
- Groundwater risks: perceived water aquifer contamination risks with fracturing fluid and natural gas from shallow and deep target zones.
- Water management: large volumes of water used during well-completion, transportation, post fracturing treatment, onsite containment, etc.

Although the life cycle operations of a hydraulically fractured well, from drilling to post abandonment, were already covered under provincial directives, the ERCB has since strengthened the unconventional regulatory framework to include language specific to hydraulic fracturing to further manage the above issues. For example, effective December 2012, Directive 059: Well Drilling and Completion Data Filing Requirements, introduces new requirements for electronic submission of fracturing fluid data along with carrier fluid, proppant, and additive types. As well, requirements to report water usage for fracturing, water source locations, and source types are also included in Directive 059. To strengthen Directive 008: Surface Casing Depth Requirements, ERCB has released Directive 083: Hydraulic Fracturing Subsurface

Integrity, effective August 2013, which specifically addresses groundwater issues and interaction with nearby wellbores.

Well-completion flaring, venting and associated air emissions from hydraulically fractured is a commonly cited concern among landowners in close proximity to gas development. In Alberta, well-completion flaring and venting is covered under Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting. Well-completion flaring and venting falls under the following well test provision:

> *"All flaring, incineration, and venting at a well site (including well tests) must be reported on the appropriate production reporting submissions, including PETRINEX (see Directive 007: Volumetric and Infrastructure Requirements)."*

Directive 60 also includes reporting thresholds and maximum flaring and venting durations as well as mandating the use of a flaring decision tree to facilitate the reduction of flaring and venting.

Similar to a key tenet of Directive 060 *"venting is not an acceptable alternative to conservation or flaring"*, the US EPA recently passed US EPA Code of Federal Regulations, 40 CFR Part 60 and 63, effective October 15, 2012, relating to national emission standards for the oil and natural gas sector (US EPA, 2012a). According to this legislation, by January 1, 2015, essentially all hydraulically fractured gas wells must route flowback emissions to a reduced emissions completion (REC) system used in combination with a well-completion combustion device.

2.2 The Revised US EPA Methane Emission Factors

The 2010 revised US EPA emission factors (US EPA, 2010) for vented methane from natural gas systems are employed by many authors to calculate lifecycle GHG studies for unconventional gas wells. Table 2.3 compares the previous (1996) and revised (2010) US EPA emission factors, along with very recently updated US EPA emission factors for unconventional wells from the 2011 GHG Inventory (US EPA, 2013b), which was released during the finalization of this report. In the latest US EPA emission factor documents, unconventional wells are defined to include wells in tight sand, shale, or coalbed methane formations that require hydraulic fracturing.

It should be noted that the 2010 and 2011 US EPA emission factors in Table 2.3 do not include the use of flaring or the implementation of reduced emission completions (REC) controls, and as such do not necessarily represent the volume of methane released to the atmosphere. Flaring and other mitigation factors are later applied by the US EPA to compute the actual methane, CO_2, and other species-specific emissions for their national greenhouse gas (GHG) inventory (US EPA, 2012c).

Table 2.3: Comparison of original (1996) and revised (2010) US EPA methane emission factors for conventional and unconventional wells

Venting source		EPA/GRI 1996 emission factors		Revised 2010 emission factors		2011 emission factors[a]
	Units	Conventional Wells	Unconventional Wells	Conventional Wells	Unconventional Wells	Unconventional Wells
Well completion	t CH_4/completion	0.02	0.02	0.71	177	173.3[b]
Liquid unloading	t CH_4/year-well	1.02	n/a[c]	11	n/a[c]	1.5-38.6[d,e] 0.06-22.7[d,f]
Workovers (re-fracturing)	t CH_4/year-workover	0.05	0.05	0.05	177	173.3[b]
Centrifugal wet seal compressors	t CH_4/year-compressor	0	0	233	233	233

[a] The US EPA 2011 National Inventory (US EPA, 2013b) updated potential methane emission factors for well completion and workovers, as well as, emission factors for actual methane emitted for liquid unloading events at wells with and without plunger lifts (US EPA, 2013a).
[b] The US EPA rounded 9175 Mcf/completion used in the 2010 National Inventory to 9000 Mcf/completion for use in the recent 2011 US Nation Inventory (US EPA, 2013a). The new emission factor for both completions and workovers is equivalent to 173.3 t CH_4/completion.
[c] As further explained in Section 2.2.2 below, the US EPA only considered liquid unloading emission factors at conventional wells in the 2010 National GHG Inventory (US EPA, 2012c)
[d] The US EPA 2011 National Inventory includes liquid unloading emissions from unconventional wells in response to the API\ANGA activity survey as discussed in Section 5.5.3.
[e] Reported as 77900 to 2003373 Scf CH_4/year-well for wells without plunger lifts over the Nation Energy Modeling System regions (US EPA, 2013a)
[f] Reported as 2856 to 1177705 Scf CH_4/year-well for wells with plunger lifts over the Nation Energy Modeling System regions (US EPA, 2013a)

The data used to calculate the 2010 and 2011 well-completion emissions factors come predominately from US EPA STAR Program Workshops presentations and is originally reported in Mcf of natural gas. To convert these natural gas volumes to tonnes of CH_4 in Table 2.3, the US EPA uses a conversion factor of 0.01926 t / Mcf which assumes a 100% methane content at 15 degrees Celsius. However, when subsequently applying these emission factors to generate the national GHG inventory, the US EPA accounts for the actual methane content as it varies by region according to the National Energy Modeling System (NEMS) (US EPA, 2012c). Further details for each entry in Table 2.3 are discussed under separate headings below, along with key assumptions made by the US EPA when applying these emission factors to compute actual emission rates.

2.2.1 US EPA Well-completion Emission Factors

Conventional Well-completion Emission Factor: The US EPA/GRI 1996 estimates that 0.733 Mcf of methane is emitted per conventional well after flaring (Shires and Harrison, 1996a, Table 4-2). The revised completion emission factor is computed using this same result, but assuming no gas is flared. Thus, by assuming a 98% flare efficiency applies to the 1996 data, the EPA back calculates a total emission of 0.733/.02 = 36.65 Mcf of methane per completion. When multiplied by a methane density of 0.01926 t / Mcf as noted above, this equates to 0.706 t of methane per completion, which rounds to the revised conventional well-completion emission factor of 0.71 t CH_4 / completion reported in Table 2.3.

When subsequently computing GHG emissions for the 2010 national inventory, the US EPA assumes that the gas is flared in 51% of completions and recompletions (US EPA, 2010). This percentage is based on legislation that requires flaring of completions in the State of Wyoming and the absence of such legislation in the States of Texas, New Mexico, and Oklahoma. The US EPA further notes that tight gas wells are not tracked by the US inventory and this could reduce the percentage of flared completions, based on the above methodology, to 15%.

Unconventional Well-completion Emission Factor: Similar to the Liquid unloading emission factor, the US EPA estimates an unconventional completion emission factor from 4 STAR Program Partner reports on reduced emission completions (RECs). These include:

1. Data from BP included in 2004 STAR program presentation, *Green Completions* (ExxonMobil et al., 2004)

   BP reported an annual loss of 45 Bcf of natural gas due to well-completion and workovers with an unknown venting/flaring rate in 2002. The US EPA attributed 0.3 Bcf of the total to low pressure conventional wells. Considering an estimated 12971 natural gas wells drilled in 2002 and assuming 60% of those are high pressure tight formation wells, the US EPA back calculated an emission rate of 44.7 Bcf/(0.6*12971)*10^6, which rounds to 6000 Mcf/completion.

2. Data from Devon Energy included in 2004 STAR program presentation, *Green Completions* (ExxonMobil et al., 2004)

   By implementing RECs at 30 shale gas wells in the Fort Worth Basin, Devon Energy reported 11900 Mcf/well of gas collected rather than vented. The US EPA rounds this data point to 10000 Mcf/completion.

3. Data from Weatherford Durango included in 2004 STAR program presentation, *Green Completions* (ExxonMobil et al., 2004)

   Weatherford Durango reported total gas savings of 2000 Mcf from a pilot project using REC on 3 coal bed methane wells. The US EPA calculation assumes 90% of the flowback gas is recovered to yield (2000/0.9)/3 = 740.74 Mcf/completion, which is rounded to 700 Mcf/completion.

4. 2007 STAR program presentations, *Reducing Methane Emissions During Completion Operations*. (US EPA, 2007)

   Data were reported from REC implemented on 426 tight gas wells in the Williams Fork formation in the Piceance Basin. In 2006, a total of 10863000 Mcf of gas was generated in 426 completions with a reported flowback gas recovery rate of 91.4%. Although the calculation is unclear, it appears the EPA used an average over the years 2002-2006 to compute 26014000 Mcf/1064 completions = 24449.25 Mcf/completion and then rounded down to 20000 Mcf/completion.

The average of the above 4 aggregate data points equals 9175 Mcf/completion which the US EPA subsequently converts to 176.7 t/completion. By directly averaging the data points, the US EPA is assuming shale gas wells, tight gas wells, and coalbed methane wells have equivalent flowback emissions. The results discussed in Chapter 5 suggest this is not generally true. As outlined above, the US EPA assumes that for 51% of completions and recompletions the gas is flared (US EPA, 2010). The slight difference in the well-completion emission factor for the US EPA 2011 inventory arises due to a difference in rounding in their calculations, where EPA "*rounded the potential emission factor for completions and workovers with hydraulic fracturing (refracturing), from 9,175 Mscf gas per completion/workover to 9,000 Mscf gas per completion/workover.*"(US EPA, 2013a).

2.2.2 US EPA Liquid Unloading Emission Factors

In the calculation of the 2010 revised emission factors, the US EPA did not account for reduced emission controls such as plunger lifts and assumed all liquid unloading events (also referred to as well cleanups) were blowdown events (U.S. EPA, 2010, pg. 90-91). However, the US EPA also assumed unconventional wells *did not* require liquid unloading (pg. 90).

The emissions per blowdown, V [Mcf/blowdown], are assumed to be proportional to the product of the well pressure, P [psi]; well depth, h [feet]; and the square of the casing diameter, D [inches] according to Eq. (1) (U.S. EPA, 2010, Exhibit B-7),

$$V = (0.37 \times 10^{-6}) D^2 h P. \qquad (1)$$

For an average pressure, depth, and diameter, the US EPA 2010 emission factor in Table 2.3 is computed by multiplying by the total number of blowdowns required by a well per year. The US EPA determined the number of well blowdowns per year to be 31, the average of aggregated data from the following two sources:

1. *Star Program Partner Update, Spring 2004* (US EPA, 2004):
   As reported in (US EPA, 2004), British Petroleum (BP) successfully installed a "Smart Automation Well Venting" system with plunger lifts on 2200 wells within the San Juan natural gas basin. The "smart" aspect of well venting system is a BP specific term referring to BPs proprietary control software. The control scheme uses past plunger lift cycle times and durations, gas well pressure, and sales line pressure to adapt to the changing well characteristics. BP reported gas savings of 4 Bcf/year over these 2200 wells.
2. *Installing Plunger lift Systems in Gas Wells: Lessons Learned for the Natural Gas STAR Partners* (US EPA, 2006):

As reported in (US EPA, 2006), plunger lifts were installed in 1995 on 2 gas wells in the ExxonMobil Big Piney natural gas field in Wyoming and subsequently on 17 additional gas wells in 1997. With the use of plunger lifts, Exxon reported a blowdown reduction of 12164 Mcf/year, from 17222 to 5058 Mcf/year vented.

Using the above high-level information contained in the Star Program Partner reports (US EPA, 2006; US EPA, 2004) in conjunction with Eq. (1), the US EPA back calculated the number of blowdowns/well required to equal the reported plunger lift gas savings. On this basis, they determined that the BP San Juan basin would have required 51 blowdowns/well and Big Piney would have required 11 blowdowns/well each year, which averaged to 31 blowdowns/well/year.

To compute a liquids unloading emission factor, the US EPA considered 35 gas basins representing 260694 conventional wells. The US EPA assumes that 41.3% of all conventional gas wells require liquid unloading (Shires and Harrison, 1996, Table 5-1) and that wells are vented for 3 hours after liquids are cleaned from the well. Within each basin the total number of well blowdowns per year was computed by:

$$(\text{Well count}) * (0.413\ [\%\ \text{requiring unloading}]) * \left(\frac{31\ \text{blowdowns}}{\text{well} \cdot \text{year}}\right). \tag{2}$$

The total methane emission per basin is then calculated using the volume per blowdown as defined in (1) and a methane content of 78.8%. Over the 35 basins, the US EPA determined a total methane emission of 149 Bcf/year or equivalently 11 t/well/year. Liquid unloading alone accounts for 51% of the US EPA estimated methane emissions from natural gas production (U.S. EPA, 2012a, Table A-129).

It is noted that the US EPA did not include liquid unloading emissions for unconventional wells when computing the 2010 US National GHG inventory. . However, in response to the API/ANGA activity data survey outlined in Section 2.3, the US EPA updated their liquid unloading emission factors and applied them to both conventional and unconventional wells in the 2011 US National Inventory (US EPA, 2013b; US EPA, 2013a). Both the 2010 and 2011 US EPA National Inventory liquid unloading emission factors are considered in Section 5.5.3 when comparing results of the present analysis with available information in the literature.

2.2.3 US EPA Workover (Re-fracturing) Emission Factor

For conventional wells, the 2010 revised emission factor is identical to the original EPA/GRI 1996 estimate of 2.454 Mcf of methane/workover (which equates to 0.047 t of methane/workover). For unconventional wells, the US EPA assumes that the emissions during workover are the same as for well-completion. The slight difference between US EPA 2010 and 2011 values is again due to a difference in rounding. For the 2010 GHG inventory, it was assumed that unconventional wells are re-fractured once every 10 years (US EPA, 2010). Based on activity data from the API/ANGA survey described in Section 2.3, the re-fracturing rate has been reduced from to 1% in the 2011 US National Inventory (US EPA, 2013a).

2.2.4 US EPA Centrifugal Wet Seal Compressors:

Emission factor data from centrifugal wet seal compressors are sourced from (Bylin et al., 2009) in the US EPA 2010 and 2011 inventories.

2.3 Industry Response to Revised 2010 US EPA Emission Factors - API/ANGA Survey

The data points and methodology used to calculate revised 2010 US EPA emission factors for unconventional gas systems have been questioned by industry, most notably in an IHS CERA report (Barcella et al., 2011). The IHS CERA report claims the US EPA emission factors for unconventional well-completion are incorrect and at odds with industrial procedures and safety practices. The report also questions the US EPA's direct averaging of well-completion data for unconventional wells (see Section 2.2 above), as well as the US EPA's flaring to venting ratio of 51%. The main underlying complaint of (Barcella et al., 2011) is that the US EPA emission factors for flowback and flaring are based on a finite dataset and do not account for the large variability in gas well properties across the national inventory.

In response to the revised EPA emission factors, the API and ANGA undertook a survey of member operators "in an attempt to provide additional data and identify uncertainty in existing data sets" (Shires and Lev-On, 2012). Whereas the revised EPA emission factors were largely based on the four STAR program workshops as discussed in Section 2.2, which draw on data from approximately 8800 wells of 488000 wells in the 2009 emission inventory, the API/ANGA survey results represent 91000 wells, covering 19 of the 21 American Association of Petroleum Geologists (AAPG) basins. These AAPG basins represent 92% of the total US EPA database, and as such these 91000 wells provide a geographically comprehensive data set. The compiled analysis of API/ANGA survey results (Shires and Lev-On, 2012) primarily outline industry activity data relating to liquid unloading, well-completion, and well re-completion rates for both conventional and unconventional gas wells. Each of these is separately discussed under the headings that follow. Although some have criticized the methodology of the API/ANGA survey (notably Howarth, Ingraffea, et al. (2012) who suggested the survey was biased since API/ANGA informed industry operators that the purpose of the survey was to dispute the revised US EPA emission estimates and provided the US EPA estimates directly in the survey questions), it is noted that the US EPA has incorporated key survey findings on liquid unloading emissions estimates and refracturing rates into their updated 2011 GHG Inventory calculations (US EPA, 2013a).

2.3.1 API/ANGA Survey Data on Liquid Unloading Practices

In contrast to the EPA assumption in the 2010 US National Inventory that liquid unloading is only relevant to conventional gas wells (see discussion of Table 2.3 in Section 2.2 above), the API/ANGA data implies that unconventional wells require liquid unloading. The API/ANGA data suggest that approximately 84% of the natural gas wells requiring liquid unloading used reduced emission controls (16% perform well blowdowns by venting to atmosphere).

However, the API/ANGA survey data also suggest that the average vent times during liquid unloading, either with or without plunger lifts, are less than that of the EPA assumption of 3 hours (Shires and Lev-On, 2012, Table 7). After removing data from wells with abnormally high liquid plunger lift unloading frequency, the API/ANGA survey data for the number of vents per well was comparable to EPA's assumed frequency. Liquid unloading emission factors in Table 2.4 can be subsequently calculated for conventional and unconventional wells, with and without plunger lifts using data reported in Tables C1, C2, C3, and C4 of (Shires and Lev-On, 2012).

Table 2.4: Liquid unloading emission factors [Mscf gas/well-year] derived from API/ANGA survey data reported in Tables C1, C2, C3, and C4 of (Shires and Lev-On, 2012)

	Conventional Wells	Unconventional Wells
With Plunger Lifts	974.8 (all data)	250.4
	20.6 (w/o outliers)*	
Without plunger lifts	104.4	486

*Excluding data from two responses "for operations with conventional wells reported very high frequencies of vents to the atmosphere. These data sets represent 174 gas wells with plunger lifts (out of a total 1140 gas wells with plunger lifts represented by the total data set) located in the Mid-Continent region. The wells represented by these data points have plunger lifts that vent to the atmosphere for each plunger cycle ... which results in very short venting durations (between 4 and 5 minutes) for each plunger cycle." **(Shires and Lev-On, 2012)**

Performing a weighted average of all *conventional* well data to directly compare with the US EPA 2010 National Inventory emission factor, which was only applied by US EPA to conventional wells in the 2010 Inventory, the API/ANGA data implies an average emission factor of 210.5 Mscf CH_4/conventional well/year which is 84% lower than the US EPA 2010 emission factor of 1316 Mscf CH_4/conventional well/year. However, while this emission factor is substantially lower, it is also noted that API/ANGA Survey Data suggest that liquid unloading emissions for unconventional wells would be more significant than for conventional wells and therefore should not be neglected as was done in the 2010 US National GHG inventory.

2.3.2 API/ANGA Survey Data on Well-completion Activities

The API/ANGA activity data covers 57.5% of national tight gas completions, 44.5% of national shale gas completion, and 7.5% of conventional gas completions. The data on well-completions are reproduced in Table 2.5 and are categorized by:

1. Region: Northeast, Gulf Coast, Mid Continent, Southwest, Rocky Mountain;
2. Well type: Conventional, Shale, Coal-bed, tight and unspecified; and
3. Well subtype:
    i. Hydraulically fractured: Vertical or Horizontal;
    ii. Non Hydraulic fractured.

Unfortunately the reported results of the API/ANGA survey (Shires and Lev-On, 2012) did not include any further information that could be used to verify, update, or suggest new emission factors for flowback. However, the activity data in Table 2.5 are illustrative of the differences among different categories of wells (i.e. shale gas, tight gas, and coalbed methane) that are commonly grouped under the single umbrella term of "unconventional wells".

Table 2.5: API/ANGA completion data for 2010 and the first half of 2011 (Shires and Lev-On, 2012)

	Conventional	Shale gas	Tight gas	Coalbed methane
Number of completions	540	2055	2528	33
Vertical wells with hydraulic fracturing [%]	59	14	81	82
Horizontal wells with hydraulic fracturing [%]	11	84	15	9
Wells without hydraulic fracturing [%]	31	1	4	9

2.3.3 API/ANGA Survey Data on Workovers (Re-completions):

The re-completion activity data of the API/ANGA survey reported in (Shires and Lev-On, 2012) provides a detailed look at workover rates among US natural gas basins. Compared to the US EPA assumption that 10% of all wells require workovers each year, the API concluded that each year only 1.6% of all previously hydraulically fractured wells are re-fractured. Interestingly, 99% of the unconventional wells requiring workovers in the API/ANGA data correspond to vertical wells. As apparent in Table 2.6, there were geographic variations in the data. In particular, wells in AAPG 540, a natural gas basin (DJ Basin) in the Rocky Mountain Region, were re-fractured at nearly twice the overall average rate. Gas wells in the AAPG 540 are predominately vertical tight gas wells with a unique geology that allows near original production rates after their re-completion (Shires and Lev-On, 2012). This increases the economic viability of workovers in the region and contributes to the uncharacteristically high rates in the AAPG 540 region.

Shires and Lev-On (2012) subsequently used the US EPA emission factor for well workovers to compute an overall emission volume based on API/ANGA refracturing rate data. This makes a significant impact on the estimated yearly methane emission estimate from natural gas wells resulting in a 72% decrease in the national methane emissions due to workovers, from 712 kt to 197 kt.

Table 2.6: Fraction of hydraulically fractured wells required workovers each year based on API/ANGA survey data (Shires and Lev-On, 2012)

<table>
<tr><th></th><th>Conven-tional</th><th>Shale gas</th><th>Tight gas</th><th>Coalbed methane</th><th>Un-specified</th></tr>
<tr><td>Hydraulically fractured workover rate</td><td>0.3</td><td>0.3</td><td>3.0 (All wells)
0.5 (without AAPG 540)</td><td>0.5</td><td>2.4</td></tr>
<tr><td>Unconventional wells</td><td></td><td colspan="4">2.2 (All unconventional wells)
0.5 (Unconventional Wells w/o AAPG 540)</td></tr>
<tr><td>All wells</td><td colspan="5">1.6 (All conventional & unconventional wells)
0.7 (All wells excluding AAPG 540)</td></tr>
</table>

2.4 Lifecycle Emissions from Natural Gas Systems

Lifecycle GHG emissions for unconventional natural gas have been estimated in numerous studies since the release of the 2010 revised US EPA methane emission factors for gas wells. The focus of most studies has been to quantify the additional GHG emissions from unconventional sources and then compare potential lifecycle emissions from the combustion of unconventional natural gas vs. combustion of coal. The results from six commonly referenced lifecycle studies are presented in Table 2.7.

A direct comparison of these numbers is difficult given that each study uses different base axioms, considers distinct natural gas basins, and considers different sets of contributing emission sources as detailed in Table 2.8. As previously stated, unconventional well emissions are heavily influenced by parameters such as:

- liquid unloading activity,
- well-completion emissions,
- workover (re-completion) rates,
- the use of emission mitigating practices (flaring, reduced emission controls/green-completions (RECs), plunger lifts), and
- the estimated ultimate recovery (EUR) of the well.

Moreover, apart from the fact that not all authors consider liquid unloading emissions for unconventional gas wells in their analyses, the large differences between the API/ANGA survey results for liquid unloading and workovers (See Section 2.3) and the 2010 US EPA emission factors used by many of the lifecycle studies is another reason for variation in results. The accounting of emissions from well-completions and workovers can also be notably different between lifecycle GHG studies, where the main difference is often the assumptions made about the amount of direct venting that occurs during the flowback stage of well-completion. Differences in the choice of time-horizon (e.g. 20- or 100-year) as well as the magnitudes of global warming potentials (GWP) used in calculations can also significantly influence results. Further context for the studies cited in Table 2.7 and Table 2.8 that have not already been discussed in detail is provided under the headings that follow.

Table 2.7: Overview of lifecycle studies

		Howarth et al., 2011 ("Howarth Study")	Skone et al., 2011 ("NETL Report")	Jiang et al., 2011 ("Carnegie Mellon Study")	S&T consultants, 2011 ("NRCan Report")	Fulton et al. 2011 (Deutsche Bank Report)	Wood et al. 2011 (Tyndall Centre Report)
Gas basin/play		-Haynesville (Louisiana) -Barnett (Texas) -Denver-Julesburg (Colorado)) -Piceance (Colorado) -Uinta (Utah)	Barnett-Woodford(Texas)	Marcellus (New York)	-Horn River (British Columbia) -Montney (British Columbia)	Top down study using EPA, EIA inventory numbers.	Marcellus (New York)
Additional emissions over conventional		≥30%	?	3%	3.8%	11%	0.2-2.9%
Methane global warming potential (GWP)	20 years	105	72	NA	NA	72-105	NA
	100 years	33	25	25	NA	25	NA
Comparison units		gCO2e/ unit of energy	gCO2e/ unit of electricity	gCO2e/ unit of electricity	gCO2e/ unit of electricity	gCO2e/ unit of electricity	gCO2e/ unit of energy
Conversion and efficiency	Coal	NA	35.1% Avg. with 9708 Btu/kWh	38% PC 39% IGCC	NA	31% Avg. with 11044 Btu/hWh	NA
	gas	35.7 MJ/m^3	53.4% Avg. with 6387 Btu/kWh	50% NGCC	NA	41% Avg. with 8044 Btu/kWh	35.6 MJ/m^3
Emissions compared to Coal	20 years	≥20%	-39%	NA	NA	≤-27%	-37% to -39%
	100 years	-18% to 15%	-52%	-40.5% to -47%	NA	-47%	

Table 2.8: Comparison of emissions factors for completion and workover of hydraulically fractured wells used in various publications†

	US EPA	Howarth et al., 2011 ("Howarth Study")	Skone et al., 2011 ("NETL Report")	Jiang et al., 2011 ("Carnegie Mellon Study")	S&T consultants, 2011 ("NRCan Report")	API/ANGA Survey
Emission factor (EF) source	-Computed using REC data from US EPA STAR partner workshops. -section 2.2	-Computed using REC data from US EPA STAR partner workshops. -Includes source data used to update the US EPA EF. -Section 2.4.1	-Modified US EPA EF to reflect less flowback from lower pressure wells. -US EPA EF used for shale wells. -Section 2.4.2	-Assumes range of model inputs for a Monte Carlo based analysis. - Section 2.4.3	-Not explicitly stated -Based on the Horn River basin -Section 2.4.4	-US EPA EF -Activity data from survey for workover rate -Section 2.3
Well categories	No distinction between tight gas and shale gas wells.	No distinction between tight gas and shale gas wells.	-Shale gas -Tight gas -CBM	-Marcellus shale	-Horn River shale	-Shale gas -Tight gas -CBM
Units per completion	Mcf CH_4	% of EUR	Mcf CH_4	Tonnes CH_4	NA	Mcf CH_4
Completion EF	9175	-1.9 -Includes venting during drillout	-Shale: 9175 -Tight gas: 3670 -CBM: 49.57	-26 to 1000 with a mean of 400. -US EPA EF equiv. is 177	-Not stated -No direct venting	9175
Liquid Unloading	Only for conventional wells	Both conventional and unconventional wells	Only for conventional wells	Not considered	Both conventional and unconventional wells*	Both conventional & unconventional wells
Workovers EF	Same as completion	NA	Same as completion	NA	NA	Same as completion
Workover rate per year	10% of all hydraulically fractured wells	NA	0.118 workovers/well	NA	NA	1.6% of all hydraulically fractured wells
% flared	51%	No	Shale: 15%; Tight gas: 15%; CBM: 51%	51% to 100%; base case 76%	NA	NA
REC gas recovery	-Covered by 51% flaring assumption and reported STAR partner voluntary REC use.	No – pure venting	No – flared and/or vented	No – flared and/or vented	Yes – 100% of flowback gas is flared or sent to sales line but flare emissions not incl.	NA

*Well testing and servicing were assumed to be the same as for conventional wells.

†Two often quoted studies are necessarily excluded from this table since they lack sufficient detail. Deutsche Bank Fulton et al. 2011is a top down study that does not explicitly compute completion emissions. Tyndall Centre, Wood et al. 2011 does not consider flared or vented completion emissions.

2.4.1 Howarth et al., 2011 ("Howarth Study")

The "Howarth Study" (Howarth et al., 2011) was perhaps the first to use the revised 2010 US EPA emission factors to compare lifecycle emissions of unconventional and conventional gas wells. Their analysis concluded that methane emissions from unconventional hydraulically fractured wells were at least 30% greater than for conventional wells. This comparison was based on the lifetime production estimates or estimated ultimate recovery (EUR) of each natural gas well. EUR estimates are highly uncertain (U.S. EIA, 2012) and are constantly being revaluated, which can often account for differences among lifecycle studies (Hughes, 2011).

Using updated global warm potential (GWP) data for methane of 33 and 105 on 20- and 100-year time scales respectively as cited from (Shindell et al., 2009), Howarth et al. (2011) also compared unconventional gas well lifecycle emissions to those of coal-derived energy on a gCO2e per unit of energy basis. They concluded that the lifecycle emissions of unconventional gas were at least 20% greater than that produced by coal on a 20-year time scale and between 18% less (deep-mined) and 15% greater (surface-mined) on a 100-year time scale. This controversial conclusion spawned rebuttals by (Cathles et al., 2012; Barcella et al., 2011), and indirectly by (Skone et al., 2011) as further discussed in Section 2.4.2. Howarth et al. subsequently published a rebuttal to (Cathles et al., 2012) standing by their approach and findings (Howarth, Santoro, et al., 2012).

2.4.1.1 Summary of key assumptions in the "Howarth Study"

Howarth et al. fugitive emissions: The Howarth study categorized well flowback and drillout emissions from unconventional wells as vented fugitives and estimated that these activities combined for an emission factor of 1.9% of the estimate ultimate recovery (EUR) of a well. The Howarth study relied on well-completion data reported during US EPA STAR program workshops to estimate well-completion emission volumes and additionally used a variety of publicly available online media to source EUR volumes for different gas formations. In particular, Howarth focused on 2 shale gas and 3 tight gas formations as outlined in Table 2.9.

Table 2.9: Estimated magnitudes of well flowback and drillout emissions and EUR data for five formations used in the analysis of (Howarth et al., 2011)

Formation	Completion Venting [1000 m^3 CH_4]	Estimated Ultimate Recovery (EUR) [1000 m^3 CH_4]	Vented CH_4 [% of EUR]
Haynesville (Louisiana shale)	6800[a]	210000[b]	3.2
Barnett (Texas, shale)	370[c]	35000[d]	1.1
Piceance (Colorado, tight gas)	710[e]	55000[f]	1.3
Uinta (Utah, tight gas)	255[g]	40000[h]	0.6
Denver-Julesburg (Colorado,tight gas)	140[i]	NA	NA

[a] Reported as the average of flowback emission reported in "IHS US industries highlights February-March 2009". This document appears to be no longer available online. However an excerpt of the original document is contained in Appendix 2 of (Barcella et al., 2011)

[b] The EUR of Haynesville wells is sourced from an internet blog pertaining to investment opportunities in the Haynesville formation. The provided link, http://shale.typepad.com/haynesvilleshale/decline-curve/, contains excerpts from a conference call on Petrohawk Energy Corporation's second quarter earnings with the full transcript is available at http://seekingalpha.com/article/218425-petrohawk-energy-q2-2010-earnings-call-transcript?part=single. It is not clear which volumes where averaged to obtain the stated EUR.

[c] Based on the reference, *Green Completions* (ExxonMobil et al., 2004), the Barnett shale formation corresponds to the Devon Energy Experience in the Fort Worth Basin. However, in this presentation the averaged captured gas from well-completion is stated as 11900 Mcf of gas which is equivalent to 336 970 m^3 rather than 370 000 m^3.

[d] This EUR is contained in the July 2002 issue of Explorer, an American Association of Petroleum Geologists publication, http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm.

[e] As outlined in Section 2.2.1, the reported average volume captured during well-completion was 24449.25 Mcf/completion in the Piceance (Colorado) (US EPA, 2007). This converts to 692330 m^3 rather than 710000 m^3; it is possible the Howarth study calculates the average volume using a different methodology.

[f] The EUR data in (Kuuskraa and Ammer, 2004) states 1.4 Bcf to 2.5 Bcf per well for the William Fork formation in the Piceance Basin. The average of these two number 1.95 Bcf converts to 55218000 m^3.

[g] The average of the estimated Methane captured per well-completion over the years 2005 to 2010 in (Samuels, 2010) equates to 9109.6 Mcf or 257.9 m^3.

[h] Exploration and Production magazine, http://www.epmag.com/archives/newsComments/6242.htm, provides a EUR of 1.563 Bcf over a 25-year life for a typical well in the Uinta Basin.

[i] The average of the estimated Methane captured per well-completion over the years 1998 to 2005 in (Bracken, 2008) is 4800 Mcf or 135.9 m^3.

Volumes of vented flowback emissions listed in Table 2.9 were assumed to be equivalent to the volumes of recovered reservoir gas collected during the green-completions as reported at the STAR partner 2004 (ExxonMobil et al., 2004) and 2007 (US EPA, 2007) workshops. These are the same references on which 2010 US EPA emission factors were based. Finally, Howarth et al. (2011) estimated methane emissions during well-completion to be 1.6% of the EUR, the mean value of the emission range 0.6% to 3.2%.

The drillout emissions were computed from the average of 5000 to 15000 Mcf vented per drillout as reported in a 2007 US EPA STAR program workshop, *Reducing Methane Emissions During Completion Operations* (US EPA, 2007). The emission percentage was then calculated using an average EUR from the above shale and tight gas formations, i.e. 0.33% = 10000 Mcf/(3001700 Mcf)*100.

For conventional wells, the completion emissions were based on 2007 well-completion activity factors found in (US EPA, 2010) and the updated well-completion emission factor of 36.65 Mcf of methane/completion as outlined in Section 2.2.1. The methane emissions from 19819 conventional well-completions in 2007 was 19819 completions*36.65 Mcf CH_4/completion = 726366.35 Mcf or 20568000 m^3 of CH_4. The Howarth study then converted this to a natural gas volume of 26 x 10^6 m^3 by assuming a 78.8% methane content and dividing by 384 x 10^9 m^3, the total onshore conventional gas production in 2007, to obtain an estimate of well-completion emissions equal to 0.01% of EUR (apparently rounded up from 0.0067%). .

Howarth et al. liquid unloading: As outlined in Section 2.4, liquid unloading requirements of unconventional wells are not universally agreed upon. The Howarth study acknowledged this fact by applying a range of liquid unloading emissions to unconventional wells from 0 to 0.26% of the EUR. Although Howarth cited the United States Government Accountability Office (US GAO, 2010), the calculation of this range is unclear from the values available. For the purposes of the lifecycle analysis these losses were applied equally to both conventional and unconventional gas wells.

Howarth et al. re-facture rate (workovers): Howarth et al. (2011) did not consider re-fractures.

Howarth et al. routine leaks and venting: This category consisted of well pad gas processing and included the separation of liquids and other raw gases to produce sales line quality natural gas. These processes may include dehydration, H_2S removal (sweetening), and CO_2 removal. The Howarth study used US EPA emission factors for field separation equipment (heaters, dehydrators, etc), gathering equipment (compressors), pipelines, condensate tanks, and other onsite equipment. Howarth et al. stated that leaks and venting ranged from 0.3% to 1.9% of the EUR of a well and referenced (US GAO, 2010). These losses were applied equally to both conventional and unconventional gas wells.

Howarth et al. gas processing: A range of 0 to 0.19% was proposed to account for processing done at large refineries (Shires et al., 2009). These losses were applied equally to both conventional and unconventional gas wells.

Howarth et al. transportation/piping/distribution: A range of 1.4% to 3.6% was given, with the lower value based on measurements along Russian pipelines (Lelieveld et al., 2005). The authors mentioned that this was comparable to the US loss but they did so without reference. The high value was based on the (Percival, 2010) article about unaccounted for natural gas in Texas. The high value of 3.6% was the average of 2.75% from 2000 Texas data and 4.91% from 2007 data, and would imply a loss of more than 1 Billion dollars in natural gas per year. However, the (Percival, 2010) article actually suggests that this gas is not actually lost as emissions and is in fact mis-measured volumes of gas from wellhead to pipeline by operators. The errors accumulate through stages of compression, removal of other gases, extraction of liquids and final round off errors between volumetric measures at the wellhead and the heating value measurement at which the processed gas is sold.

Based on the above sources, Howarth et al. (2011) estimated that total GHG emissions from unconventional wells sum to 3.6% to 7.9% of their EUR and GHG emissions from conventional gas wells sum to 1.7% to 6.0% of their EUR.

2.4.2 National Energy Technology Laboratory Lifecycle Analysis (Skone et al., 2011)

The National Energy Technology Laboratory (NETL) lifecycle analysis (Skone et al., 2011) was published 6 months after the Howarth study. As reported by (Hughes, 2011) in his comparative analysis of the two studies, the NETL study (Skone et al., 2011) was based on a presentation that is seen by some as a direct rebuttal to (Howarth et al., 2011). It is worth noting that (Hughes, 2011) is critical of the NETL study analysis and the veracity of the input lifecycle parameters.

The NETL lifecycle analysis includes emissions from onshore conventional and unconventional gas wells, as well as emissions from offshore production. The lifecycle is split into extraction, processing, pipeline transport, energy conversion, and distribution to the end user. The analysis compared GHG emissions from base load natural gas power plants to those from coal-fired plants. Thus, the analysis did not capture peak load situations where lower efficiency power plants may be utilized which would decrease the overall average efficiency of the natural gas plants (Hughes, 2011). The conversion efficiency for natural gas to electricity was assumed to range between 46.5% to 53.4% and 30.8% to 35.1% for coal.

2.4.2.1 Summary of key assumptions in the "NETL Report" (Skone et al., 2011)

NETL flare venting ratio: Based on the (US EPA, 2010), the NETL analysis assumed that 51% of gas released during completions, workovers, and liquid unloading of conventional wells was flared. For unconventional sources, it was assumed that 15% of gas released from well-completions and workovers was flared (Skone et al., 2011, Table 4-1), and liquid unloading emissions from unconventional wells were not considered. For all wells, gas associated with acid removal and dehydration processing was assumed to be 100% flared.

NETL fugitive emissions: As part of the gas extraction process for unconventional wells, the NETL report considered fugitive emissions released during the flowback period of a well-completion. The US EPA emission factor for unconventional wells of 9175 Mcf / completion (78.8% CH4) was adjusted in the NETL analysis to account for different reservoir gas pressures. The following well-completion emission factors were then assigned:

- Shale gas: 9175 Mcf /completion (78.8% CH_4)
- Tight gas: 3670 = .4*9175 Mcf /completion (78.8% CH_4).
  NETL argued from their own survey (although it is noted that no supporting data are provided) that tight gas wells across the US generally have lower pressures than the wells used in the US EPA analysis, and on this basis they multiplied the US EPA factor by 0.4 prior to applying it to tight gas wells. They further estimated that the EUR of tight gas wells is 40% that of shale gas wells in the same basin, 1.2 Bcf vs. 3 Bcf respectively. It should be noted that the choice of EUR is a very influential assumption in the analysis. Hughes (2011) suggests that the EUR in the Barnett Shale region could actually be as low as 0.84 Bcf/well and critically notes that with an EUR of 0.84 Bcf/well the NETL total

vented emissions as a percentage of EUR are in fact greater than those presented by Howarth et al. (Howarth et al., 2011, see electronic supplementary materials).

- Coalbed methane: 49.57 Mcf/well (as used by the US EPA in (US EPA, 2010) for low pressure well-completions).

NETL liquid unloading: Liquid unloading was considered only for conventional wells and the revised US EPA 2010 National Inventory emission factors were used. While the 2010 US EPA conventional well emission factor was much higher than a comparable emission factor for conventional wells inferred from the API/ANGA Survey data (see Section 2.3.1 above), by neglecting liquid unloading at unconventional wells the NETL study may still be under estimating emissions given that the API/ANGA survey data suggests unconventional wells require liquid unloading and apparent emission factors are potentially higher for liquid unloading at unconventional wells vs. conventional wells (See Table 2.4 above).

NETL re-facture rates (workovers): The NETL report uses the US EPA revised emission factors for workovers with re-fracture rates of 0.037 and 0.118 workovers/well/year for conventional and unconventional wells respectively. These rates were based on US EPA activity estimates for 2007 (US EPA, 2010) and differ from the US EPA numbers due to a choice of rounding.

NETL Routine leaks and venting: For both gas extraction and processing, the NETL report included "other point source emissions," "other fugitive emissions," and "valve fugitive emissions" as routine leaks and venting sources. Point source emissions included wellhead and gathering equipment releases that are flared. In addition, under processing, the report considered acid gas removal (sweetening), dehydration, and centrifugal/reciprocating compressor emissions which amounted to 2.3% of total emissions (Skone et al., 2011, Table 3.1). All calculated values were based on data found in (US EPA, 2010).

2.4.3 Jiang et al. (2011) (Carnegie Mellon study)

Jiang et al. (2011b) considered GHG emissions from natural gas production in the Marcellus shale basin. Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) were converted to CO_2 equivalents using International Panel on Climate Change's (IPCC) global warming potential

(GWP) factors for a 100-year time horizon (IPCC, 2007). The lifecycle analysis included emission sources from well development, gas production, gas processing, transmission, distribution, and gas combustion. The Marcellus shale well development GHG sources included:

- well pad preparation (removal of vegetation);
- well drilling (energy consumption);
- water usage and transportation for hydraulic fracturing;
- pump energy consumption for fracturing;
- well-completion flowback and flaring; and
- water disposal by deep well injection.

2.4.3.1 Summary of key assumptions in Jiang et al. (2011)

Jiang et al. (2011) flowback emissions: The study allowed for a range of values on many of their models' input parameters. The GHG emissions, mainly methane due to the assumption that Marcellus shale gas is 97.2% methane (Jiang et al., 2011a), was given as 26-1000 tCH_4 per completion with a mean value of 400. In comparison, the US EPA revised emission factor is 177 tCH_4 per completion. The input parameters associated with flowback included:

- Flaring duration:
  - 12 to 24h (base case is 18h) for wells with a pipeline in place.
  - 4 to 15 days, base case is 9.5 days, for wells with no pipeline gas gathering system in place.
- Gas release rate during completion, assumed equal to the initial 30 day production rate of 0.7-10 MMscf/well with a base rate of 4.1 MMscf/well.
- Flare fraction, assumed to range from 51% to 100%, with a base case at 76%

Jiang et al. (2011) other emissions: Emission from production, transmission, distribution, and combustion were assumed to be the same as the average domestic gas estimates provided by (Jaramillo et al., 2007) and further expanded in (Venkatesh et al., 2011). The mean GHG emissions for production; processing; transmission and storage; distribution; and combustion are 9.7 g CO_2e/MJ; 4.3 g CO_2e/MJ; 1.4 g CO_2e/MJ; 0.8 g CO_2e/MJ; and 50 g CO_2e/MJ, respectively.

Jiang et al. (2011b) concluded that in the worst case, with a five year well lifespan, the Marcellus shale gas well development GHG emissions accounted for less than 15% of the total lifecycle emissions. They concluded that overall, Marcellus shale gas adds only 3% more emissions to the average conventional well emissions. However, the study did not include fugitive emissions from well drilling, drill out, liquid unloading, or workovers (re-fracturing).

2.4.4 S&T Consultants Report, 2011 (NRCan Report)

This report focused on GHG emission from shale gas in the Horn River basin of British Columbia for the purpose of updating the Natural Resources Canada GHGenius model. An overview of lifecycle GHG emissions from conventional wells was presented based directly on Canadian Association of Petroleum Producers (CAPP) 2004 emission factor data (CAPP, 2004a), which are shown in Table 2.10. However as explained in the table and footnotes, there appear to be a few minor errors in both the CAPP document (i.e. addition/transcription errors as noted) and in the S&T Consultants Report (i.e. apparent interpretation error related to the CAPP report minor errors).

To estimate emissions from shale gas production ((S&T)2 Consultants Inc., 2011) used data from two drilling operations, stating:

> *"For this work some actual energy and emission data was received for two drilling operations. This is a very small sample and the two operations each provided partial information, but the data can be compared to the average natural gas emission information described in the previous section"*

The location, number of wells, and type were not explicitly stated.

Table 2.10: CAPP 2004 Emission Factor Data from (CAPP, 2004a) **based on Year 2000 Data**

Emission source	Conventional gas wells [t/well]				Notes and comments
	CO_2	CH_4	N_2O	CO_2e	
Well drilling	61.1	0.023	0.005	63.3	20566 wells drilled CO_2e 1301000/20566=63.3 CO_2 1257000/20566=61.1 [a] CH_4 466/20566=0.02265 N_2O 113/20566=0.00549
Well servicing -rig servicing -pumping units -blowdowns/ liquid unloading	15	0.51	0.0018	26.3 28.3 NRCan[b]	CO_2 309000/20566=15.02 CH_4 10520/20566=0.51152 N_2O 38/20566=0.001847 CO_2e 541000/20566=26.3[c]
Well testing	42.7	0.24	0.0	47.7 48.7 NRCan[b]	CO_2 878000/20566=42.6918 CH_4 4932/20566=0.2398 N_2O 0/20566=0 CO_2e 981000/20566=47.7

[a] There is a minor addition error in CAPP 2004, Table A, Page36,which incorrectly sums the total CO2 emissions for well drilling as 1247 kt rather than 1257 kt. However, all amounts are correctly carried forward when calculating CO_2eq emissions on page 35.

[b] The S&T Consultants Report corrects the calculation of CO_2 equivalent emissions to use the more recent IPCC GWP value for CH_4 of 25 (IPCC, 2007) rather than the legacy value of 21 used in the CAPP 2004 National GHG Inventory.

[c] Note that Table A, Pg 34, appears to miscategorize 220 kt CO_2e under flaring during blowdown treatments rather than under venting. Table A, pg. 38, specifies that 10471 tonnes of CH_4 were vented during blowdowns, which using a GWP value for CH_4 of 21 (as is used throughout the CAPP 2004 document), equates to 220 kt of CO_2e. This apparent incorrect categorization is copied in ((S&T)2 Consultants Inc., 2011) on page 10, Table 2 and below, to incorrectly conclude that gas during blowdowns was flared and reported venting was insignificant. However, since data are presented on a CO2e basis, the calculated GHG emissions should be unchanged.

2.4.4.1 Summary of key assumptions in S&T Consultants Report, 2011 (NRCan Report)

NRCan well drilling: The combustion of natural gas, gasoline, and diesel for drilling, fracturing fluids production/disposal, fracturing, and logistics of moving site equipment and material was tabulated for the Horn River drilling operation. The report states that the data did not suggest that venting or flaring emissions were significantly different than conventional wells. Again, no explicit calculations/numbers were provided to support this.

NRCan drillout: The NRCan report assumed all gas was flared based on practices in Horn River British Columbia.

NRCan flowback emissions: ((S&T)2 Consultants Inc., 2011) argued that the EPA data, as outlined in Section 2.3, was not applicable to Canadian gas plays. Their rational for this conclusion was based on:

- Their assumption that bridge plugs are universally used in Horn River and with these plugs there is no flowback between fracturing stages;
- Their assumption that the plugs are drilled out using coil tubing and flowback is directed through tanks to separate out water and sand, and recovered gases are subsequently directed to a flare or into a pipeline for processing; however, no flaring rate or emissions due to flaring is explicitly stated. From ((S&T)2 Consultants Inc., 2011), Table 5-1, it is apparent that emissions are assumed to be the same as for conventional wells.
- The assumption that there is no open pit flowback or "cold venting" in Horn River. Cold venting is an industry term referring to the mechanical separation of the flowback fluid and gas by perforated grates and baffles where the gas is subsequently vented to atmosphere.

However, while the above measures should certainly allow for full gas recovery if universally applied, they would not necessarily change the total volumes of gas produced during completion. While ((S&T)2 Consultants Inc., 2011) correctly argue that the flaring/venting ratio assumptions in EPA are out of line with industry practice, this is not relevant if the US EPA emission factors are simply used to estimate produced gas volumes prior to application of any GHG mitigation technology such as flaring or collection into pipelines.

NRCan liquid unloading: The NRCan report ((S&T)2 Consultants Inc., 2011) assumed the emissions for well servicing and testing were the same as for conventional wells.

NRCan gas processing: The energy required for site processing of the gas such as dehydration and compression was specified as 2.2% of the gas processed for conventional wells. The NRCan report assumed this also applied to shale gas wells. It is noted that the two cited drill operations provided estimates of 2% and 4% of the gas is consumed for production. Horn River shale gas also contains high levels of CO_2 (up to 12%) which is removed after transportation to a gas processing plant. However, this is less of an issue in the Montney field which reports CO_2 levels of 1%. The total energy consumption associated with such processing is estimated to range from

1% to 4% of the gas produced. For their model they assumed that the energy consumption for gas processing was 3.5% of production for shale gas (as compared to 3.16% for conventional gas), with a loss rate during processing of 0.27% in both cases.

((S&T)2 Consultants Inc., 2011) concluded that for shale gas with an average CO_2 content of 6.4%, GHG lifecycle emissions were 3.8% higher than for conventional gas, measured in CO2eq/GJ of fuel energy (at burner). This is attributed mostly to a high CO_2 content in Horn River shale gas and higher combustion emissions due to increased drilling depths.

2.4.5 Wood et al. 2011 (Tyndall Report)

Wood et al. (2011) is a top down study that considers the risks and benefits of shale gas development in the United Kingdom. The conclusions were mainly drawn from US-based data for the Marcellus shale basin. The analysis assumed that the end uses and distribution of unconventional gas were the same as conventional gas and focused on the differences in GHG emissions coming from extraction and production processes. Fugitive emissions, venting, and flaring during well-completion were not considered.

The additional GHG emissions associated with the production of unconventional natural gas sources were attributed to combustion of fossil fuels, fugitive emissions, and venting that occur during the life of the well. The combustion of fossil fuels occurs at all stages on well development and production. The analysis considered the combustion of fossil fuels mainly for diesel-powered equipment used for:

- land clearing and road building between well pads;
- drilling, pumps for hydraulic fracturing, and compressors for on-site gas processing; and
- the transportation of resources, equipment, and wastes by truck on and off site.

The overall GHG emissions from combustion for unconventional wells are generally viewed to be higher than for conventional gas resources. As shown in Table 2.11, the main contributor is the fuel required to pump the fracturing fluid during well-completion. Wood et al. (2011) concluded that for a Marcellus shale gas well, based on one fracturing process, the combustion of fuel by the hydraulic fracturing pumps amounts to 295 tonnes CO_2e per well. This is 67% to 85% of the total additional combustion emissions over conventional wells from that same basin.

Table 2.11: Additional emissions from shale extraction as specified in the Tyndall Report (Wood et al., 2011)

	Combustion [t CO_2e]	Assumptions
Horizontal drilling	15-75	Horizontal drilling 300-1500m, does not include vertical drilling component
Hydraulic fracturing and flowback	295	109777 liters of diesel fuel per 8 well leg well pad
Transportation of water	26.2-40.8	Based on heavy ground vehicle emissions
Brine transportation	11.8-17.9	Based on heavy ground vehicle emissions
Waste water treatment	0.33-9.4	Based on 9-80% of recovery of fracturing fluid
Total	348-438	Based on one fracturing process

2.5 Summary of Available Emission Factors and Lifecycle Analyses

From the preceding detailed literature review it is apparent that there are a number of shortcomings in available data for unconventional gas production that complicate any emissions analysis. Most current analyses draw in whole or in part on available US EPA 2010 National Inventory emission factor data. However because many key emission sources are not directly measured or are not universally reported, and many key operational practices are not fully tracked, there is necessarily a great deal of uncertainty in these data. In particular, the duration and flow rates of gas during flow back; the frequency of liquid unloading events and the volumes of gas released during liquid unloading; and the rate of use and effectiveness of flares and reduced emission completion technologies are all uncertain and all have significant impact on overall emission rates.

When using these data in lifecycle analyses, several additional complications arise. Since most of these analyses aim to make comparisons on a per unit energy basis over the lifetime of a well, the total volume of gas produced over the lifetime of the well (Estimated Ultimate Recovery, EUR) is a critically influencing parameter that is seldom known, and often held confidential or proprietary by an operator. As discussed above, (Hughes, 2011) effectively argued that the disparate conclusions of (Howarth et al., 2011) and (Skone et al., 2011) could essentially be made to overlap by adjusting the assumed EUR. Differences in assumed time horizons for climate forcing (typically 20- or 100-years) as well as differences in specific GWP values used in calculations are also important to consider, especially given that coherent arguments can be made for a combination of approaches in any single analysis.

Finally, for the purpose of quantifying emissions associated with unconventional gas production in Canada, there are additional challenges regarding the lack of data derived from Canadian operations. While many operations are likely to be sufficiently consistent throughout the North American industry to enable combined analysis, as revealed in the API/ANGA survey data (Shires and Lev-On, 2012), some specific operational practices vary by region (e.g. significantly higher rates of liquid unloading in Rocky Mountain AAPG region 540). Similarly, as discussed in the following analysis of Alberta data for 2011, venting is much less prevalent and flaring much more prevalent during well-completions in Alberta as compared to current US EPA assumptions. Thus, the primary purpose of the present analysis was to conduct an exhaustive analysis of available Alberta-based well activity and production accounting data to glean fresh information on emissions for unconventional gas production in a Canadian context.

3 ANALYSIS OF ALBERTA 2011 WELL ACTIVITY DATA: IDENTIFICATION OF TYPES AND NUMBERS OF HYDRAULICALLY FRACTURED WELLS

3.1 Primary Data Sources

Two main data sources were used in this inventory study: the Alberta Energy Resources Conservation Board's (ERCB) general well data file (GENWELL) and the Petroleum Registry of Alberta (PRA) 2011 volumetric facility activity report. As detailed in this chapter, a base set of hydraulically fractured natural gas wells completed in 2011 were first identified, primarily using the ERCB's GENWELL data file. This set of wells was subsequently linked with the PRA activity report, which was then used to assign flaring and venting volumes at the well-level as detailed in Chapter 4.

3.1.1 The ERCB General Well Data File

The ERCB GENWELL data file consists of 15 reports which combine into roughly 6.9 million lines of data as of January 31, 2013. The present analysis draws primarily on the reports outlined in Table 3.1.

Table 3.1: GENWELL data file reports

Report number	Name
005	Licensing Data
010	Drilling Occurrence Data
035	Tour-Directional Drilling Data
055	Tour-Perforation/Treatment Data
070	Well Status History Data

The database is keyed using a unique well identifier (UWI) for each drilled surface-hole or well leg. A UWI is a 16 character code based on the Dominion Land Survey System of Alberta and defines the approximate geographical bottom-hole location of the licensed drilling event. For example, 100043306018W500 is composed of ten substrings, 1-00-04-33-06-018-W-5-0-0, denoted by SS-LE-LSD-SC-TWP-RG-W-M-P-ES which correspond to a survey system, a location exception code, a legal subdivision, a section, a township, a range, the string “W” for “west of,” a meridian, a padding character, and an event sequence code, respectively. The survey system in Alberta is denoted by SS and is set equal to 1. A spatial representation explaining the location of UWI 1-00-04-33-06-018-W-5-0-0 is provided by Figure 3.1.

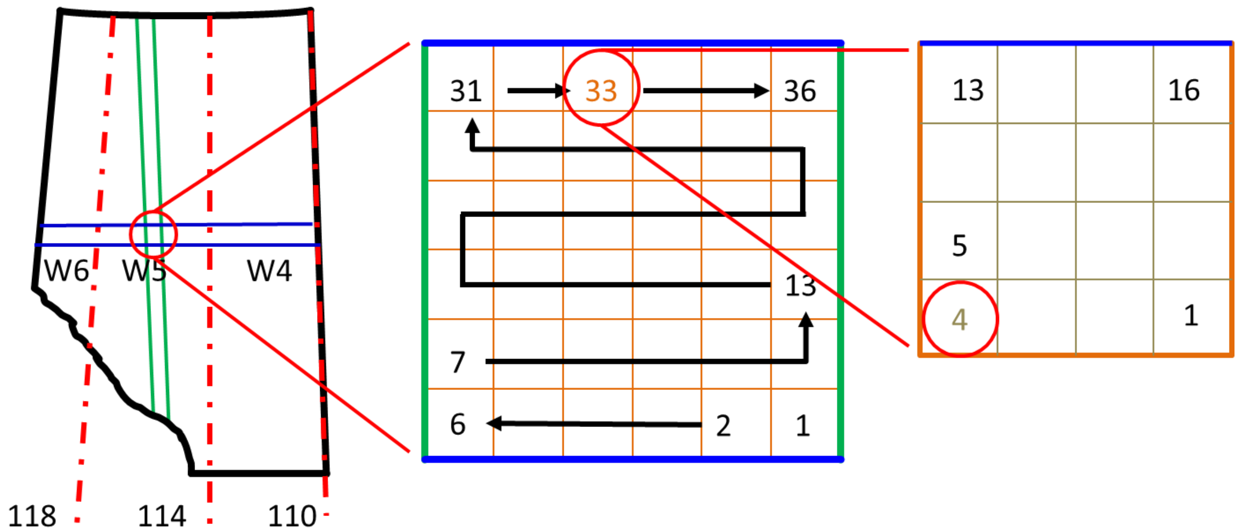

Figure 3.1: A spatial representation of UWI 1-00-04-33-06-018-W-5-0-0. Alberta is divided into three regions (W4, W5 and W6) by meridian lines of longitude (red dashed-dotted lines in left figure). The UWI corresponds to a location within legal subdivision 04 (right figure), which is one of 16 legal subdivisions within section 33 (middle figure), which is one of 36 sections defined at the intersection of range 018 (green lines) and township 06 (blue lines), which are located west of meridian 5

Within the ERCB database, the survey system, padding character, and the “W” for “west of” are dropped and UWIs are represented by the reordered substrings TWP-M-RG-SC-LSD-LE-ES. Following the above example, 100043306018W500 reduces to 0605183304000.

From an emission estimate point of view, it is important to make the distinction between the use of “per well” and “per UWI”. A well, as shown in Figure 3.2, is a structure (hence a "well structure") that consists of one or more drilled legs, each of which is represented by a UWI. In some instances, a single vertical well leg may be assigned more than one UWI if it passes through more than one distinct geologic formation. A detailed description of how a UWI is assigned to a drilling event is available in ERCB’s Directive 59, *Well Drilling and Completion Data Filing Requirements*, (ERCB, 2012a).

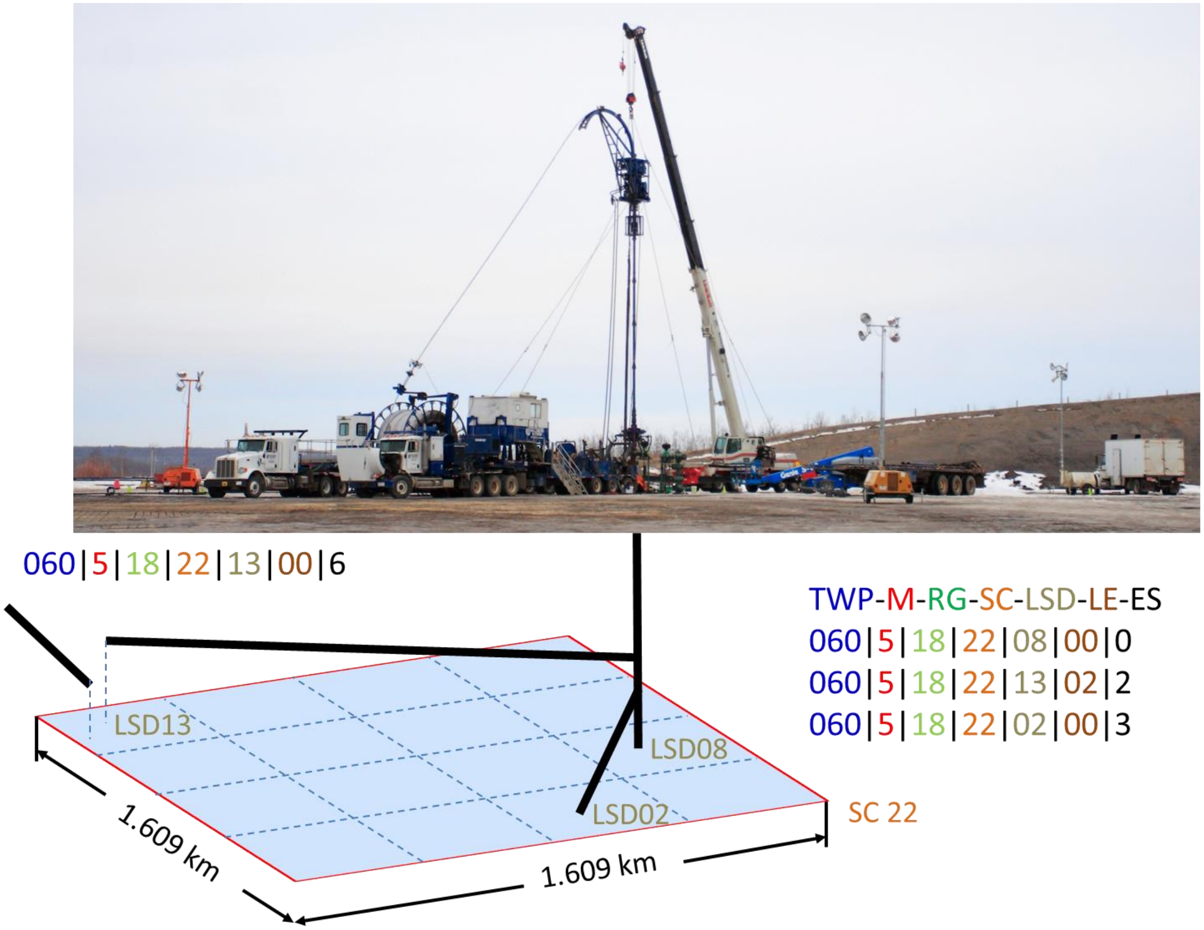

Figure 3.2: A depiction of a fictional well structure in Alberta located west of meridian 5 consisting of three UWIs that bottom in the legal subdivisions 02, 08, and 13 of section 22 as defined by township 60 and range 18. The horizontal leg requires a location exception code as it is the second hole to bottom in LSD 13

3.2 Derived Datasets and Reports for Alberta 2011

In this section, datasets and their subsequent quantitative reports are derived from the ERCB's GENWELL data. A summary of derived data is contained in Table 3.2 and their position in the overall workflow with respect to emission estimates is shown in Figure 3.3.

Table 3.2: Datasets derived from GENWELL data

Name	Derivation	Number of UWIs	Parent data
All UWIs Drilled in 2011	Section 3.2.1	12800	Licensing Data, Drilling Occurrence Data
All UWIs Drilled in 2011 with a fluid code	Section 3.2.2	8638	All UWI Drilled in 2011, Licensing Data, Well Status History Data, Tour-Perforation/Treatment Data
All gas UWIs drilled 2011	Section 3.2.2	2989	All UWI Drilled in 2011 with a fluid code
All fractured gas UWIs completed 2011	Section 3.2.3	2252	All UWI Drilled in 2011 with a fluid code, Tour-Perforation/Treatment Data

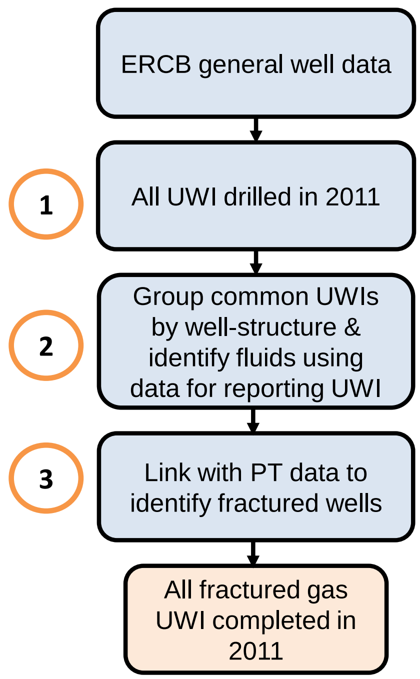

Figure 3.3: GENWELL and derived datasets workflow

3.2.1 All UWIs Drilled in 2011:

The GENWELL Licensing file (report 005) contains a full history of licensed UWIs issued in the province of Alberta dating back to 1911. As a first step, this dataset is restricted to UWIs drilled in 2011 using the final drilling date found in the Drilling Occurrence Data (Report 010). This was necessary since available volumetric data was restricted to the reporting year of 2011. The resultant subset contains 12800 UWIs. The surface-hole location of each well structure was identified using the Licensing file (Report 005); these are plotted in Figure 3.4.

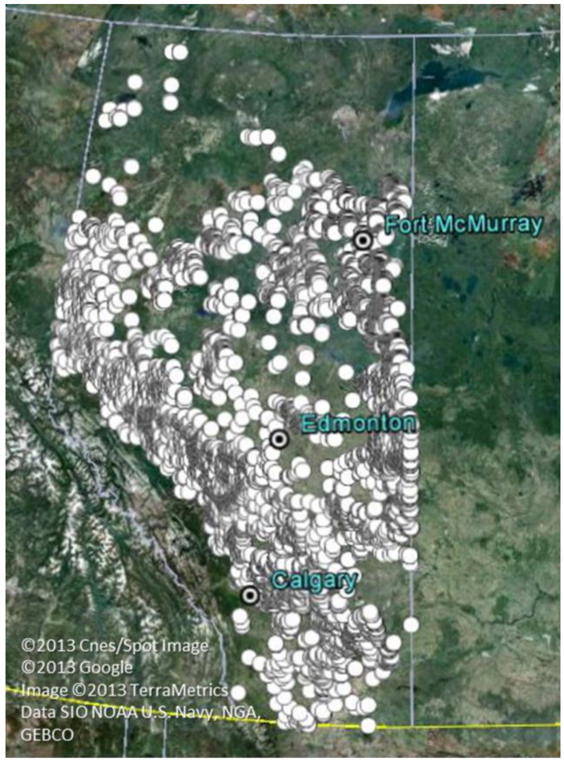

Figure 3.4: Surface-hole locations corresponding to all UWIs drilled in Alberta in 2011

The Licensing file (Report 005) may also be used to assign a Lahee class to each UWI as provided in Table 3.3. Possible Lahee class codes are Development, Exploratory, Experimental, Evaluation, or Oil Sands (OS) Evaluation. This code characterizes the potential likelihood of hydrocarbon production, pool geology, and pool location relative to known producing pools (ERCB, 2011d). Of the UWIs drilled in 2011, 72% were Development wells.

Table 3.3: All UWIs drilled in Alberta in 2011 by Lahee class

Lahee class code	All UWIs drilled in 2011
Development	9222
Evaluation	2
Experimental	43
Exploratory	1157
OS Evaluation	2376
Total	**12800**

It is worth noting that the set of natural gas wells completed in 2011 will not be fully captured by using a final drill date of 2011. For example, it is possible for a UWI to have been drilled in previous years but not completed until 2011. At this time such UWIs will not be considered in the final emission volume estimate.

3.2.2 All UWIs Drilled in 2011 with a Fluid Code:

The first step to compiling a set of all fractured gas UWIs completed in 2011 is to identify the fluid type of each UWI. A fluid code, if assigned to a UWI, is recorded as part of a well status code, a 10 digit integer that is paired with an occurrence date and is found within the Well Status History Data file (Report 070). Not all completed UWIs within a well structure will receive a fluid code. In the present analysis, for cases where a UWI has not been given a fluid code in Report 070, then it can reasonably be assigned a fluid code from a different UWI (if available) within the same well structure. Note that all UWIs with a common well structure are assigned the same Licence Number in the Licensing file (Report 005).

Each 10 digit well status code may contain a two digit fluid, mode, type, or structure sub-code followed by two padding digits. Within the ERCB reporting system, an operator may select the following sub-codes listed in Table 3.5 through
Table 3.8. For convenience, the following abbreviations of ERCB's natural gas fluid designations are introduced in Table 3.4.

Table 3.4: Abbreviations and ERCB fluid types

Within this report	Fluid sub-code	ERCB fluid designation	ERCB abbreviations
CBM hybrid	22	Coalbed methane – coals and other lithology	CBMOT
CBM	23	Coalbed methane – coals only	CBMCLS
Shale hybrid	24	Shale gas and other sources	SHGOT
Shale	25	Shale gas only	SHG
CBM/shale/other	26	CBM and Shale gas and other sources	CBMSOT

Fluid sub-codes are assigned by the composition of the producing target formation and are defined in Section 1.020 of the Alberta Oil and Gas Conservation Act (Province of Alberta, 2013).

Table 3.5: Fluid sub-codes

0	NA	7	Brine	11	Air	17	Crude bitumen	24	Shale hybrid
1	Crude oil	8	Waste	13	Carbon Dioxide	20	Acid gas	25	Shale
2	Gas	9	Solvent	15	Nitrogen	22	CBM hybrid	26	CBM/Shale/other
6	Water	10	Steam	16	Liq. petroleum gas	23	CBM		

Table 3.6: Mode sub-codes

0	NA	4	Abd and re-entered	9	Closed	13	Testing
1	Suspended	6	Potential	10	Flowing	14	Abd & Whipstocked
2	Abandoned (Abd)	7	Drilling and cased	11	Pumping	15	Drilling & completing
3	Abd zone	8	Junked and Abd	12	Gas lift	16	Test Completed

Table 3.7: Type sub-codes

0	NA	5	Observation	10	Cyclical
2	Storage	6	Training	11	Source
3	Injection	8	Farm	12	Steam assisted gravity drain
4	Disposal	9	Industrial	13	Fire flood

Table 3.8: Structure sub-codes

0	NA
5	Commingled
6	Drain

In general, a fluid type is assigned to a UWI within the ERCB database when an operator is required to report a status code of Drilling and Completing, Well Testing, Test Completed, Flowing, or Pumping. These status codes are interpreted as follows:

> **Drilling and Completing**: This includes fluids that are recovered during drilling operations such as swabbing or drill stem testing. This status can only be used prior to a status of drilled and cased, and only to report volumetric data for one month.
>
> **Well Testing:** This status code is used to report fluids that are produced after the drilling operations have been completed but prior to the well being placed on production. For

each testing well status: oil/condensate, gas, and water can be reported for three consecutive months and the hours must be reported.

Test Completed: A status code for a well that has been tested for a three month period and requires a volumetric submission beyond the three months.

Flowing: Well has progressed into producing status.

Pumping: The fluids are produced with the assistance of mechanical equipment (e.g., pump jack or downhole pump) to lift fluids to the surface.

The set of all UWIs drilled in 2011 may be divided into four main categories: natural gas UWIs, crude oil/crude bitumen UWIs, other (water, steam, solvent and waste) UWIs and UWIs with no fluid code. The distribution of UWIs drilled in 2011 is shown in Figure 3.5.

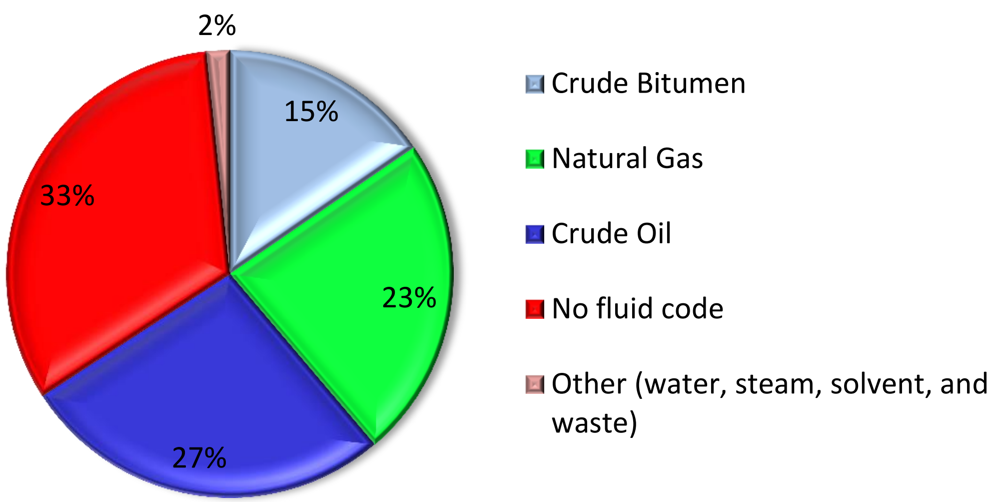

Figure 3.5: UWIs drilled (but not necessarily fractured) in Alberta in 2011 by fluid type

The set of UWIs with no fluid code can be further subdivided by considering Lahee class codes. As shown in Table 3.9, the set of UWIs with no fluid were mostly either Development or Oil Sands (OS) Evaluation UWIs. The large portion of Oil Sands UWIs is consistent with the heavy concentration of no fluid code UWIs near Fort McMurray in Figure 3.7 (Bottom Left).

Table 3.9: No fluid code by Lahee classes

Lahee class code	UWIs with no fluid code
Development	1433
Evaluation	2
Experimental	15
Exploratory	323
OS Evaluation	2374

By further studying the Well Status History Data file (Report 070), it is verifiable that the majority of the Development UWIs obtain a drilling and cased status code as defined in Table 3.6. However, a search of the Tour-Perforation/Treatment Data file (Report 055) for these UWIs reveals that roughly half do not have any perforation treatment codes (PT codes) and of the UWIs that do, only 159 have a fracture code (PT code 41). Furthermore, none of these drilling and cased UWIs are part of a well structure that has gone to a status of testing or flowing. Thus it is plausible that this drilling and cased grouping, apart from the 159 cases with a PT code 41, were not completed by the operator. Figure 3.6 summarizes identifiable fluid and well type information for all UWIs drilled in Alberta in 2011. Figure 3.7 maps the surface holes for these UWIs and separately identifies the locations of natural gas wells (top right) and crude oil/bitumen/other wells (bottom right).

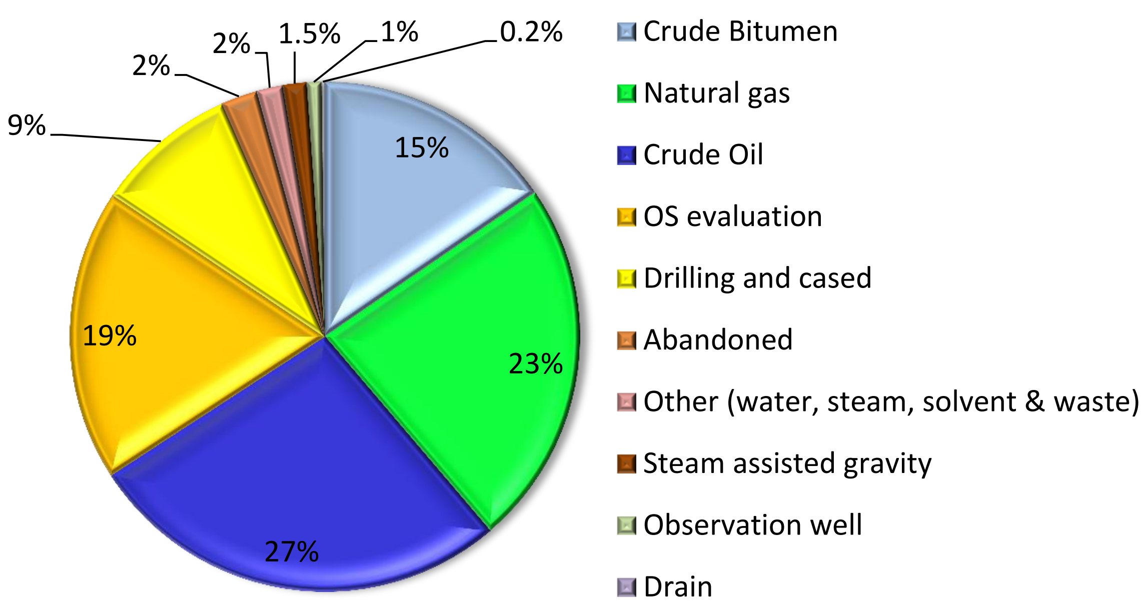

Figure 3.6: UWIs drilled in Alberta in 2011

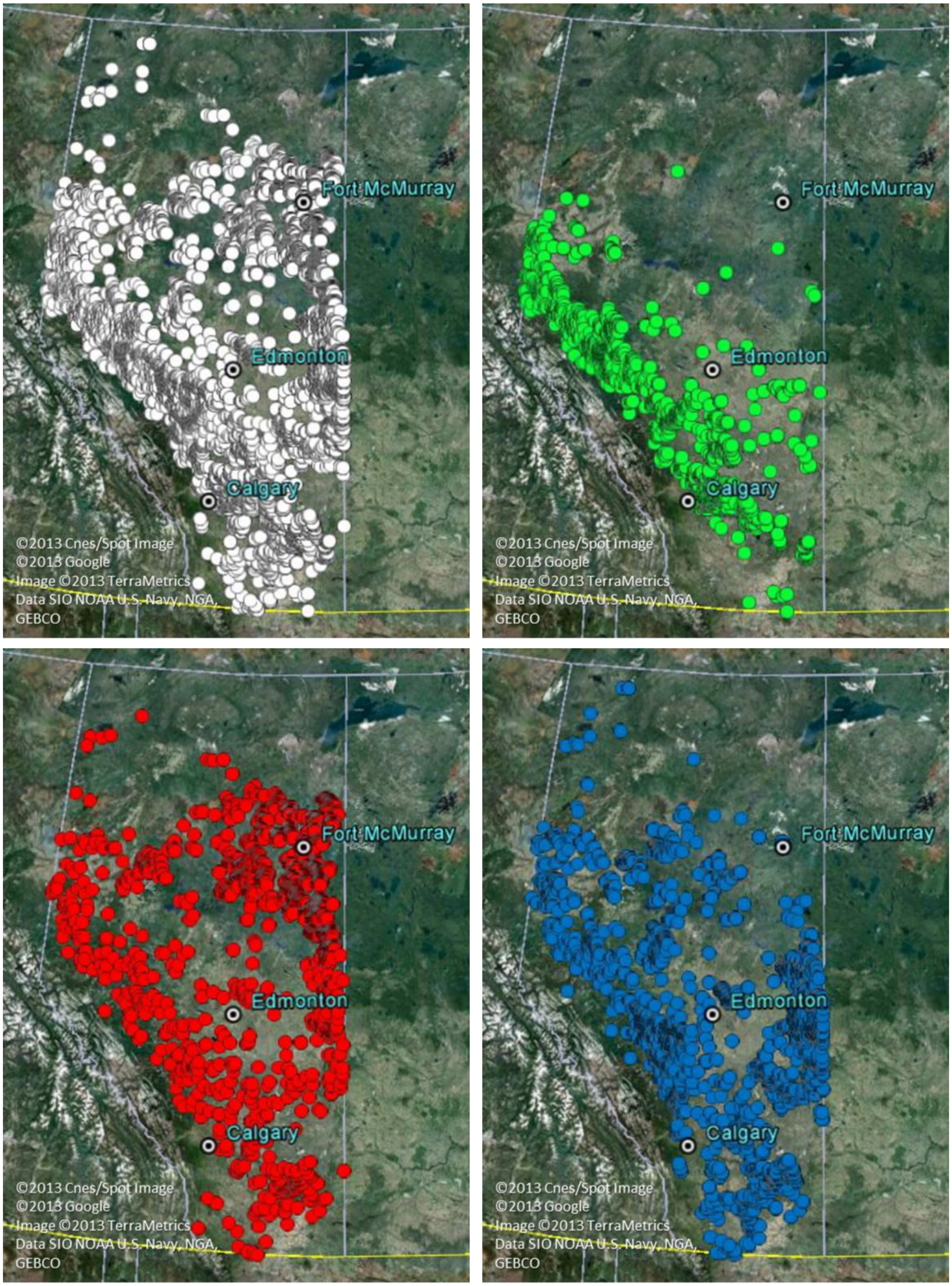

Figure 3.7: Surface holes drilled in Alberta in 2011: All UWIs (Top Left), Natural gas UWIs (Top Right), UWIs with no fluid code (Bottom Left), Crude oil/Bitumen/other UWIs with a fluid code (Bottom Right)

3.2.3 All Fractured Gas UWIs Completed in 2011

The ERCB fluid sub-codes specified in Table 3.5 that potentially correspond to hydraulically fractured natural gas wells include Gas, CBM, CBM hybrid, CBM shale hybrid, Shale, Shale Hybrid, and CBM/Shale/other. Although at this time the ERCB does not directly track tight gas, this report assumes, based on input from industry partners, that all fractured gas UWIs drilled in 2011 are tight gas UWIs. Tight gas formations include sandstone, siltstone and other carbonates with low permeability that require hydraulic fracturing to stimulate well production (ERCB, 2012b). The fluid subtype distribution for all natural gas UWIs drilled in 2011 is given in Figure 3.8. Table 3.10 breaks down the gas types associated with each Lahee class for these same UWIs.

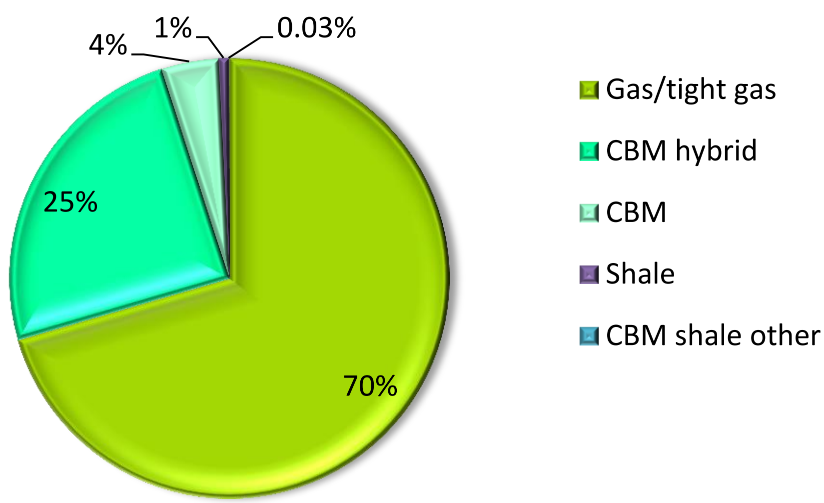

Figure 3.8: Alberta natural gas UWIs drilled in Alberta in 2011 by gas type

Table 3.10: Natural gas UWIs drilled in 2011 by Lahee class

Lahee class code	Tight gas	CBM hybrid	CBM	Shale	CBM Shale other
Development	1732	731	118	18	1
Evaluation	0	0	0	0	0
Experimental	1	0	0	0	0
Exploratory	374	2	8	4	0

From the set of all natural gas UWIs drilled in 2011, the number of subsequently fractured natural gas UWIs is a subset that has a PT code 41, signifying a fracture event, within the Tour-

Perforation/Treatment Data file (Report 055). The well leg/surface-hole orientation, vertical or horizontal, is determined from a direction drilling reason code within the Tour-Directional Drilling Data file (Report 035); a direction drilling reason code of 4 implies horizontal. In Table 3.11, fractured and non-fractured UWIs are categorized by gas type and orientation. In general, tight gas and CBM UWIs are fractured vertical well legs, whereas shale UWIs are fractured horizontal well structures. These general trends follow those of the API/ANGA survey results shown in Table 2.5, Section 2.3.2. Also, comparing the number of fractured natural gas UWIs to non-fractured natural gas UWIs in Table 3.11 yields a hydraulic fracturing rate of 92% for wells drilled in 2011, as shown in Figure 3.9. This is consistent with feedback from industry representatives regarding the proportion of fractured wells in Alberta as discussed previously. The surface-hole location of each hydraulically fractured natural gas well structure is plotted in Figure 3.10.

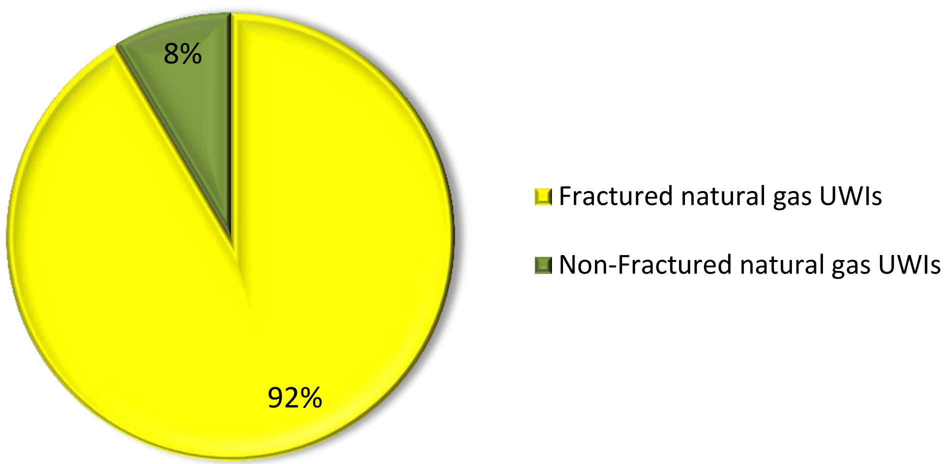

Figure 3.9: Fractured natural gas UWIs as a subset of all natural gas UWIs drilled in Alberta in 2011

Table 3.11: Natural gas UWIs by UWI type

UWI type	Tight gas	CBM hybrid	CBM	Shale	CBM Shale other
Horizontal Fractured	572	1	0	17	0
Horizontal No PT-code	31	0	2	1	0
Horizontal Non-Fractured	28	0	16	0	0
Vertical Fractured	1316	722	103	3	1
Vertical No PT-code	51	0	1	1	0
Vertical Non-Fractured	109	10	4	0	0

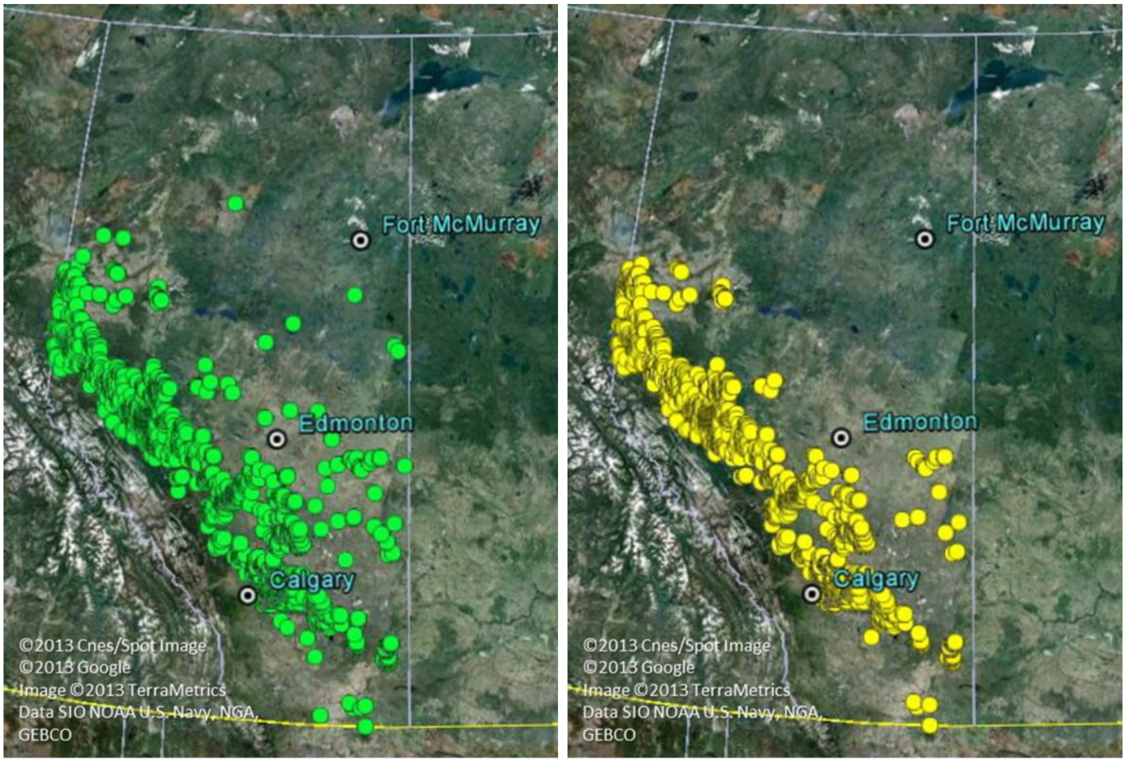

Figure 3.10: Alberta surface-hole locations for natural gas UWIs drilled in 2011 (left) and hydraulically fractured natural gas UWIs (right).

Summing the number of horizontal and vertical fractured UWIs in Table 3.11 results in a base set of 2735 hydraulically fractured natural gas UWIs. This set of fractured UWIs is distributed among 1934 well structures that contain an additional 116 non-fractured UWIs. Characteristics of these well structures are summarized in Table 3.12, Table 3.13, and Table 3.14.

Table 3.12: Hydraulically fractured UWI properties

Natural gas type	Number of well structures	Maximum number of fractured UWI	Minimum number of fractured UWI	Average number of fractured UWI	Std. Dev. of fractured UWI
Tight gas	1334	9	1	1.42	1.27
CBM hybrid	498	6	1	1.44	0.95
CBM	81	4	1	1.25	0.60
CBM shale other	1	1	1	1.00	0.00
Shale	20	1	1	1.00	0.00

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 correlation between the number of stages and total well depth in the reported data.

Table 3.13: Number of stages per *horizontal* hydraulically fractured UWI

Natural gas type	Number of horizontal UWIs	Maximum number of stages per UWI	Minimum number of stages per UWI	Average number of stages per UWI	Std. Dev. of stages per UWI
Tight gas	572	40	1	11.4	5.1
CBM hybrid	1	1	1	1	n/a
CBM	0	n/a	n/a	n/a	n/a
CBM shale other	0	n/a	n/a	n/a	n/a
Shale	17	25	1	11.4	5.1

Table 3.14: Number of stages per *vertical* hydraulically fractured UWI

Natural gas type	Number of vertical UWI	Maximum number of stages per UWI	Minimum number of stages per UWI	Average number of stages per UWI	Std. Dev. of stages per UWI
Tight gas	1316	23	1	6.4	3.9
CBM hybrid	722	39	1	6.2	7.5
CBM	103	20	1	4.7	5.0
CBM shale other	1	37	37	37	n/a
Shale	3	20	1	7.3	11.0

As it possible for a UWI drilled in late 2011 to have been subsequently completed in 2012, it was necessary to consider the date of fracture to accurately estimate the total emissions associated with well completions for the year 2011 in Sections 5.1.2 and 5.3.1. Therefore a UWI will be considered completed in 2011 if it has a fractured date recorded in 2011. The number of fractured UWIs completed in 2011 consists of 2252 UWIs contained within 1579 well structures. The distribution of UWIs completed in 2011 over each fluid type is provided in Table 3.15.

Table 3.15: Hydraulically fractured UWI completed in 2011

Natural gas type	Number of well structures	Number of fractured UWI
Tight gas	1143	1576
CBM hybrid	372	591
CBM	44	65
CBM shale other	1	1
Shale	19	19
Total	1579	2252

3.2.4 All Fractured Oil UWIs Completed in 2011

The number of fractured oil wells completed in 2011 is identified in a similar manner as was done for gas wells in Section 3.2.3. Using the ERCB fluid sub-codes specified in Table 3.5, oil wells are subdivided into crude oil and crude bitumen wells. Crude oil and crude bitumen wells account for 42% of the drilled UWIs in Alberta in 2011.

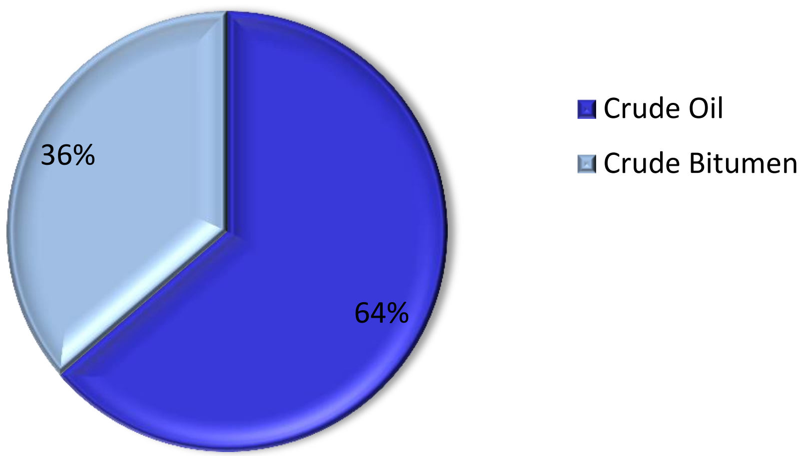

Figure 3.11: Alberta oil UWIs drilled in Alberta in 2011 by oil type

The relative proportion of UWIs by oil type and a breakdown by Lahee class for all oil UWIs drilled in 2011 is provided in Figure 3.11 and Table 3.16 respectively.

Table 3.16: Oil UWIs drilled in Alberta in 2011 by Lahee classes

Lahee-class-code	Crude Oil	Crude Bitumen
Development	3026	1970
Evaluation	0	0
Experimental	0	3
Exploratory	438	1
Total	**3464**	**1974**

The fracturing rate of oil UWIs completed in 2011 is 37%, which is roughly 2.5 times less than the fracturing rate of natural gas UWIs, as provided in Figure 3.12. The majority, 99%, of fractured oil wells are crude oil. From Table 3.17 it can be seen that roughly 70% of fractured crude oil UWIs are horizontal and in general crude bitumen UWIs are not fractured.

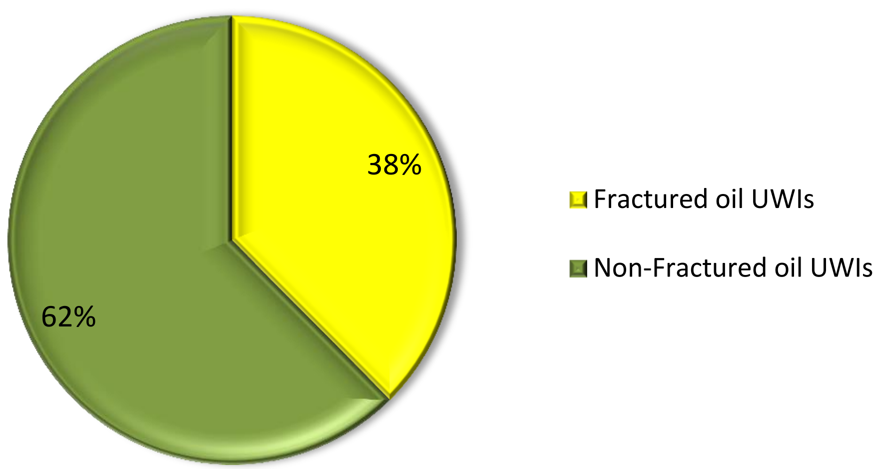

Figure 3.12: Fractured oil UWIs as a subset of all oil UWIs drilled in Alberta in 2011

Table 3.17: Oil UWIs by UWI type

UWI type	Crude Oil # of UWIs	Crude Bitumen # of UWIs
Horizontal Fractured	1442	0
Horizontal No PT-code	55	3
Horizontal Not Fractured	534	707
Vertical Fractured	583	18
Vertical No PT-code	105	26
Vertical Not Fractured	745	1220
Total	3464	1974

The 2025 drilled and fractured crude oil UWIs combine to form 1955 well structures. Although these counts are similar to that of fractured gas wells in Alberta for 2011, the duration of emissions from fractured crude oil and fractured natural gas wells are fundamentally different. The volumetric data shows two distinct trends. 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 (See Section 4.2.3). On the other hand, 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 as shown in Figure 3.13.

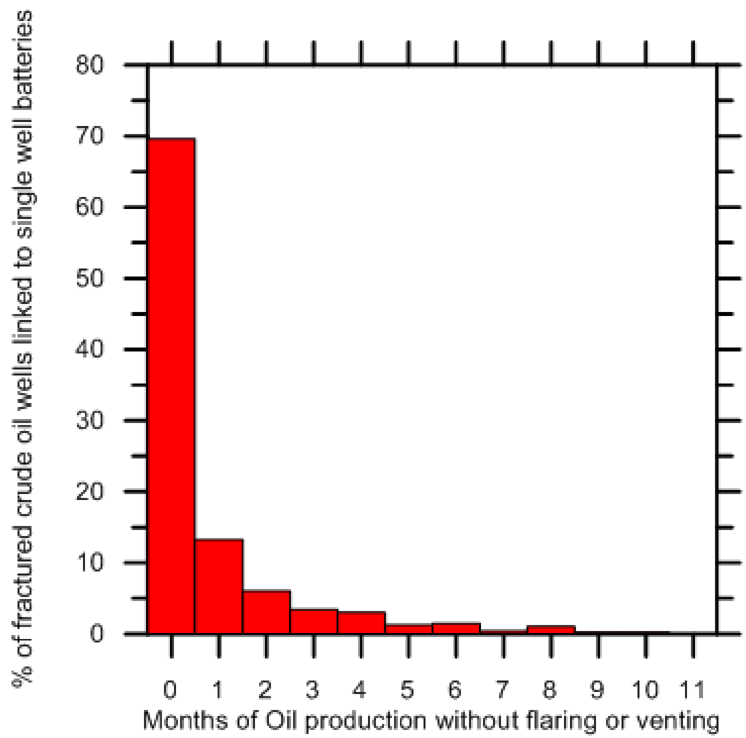

Figure 3.13: The percentage of fractured crude oil wells flaring and/or venting during oil production after fracture. Within the available volumetric data there are 467 fracture crude oil wells linked to crude oil single-well batteries that reported flaring and/or venting activity in Alberta during 2011

The continuous flaring and/or venting of solution gas at crude oil wells precludes the use of flaring and/or venting trends in identifying well-completion emissions. Furthermore without a test battery designation for crude oil in the reporting framework, as there is for gas wells, defining an unambiguous time period and criteria for well-completion volumes is problematic.

The flaring and/or venting of solution gas from crude oil wells is a topic of mitigation practices and thus falls outside of the scope of this report on emissions due to hydraulic fracturing.

4 DETERMINING FLARING, VENTING, AND DIESEL COMBUSTION EMISSIONS ASSOCIATED WITH HYDRAULICALLY FRACTURED NATURAL GAS WELLS

4.1 The Petroleum Registry of Alberta (PRA)

All flaring and venting related emission estimates for hydraulically fractured gas wells in this report were derived from detailed monthly regulatory and production data for 2011 reported in the Petroleum Registry of Alberta (PRA). The PRA framework links volumetric reporting facilities such as batteries, gas plants, and metering stations to a contributing node such as another battery and/or well using battery reference codes and UWIs, respectively. ERCB Directive 60 specifies that monthly flared, incinerated or vented gas volumes of 100 m^3/month or greater must be reported to the PRA, although for facilities not "routinely" submitting production data, Directive 60 specifies that reporting requirements may be waived if total monthly volumes are less than 500 m^3/month.

A basic comprehension of the PRA reporting framework is necessary for full understanding of the methodology used to derive the well-completion and operational emission factor results presented in this report. Table 4.1 provides a brief sample of the raw volumetric data within the PRA. As apparent in the table, all volumes within the PRA are reported by facility IDs shown in the first column. Associated with each facility ID entry is a "From/To Facility Node ID," which indicates the relevant source/destination of the volume being reported. A third key piece of information associated with each facility ID entry is the "Activity Code," which may include 30 different types of activities including production (PROD), disposition (DISP), flaring (FLARE), or venting (VENT). The remaining sample columns shown in Table 4.1 relate to the volumes and types of fluid (oil, gas, and water) associated with the specified activity.

This reporting framework raises a number of critical complications when trying to attribute specific flare or vent volumes to specific well-related activities, which is a key objective of the present work. Firstly, not all UWIs appear in the PRA. For multi-leg well structures (i.e. well structures comprising more than one UWI), an operator will generally choose a single producing UWI under which to report all data for all UWIs within the entire associated well structure. Secondly, since volumetric reporting within the PRA is by facility rather than by UWI, as further explained in Section 4.1.1 below, there are two distinct ways in which flaring and venting volumes associated with a specific reporting UWI can appear in the PRA data. This has the critical implication that it can be quite difficult or even impossible to directly attribute specific flaring and venting volumes to specific wells. Thus, a number of different reporting modes need to be considered and diverse data must be carefully analyzed prior to attempting to develop robust well-level emissions estimates.

4.1.1 "Well-level" vs. "Battery-level" reporting of Flaring and Venting Volumes

Flaring and venting volumes for a given well-structure (i.e. for the reporting UWI) may be reported either at the "well-level" or at the "battery-level", depending on the source specified in the associated "from/to node". Referring to Table 4.1, the sample UWI identified as AB WI 5555 provides an example of well-level reporting. Starting with the third row of the table, highlighted in green, sample battery AB BT 0001 reports production of 1215*1000 m^3 of gas, 2.4 m^3 of oil, and 322.3 m^3 of water, where the from/to node indicates the production originated from AB WI 5555. The second row of the table, highlighted in orange, shows that 200.3*1000 m^3 of gas were flared, where the from/to node indicates the flared gas came from UWI AB WI 5555. This direct identification of a UWI as the source of the flared gas is termed well-level reporting. As indicated in the first row of the table, highlighted in yellow, the remaining 1014.7*1000 m^3 of produced gas was sent from the battery AB BT 0001 to the gathering system identified by AB GS 0002622. Thus, the volume of produced gas is equal to the sum of the flared and dispensed gas, and the reported flared volume is directly linked to a specific well (UWI) by the from/to node ID.

In the middle section of Table 4.1, sample battery AB BT 0002 provides a contrasting example of battery-level reporting of flare volumes. As highlighted in blue, battery AB BT 0002 reports production of 546.7*1000 m^3 of gas and 117.4 m^3 of water from the UWI identified as AB WI 6666. A portion of this gas (524.1*1000 m^3) is sent to gathering system AB GS

0006072, as highlighted in purple. As highlighted in red, the remaining 22.5*1000 m^3 was flared, however the from/to node ID indicates the gas originated at that same battery, AB BT 0002. In this particular example, since AB BT 0002 is a single-well battery that is not receiving gas from any other sources, it is possible to definitively conclude that AB WI 6666 was the source for the battery-level-reported flared volume at AB BT 0002. However, for multi-well batteries, where gas is received from two or more sources, it is not always possible to directly attribute reported flared or vented volumes to specific wells. Further complications arise where volumetric data for some wells has been excluded by ERCB from the currently available data set for reasons of confidentiality as further discussed in Section 4.1.2.

Table 4.1: Sample of data from the PRA used to illustrate different reporting modes for flaring and venting volumes associated with a well

Facility ID	From/To Facility Node ID	Activity	Hours	Oil	Gas	Water	Product	Product Grouping	Volume
AB BT 0001	AB GS 0002622	DISP					GAS	GAS	1014.7
AB BT 0001	AB WI 5555	FLARE			200.3				
AB BT 0001	AB WI 5555	PROD	252	2.4	1215	322.3			
AB BT 0001	AB WP 0000650	DISP					WATER	WATER	3
AB BT 0001	AB WP 0000652	DISP					OIL	WATER	2.4
AB BT 0001	AB WP 0000652	DISP					WATER	WATER	14.7
AB BT 0001	AB WP 0000660	DISP					WATER	WATER	12.6
AB BT 0001	AB WP 0079474	DISP					WATER	WATER	292
AB BT 0002	AB BT 0062256	DISP					WATER	WATER	54.9
AB BT 0002	AB BT 0002	FLARE					GAS	GAS	22.5
AB BT 0002	AB GS 0006072	DISP					GAS	GAS	524.1
AB BT 0002	AB WI 6666	PROD	45		546.7	117.4			
AB BT 0002	AB WI 6666	FUEL			0.1				
AB BT 0002	AB WP 0078822	DISP					WATER	WATER	62.5
AB BT 0003	AB GS 0006072	DISP					GAS	GAS	3000
AB BT 0003	AB WI 7777	PROD			500				
AB BT 0003	AB WI 8888	PROD			1000				
AB BT 0003	AB BT 0003	FLARE					GAS	GAS	400
AB BT 0003	AB BT 0003	FUEL					GAS	GAS	200

Reporting at sample multi-well battery AB BT 0003 in Table 4.1 shows an example case where data are insufficient to directly attribute flare and vent volumes to specific UWIs. In this case the gas dispositions of 3000*1000 m^3, additional fuel use of 200*1000 m^3, and flaring of 400*1000 m^3 at AB BT 0003 total 3600*1000 m^3. This exceeds the total *non-confidential* reported production volumes of 1500*1000 m^3 (i.e. 500*1000 m^3 from AB WI 7777 and 1000*1000 m^3 from AB WI 8888). Moreover, since the received gas was divided among flaring, fuel use, and dispositions into a gathering system, there is no definitive way to reliably determine whether any portion of the reported flaring should be attributed to the non-confidential wells, AB WI 7777 or AB WI 8888. Emission factors derived in Chapter 5 are therefore derived based only on data where the fate of the produced gas during completion or operation can be conclusively determined.

4.1.2 PRA Node Confidentiality

The available PRA volumetric data from ERCB used in this study did not include UWIs flagged as confidential within the PRA database. As identified in Section 3.2.3, there were a total of 2252 gas UWIs drilled and fractured in 2011, which were grouped within 1579 unique well structures. A cross-reference of these with the available PRA data to screen for any type of reporting activity yielded records for 1228 UWIs or 1208 unique well structures. Thus of the 1579 unique well structures with at least one drilled and fractured leg in 2011, 23.5% (371/1579) were excluded by the ERCB for reasons of confidentiality. As shown in Figure 4.1 the excluded well structures are geographically widespread over Alberta's gas producing region. Most of these wells (77.6%) deemed confidential by ERCB were classified as development wells, whereas 22.4% were classified as exploratory wells. Table 4.2 summarizes the excluded gas wells by well type and Lahee class. Emission factor estimates presented in this report were necessarily derived solely from the available non-confidential data representing 1208 unique well structures containing one or more drilled and fractured UWIs in 2011.

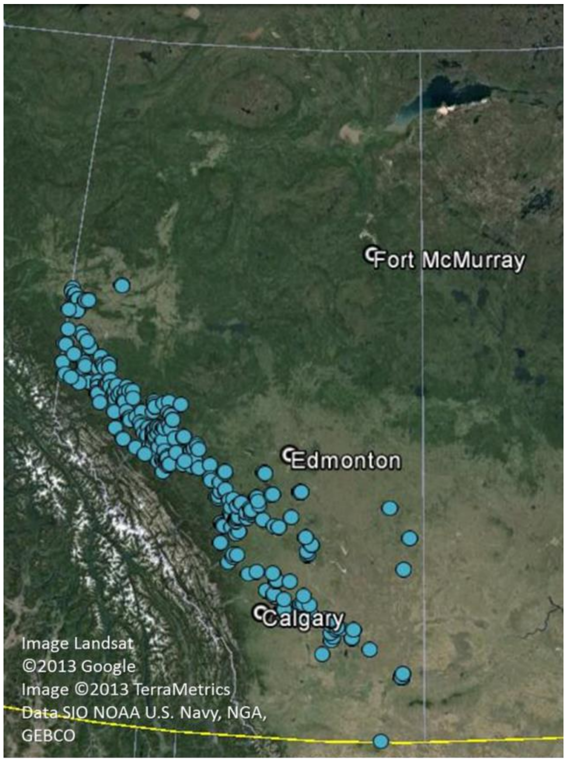

Figure 4.1: Surface-hole locations in Alberta for fractured natural gas wells drilled in 2011 that are flagged as confidential in the available PRA volumetric data

Table 4.2: Fractured natural gas wells drilled in Alberta in 2011 flagged as confidential in the available PRA volumetric data by Lahee class

Gas type	LAHEE class			
	Development		Exploratory	
	# of well structures	# of UWIs	# of well structures	# of UWIs
Tight gas	207	268	81	134
CBM hybrid	65	67	0	0
CBM	15	16	0	0
Shale	1	1	2	2
Total	**288**	**352**	**83**	**136**

4.2 Procedures for Determining Flaring and Venting Volumes Associated with Well-completions

4.2.1 Relating Fracturing Events to Monthly Emissions Data

Since the PRA is set up to report flaring and venting volumes only on a monthly basis, calculation of well-completion emissions required the development of defensible criteria to relate relevant reported monthly flaring and venting volumes in the PRA to identifiable well-completion activities at the well-head. Unfortunately, completion or flow back at UWIs are not currently tracked as specific activities in the ERCB general well file. However, as noted in Section 3.2.3, Report 055 of the ERCB general well file does contain tour and perforation treatment codes (PT codes), where a PT code entry of 41 indicates that a UWI has been fractured and the associated entry date defines the time of fracture. Thus, by linking the fracture date for each UWI with monthly reported flaring and venting volumes within the PRA, associated well-completion related emissions could be quantified.

In practice, two different criteria were used to identify relevant well-completion volumes from available monthly data depending on whether flaring and venting volumes for a particular UWI were reported at the well- or battery-level (see Section 4.1.1). For well-level reported data, monthly volumes reported within 1 month of the fracture date (i.e. during the month of the fracture date or in the following month) were considered well-completion emissions. As shown in Section 4.2.3, reported flaring and venting volumes during this interval were clearly distinguishable from any subsequent reported emissions, which were separately considered as part of operational emissions as discussed in Section 4.3. In this manner, all reported well-level flaring and venting volumes were accounted for in the analysis.

A similar procedure was used for battery-level reported data. However, since for battery-level reporting, only the gas production volume from a UWI is recorded, the relevant completion interval was defined as the first month in which a UWI reported gas production to a battery following the fracture date. Any flaring and venting reported at a battery during this same month that could be directly attributed to the relevant UWI in the production accounting, was then identifiable as a well-completion related emission.

4.2.2 Battery Sub-Types for Reporting of Flaring and Venting Volumes

As explained in Section 4.1, relevant data for individual UWIs are always reported at a battery within the PRA, where the associated from/to node ID allows for either well- or battery-level reporting of flare and vent volumes (See Section 4.1.1). Reporting batteries may be categorized by their assigned sub-type codes, which are tabulated daily for all PRA facilities in the ERCB Statistical Report 102 (ST 102). Relevant battery sub-types for the present analysis include:

- Gas-Test Batteries (sub-type 371);
- Drilling and Completing Batteries (sub-type 381);
- Single-Well Batteries (sub-type 351);
- Gas multi-well group batteries (sub type 361);
- Gas multi-well effluent measurement batteries (sub-type 362);
- Gas multi-well proration SE Alberta batteries (sub-types 363); and
- Gas multi-well proration outside SE Alberta batteries (sub-types 364).

From discussions with industry and ERCB representatives, it was originally expected that flaring and venting volumes associated with well-completions would be reported at the well-level for batteries with either sub-type 371 (gas-test batteries) or sub-type 381 (drilling and completing). The ERCB defines battery sub-types 371 and 381 as follows (ERCB, 2011b):

Sub-type 371, Gas-Test Battery: A reporting entity to accommodate the reporting of production from a well or wells during deliverability testing and before commencement of regular production. This subtype code:

- only applies to wells with the well status of Gas Test;
- permits wells to report for a maximum of three months;
- permits battery location to be anywhere within Alberta; and
- allows multiple wells to be linked to the facility ID.

Sub-type 381, Drilling and Completing: A reporting entity to accommodate the reporting of production from a well during drilling or completion operations and before commencement of regular production. This subtype code:

- only applies to wells with the well status of Drilling and Completing. Drilling and Completing means the well is still drilling and has not completed or reached the total depth of a well;
- can only be used by wells for a maximum of one month; and
- requires a new battery ID for each well.

Close examination of the PRA data revealed that 26% (319/1208) of the fractured well structures in 2011 reported initial production and/or well-completion emissions at gas-test batteries (sub-type 371), and *none* reported relevant emissions at drilling and completing batteries (sub-type 381). Full analysis of all other possibilities revealed relevant emissions at a range of other battery sub-types. In addition, the results showed evidence for larger numbers of apparent green-completions when considering other sub-types as further discussed below.

4.2.3 Completion Flaring and Venting Emissions Reported for UWIs Linked to Gas-Test Batteries (sub-type 371)

Figure 4.2 provides a summary schematic of the analysis steps required to identify and calculate well-completion-related flaring and venting volumes reported at gas-test batteries (sub-type 371). Battery sub-types were identified in step 4 by linking data from ERCB ST 102 with PRA data. Data for the selected UWIs reporting at gas-test (sub-type 371) or drilling and completing (sub-type 381) batteries were then cross-referenced with the set of 2252 identified hydraulically fractured natural gas UWIs previously derived in step 3 (see Section 3.2.3). Depending on how flaring and venting data were reported within the PRA, well-completion volumes were then necessarily determined either via step 6 to calculate well-level reported flaring and venting within 1 month of the fracture date, or via step 7 to calculate battery-level reported flaring and venting volumes in the first production month after fracture and appropriately attribute these volumes to individual UWIs. These data could then be combined in step 8 to determine overall well-completion related reported flaring and venting volumes at gas-test batteries.

Of the 1208 unique well-structures consisting of one or more gas UWIs that were drilled and fractured in 2011, only 307 (25%) reported flaring and venting volume data associated with well-completions at gas-test (sub-type 371) batteries. Of these, only one UWI reported venting volumes. None reported well-completion related flaring and venting at drilling and completing (sub-type 381) batteries. For the gas-test battery data, 105 well-structures (8.7%) reported well-level flaring and venting volumes and 202 (16.7%) reported battery-level flaring and venting volumes.

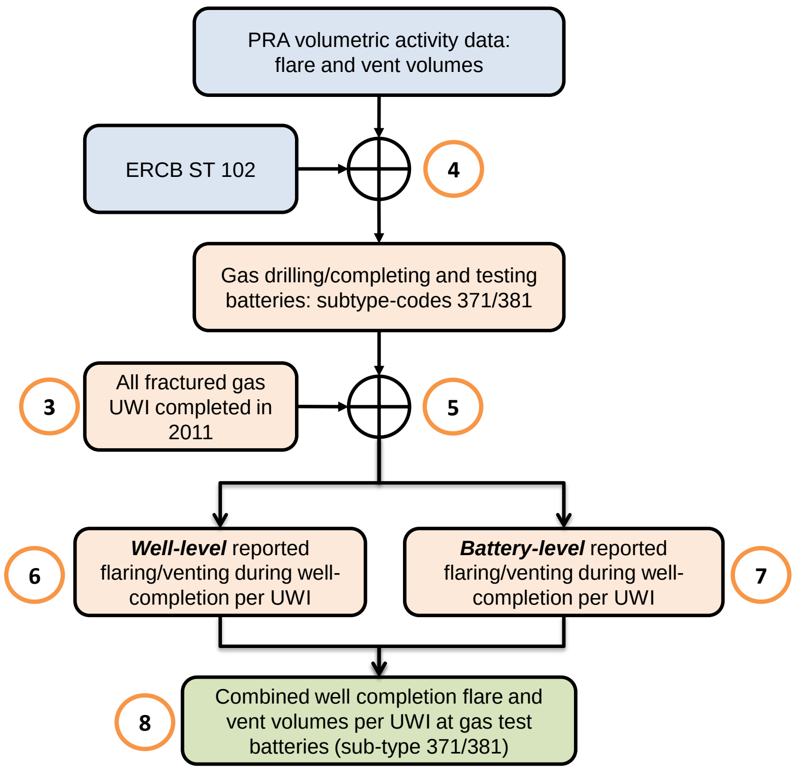

Figure 4.2: PRA and derived dataset workflow

Figure 4.3 plots the well-level reported flare volumes in each month since the fracture date. Figure 4.3a shows data for individual UWIs, which indicate that almost all reports of flaring occur within 1 month of the fracture date. Figure 4.3b shows data for all UWIs, which further demonstrates that essentially all of the total volume of well-level reported flaring occurs during this same time interval. This anticipated trend is consistent with the flaring being directly attributable to well-completion and flow back, and the data support the use of a 1-month criterion for the calculation of well-level reported well-completion flare volumes as proposed in Section 4.2.1.

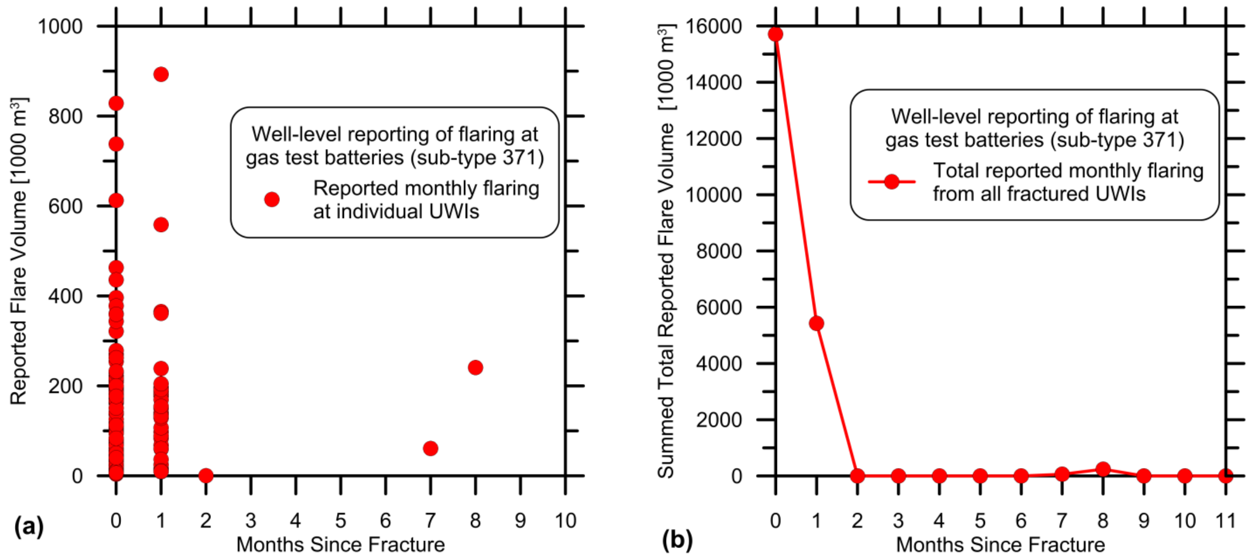

Figure 4.3: Well-level flaring volumes associated with well-completion reported at gas-test (sub-type 371) batteries. (a) monthly flaring reported for individual UWIs in each month since fracture date, (b) summed total reported flare volume in each month since fracture date indicating that essentially all volume is reported within 1-month of fracture

Table 4.3 details the calculated well-completion flaring and venting volumes for UWIs reporting at gas-test batteries. The first section of the table provides summary totals from well-level reported flare and vent volumes (i.e. determined in step 6 of Figure 4.2), whereas the second part of the table lists totals for battery-level reported data (i.e. determined in step 7 of Figure 4.2). Data are further segregated by well type, i.e. tight gas, CBM, CBM hybrid, CBM shale other, and shale.

Table 4.3: Well-completion flaring and venting at gas-test batteries (sub-type 371) in Alberta in 2011 as reported at the well- and battery-level

Well type	Flaring			Venting		
	# of well-structures reporting flaring	# of associated UWIs reporting flaring	Total gas volume [1000 m^3]	# of well-structures reporting venting	# of associated UWIs reporting venting	Total gas volume [1000 m^3]
Well-level reporting of flaring and venting at sub-type 371, gas-test batteries						
Tight gas	100	134	21099.4	1	1	3.2
CBM hybrid	1	1	5.7	0	0	0
CBM	4	4	31.9	0	0	0
CBM shale other	0	0	0	0	0	0
Shale	0	0	0	0	0	0
Battery-level reporting of flaring and venting at sub-type 371, gas-test batteries						
Tight gas	65	69	4262.9	0	0	0
CBM hybrid	127	290	175.5	0	0	0
CBM	10	26	14.2	0	0	0
CBM shale other	0	0	0	0	0	0
Shale	0	0	0	0	0	0

The available well- and battery-level reported data for gas-test batteries are combined in Table 4.4 to calculate total flaring and venting volume data. The majority of UWIs reporting flaring and venting data at gas-test batteries were classified as tight gas wells with CBM hybrid and CBM wells forming the balance. In 2011, there were no drilled and fractured UWIs identified as "CBM shale other" or "Shale" that reported well-completion flaring and venting at gas-test batteries in Alberta. As noted above, only a single facility reported venting volumes and essentially all of the generated gas volumes that were not otherwise captured were flared. For UWIs reporting at gas-test batteries but not reporting any flaring and venting volumes, Table 4.4 also summarizes apparent "green-completion" rates. After using the well- and battery-level data analysis procedures outlined in Section 4.1.1, green-completed UWIs were identified in cases where well-level reported production volumes exactly matched battery receipts, and no well- or battery-level flaring or venting were reported. Results suggest that 12 of 177 well structures (7%) had apparent green-completions for which any flaring and venting was below reportable limits (i.e. generally less than 500 m^3 per month as specified in ERCB Directive 60).

Table 4.4: Summary of well-completion flaring and venting volumes, reporting rates, and apparent green-completions for Alberta wells drilled and fractured in 2011 that reported at gas-test batteries (sub-type 371)

Well type	Total # of fractured wells or UWIs in 2011 with gas volumes at sub-type 371 batteries		Green-completions at sub-type 371 batteries (no well- or battery-level flaring or venting)		Flaring			Venting		
	# of well-structures	# of UWIs	# of well-structures	# of UWIs	# of well-structures reporting flaring	# of UWIs reporting flaring	Total gas volume [1000 m^3]	# of well-structures reporting venting	# of UWIs reporting venting	Total gas volume [1000 m^3]
Combined well- and battery-level reporting of flaring and venting at sub-type 371, gas-test batteries										
Tight gas	177	227	12	24	165	203	25362.3	1	1	3.2
CBM hybrid	128	291	0	0	128	291	181.2	0	0	0
CBM	14	30	0	0	14	30	46.1	0	0	0
CBM shale other	0	0	0	0	0	0	0	0	0	0
Shale	0	0	0	0	0	0	0	0	0	0

4.2.4 Completion Flaring and Venting Emissions Reported for UWIs Linked to Single-Well Batteries (sub-type 351)

Full accounting of well- and battery-level reported data to reliably attribute flaring and venting volumes to specific UWIs was also possible at single-well batteries (sub-type 351). Analysis procedures were identical to those for gas-test batteries as summarized in Figure 4.2 and described in the previous section. Table 4.5 summarizes the well- and battery-level reported flaring and venting volumes attributable to specific UWIs during well-completion. In total, 16 well structures with drilled and fractured legs in 2011 reported well-completion flaring emissions and 13 reported venting emissions. All of these were tight gas wells. The well- and battery-level reported data are aggregated together in Table 4.6, which also calculates apparent green-completion rates based on matched well-level production and battery-level dispositions in the absence of well-level flaring or venting as discussed above. Overall, fractured UWIs reporting well-completion emissions (i.e. initial production) at single-well batteries have much higher green-completion rates than UWIs reporting at gas-test batteries as presented in Section 4.2.3. The 137 non-confidential tight gas well-structures reporting well-completion related data at single-well (sub-type 351) batteries represent 11.3% of the 1208 non-confidential well structures with drilled and fractured legs in Alberta in 2011.

Table 4.5: Well-completion flaring and venting at single-well batteries (sub-type 351) in Alberta in 2011 as separately reported at the well- and battery-level

Well type	Flaring			Venting		
	# of well-structures reporting flaring	# of associated UWIs reporting flaring	Total gas volume [1000 m^3]	# of well-structures reporting venting	# of associated UWIs reporting venting	Total gas volume [1000 m^3]
Well-level reporting of flaring and venting at sub-type 351, single-well batteries						
Tight gas	6	6	704.4	6	6	25.6
CBM hybrid	0	0	0	0	0	0
CBM	0	0	0	0	0	0
CBM shale other	0	0	0	0	0	0
Shale	0	0	0	0	0	0
Battery-level reporting of flaring and venting at sub-type 351, single-well batteries						
Tight gas	10	11	1030.7	7	7	105
CBM hybrid	0	0	0	0	0	0
CBM	0	0	0	0	0	0
CBM shale other	0	0	0	0	0	0
Shale	0	0	0	0	0	0

Table 4.6: Summary well-completion flaring and venting volumes, reporting rates, and apparent green-completions for Alberta wells drilled and fractured in 2011 that reported at single-well gas batteries (sub-type 351)

Well type	Total # of fractured wells or UWIs in 2011 with gas volumes at sub-type 351 batteries		Green-completions at sub-type 351 batteries (no well- or battery-level flaring or venting)		Flaring			Venting		
	# of well-structures	# of UWIs	# of well-structures	# of UWIs	# of well-structures reporting flaring	# of UWIs reporting flaring	Total gas volume [1000 m^3]	# of well-structures reporting venting	# of UWIs reporting venting	Total gas volume [1000 m^3]
Combined well- and battery-level reporting of flaring and venting at sub-type 371, gas-test batteries										
Tight gas	137	152	108	122	16	17	1735.1	13	13	130.6
CBM hybrid	0	0	0	0	0	0	0	0	0	0
CBM	0	0	0	0	0	0	0	0	0	0
CBM shale other	0	0	0	0	0	0	0	0	0	0
Shale	0	0	0	0	0	0	0	0	0	0

4.2.5 Completion Flaring and Venting Emissions Reported for UWIs Linked to Other Battery Sub-types (sub-types other than 371 and 351)

As outlined in Section 4.1.1, ambiguities in the PRA framework preclude definitive attribution of reported flaring and venting volumes at other battery sub-types (i.e. other than gas-test batteries or single-well batteries) to individual UWIs. However, any well-level flaring and venting data reported at these other batteries was still directly attributable. Table 4.7 summarizes the well-level reporting of well-completion related flaring and venting volumes at these other battery sub-types which included Gas Multi-well Effluent Measurement Batteries (sub-type 362) and Gas Multi-well Group Batteries (sub-type 361). All of the UWIs reporting flaring and/or venting data at these facilities were tight gas wells. In total, 6.8% (82/1208) of the non-confidential well structures containing drilled and fractured UWIs in 2011 reported well-level flaring and venting data associated with well-completions at these other battery sub-types.

Table 4.7: Well-completion flaring and venting at other battery sub-types (excluding gas-test and single-well batteries detailed in previous tables) in 2011. As detailed in Section 4.1.1, the limits of the PRA reporting framework preclude definitive attribution of flaring and venting volumes to specific UWIs where the flaring and venting are reported at the battery-level

Well type	Flaring			Venting		
	# of well-structures reporting flaring	# of associated UWIs reporting flaring	Total gas volume [1000 m^3]	# of well-structures reporting venting	# of associated UWIs reporting venting	Total gas volume [1000 m^3]
Well-level reporting of flaring and venting at other battery sub-types						
Tight gas	76	168	7999.3	6	6	33.5
CBM hybrid	0	0	0	0	0	0
CBM	0	0	0	0	0	0
CBM shale other	0	0	0	0	0	0
Shale	0	0	0	0	0	0
Battery-level reporting of flaring and venting at other battery sub-types						
Tight gas	n/a	n/a	n/a	n/a	n/a	n/a
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a
CBM	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a
Shale	n/a	n/a	n/a	n/a	n/a	n/a

For cases where there were no reported battery- or well-level flaring and venting volumes and reported well-level production matched battery-level dispositions to gathering systems (i.e. none of the wells feeding a battery were deemed confidential), it was also possible to identify green-completions. Table 4.8 summarizes the combined well- and battery-level reporting statistics for all UWIs reporting at battery types other than the gas-test batteries (sub-type 371) and single-well batteries (sub-type 351) discussed in previous sections. Because of the cited limits to the PRA reporting framework for relating battery-level reported flaring and venting volumes to individual UWIs at these facilities, summary flaring and venting reporting statistics and volumes in Table 4.8 are not calculable. However, the results of Table 4.8 do provide several further key insights. First, 60% (722/1208) of non-confidential well-structures containing UWIs drilled and fractured in 2011 reported well-completion related production, flaring, and/or venting data at a range of additional battery sub-types which included Gas Multi-well Group Batteries (sub-type 361), Gas Multi-well Effluent Measurement Batteries (subtype 362), Gas Multi-well Proration

SE Alberta Batteries (subtype 363), Gas Multi-well Proration Outside SE Alberta Batteries (sub-type 364), Crude Oil Single-Well Batteries (sub-type 311), and Crude Oil Multi-well Proration Battery (sub-type 322). Secondly, a larger number of CBM hybrid, CBM, and Shale well structures reported well-completion related data at these other battery types than at gas-test (sub-type 371) and single-well (sub-type 351) batteries. Lastly, the apparent green-completion rates at these other battery sub-types were generally much higher than at gas-test or single-well batteries.

Table 4.8: Summary well-completion flaring and venting volumes, reporting rates, and apparent green-completions for Alberta wells drilled and fractured in 2011 that reported at other battery sub-types (excluding gas-test and single-well batteries detailed in previous tables) in 2011. As detailed in Section 4.1.1, the limits of the PRA reporting framework preclude definitive attribution of flaring and venting volumes to specific UWIs where the flaring and venting are reported at the battery-level

Well type	Total # of fractured wells or UWIs in 2011 with gas volumes at other battery sub-types (excluding gas-test and single-well batteries)		Green-completions (no well- or battery-level flaring and/or venting) at other battery sub-types		Flaring			Venting		
	# of well-structures	# of UWIs	# of well-structures	# of UWIs	# of well-structures reporting or link to flaring	# of UWIs reporting or linked to flaring	Total gas volume [1000 m^3]	# of well-structures reporting or linked to venting	# of UWIs reporting or linked to venting	Total gas volume [1000 m^3]
Combined well- and battery-level reporting of flaring and venting at other battery sub-types										
Tight gas	521	776	351	494	113	213	n/a	66	82	n/a
CBM	15	17	7	8	0	0	n/a	8	9	n/a
CBM hybrid	179	228	153	188	0	0	n/a	26	40	n/a
CBM shale other	1	1	1	1	0	0	n/a	0	0	n/a
Shale	15	15	11	11	0	0	n/a	4	4	n/a

4.2.6 Summary of Reporting Modes for Well-Completion Related Production, Flaring, and Venting Data within the PRA

Figure 4.4 summarizes the results of Sections 4.2.3 through 4.2.6 and illustrates the percentage breakdown of how flaring and venting data associated with well-completions were identified for the 1579 well structures in Alberta that contained one or more legs (UWIs) that were drilled and fractured in 2011. Slightly less than one-quarter (371 of 1579, or 23.5%) of the well structures were not identifiable within the available PRA data as discussed in Section 4.1.2 and were presumed to have been excluded by ERCB 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.

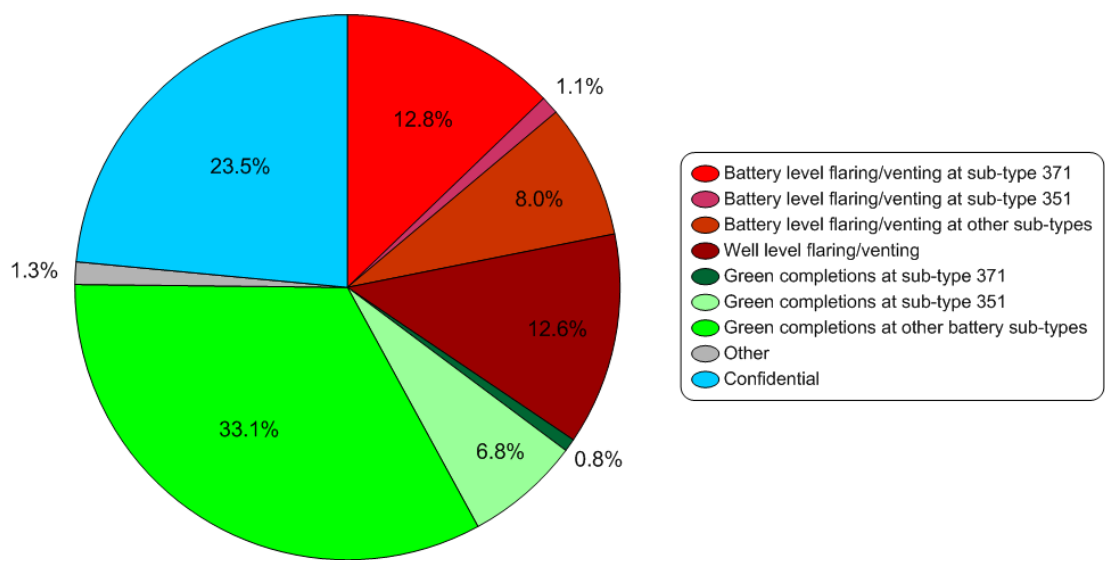

Figure 4.4: Percentage breakdown of how flaring and venting data associated with unconventional gas well-completions could be tracked within the confines of the available ERCB and PRA data for Alberta in 2011

Table 4.9 provides a detailed breakdown of how reported flaring and venting data could be linked with well-completions based on reporting mode (i.e. well- and battery-level reporting at different battery sub-types). The 21 well structures falling into the "Other" category in Table

4.9 (~1.3% of the 1579 hydraulically fractured well structures in Alberta in 2011 as shown in Figure 4.4) were analyzed individually to glean reasons why they fell outside the other categories. These 21 well structures included:

- 3 well structures reporting produced volumes other than gas and no flaring and venting volumes, two of which were subsequently shut-in;
- 15 well structures, mostly linked to sub-type 351/361 batteries ("Gas Single-well" and "Gas Multi-well Group" Batteries), that reported flaring and venting volumes, but only 2 or more months after fracturing and therefore did not meet the criteria for attributing volumes to well-completion outlined in Section 4.2.1, but also could not be classed as green-completions; and
- 3 well structures that were shut-in after fracturing.

Table 4.9: Detailed breakdown of numbers of well structures and fractured UWIs within these well structures that could be linked to reported flaring and venting data based on reporting mode (i.e. battery sub-type etc.). There were a total of 1579 well structures completed in Alberta in 2011 that each contained one or more hydraulically fractured legs (UWIs)

Well-completion reporting	Number of fractured well structures	Number of fractured UWIs			
		Total	Flare	Vent	Green
Well-level Flaring/venting reported at gas-test batteries (sub-type 371)	105	139 [a]	139	1	--
Battery-level Flaring/venting reported at gas-test batteries (sub-type 371)	202	385	385	0	--
Well-level Flaring/venting reported at single-well batteries (sub-type 351)	12	12	6	6	--
Battery-level Flaring/venting reported at s single-well batteries (sub-type 351)	17	18	11	7	--
Well-level Flaring/venting linked to other battery sub-types	82	174	168	6	--
Battery-level Flaring/venting linked to other battery sub-types	126	161 [b]	45	129	--
Apparent green-completions at gas-test batteries (sub-type 371)	12	24	--	--	24
Apparent green-completions at single-well batteries (sub-type 351)	108	122	--	--	122
Apparent green-completions at other battery sub-types	523	702	--	--	702
Assumed confidential/not found in PRA	371	488	--	--	--
Other	21	28			

[a] 1 UWI both flared and vented; [b] 13 UWIs both flared and vented

The overall flaring and venting rates for well-completion operations by natural gas well type are provided in Table 4.10. The dataset for shale related wells is small, and therefore the perceived variation in rates among the different gas types may be due to sample size. In general, the number of actively producing shale wells in Alberta in 2011 was negligible relative to tight gas CBM and CBM hybrid wells with 99 shale, 48 CBM shale other, and 2 shale hybrid wells reporting gas volumes in the available volumetric data.

Table 4.10: Overall reporting rates of reported flaring, venting, and apparent green-completions for non-confidential well-structures with one or more drilled and fractured legs in Alberta in 2011

Well type	Number of non-confidential fractured well structures in Alberta in 2011			
	Total	# linked with Flaring (%)	# linked with Venting (%)	# without reported flaring / venting (%)
Tight gas	835†	294 (35.2)	80 (9.6)	471 (56.4)
CBM	29	14 (48.3)	8 (27.6)	7 (24.1)
CBM hybrid	307	128 (41.7)	26 (8.5)	153 (49.8)
CBM shale other	1	0 (0.0)	0 (0.0)	1 (100.0)
Shale	15	0 (0.0)	4 (26.7)	11 (73.3)
TOTAL	**1187**	**436 (36.7)**	**118 (9.9)**	**643 (54.2)**

†10 well structures both flared and vented

4.3 Procedure for Estimating Diesel Combustion Emissions during Well Drilling

Air emissions from well drilling operations are dominated by diesel combustion emissions from drilling rigs and casing equipment. From an operational standpoint, the duration of the drilling process and thus the diesel combustion emissions will depend on the depth of the well. The National GHG inventory intensity factor of 60.6 t CO_2 / UWI for well drilling in Canada in 2000 (Table 4, CAPP, 2004a) does not directly apply to wells drilled in 2011 given the increased drilling depths associated with hydraulically fractured wells. However, by back calculating the volume of combusted diesel and knowing the average depth of a UWI drilled in 2000, a drilling year independent intensity factor based on meters drilled can be obtained. More specifically, by assuming all emitted CO_2 is a product of diesel combustion during well drilling and considering an emission factor of 2709.8 kg CO_2/ m^3-of-combusted-diesel for large diesel engines (see U.S. EPA AP-42 Section 3.4, US EPA, 1995a), a diesel usage factor of 22.4 m^3 diesel / UWI-drilled-in-2000 can be derived. This diesel usage factor can be converted to a per meter drilled basis by multiplying by the average distance drilled for a natural gas UWI in 2000. As summarized in Table 4.11, from the 2011 PRA production data, a total of 9418 natural gas UWIs with a spud date in the year 2000 can be identified. Since the CAPP factor of 60.6 t CO_2 / UWI for the year 2000 data does not delineate between gas types, the average of 1023.9 m was used to compute a diesel usage factor of 0.022 m^3 diesel / m-drilled.

Table 4.11: Depths of natural gas wells producing in 2011 that were drilled in Alberta in 2000

Well type	Number of UWIs	Total drilled length [m]	Average UWI drilled length [m/UWI]	Standard deviation of UWI drilled length [m/UWI]
(Tight) gas	8089	5863749	1034.7	756.7
CBM	388	144699.9	898.8	361.3
CBM hybrid	939	351546	917.9	280.0
CBM Shale other	n/a	n/a	n/a	n/a
Shale	2	750	750.0	n/a

The average drilling lengths for the set of natural gas wells drilled and completed in 2011 are provided in Table 4.12. The major differences in distances drilled between 2000 and 2011 occur for tight gas and shale wells. This is in part due to the current usage rates of horizontal drilling practices, which is much more common in tight gas and shale gas wells than in CBM wells (see Table 3.11).

Table 4.12: Drilling statistics for the set of UWI drilled in Alberta in 2011 and subsequently fractured

Well type	Number of fractured UWIs drilled in 2011	Total drilled length [m]	Average UWI drilled length [m/UWI]	Standard deviation of UWI drilled length [m/UWI]
Tight gas	1888	585047.8	2958.2	1154.1
CBM	103	78471.9	761.9	293.5
CBM hybrid	723	751944.6	1040.0	186.8
CBM Shale other	1	1081.0	1081.0	n/a
Shale	20	43457.3	2172.9	1107.7

The total estimated diesel volume combusted during well drilling for hydraulically fractured natural gas wells drilled in 2011 was computed for each gas type and is summarized in Table 4.13.

Table 4.13: Estimated diesel used during well drilling for fractured wells drilled in Alberta in 2011

Well type	Number of Fractured UWIs drilled in 2011	Total drilled length [m]	Total diesel usage [m^3]
Tight gas	1888	5585047.8	121981.9
CBM	103	78471.9	1713.9
CBM hybrid	723	751944.6	16423
CBM Shale other	1	1081.0	23.6
Shale	20	43457.3	949.1
Total	**2735**	**6460002.6**	**141091.3**

4.4 Procedures for Estimating Diesel Combustion Emissions during Well-Completion

Diesel consumption associated with drilling, pumping of fracturing fluids; sand and blender trucks; wireline equipment; heaters for fracturing fluids; light towers; office trailers; and other on-site equipment of the types shown in Figure 4.5 and Figure 4.6 is not tracked as part of the upstream oil and gas regulatory system. Thus, in the absence of direct, centrally tracked data for on-site diesel fuel use, emissions estimates must be derived indirectly using other means.

Figure 4.5: (a) Blender truck receiving sand, (b) Diesel powered light stand, (c) Wireline truck, (d) Heated water tanks, (e) Sand conveyor

Consistent with procedures co-developed through the creation of the 2012 Canadian National Greenhouse Gas Inventory, diesel fuel use estimates were made based on the assumption that on-site fuel use scales with the total volume of fracturing fluid used during a well-completion. This scaling is also assumed to be independent of fracturing fluid composition. Using privately shared diesel fuel volume data for 22 completion jobs that occurred in western Canada during 2012, a scaling factor of 0.0245 m^3 of diesel per m^3 of injected fracturing fluid was derived. This factor includes diesel consumed during heating of fracture fluids; blending of the carrier fluid with chemicals; sand and gel additives; wireline and pumping operations; as well as generating power for office trailers, lights, and other on-site electrical requirements.

Figure 4.6: (a) Coil tubing operation drilling out stage plugs, (b) Onsite fuel delivery, (c) Pump trucks for fracturing fluid

An estimate of the total diesel volume consumed during well-completions in Alberta for the year 2011 was computed using available "Load fluid injected volumes" reported within the PRA. Unfortunately current ERCB regulations do not mandate reporting of injected fluid volumes during well-completions, although operators may choose to supply this information as outlined in Directive 007 (ERCB, 2011b):

> *"When a well that is being completed (not on production or injection) receives load fluid for injection, the operator of the well may choose to submit the transaction to the Registry as load injection."*

Only in cases where the recovered fluid volume exceeds the injected fluid volume and/or the recovered fluid includes other products, does the reporting become mandatory. When injected volume data are reported, Directive 7 specifies (ERCB, 2011b):

> *"An operator will enter LDINJ to report the volume of product injected to a well for the purpose of completing or servicing the well."*

where the injected products may be classified as “OIL”, “COND” (defined as “Condensate”), or “WATER.”

A search of the year 2011 PRA data for LDINJ volumes corresponding to the identified 1208 non-confidential fractured natural gas wells yielded 120 well structures with reported LDINJ data. Figure 4.7 plots the reported LDINJ volumes versus the number of months since the well’s fracture date for each injected fluid type.

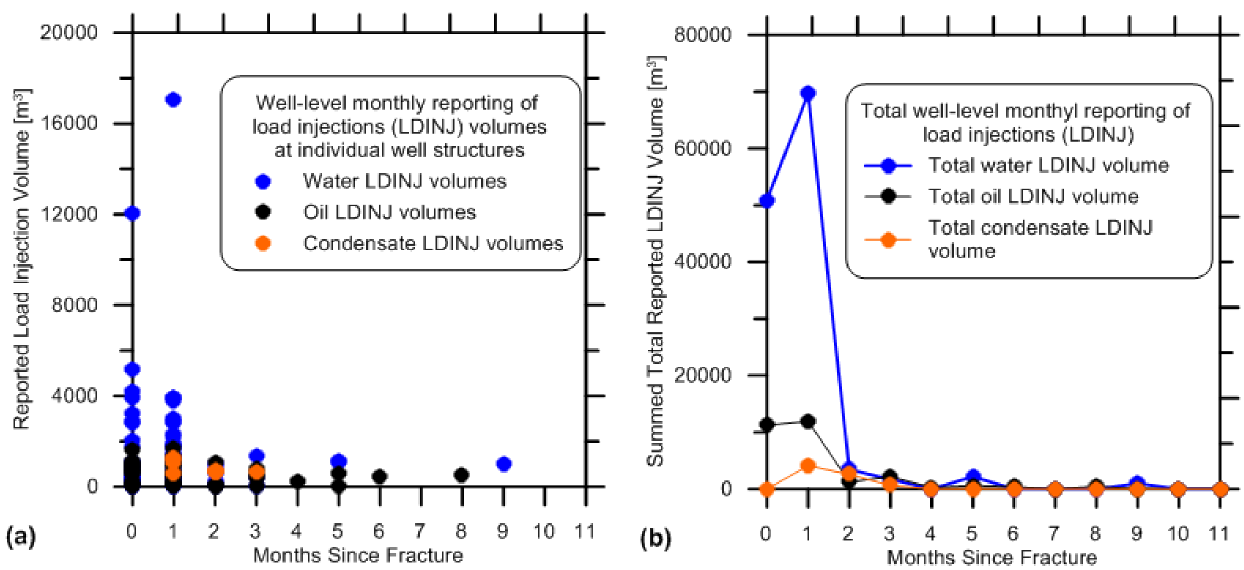

Figure 4.7: Well-level load injection (LDINJ) volumes associated with well-completion reported (a) monthly LDINJ volumes reported for individual wells in each month since their fracture date, (b) summed total reported LDINJ volumes in month since fracture data indicating that essentially all volume is reported within 1-month of fracture.

Both Figure 4.7(a) and Figure 4.7(b) show that the majority of the reported injected volumes occur within 1 month of each well’s fracture date. This trend is consistent with that of well-level well-completion flaring as discussed in Section 4.2.3. Load injected fluid volumes reported within 1 month of the fracture date for all 120 reporting well structures in 2011 are summarized in Table 4.14. An estimated diesel usage volume was calculated from these data by multiplying the sum of the water, oil, and condensate volumes by 0.0245 [m^3 of diesel per m^3 of LDINJ].

Table 4.14: Load fluid injected volumes reported within 1 month of fracturing at well linked to any battery sub-type

Gas type	Water			Oil			Condensate			Diesel usage [m³]
	# of wells	# of frac'd UWIs	volume [m³]	# of wells	# of frac'd UWIs	volume [m³]	# of wells	# of frac'd UWIs	volume [m³]	
Tight gas	77	102	119545.9	37†	61†	23185.9	4	4	4120.2	3597.9
CBM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale	5	5	947	n/a	n/a	n/a	n/a	n/a	n/a	23.2
Total	82	107	120492.9	37†	61†	23185.9	4	4	4120.2	3621.1

† Includes 3 single UWI well structures that also injected water. In each case the majority of the injected fluid was water with water to oil ratios of 90%, 97% and 99%.

4.5 Procedures for Estimating Well Operational Emissions for Hydraulically Fractured Well structures

Well operational emissions over the lifetime production period of a well may include onsite fuel (natural gas) combustion, as well as, venting and flaring occurring after well-completion associated with liquid unloading (i.e. well cleanup or blowdown treatments), equipment (separator tanks, compressors, etc.) maintenance, and/or required work to service/repair down-hole equipment. Although Directive 60 specifies flared and vented volumes associated with "depressurizing of pipeline, compression, and processing systems" must be reported if volumes exceed 100-500 m^3 (ERCB, 2006; ERCB, 2011a), non-routine flaring and venting that may be associated with liquid unloading is not specifically identified for required reporting. Indeed, the CAPP National Inventory of Greenhouse Gases (CAPP, 2004c) outlines procedures for separately estimating emissions for blowdown treatments of natural gas wells to augment reported data. These procedures and estimates from other agencies (e.g. US EPA and ANGA) are further discussed in Section 5.4.

Any gas volumes that are reported over the production lifetime of a well are aggregated under monthly fuel, venting, and flaring reporting within the PRA at both the well- and battery-level. Although the Petrinex volumetric data available for the present analysis were restricted to the 2011 reporting year, through deeper analysis it was possible to investigate flaring and venting trends at various stages during the production life of a well by considering any wells completed in the previous 10-years (as gleaned from analysis of the ERCB General Well data file) and linking them with any relevant reported volumes in Petrinex for the year 2011. With these limited data, fuel, flaring and venting volumes were identified for natural tight gas wells which:

- were linked to single-well gas batteries (sub-type 351);
- had a fracture date between the January 1st 2000 and December 31st 2011; and
- reported gas production in the available 2011 volumetric data.

To remain consistent with the definitions for well-completion applied in Section 4.2 so as to avoid any potential double-counting of emissions associated with well-completion in the analysis, only produced gas, fuel, venting, and flaring volumes that were reported at least 2 months after the most recent fracture date for each well were considered when estimating well operational emissions.

Figure 4.8 shows the frequency with which tight gas wells most recently fractured in 2000-2005 or 2006-2010 reported monthly flaring (a) or venting (b) volumes during 2011. The vast majority of tight gas wells (93.1%) reported no flaring or venting during any month in 2011. The reader should note the broken scales on the vertical axes of these plots which were necessary to plot all data on the same figure. In general, for wells that reported flaring, most did so only for a single month of the year. By contrast, wells that reported venting tended to reported more frequently.

Figure 4.9 plots the frequency of monthly reported fuel use in 2011 for tight gas wells most recently fractured in either 2000-2005 or 2006-2010. The trends in fuel usage suggest approximately one-third of gas wells are continuously using fuel during operation. The frequency plots for flaring, venting, and fuel use show that, in general, the operational trends for tight gas wells remained constant between wells fractured during the years 2000-2005 and those fractured between 2006 and 2010.

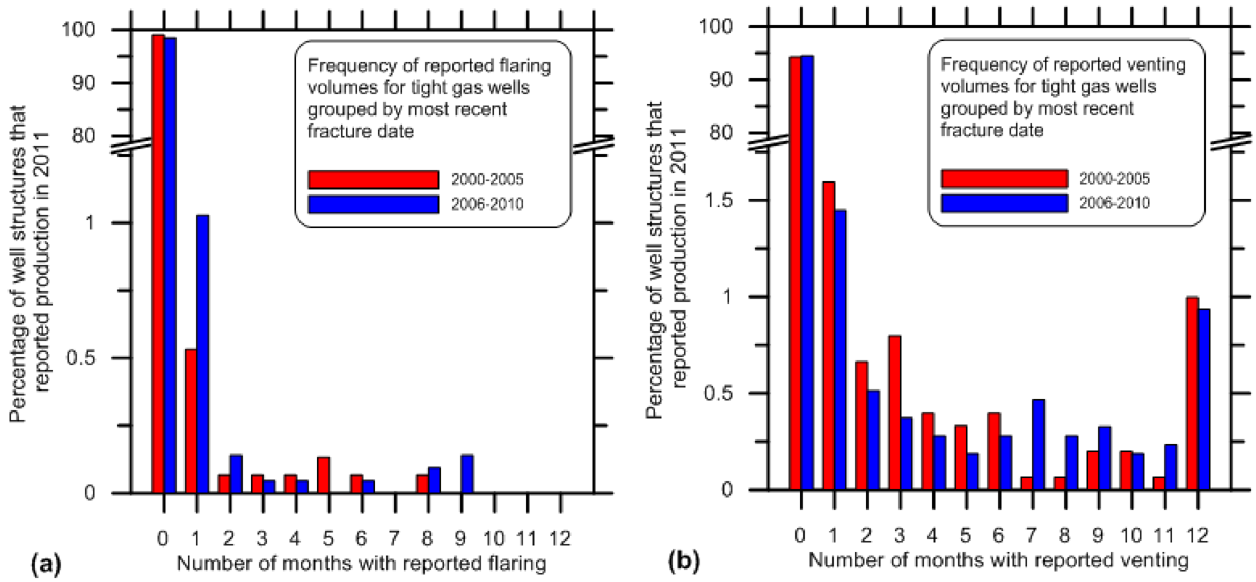

Figure 4.8: Frequency of monthly reported flaring volumes (a) and venting volumes (b) grouped by most recent fracture date. Note the broken scale on the vertical axis necessary to plot the frequency of zero months reporting on the same figure. Since the wells fractured in 2011 do not have a full 12 months of activity available, they are not included to prevent a potential bias in the frequency of monthly reporting

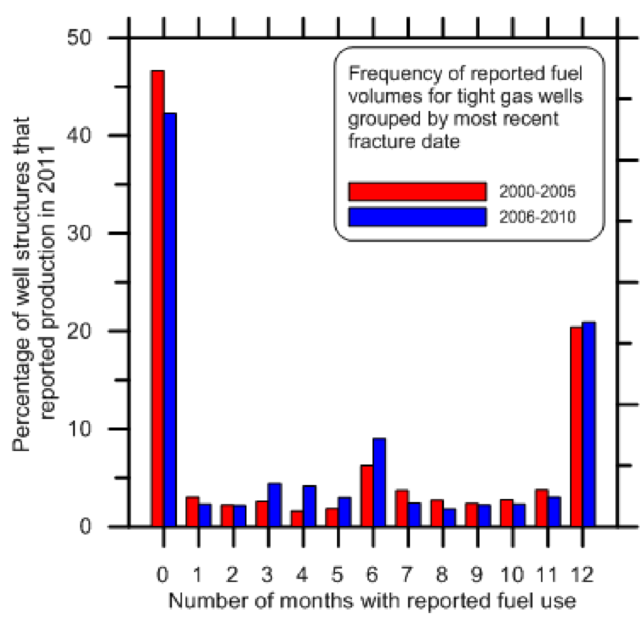

Figure 4.9: Frequency of monthly reported fuel use grouped by most recent fracture date. Since the wells fractured in 2011 do not have a full 12 months of activity available, they are not included to prevent a potential bias in the frequency of monthly reporting

From the aggregate volumes summarized in Table 4.15, it is verifiable that fuel usage occurs at 56% of the considered tight gas wells and accounts for 0.7% of the produced gas. The average fuel use from all gas batteries in 2010 was reported to be 1.27% of raw gas production (ERCB, 2012c). The percentage of wells reporting flaring and venting volumes are considerably lower at roughly 1.4% and 5.9% respectively.

Table 4.15: Production, fuel, venting, and flaring volumes for tight gas wells reported at least 2 months after the most recent fracture date to exclude well-completion emissions.

Activity	Number of reporting well structures	Number of reporting fractured UWIs	Total reported volumes excluding well-completions [1000 m^3]
Production	3846 (100%)	6919 (100%)	8248851.4
Fuel	2151 (55.9%)	3934 (56.9%)	54810.4
Venting	225 (5.9%)	358 (5.2%)	1139.2
Flaring	55 (1.4%)	108 (1.6%)	642.1

The individual volumes on a per UWI basis for flaring, venting, and fuel use are plotted against months since the most recent fracture date for each reporting well in Figure 4.10 and Figure 4.11 respectively. With the exception of a few "outliers" under each reporting activity, the trends are very consistent with comparatively low-levels of flaring and venting being reported over the lifetime of the well following the initial well-completion. The apparent outliers in reported flaring volumes (Figure 4.10a) occurring in the first 12 months since fracture date are monthly volumes from 3 well structures, of which 1 well flared nearly continuously over the year 2011. For Figure 4.10b, 7 of the 8 outlying volumes are from a single-well structure. These apparent outliers from a small number of well structures were removed when calculating well service emission factors presented in Section 5.4.

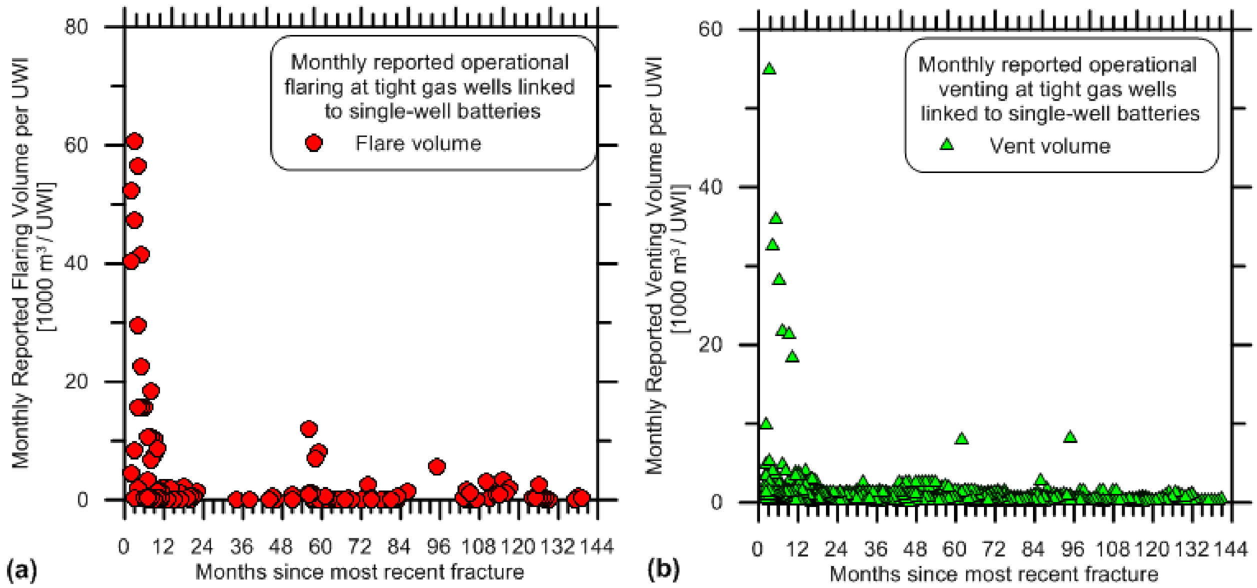

Figure 4.10: Reported monthly flaring volumes (a) and venting volumes (b) per UWI for fractured tight gas wells, 2 or more months following well-completion

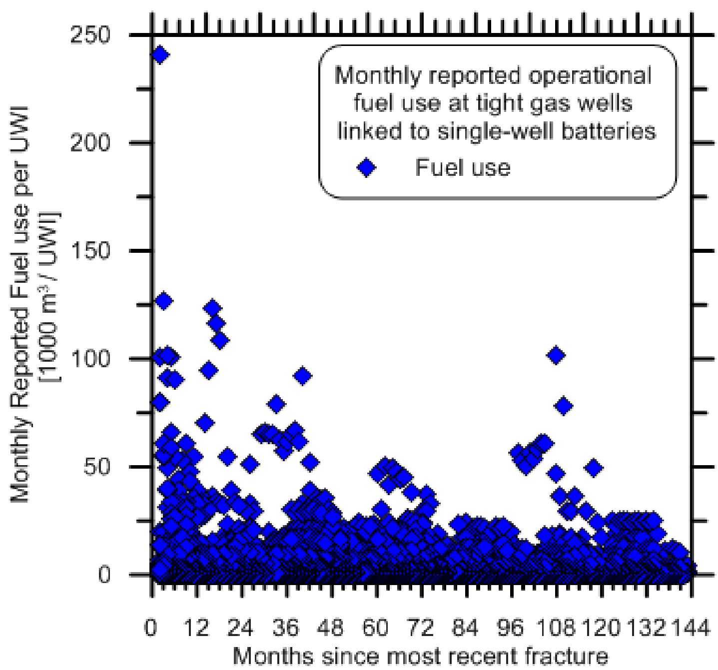

Figure 4.11: Reported fuel usage volumes per UWI for fractured tight gas wells, 2 or more months following well-completion

For the fuel usage data plotted in Figure 4.11, variations in reported volumes appear more indicative of inherently greater variability among individual sites rather than being considered "outliers." It is possible that these higher volume values at some sites are a result of different operational procedures, such as the use of fuel during flaring verses fuel used to run a compressor or boiler, and are therefore equally valid in the calculation of an emission factor. Figure 4.12 shows the range and distribution of reported monthly fuel volumes among different tight gas wells. Analysis of the figure reveals that:

- 60% (10606 of 17612) of reported monthly fuel usage volumes per UWI were between 100 m^3 and 1000 m^3;
- 30% (5210 of 17612) of reported monthly fuel usage volumes per UWI were between 1100 m^3 and 5000 m^3;
- 6% (1049 of 17612) of reported monthly fuel usage volumes per UWI were between 5100 m^3 and 10000 m^3; and
- 4% (747 of 17612) of reported monthly fuel usage volumes per UWI were greater than 10000 m^3 with a maximum value of 240700 m^3.

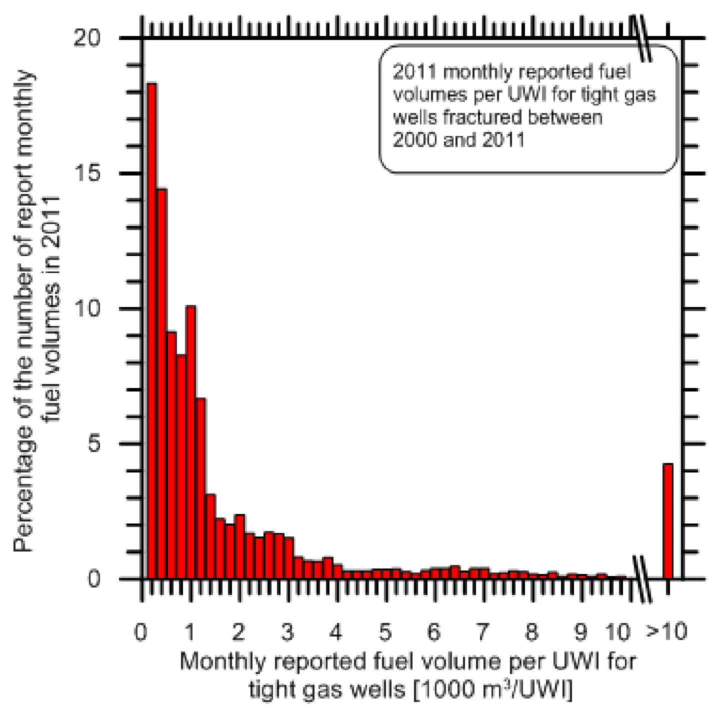

Figure 4.12: Distribution of reported monthly fuel usage volumes in 2011 for tight gas wells most recently fractured in 2000-2011

5 DERIVATION OF EMISSION FACTORS FOR DRILLLING, COMPLETION, AND OPERATION OF UNCONVENTIONAL GAS WELLS IN ALBERTA

5.1 Flaring and Venting Emission Factors for Unconventional Gas Well-completions in Alberta

Using the completion flaring and venting volume emission data derived and discussed in section 4.2, average unconventional well-completion flaring and venting emission factors, Criteria Air Contaminants (CAC) emission factors, and Greenhouse Gas (GHG) emission factors were derived for each gas-well type where data permitted. Figure 5.1 plots the distribution of reported flaring and venting volumes associated with completion of individual tight gas wells derived using the procedures detailed in Section 4.2. Available reported flaring volumes for completion of CBM Hybrid, and CBM wells are plotted in Figure 5.2 and Figure 5.3, respectively. Unfortunately, the sample sizes in the available reported data were insufficient to permit well-completion venting estimates for CBM Hybrid and CBM wells, or to permit flaring and/or venting estimates for wells classed as shale or CBM shale.

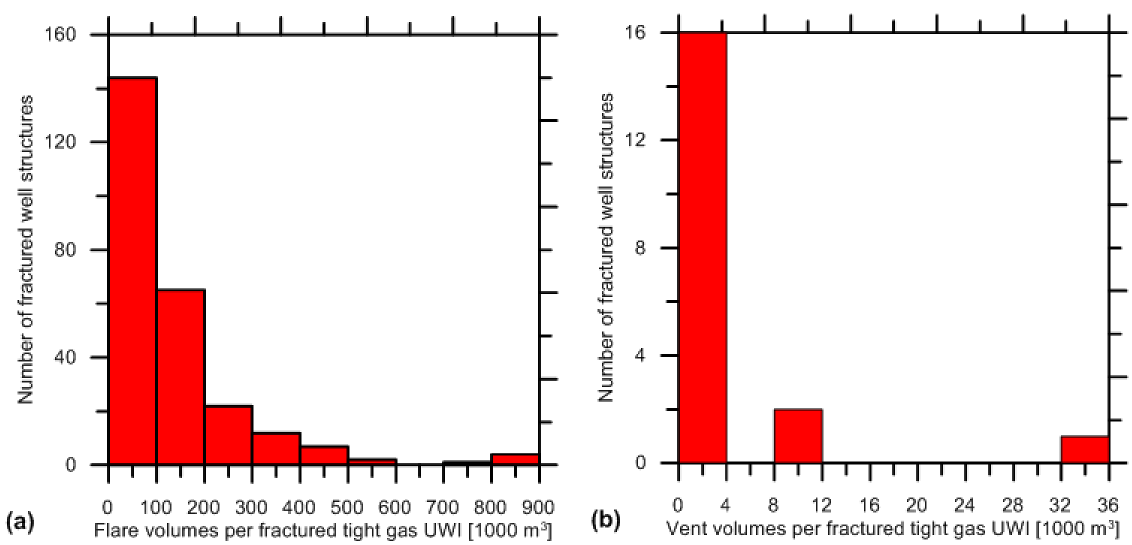

Figure 5.1: Histograms of reported (a) flaring and (b) venting volumes during well-completion at tight gas wells in Alberta in 2011

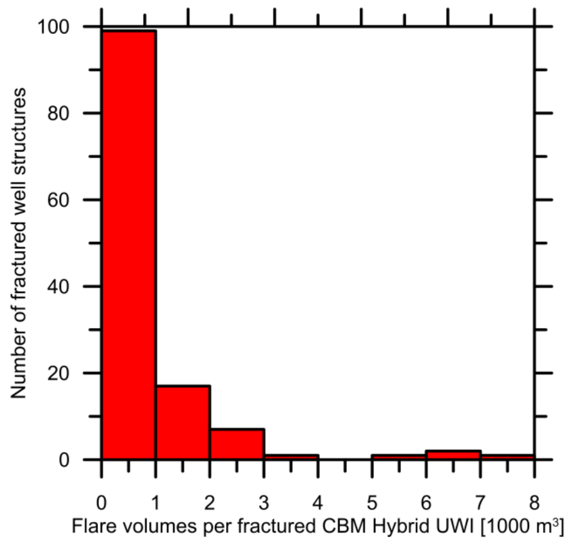

Figure 5.2: Histogram of reported flaring volumes during well-completion at CBM hybrid wells in Alberta in 2011

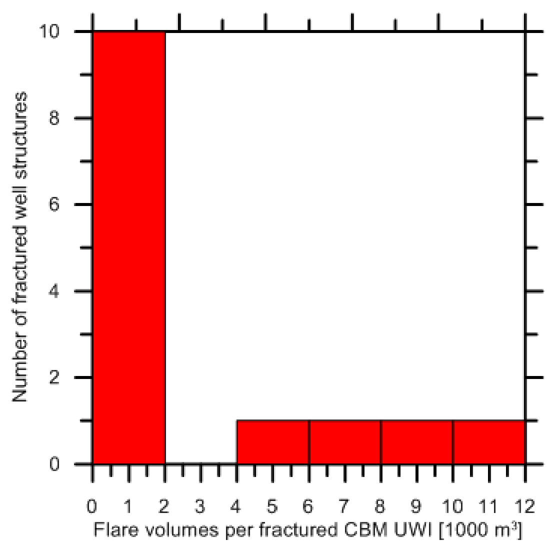

Figure 5.3: Histogram of reported flaring volumes during well-completion at CBM wells in Alberta in 2011

Table 5.1 presents estimated average emission factors for flaring and venting during well-completion, which were computed using the data presented in Figure 5.1, Figure 5.2, and Figure 5.3. The emission factors were calculated by first normalizing the reported volumes for each well structure by the number of contributing fractured UWI within that well structure, and subsequently computing the average of these data across all well-structures of a specified type. Due to the low number of reporting well-structures for CBM-type wells in particular, appropriate caution should be used applying these factors. Section 5.5 compares these and all other emission factors derived in this report using 2011 data specific to Alberta operations with available emission factors in the literature.

Table 5.1: Volumetric emission factors for reported flaring and venting during unconventional well-completions in Alberta derived using available data for 2011

Well type	# of UWIs reporting flaring and/or venting in 2011	Flaring		Venting	
		Mean Rate [1000 m^3 / UWI]†	Standard Deviation [1000 m^3 / UWI]†	Mean Rate [1000 m^3 / UWI]†	Standard Deviation [1000 m^3 / UWI]†
Tight gas	407 *	113.2	151.3	0.6	6.5
CBM hybrid	291	0.9	1.2	--	--
CBM	30	2.7	3.7	--	--
CBM shale other	0	n/a	n/a	n/a	n/a
Shale	0	n/a	n/a	n/a	n/a

† Note: mean rate and standard deviation data are correctly calculated as the average and standard deviation of the set of volume/UWI data first calculated for each UWI. These are properly representative of an average well emission factor but are not necessarily equal to the simple average of the total reported volume from all UWIs divided by the total number of UWIs.
* 388 of the 407 sites reported flaring volumes. Only 20 of the 407 sites reported venting volumes. Calculated venting emission factors exclude a single outlier that reported a venting volume of 102.5*1000 m^3/UWI.
.

5.1.1 GHG and CAC Emission Factors for Flaring and Venting during Unconventional Gas Well-completions in Alberta

Table 5.2 presents greenhouse gas (GHG) emission factors for flaring and venting during unconventional gas well-completions in tonnes of CO_2 equivalent per UWI, which were derived based on the data summarized in Table 5.1. Calculations were performed using relevant GHG emission factors specifically derived from data for flared and vented gas in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012) and assuming a 98% flare efficiency. In the absence of further well-type-specific composition data, common emission factors were applied to all well types which assumed a mean methane content of 83.5% and 86.7% in flared and vented gas respectively (see Johnson and Coderre, 2012). Results are presented for a range of global warming potential (GWP) values and time-horizons as noted in Table 5.2 and associated footnotes, where it is understood that these different calculations may all be useful in different applications. Reported volumes are referenced to a pressure of 101.325 kPa and a temperature of 15°C.

Table 5.2: Greenhouse gas emission factors for unconventional well-completions in which gas is flared and/or vented, derived using available reported data for Alberta in 2011

Well type	# of UWIs reporting flaring and/or venting in 2011	Greenhouse gas (GHG) emission factors† [t CO_2e /UWI]					
		100-year time horizon				20-year time horizon	
		$\mathrm{GWP}_{CH_4} = 21$‡		$\mathrm{GWP}_{CH_4} = 25$‡		$\mathrm{GWP}_{CH_4} = 72$‡	
		Mean	Standard Deviation	Mean	Standard Deviation	Mean	Standard Deviation
Tight gas	407	279.1	371.8	280.6	375.5	357.8	525.1
CBM hybrid	291	2.1	3.0	2.1	3.0	2.6	3.6
CBM	30	6.5	8.9	6.5	8.9	7.9	10.8
CBM shale other	0	n/a	n/a	n/a	n/a	n/a	n/a
Shale	0	n/a	n/a	n/a	n/a	n/a	n/a

† Derived using volumetric emission factor data presented in Table 5.1. Note: mean rate data are correctly calculated as the average of the set of CO_2e/UWI data first calculated for each UWI. These are properly representative of an average well emission factor but are not necessarily equal to the simple average of the total GHG emissions from all UWIs divided by the total number of UWIs.

‡ Refers to the assumed time-horizon and the corresponding global warming potential (GWP) used to calculate CO_2 equivalent GHG emissions. The 100- and 20-year time horizon GWP values for methane of 25 and 72 respectively are from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (AR4, IPCC, 2007). At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The 100-year time horizon GWP value for methane of 21 is from the legacy IPCC 2nd Assessment Report (IPCC, 1996), which was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998). Calculations were performed using relevant GHG emission factors specifically derived from data for flared and vented gas in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012) and assuming a 98% flare efficiency. In the absence of further, well-type-specific composition data, common emission factors were applied to all well types which assumed a mean methane content of 83.5% and 86.7% in flared and vented gas respectively (see Johnson and Coderre, 2012).

The results show that well-completion flaring and venting emissions are substantially larger for tight gas wells than for CBM wells, although the lesser number of data points for fractured CBM and CBM hybrid wells means that their associated emission factor estimates would have a larger degree of uncertainty. In general, there were insufficient “shale” or “CBM shale other" gas well-completions in Alberta in 2011 to allow calculation of emission factors for these wells.

Table 5.3 summarizes calculated emission factors for CACs associated with flaring and venting during unconventional well-completions derived based on Alberta data for 2011 as above. As further detailed in the footnotes to the table, the emission factors were calculated primarily using data for flares provided in AP-42, Chapter 13 (US EPA, 1995b) and US EPA WebFIRE (US EPA, 2009) which is similarly used in (CAPP, 2004b).

Table 5.3: Emission factors for Criteria Air Contaminants (CAC) emitted via flaring and venting during unconventional well-completions in Alberta in 2011

Well type	# of UWIs reporting flaring and/or venting in 2011	NO_x[1] [kg/UWI]		$PM_{2.5}$[2] [kg/UWI]		CO[1] [kg/UWI]		VOC[1] [kg/UWI]		THC[1] [kg/UWI]	
		Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.	Mean	Std. Dev.
Tight gas	407	128.2	171.4	249.8	333.9	697.7	932.5	97.7	130.6	264.6	352.9
CBM hybrid	291	1.0	1.4	2.0	2.6	5.5	7.4	0.8	1.0	2.1	2.8
CBM	30	3.1	4.2	6.0	8.2	16.6	22.8	2.3	3.2	6.3	8.6
CBM shale other	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

[1] Calculated based on data presented in Table 5.1 using emission factors for flares provided in AP-42, Chapter 13 (US EPA, 1995b) and also used in (CAPP, 2004b). Calculations assume a mean gas heating value of 38.747 MJ/m^3 based on compositional analysis of flared and vented in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012).
[2] Calculated as above using flare emission factor data in US EPA WebFIRE (US EPA, 2009) attributed to (US EPA, 1991).

5.1.2 Estimated Total GHG and CAC Emissions from Flaring and Venting during Unconventional Well-completions in Alberta in 2011

To estimate the total GHG and CAC emissions from unconventional well-completion in Alberta in 2011 it was necessary to assume that the identified non-confidential fractured UWIs are representative of the UWIs held confidential by ERCB in the present dataset, such that the proportions of green-completions and flaring and venting rates are consistent. In Table 5.4 total prorated volumes for flaring and venting are calculated for each gas type as the sum of: (i) the

Attributable Reported Volume, (ii) the number of fractured UWIs deemed confidential times the flaring/venting percentage in Table 4.10 times the emission factor in Table 5.1, and (iii) the number of wells without attributable volumes linked to flaring and venting batteries times the emission factor in Table 5.1. Although four shale gas wells were linked to multi-well batteries reporting flaring and venting, as further discussed in Section 4.2.5 because of lack of data it was not possible to calculate prorated flaring and venting volumes for these wells and they have necessarily been excluded from subsequent calculations.

Table 5.4: Estimated total unconventional well-completion flaring and venting volumes in Alberta in 2011 derived using available reported data

Well type	Total # of fractured UWIs	# of fractured UWIs deemed confid-ential	# of fractured UWIs linked with flaring and /or venting (incl. at other battery types)	# of fractured UWIs reporting flaring and /or venting for which volumes can be attributed	Flaring		Venting	
					Attributable Reported Volume [1000 m^3]	Prorated Total Volume [1000 m^3]	Attributable Reported Volume [1000 m^3]	Prorated Total Volume [1000 m^3]
Tight gas	1576	402	515	407	35096.7	56205.4	167.3	236.8
CBM hybrid	591	67	331	291	181.2	205.6	0	0
CBM	65	16	39	30	46.1	61.3	0	0
CBM shale other	1	0	0	0	n/a	n/a	n/a	n/a
Shale	19	3	4	0	n/a	n/a	n/a	n/a
TOTAL	**2252**	**488**	**889**	**728**	**35324**	**56472.3**	**167.3**	**236.8**

With the above assumptions, the total estimated GHG emissions from well-completions in Alberta in 2011 can be calculated as summarized in Table 5.5. For the 2252 hydraulically fractured well legs (UWIs) in Alberta in 2011 contained within 1579 well structures (i.e. well legs linked to a common surface hole), total GHG emissions were estimated to be approximately 139 kt CO_2e on a 100-year time horizon.

Table 5.5: Estimated total GHG emissions from flaring and venting during unconventional well-completions in Alberta in 2011 derived using available reported volumetric data presented in Table 5.4

Well type	Total # of fractured UWIs	Total Estimated Greenhouse gas (GHG) emissions [t CO_2e]		
		100-year time horizon		20-year time horizon
		$\mathrm{GWP}_{CH_4} = 21$‡	$\mathrm{GWP}_{CH_4} = 25$‡	$\mathrm{GWP}_{CH_4} = 72$‡
Tight gas	1576	137825	138381	174928
CBM hybrid	591	493	493	602
CBM	65	147	147	180
CBM shale other	1	n/a	n/a	n/a
Shale	19	n/a	n/a	n/a
TOTAL	**2252**	**138465**	**139022**	**175710**

‡ Refers to the assumed time-horizon and the corresponding global warming potential (GWP) used to calculate CO_2 equivalent GHG emissions. The 100- and 20-year time horizon GWP values for methane of 25 and 72 respectively are from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007). At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. The 100-year time horizon GWP value for methane of 21 is from the legacy IPCC 2nd Assessment Report (IPCC, 1996), which was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998). Calculations were performed using relevant GHG emission factors specifically derived from data for flared and vented gas in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012) and assuming a 98% flare efficiency. In the absence of further, well-type-specific composition data, common emission factors were applied to all well types which assumed a mean methane content of 83.5% and 86.7% in flared and vented gas respectively (see Johnson and Coderre, 2012).

Similarly, the total CAC emissions associated with flaring and venting during unconventional well-completions in Alberta in 2011 were estimated using the data and prorated volumes presented in Table 5.4. The resulting total estimated emissions of NOx, PM2.5, CO, VOC, and THC are summarized in Table 5.6.

Table 5.6: Estimated total CAC emissions from flaring and venting during unconventional well-completions in Alberta in 2011 derived using available reported volumetric data presented in Table 5.4

Well type	Total # of fractured UWIs	NOx[1] [kg]	$PM_{2.5}$[2] [kg]	CO[1] [kg]	VOC[1] [kg]	THC[1] [kg]
Tight gas	1576	63667	124047	346424	48509	131304
CBM hybrid	591	233	454	1267	177	479
CBM	65	69	135	378	53	143
CBM shale other	1	n/a	n/a	n/a	n/a	n/a
Shale	19	n/a	n/a	n/a	n/a	n/a
TOTAL	**2252**	**63969**	**124636**	**348069**	**48739**	**131927**

[1] Calculated based on data presented in Table 5.4 using emission factors for flares provided in AP-42, Chapter 13 (US EPA, 1995b) and also used in (CAPP, 2004b). Calculations assume a mean gas heating value of 38.747 MJ/m^3 based on compositional analysis of flared and vented in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012).
[2] Calculated as above using flare emission factor data in US EPA WebFIRE (US EPA, 2009) attributed to (US EPA, 1991).

5.2 Estimation of Diesel Well Drilling Emission Factors

To estimate the air emissions from diesel combustion during well drilling, a diesel usage factor was derived for each natural gas well type based on well depth. The total drilling depth for each UWI is reported in the GENWELL data file under report 010, drilling occurrence data. By applying the diesel usage factor of 0.022 m^3 diesel / m-drilled, estimated in Section 4.3, to the total drill depth for each UWI, an average combusted diesel volume can be estimated. These average combusted diesel volumes were separately determined for each of the five main gas well types as summarized in Table 5.7.

The apparent variability in tight gas drilling lengths is partially a consequence of horizontal drilling, which was used in roughly 30% of fractured tight gas wells drilled in 2011 (See Table 3.11). The average fractured horizontal tight gas UWI was approximately 950m longer than the average fractured vertical tight gas UWI. In the case of shale gas wells, where 85% involved horizontal drilling, the differences in drilling depths can be attributed to geographic location. In particular, 17 of the 20 shale gas wells were located in the Shallow Upper Colorado formation with an average drilling length of 1726 m and a standard deviation of 152 m. The remaining 3 shale gas wells had substantially longer drill lengths of 4400 m, 4557.3 m and 5157 m and were part of the Second white speckled shale formation.

Table 5.7: Estimated diesel used during well drilling per UWI for fractured wells drilled and completed in Alberta in 2011

Well type	# of well structures	# of fractured UWIs drilled in 2011	Length drilled [m/UWI]		Diesel usage [m^3/UWI]	
			Mean	Standard Deviation	Mean	Standard Deviation
Tight gas	1334	1888	2958.2	1154.1	64.6	25.2
CBM hybrid	498	723	1040.0	186.8	22.7	4.1
CBM	81	103	761.9	293.5	16.6	6.4
CBM shale other	1	1	1081	n/a	23.6	n/a
Shale	20	20	2172.9	1107.7	47.5	27.5

The average combusted diesel volume per UWI for each well type was used to calculate mean emission factors for individual CACs and GHGs. Calculations were performed using relevant emission factor data for large diesel engine sources published in U.S. EPA AP-42 Section 3.4 (US EPA, 1995a). The resulting mean emission factor data are summarized in Table 5.8 and the associated standard deviations are provided in Table 5.9.

Table 5.8: Mean emission factors for specific GHGs and CACs emitted via diesel combustion during unconventional well drilling in Alberta in 2011

Well type	Mean diesel usage [m^3/UWI]	Mean GHG and CAC emission factors [kg/UWI]†										
		CO_2	CO	CH_4	N_2O	SO_2	NOx	TPM	PM_{10}	$PM_{2.5}$	VOC	THC
Tight gas	64.6	175074.6	901.9	8.6	25.5	307.7	3395.4	65.8	52.6	50.8	86.9	95.5
CBM hybrid	22.7	61552.5	317.1	3.0	9.0	108.2	1193.7	23.1	18.5	17.9	30.6	33.6
CBM	16.6	45089.5	232.3	2.2	6.6	79.2	874.5	16.9	13.6	13.1	22.4	24.6
CBM shale other	23.6	63977.0	329.6	3.1	9.3	112.4	1240.8	24.0	19.2	18.6	31.8	34.9
Shale	47.5	128597.0	662.5	6.3	18.7	226.0	2494.0	48.3	38.7	37.3	63.8	70.1

† Derived from diesel fuel consumption factor using emission factor data for large diesel engines sources from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a) and similarly used in (CAPP, 2004b). For calculation of SO_2 emissions, a fuel sulphur content of 0.2875% is assumed which is consistent with the reported SO_2 emission factor of 124.1 ng/J used in the CAPP 2004 National Inventory (CAPP, 2004b). Following (CAPP, 2004b) N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2 of (Environment Canada, 1997).

Table 5.9: Standard deviations of specific GHG and CAC emission factors for diesel combustion during unconventional well drilling in Alberta in 2011

Well type	Standard deviation of diesel usage [a] [m^3/UWI]	Standard deviations of GHG and CAC emission factors [kg/UWI]†,[a]										
		CO_2	CO	CH_4	N_2O	SO_2	NOx	TPM	PM_{10}	$PM_{2.5}$	VOC	THC
Tight gas	25.2	68303.3	351.9	3.4	9.9	120.0	1324.7	25.7	20.5	19.8	33.9	37.3
CBM hybrid	4.1	11053.2	56.9	0.5	1.6	19.4	214.4	4.2	3.3	3.2	5.5	6.0
CBM	6.4	17371.8	89.5	0.9	2.5	30.5	336.9	6.5	5.2	5.0	8.6	9.5
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale	27.5	65560.1	337.7	3.2	9.5	115.2	1271.5	24.6	19.7	19.0	32.5	35.8

† Derived from diesel fuel consumption factor using emission factor data for large diesel engine sources from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a) and similarly used in (CAPP, 2004b). For calculation of SO_2 emissions, a fuel sulphur content of 0.2875% is assumed which is consistent with the reported SO_2 emission factor of 124.1 ng/J used in the CAPP 2004 National Inventory (CAPP, 2004b). Following (CAPP, 2004b) N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2 of (Environment Canada, 1997).
[a]The standard deviation is a result of the variation in drill length

Table 5.10 provides estimated GHG emission factors from diesel combustion during drilling of unconventional wells where GHG contributions of carbon dioxide, nitrous oxide, and methane have all been considered. Calculations were performed using a range of global warming potential (GWP) values and time-horizons as noted in Table 5.10 and associated footnotes, where it is understood that these different calculations may all be useful in different applications.

Table 5.10: GHG emission factors for diesel combustion during unconventional well drilling in Alberta 2011

Well type	Diesel consumption [m^3/UWI]	Greenhouse gas (GHG) emission factors† [t CO_2e /UWI]					
		100-year time horizon				20-year time horizon	
		(IPCC, 1996)‡		(IPCC, 2007)‡		(IPCC, 2007)‡	
		Mean	Standard Deviation[a]	Mean	Standard Deviation[a]	Mean	Standard Deviation[a]
Tight gas	64.6	183.1	71.5	182.9	71.3	183.1	71.4
CBM hybrid	22.7	64.4	11.6	64.3	11.5	64.4	11.6
CBM	16.6	47.2	18.2	47.1	18.1	47.1	18.2
CBM shale other	23.6	66.9	n/a	66.8	n/a	66.9	n/a
Shale	47.5	134.5	68.6	134.3	68.5	134.5	68.5

† GHG emission factors were calculated using CO_2, CH_4 and N_2O emission factor data derived in Table 5.8.
‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007) specifies 100- and 20-year time horizon GWP values for methane of 25 and 72, and for N_2O of 298 and 289 respectively. At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The legacy IPCC 2nd Assessment Report (IPCC, 1996) was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998), and includes 100-year time horizon GWP values for CH_4 and N_2O of 21 and 310 respectively.
[a]The standard deviation is a result of the variation in drill length

It is noted that the use of dual-fuel drilling rigs have the potential to reduce air pollutant emission from well drilling. Dual fuel rigs have achieved fuel substitution rates in the “mid-40%” to “mid-60%” range depending on the type of engine being used (Scott, 2013). Since natural gas combustion emits negligible particulate and sulphur emissions relative to diesel combustion, the percentage reduction in diesel fuel usage achieved with dual-fuel technology results in a one-to-one reduction in particulate and sulphur related CAC emissions. In addition, assuming a 60% reduction in diesel usage at full load (Scott, 2013), CO_2 equivalent greenhouse gas emissions from rig operated on dual fuel would be reduced by approximately 15.5%, as detailed in Table 5.11. Estimating the potential impact of dual-fuel rig usage on emissions from well-drilling in Alberta requires an estimate of dual-fuel rig availability and usage. Based on input from Canada's largest drilling operator, which drilled 36% (990 of 2735) of the fractured natural gas UWIs in Alberta in 2011, it was estimated that 5-6% of their fleet was equipped for dual-fuel use with a utilization factor of 80%. Assuming that other drilling operators had similar dual-fuel rig availability and usage rates, then the estimated current greenhouse gas reduction from implementation of dual-fuel technology in Alberta would be 0.75% of total well drilling related CO_2e emissions, evaluated over a 100-year time horizon as indicated in Table 5.11.

Table 5.11: GHG emission factors for diesel and dual-fuel combustion during unconventional well drilling in Alberta 2011

Well type	Greenhouse gas (GHG) emission factors [t CO_2e /UWI] 100-year time horizon (IPCC, 2007)‡		
	Diesel rig	Dual-fuel rig[a]	Prorated based on dual-fuel use Alberta[b]
Tight gas	182.9	154.5	181.5
CBM hybrid	64.3	54.3	63.8
CBM	47.1	39.7	46.7
CBM shale other	66.8	56.4	66.3
Shale	134.3	113.5	133.3

‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007) specifies 100- and 20-year time horizon GWP values for methane of 25 and 72 and for N_2O of 298 and 289 respectively.

[a] Derived using an energy balance assuming: a 60% diesel usage reduction at full load, a diesel heating value of 38192.5 MJ/m^3-diesel, a natural gas heating value of 38.236 MJ/m^3-gas, and a natural gas combustion efficiency of 100%.

[b] Calculated assuming that 6% of drilling rigs in Alberta were equipped for dual-fuel use with a utilization factor of 80%.

5.2.1 *Total Diesel GHG and CAC Emissions from Unconventional Well Drilling in Alberta in 2011*

The estimated total GHG and CAC emissions from the combustion of diesel attributed to well drilling for hydraulically fractured natural gas wells in Alberta in 2011 is calculated in Table 5.12 and Table 5.13 using the emission factors derived in Table 5.10 and Table 5.8.

Table 5.12: Total estimated GHG emissions from diesel combustion due to well drilling for hydraulically fractured natural gas UWIs in Alberta in 2011

Well type	Total # of fractured UWIs drilled in 2011	Total Estimated Greenhouse gas (GHG) emissions [t CO_2e]		
		100-year time horizon		20-year time horizon
		(IPCC, 1996)‡	(IPCC, 2007)‡	(IPCC, 2007)‡
Tight gas	1888	345785.9	345273.9	345603.8
CBM hybrid	723	46555.0	46486.0	46530.5
CBM	103	4858.4	4851.2	4855.9
CBM shale other	1	66.9	66.8	66.9
Shale	20	2690.6	2686.6	2689.1
TOTAL	**2735**	**399956.8**	**399364.5**	**399746.2**

‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007) specifies 100- and 20-year time horizon GWP values for methane of 25 and 72 and for N_2O of 298 and 289 respectively. At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The legacy IPCC 2nd Assessment Report (IPCC, 1996) was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998), and includes 100-year time horizon GWP values for CH_4 and N_2O of 21 and 310 respectively.

Table 5.13: Total estimated emissions of specific GHGs and CACs from diesel combustion due to well drilling for hydraulically fractured natural gas UWIs in Alberta in 2011

Gas type	Diesel usage [m^3]	Estimated total 2011 emissions from diesel combustion during unconventional well-completions [t]										
		CO_2	CO	CH_4	N_2O	SO_2	NOx	TPM	PM_{10}	$PM_{2.5}$	VOC	THC
Tight gas	121981.9	330540.8	1702.8	16.2	48.1	581.0	6410.5	124.2	99.4	96.0	164.1	180.3
CBM	1713.9	44502.5	229.3	2.2	6.5	78.2	863.1	16.7	13.4	12.9	22.1	24.3
CBM hybrid	16423	4644.2	23.9	0.2	0.7	8.2	90.1	1.7	1.4	1.3	2.3	2.5
CBM shale other	23.6	64.0	0.3	0.0	0.0	0.1	1.2	0.0	0.0	0.0	0.0	0.0
Shale	949.1	2571.9	13.2	0.1	0.4	4.5	49.9	1.0	0.8	0.7	1.3	1.4
TOTAL	**141091.3**	**382323.3**	**1969.5**	**18.8**	**55.6**	**672.0**	**7414.8**	**143.7**	**114.9**	**111.0**	**189.8**	**208.5**

5.3 Estimation of Diesel Well-completion Emission Factors

Diesel CAC and GHG emission factors for hydraulically fractured natural gas wells were developed using available load injection volumes reported in the PRA as described in Section 4.4. Specifically, the calculated LDINJ volumes per well structure shown in Figure 4.7 that occurred within 1 month of the fracture date were normalized by the number of fractured UWIs in each corresponding well. It is worth noting that no correlation between the volume of injected fluid and the number of fracture stages per UWI was found in the data. To obtain the associated diesel fuel use on a per UWI basis, the scaling factor of 0.0245 [m^3 of diesel per m^3 of injected fracturing fluid], also derived in Section 4.4, was applied to each well. Figure 5.4 plots the resulting diesel usage data for tight gas and shale gas wells. Since only limited LDINJ data were reported via Petrinex in 2011, it was not possible to make reliable estimates of diesel usage for other gas well types.

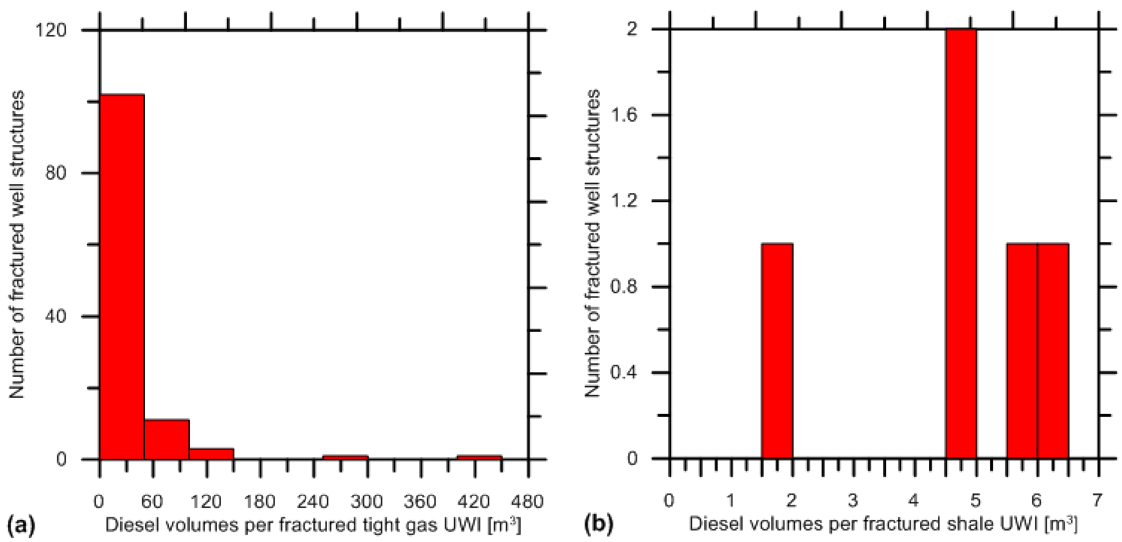

Figure 5.4: Histograms of calculated diesel usage for (a) tight gas wells (b) shale wells during well-completion in Alberta in 2011

The mean and standard deviations of injected fluid volumes and diesel usage per UWI are provided in Table 5.14. The tight gas and shale gas diesel usage factors are estimated to be 30.1 m^3 / UWI and 4.6 m^3 / UWI respectively. The tight gas diesel usage factor is consistent with an estimate of 36 m^3 of diesel usage provided by onsite personnel during an Encana site visit to witness the hydraulic fracturing of a single leg tight gas well in Dawson Creek, British Columbia. This particular Encana operation targets the Montney deep basin tight gas formation (Encana, 2013) .

The estimated shale gas diesel usage factor for Alberta gas wells in 2011 of 4.6 m^3 / UWI is roughly 3 times smaller than 13.7 m^3 / (Marcellus shale UWI) estimated in the Tyndall center report (Wood et al., 2011) as reviewed in Section 2.4.5.

Table 5.14: Injected fluid and diesel consumption factors for unconventional well-completions in Alberta in 2011

Well type	# of well structures	# of fractured UWIs	Injected fluid [m^3/UWI]		Diesel consumption [m^3/UWI]	
			Mean	Standard Deviation	Mean	Standard Deviation[a]
Tight gas	115	164	1229.8	2094.1	30.1	51.3
CBM	n/a	n/a	n/a	n/a	n/a	n/a
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a
Shale	5	5	189.4	71.0	4.6	1.7

[a] The standard deviation is a result of the variation in injected fluid volumes.

The average diesel consumption per UWI data in Table 5.14 were used to calculate mean CAC and GHG emission factors for well-completions. Mean and standard deviations of the resulting CAC emission factors are presented in Table 5.15 and Table 5.16, respectively. As in earlier calculations, relevant emission factor data for large diesel engine sources published in U.S. EPA AP-42 Section 3.4 (US EPA, 1995a) were used.

Table 5.15: Mean emission factors for specific GHGs and CACs emitted via diesel combustion during unconventional well-completions in Alberta in 2011

Well type	Injected fluid [m^3/UWI]	Diesel usage [m^3/UWI]	Mean GHG and CAC emission factors [kg/UWI]†										
			CO_2	CO	CH_4	N_2O	SO_2	NOx	TPM	PM_{10}	$PM_{2.5}$	VOC	THC
Tight gas	1229.8	30.1	81642.0	420.6	4.0	11.9	143.5	1583.4	30.7	24.5	23.7	40.5	44.5
CBM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale gas	189.4	4.6	12574.1	64.8	0.6	1.8	22.1	243.9	4.7	3.8	3.7	6.2	6.9

† Derived from diesel fuel consumption factor using emission factor data for large diesel engine sources from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a) and similarly used in (CAPP, 2004b). For calculation of SO_2 emissions, a fuel sulphur content of 0.2875% is assumed which is consistent with the reported SO_2 emission factor of 124.1 ng/J used in the CAPP 2004 National Inventory (CAPP, 2004b). Following (CAPP, 2004b) N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2 of (Environment Canada, 1997).

Table 5.16: Standard deviations of emission factors for specific GHGs and CACs for diesel combustion during unconventional well-completions in Alberta in 2011

Well type	Standard deviation of injected fluid [m^3/UWI]	Standard deviation of diesel usage[a] [m^3/UWI]	Standard deviations of GHG and CAC emission factors [kg/UWI]†,[a]										
			CO_2	CO	CH_4	N_2O	SO_2	NOx	TPM	PM_{10}	$PM_{2.5}$	VOC	THC
Tight gas	2094.1	51.3	139026.4	716.2	6.8	20.2	244.3	2696.3	52.2	41.8	40.4	69.0	75.8
CBM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale gas	71.0	1.7	4712.9	24.3	0.2	0.7	8.3	91.4	1.8	1.4	1.4	2.3	2.6

† Derived from diesel fuel consumption factor using emission factor data for large diesel engine sources from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a) and similarly used in (CAPP, 2004b). For calculation of SO_2 emissions, a fuel sulphur content of 0.2875% is assumed which is consistent with the reported SO_2 emission factor of 124.1 ng/J used in the CAPP 2004 National Inventory (CAPP, 2004b). Following (CAPP, 2004b) N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2 of (Environment Canada, 1997).
[a] The standard deviation is a result of the variation in injected fluid volumes.

Table 5.17 presents combined greenhouse gas emission factors for diesel consumption during unconventional well-completion in tonnes of CO_2 equivalent per UWI calculated using individual species emission factor data presented in Table 5.15 and Table 5.16. GHG contributions of carbon dioxide, nitrous oxide, and methane have all been considered using different time horizons and GWP data as may be relevant for a range of applications.

Table 5.17: GHG emission factors for diesel combustion during unconventional well-completions in Alberta

Well type	Diesel consumption [m^3/UWI]	Greenhouse gas (GHG) emission factors† [t CO_2e /UWI] 100-year time horizon (IPCC, 1996)‡ Mean	Standard Deviation	100-year time horizon (IPCC, 2007)‡ Mean	Standard Deviation	20-year time horizon (IPCC, 2007)‡ Mean	Standard Deviation
Tight gas	30.1	85.4	145.4	85.3	145.2	85.4	145.4
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale gas	4.6	13.2	4.9	13.1	4.9	13.1	4.9

† GHG emission factors were calculated using CO_2, CH_4 and N_2O emission factor data derived in Table 5.15.
‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (AR4, IPCC, 2007) specifies 100- and 20-year time horizon GWP values for methane of 25 and 72 and for N_2O of 298 and 289 respectively. At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The legacy IPCC 2nd Assessment Report (IPCC, 1996) was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998), and includes 100-year time horizon GWP values for CH_4 and N_2O of 21 and 310 respectively.

5.3.1 Total Diesel GHG and CAC Emissions from Unconventional Well-completions in Alberta in 2011

Based on the emission factors derived in Table 5.15, estimated total emissions of specific GHGs and CACs associated with diesel combustion during completion of hydraulically fractured natural gas UWIs in Alberta in 2011 were calculated, as summarized in Table 5.18. Estimated combined GHG emissions in tonnes of CO_2 equivalent were similarly calculated in Table 5.19, based on emission factors presented in Table 5.17. As noted in the footnotes to the tables, since there were no reported data available with which to estimate diesel combustion emissions at 'CBM hybrid,' 'CBM,' and 'CBM shale other' wells in Alberta in 2011, estimated totals from these wells are necessarily excluded. Thus, the totals in Table 5.18 in Table 5.19 represent the contributions from 1595 of the 2252 hydraulically fractured UWI completed in 2011 in Alberta. However, because the missing data are only for CBM type wells, it is not advisable to extrapolate data from other well types, since the emissions characteristics are likely quite different based on noted differences in reported well-completion flaring volumes, as discussed in Section 5.1

Table 5.18: Total estimated emissions of specific GHGs and CACs from diesel combustion during well-completion for hydraulically fractured natural gas UWIs in Alberta in 2011

Gas type	Diesel consumption [m^3]	Estimated total 2011 emissions from diesel combustion during unconventional well-completions [t]										
		CO_2	CO	CH_4	N_2O	SO_2	NOx	TPM	PM_{10}	$PM_{2.5}$	VOC	THC
Tight gas	47483.1	128667.9	662.8	6.3	18.7	226.1	2495.4	48.3	38.7	37.4	63.9	70.2
CBM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM hybrid	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale	88.17	238.91	1.23	0.01	0.03	0.42	4.63	0.09	0.07	0.07	0.12	0.13
TOTAL†	47571.3	128906.8	664.1	6.3	18.8	226.6	2500	48.4	38.8	37.4	64.0	70.3

† Since no reported data were available with which to estimate diesel combustion emissions at 'CBM hybrid', 'CBM', and 'CBM shale other' wells in Alberta in 2011, estimated totals are necessarily only for 1595 of the 2252 hydraulically fractured wells in Alberta in 2011. Because the missing data are only for CBM type wells, it is not advisable to extrapolate data from other the well types since the emissions characteristics are likely quite different based on differences noted in reported well-completion flaring volumes discussed in Section 5.1.

Table 5.19: Total estimated combined GHG emissions from diesel combustion during well-completion for hydraulically fractured natural gas UWIs in Alberta in 2011

Well type	Total # of fractured UWI	Total Estimated Greenhouse gas (GHG) emissions [t CO_2e]		
		100-year ($GWP_{CH_4} = 21$)‡	100-year ($GWP_{CH_4} = 25$)‡	20-year ($GWP_{CH_4} = 72$)‡
Tight gas	1576	134602.3	134402.9	134531.4
CBM hybrid	n/a	n/a	n/a	n/a
CBM	n/a	n/a	n/a	n/a
CBM shale other	n/a	n/a	n/a	n/a
Shale	19	249.9	249.6	249.8
TOTAL†	**1595†**	**134852.2†**	**134652.5†**	**134781.2†**

† Since no reported data were available with which to estimate diesel combustion emissions at 'CBM hybrid', 'CBM', and 'CBM shale other' wells in Alberta in 2011, estimated totals are necessarily only for 1595 of the 2252 hydraulically fractured wells in Alberta in 2011. Because the missing data are only for CBM type wells, it is not advisable to extrapolate data from other the well types, since the emissions characteristics are likely quite different based on differences noted in reported well-completion flaring volumes discussed in Section 5.1.

‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007) specifies 100- and 20-year time horizon GWP values for methane of 25 and 72 and for N_2O of 298 and 289 respectively. At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The legacy IPCC 2nd Assessment Report (IPCC, 1996) was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998), and includes 100-year time horizon GWP values for CH_4 and N_2O of 21 and 310 respectively.

5.4 Well Operational Emissions

Well operational emissions in the form of short-term, non-routine, and/or temporary flaring and/or venting, such as those that are related to liquid unloading events, are allowed under Directive 060 (ERCB, 2011a). For planned non-routine flaring including well blowdowns, Directive 060 Section 3.3.1 2(a)iii specifies that up to 200,000 m^3 of gas may be flared without the need for a permit. Similarly, venting of up to 2000 m^3 of gas is allowed without the need for a permit as specified in Section 8.1 (5)d. Furthermore, as discussed previously in Section 4.5, although Directive 060 specifies flared and vented volumes associated with "depressurizing of pipeline, compression, and processing systems" must be reported if volumes exceed 100-500 m^3 (ERCB, 2006; ERCB, 2011a), non-routine flaring and venting as may be associated with liquid unloading is not specifically identified for required reporting. This lack of firm reporting requirements is consistent with the present analysis of the available 2011 Petrinex volumetric data, which did not contain any obvious trends relating to location, reporting frequency, year of fracture or well type that allowed for the direct identification of flaring and/or venting associated with liquid unloading events within the reported data.

As outlined in Section 4.5, excluding well-completion emissions, 93.1% of the 3846 producing tight gas wells fractured between January 1st 2000 and December 31st 2011, that were linked to a single-well gas battery, did not report any monthly flaring or venting in the available 2011 volumetric data. Of the 143 individual monthly flaring volumes reported from 55 well structures in 2011, all were below the lowest threshold of 200,000 m^3 that might otherwise require a permit as detailed in Directive 60 (ERCB, 2011a). Similarly, 93% of the 1192 individually reported monthly vented volumes from 225 wells in 2011 were below the permit requirement threshold of 2000 m^3, although it is noted that the mean monthly reported vented gas volume from these sites was 600 m^3/UWI. Table 5.20 summarizes intensity factors calculated using the monthly reported fuel use, flaring, and venting volumes with flaring and venting outliers removed as described in Section 4.5.

Table 5.20: Intensity factors for fuel use, flaring, and venting attributed to well operation for fractured tight gas wells

Well activity	# of reporting well structures	# of reporting fractured UWI	Monthly reported volumes [1000 m^3/UWI]	
			Mean	Standard Deviation
Fuel use	2151	3934	2.2	5.7
Venting	225	358	0.6	0.8
Flaring	55	108	1.5	3.3

As further discussed below, it is likely that most or all flaring and venting volumes from liquid unloading events are not captured in the data shown in Table 5.20. Indeed, for the CAPP National Greenhouse Gas Inventory, "unreported venting" due to liquid unloading events is separately estimated (reported as blowdowns in Table A (CAPP, 2004a)) rather than calculated from reported data. As outlined in (CAPP, 2004c), estimates of unreported venting are derived based on data from a single industry operator using the following assumptions:

- shallow gas wells, those less than 1000 m, have insufficient pressure to self-unload;
- the average gas emission rate while venting to the atmosphere is approximately the same as the average rate of production per well;
- unassisted blowdowns last between 0.2 and 2.0 hours, with an average duration of 0.79 hours, and occur 0.14 times per month per well;
- swabbing events average 0.5 hours per operation and the well vents to atmosphere 50 percent of this time with an occurrence of 0.05 per month per well; and
- coil tubing clean-outs require 2 hours and occur approximately 0.05 times per month per well.

Of the 3846 tight gas wells fractured between January 1st 2000 and December 31st 2011 that are linked to a single-well gas battery, 664 (17.3%) consisted of UWIs with a total depth of less than 1000 m. The average monthly production from these wells ranged from 50 m^3 to 516200 m^3 with an average, over all wells, of 37686 m^3. Applying the above CAPP durations and activity factors to each tight gas well yields a liquid unloading emission factor range of 7.3 m^3/UWI per month to 20.3 m^3/UWI per month with an average of 11.5 m^3/UWI per month or on a per well basis 9.2 m^3/well per month to 25.8 m^3/well per month with an average of 14.6 m^3/well per month. Although the emission factors are small enough that estimated volumes fall below the minimum monthly reporting threshold of 100 m^3, applying this factor to all relevant wells (i.e. the 56567 producing gas wells in Alberta in 2011 that contained a UWI with a total depth of less than 1000 m, and with a fracture code between January 1, 2000 and December 31, 2011) yields an estimated total unreported venting volume from liquid unloading of between 6.8-18.6 million m^3 in 2011. As summarized in Table 5.21, this volume equates to a non-negligible total estimated greenhouse gas emissions in 2011 of between 98.8-274.5 kt CO_2e on a 100 year time horizon, which is comparable to the total estimated greenhouse gas emissions for well-completions in Alberta in 2011 of 139 kt CO_2e as presented in Section 5.1.2.

Table 5.21: Estimated annual liquid unloading GHG emission from shallow fractured gas wells active in Alberta in 2011

Well type	# of active shallow wells in Alberta in 2011	Total # of fractured UWI	Total Estimated Greenhouse gas emissions† [kt CO_2e]		
			100-year ($GWP_{CH_4} = 21$)‡	100-year ($GWP_{CH_4} = 25$)‡	20-year ($GWP_{CH_4} = 72$)‡
Tight gas	42834	51978	55.8-1551	66.4-184.6	195.2-542.7
CBM hybrid	7746	16428	17.6-49	20.9-58.3	61.7-171.5
CBM	5309	7340	7.9-21.9	9.4-26.1	27.6-76.6
CBM shale other	41	60	0.1-0.2	0.1-0.2	0.2-0.6
Shale	72	78	0.1-0.2	0.1-0.3	0.3-0.8
Shale hybrid	1	2	Negl.	Negl.	Negl.
TOTAL[a]	**56567**	**77354**	**83.0-230.8**	**98.8-274.5**	**290.4-457.5**

† Derived assuming the emission factor range of 7.3 m^3/UWI per month to 20.3 m^3/UWI per month applies to all well types.
‡ Refers to the assumed time-horizon and the corresponding global warming potential (GWP) values used to calculate CO_2 equivalent GHG emissions. The 100- and 20-year time horizon GWP values for methane of 25 and 72 respectively are from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (IPCC, 2007). The 100-year time horizon GWP value for methane of 21 is from the legacy IPCC 2nd Assessment Report (IPCC, 1996), which was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998). Calculations were performed using relevant GHG emission factors specifically derived from data for flared and vented gas in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012) and assuming a 98% flare efficiency. In the absence of further, well-type-specific composition data, common emission factors were applied to all well types which assumed a mean methane content of 85.79% in vented gas (see Johnson and Coderre (2012).
[a] The total is not the sum of the above rows. There are 564 wells with 1468 fractured UWI which have multiple fluid types within the same well structure that are not included in the breakdown by well type.

The estimated unreported vented volume range of 7.3 to 20.3 m^3/UWI per month calculated using the CAPP inventory methodology (CAPP, 2004c) is significantly lower than other reported emission factors for liquid unloading events in the literature, and therefore is likely quite conservative (see Table 5.25 in Section 5.5.3). If the activity factors and liquid unloading factors for unconventional wells reported by API/ANGA (Shires and Lev-On, 2012) were instead used, the estimated total GHG emissions from liquid unloading at unconventional gas wells in Alberta in 2011 would be 1.6 Mt CO_2e as detailed in Table 5.22.

Table 5.22: Estimated annual liquid unloading GHG emission from fractured gas wells active in Alberta in 2011 using API/ANGA emission factors and activity data

	Natural gas wells in Alberta with a fracture date between January 1st 2000 and December 31st 2011		
All wells	84625		
Estimated number with plunger lifts	11340[a]		
Estimated number with plunger lifts that vent	2393[b]		
Estimated number without plunger lifts that vent	6816[c]		
Estimated total vented gas volume in 2011 [million m^3]	110.8[d]		
	100-year ($GWP_{CH_4} = 21$) ‡	**100-year** ($GWP_{CH_4} = 25$)‡	**20-year** ($GWP_{CH_4} = 72$)‡
Total Estimated Greenhouse gas emissions† [kt CO_2e]	1356.7	1614.6	4746.9

† Derived assuming the emission factor range of 7.3 m^3/UWI per month to 20.3 m^3/UWI per month applies to all well types.
‡ Refers to the assumed time-horizon and the corresponding global warming potential (GWP) values used to calculate CO_2 equivalent GHG emissions. The 100- and 20-year time horizon GWP values for methane of 25 and 72 respectively are from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (AR4, IPCC, 2007). At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The 100-year time horizon GWP value for methane of 21 is from the legacy IPCC 2nd Assessment Report (IPCC, 1996), which was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998). Calculations were performed using relevant GHG emission factors specifically derived from data for flared and vented gas in the Western Canadian Sedimentary Basin published in (Johnson and Coderre, 2012) and assuming a 98% flare efficiency. In the absence of further, well-type-specific composition data, common emission factors were applied to all well types which assumed a mean methane content of 85.79% in vented gas (see Johnson and Coderre (2012)).
[a] API/ANGA reports 13.4% of all wells have plunger lifts in Table 5 of (Shires and Lev-On, 2012)
[b] API/ANGA reports 21.1% of all wells with plunger lifts vent in Table 6 of (Shires and Lev-On, 2012)
[C] API/ANGA reports 9.3% of all wells without plunger lifts vent in Table 6 of (Shires and Lev-On, 2012)
[d] Calculated using API/ANGA emission factors detailed in Table 2.4 in Section 2.3.1

5.5 Comparison of Emission Factors

In the tables presented under the subheadings that follow, the newly derived flaring, venting, and diesel intensity factors for drilling, completion, and operation of hydraulically fractured gas wells in Alberta are compared to the limited range of emission factor data that can be derived from other sources. Comparable emission factor data was calculated using available information from CAPP (See Section 2.4.4), US EPA (See Section 2.2), API/ANGA (See Section 2.3), the Tyndall Center (Wood et al., 2011) and the recently published measurement study conducted by (Allen et al., 2013b). All assumptions required to derive comparable emission factor data in a consistent set of units using available information from each comparator study are detailed in the footnotes of each table.

5.5.1 A Comparison of Well Drilling Emission Factors

Table 5.23 compares available sources of information on diesel usage, flared volumes, and vented volumes associated with well drilling on a per UWI basis, as well as associated greenhouse gas emissions from each source category. Well drilling emission estimates are dominated by diesel combustion which is governed by overall well depth. For hydraulically fractured gas wells drilled in Alberta in 2011, diesel usage estimates range from 16.6 to 64.6 m^3 diesel /UWI based on the intensity factor of 0.022 m^3 diesel / m-drilled presented in Section 4.3. The only other available estimate of diesel usage during drilling of unconventional wells comes from the Tyndall Center Report (Wood et al., 2011) which estimates a diesel intensity factor of 0.0186 m^3 diesel / m-drilled. Applying this factor to Alberta well-depths yields a diesel usage range of 14.2 to 55 m^3 diesel /UWI which compares well with the data derived in the present analysis. The slightly higher intensity factors obtained using Alberta-based data may be attributable to differences in formation geology. The increase in diesel usage and associated emission rates for the present analysis of unconventional wells relative to the CAPP-based estimates for wells drilled in 2000 are entirely attributable to increased drill lengths.

Table 5.23: GHG emission factors for diesel combustion during hydraulically fractured well drilling in Alberta 2011

Well type	# of wells	# of fractured UWIs	Length drilled [m/UWI] Mean (Standard Deviation)	Diesel consumption [m^3/UWI] Mean (Standard Deviation)*	Greenhouse gas (GHG) emission factors† [t CO_2e /UWI] 100-year time horizon (IPCC, 1996)‡ Mean (Standard Deviation)*	100-year time horizon (IPCC, 2007)‡ Mean (Standard Deviation)*
Current Analysis of Alberta Data for 2011						
Tight gas	1334	1888	2958.2 (1154.1)	64.6 (25.2)	183.1 (71.5)	182.8 (71.3)
CBM hybrid	498	723	1040.0 (186.8)	22.7 (4.1)	64.4 (11.6)	64.3 (11.5)
CBM	81	103	761.9 (293.5)	16.6 (6.4)	47.2 (18.2)	47.1 (18.1)
CBM shale other	1	1	1081.0 (n/a)	23.6 (n/a)	66.9 (n/a)	66.8 (n/a)
Shale	20	20	2172.9 (1107.7)	47.5 (27.5)	134.5 (68.6)	134.3 (68.5)
Available estimates that can be derived from other sources (see footnotes)						
CAPP	6100	9418	1023.9 (729.3)	22.4[a] (15.9)	63.4 (45.2)	63.3 (45.1)
(Wood et al., 2011)	AB 2011 well count	AB 2011 UWI count	AB 2011 drill lengths	14.2-55[b] (3.5-21.5)	40.2-156 (9.8 -60.8)	40.1-155.7 (9.8 -60.8)

† GHG emission factors were calculated using CO_2, CH_4 and N_2O emissions derived from diesel fuel consumption. The combustion product volumes of CO_2 and CH_4 were calculated using emission factor data for large diesel engines sources from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a). Following (CAPP, 2004b) N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2 of (Environment Canada, 1997).

‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (AR4, IPCC, 2007) specifies 100- year time horizon GWP values for methane and N_2O of 25 and 298 respectively. At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which GWP values for fossil methane have been updated to 36 and 87 on 100- and 20-year time horizons respectively, including climate carbon feedbacks. Use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The legacy IPCC 2nd Assessment Report (IPCC, 1996) was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998), and included 100-year time horizon GWP values for CH_4 and N_2O of 21 and 310 respectively.

*The standard deviation is a resultant of the variation in drill length.

[a] Calculated based on a reported intensity factor of 60.6 t CO_2 / well (CAPP, 2004a) and an emission factor of 2709.8 kg CO_2/ m^3-of-combusted-diesel for large diesel engines from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a).

[b] Based on their reported value of 18.6 m^3 diesel /m drilled (Table 3.2 Wood et al., 2011) applied to the average drill length for each natural gas well type drilled and fractured in Alberta in 2011.

None of the available data sources including the present analysis contained information sufficient to estimate flaring and venting volumes that may be directly associated with drilling of unconventional wells. However, there are reasons to believe that any relevant emissions from flaring and venting during drilling of unconventional wells are unlikely to be significant relative to the estimated diesel usage emissions. Historically, after drilling a conventional UWI, a drill stem test (DST) has been used to estimate the initial gas production and the overall economic viability of the well prior to insertion of the well casing. Although in Alberta drill stem tests are not mandatory, regulations do stipulate that any conducted drill stem tests, even a misrun, must be reported (ERCB, 2010). Furthermore, according to Section 7.060 of Alberta's Oil and Gas Conservation Regulation, any gas produced to the atmosphere during a drill stem test for a period of time greater than 10 minutes must be flared (Province of Alberta, 2013). As illustrated in Figure 5.5, an analysis of report 025 "DST-Wireline-CR-Sampler Data" within the GENWELL data files reveals that the number of reported DST (including misruns) has declined dramatically from 4186 in the year 2000 to just 41 in 2011. Moreover, of the 41 DST conducted in 2011, only one corresponded to a fractured well. Thus flaring and venting from drill stem tests is not expected to be a significant emission source for hydraulically fractured wells in Alberta. The decline in drill stem tests is most likely attributable to the development of formations with low gas permeability that require fracturing to produce an economic gas flow.

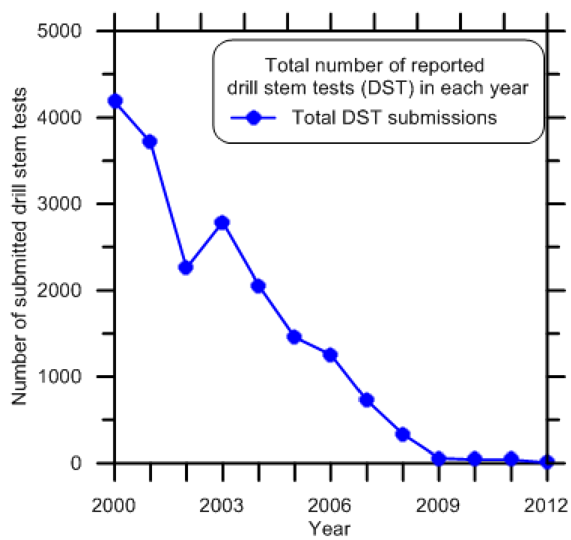

Figure 5.5: The decline of drill stem test submissions since 2000 in Alberta for all natural gas wells.

5.5.2 A Comparison of Well-completion Emission Factors

Table 5.24 compares the set of well-completion diesel, flaring, and venting intensity/emission factors derived for fractured gas wells completed in Alberta in 2011 to relevant estimates that can be derived from information in other sources. These other estimates include conventional and unconventional well-completion emission factor estimates derived from the US EPA (US EPA, 2010), CAPP (CAPP, 2004a), from information gleaned during a site visit to witness a natural gas well-completion as part of the present analysis, and from publications of (Wood et al., 2011) and (Allen et al., 2013a) where the data permit.

On site diesel combustion during well-completion is primarily attributed to the large diesel pumps and supporting equipment required to hydraulically fracture a well. The diesel usage estimate of 30.1 m^3 diesel per well-completion derived for tight gas in the present analysis is consistent with the on-site estimate of 36 m^3 for a tight gas well-completion near Dawson Creek, BC provided during a site visit as part of the present study. The estimated Alberta shale gas diesel usage factor of 4.6 m^3 / UWI is roughly 3 times smaller than the only other available estimate of 13.7 m^3 diesel/Marcellus shale UWI as used by (Wood et al., 2011). Since diesel use is typically not directly tracked as part of regulatory reporting, associated emissions estimates are generally unavailable in the literature.

To facilitate a comparison of flaring emission factors associated with well-completion, the potential methane release factors provided by the US EPA and (Allen et al., 2013a) were converted to relevant flared and vented volumes based on operational practices relevant to Alberta as determined via the present analysis. The potential methane release volumes were used to calculate equivalent natural gas volumes at 15°C and 101.325 kPa assuming a methane mean content of 85.79% as relevant to flared gas in the Western Canadian Sedimentary Basis (Johnson and Coderre, 2012). A flared and vented volume per UWI was then calculated using the mean flaring to venting ratio for Alberta tight gas well-completions determined as part of the present analysis. Under these assumptions, the flaring emission factor estimates for Alberta tight gas wells derived in this report based on industry data reported to ERCB are roughly 2.5 times smaller than current US EPA emission factor estimates and those derived from measurement data of 27 well-completions in (Allen et al., 2013a).

Table 5.24 also includes a preliminarily comparison of the newly derived emission factors for Alberta unconventional gas well-completions to the current CAPP conventional flaring numbers (CAPP, 2004a), where the latter are based on wells drilled and completed in 2000. This comparison suggests that the flaring per UWI during completion of fractured tight gas wells in Alberta during 2011 is roughly 6 times larger than flaring volumes per UWI for conventional wells circa 2000. However, without knowing the underlining assumptions and precision of the methodologies used to develop the CAPP conventional emission factor, it is not clear whether this is a fair comparison. Additionally, a true “apples-to-apples” comparison would consider these emission factors on a unit production basis since ultimate recoverable volumes of conventional and unconventional wells in Alberta could be sufficiently different that differences in one time emissions from well-completion may or may not be as significant in terms of each m^3 of gas produced over the lifetime of a well. An initial look at the available 2011 PRA production data used in the present study suggest there are approximately 900 natural gas wells that were drilled in the year 2000 and were not fractured in subsequent years after being completed. This suggests there would be sufficient conventional well data in the PRA production data between 2000 and 2012 to compare the long term production to that of unconventional wells over the same time period. The authors have proposed to PTAC to undertake this analysis as part of a future phase of this project.

Table 5.24: A comparison of well-completion diesel usage and emission factors for flaring and venting.

	Diesel usage [m^3/UWI]	Flaring [1000 m^3 / UWI]	Venting [1000 m^3 / UWI]	Greenhouse gas (GHG) emission factors using a 100-year time horizon [t CO_2e /UWI] (IPCC, 1996)‡ Diesel usage	(IPCC, 1996)‡ Flaring	(IPCC, 1996)‡ Venting	(IPCC, 2007)‡ Diesel usage	(IPCC, 2007)‡ Flaring	(IPCC, 2007)‡ Venting
Current Analysis of Alberta Data for 2011									
Tight gas	30.1	113.2	0.6	85.4	271.6	7.5	85.3	271.6	8.9
CBM hybrid	n/a	0.9	n/a	n/a	2.1	n/a	n/a	2.1	n/a
CBM	n/a	2.7	n/a	n/a	6.5	n/a	n/a	6.5	n/a
CBM shale other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Shale	4.6	n/a	n/a	13.2	n/a	n/a	13.1	n/a	n/a
Tight gas Dawson Creek, BC	36[a]	n/a	n/a	102.1[f]	n/a	n/a	101.9[f]	n/a	n/a
Available estimates that can be derived from other sources (see footnotes)									
CAPP[ψ] (CAPP, 2004a)	--	18.8[b]	0.4[b]	--	43.3[c]	4.5[d]	--	43.4[c]	5.3[d]
(Wood et al., 2011)	13.7[e]	n/a	n/a	38.8[f]	n/a	n/a	38.8[f]	n/a	n/a
US EPA *unconventional* (US EPA, 2013a)	--	296.1[g]	1.6[g]	--	710.8	19.4	--	710.8	23.1
US EPA *conventional* (US EPA, 2010)	--	1.2[g]	0.006[g]	--	2.9	0.08	--	2.9	0.09
(Allen et al., 2013a)	--	270[h]	1.4[h]	--	620.7	17.5	--	633.3	20.8

‡ Refers to the source for CH_4 and N_2O global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions. The Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (AR4, IPCC, 2007) specifies 100- year time horizon GWP values for methane and N_2O of 25 and 298 respectively. At the time of writing of this report, the IPCC is in the process of releasing their 5th Assessment report (AR5, Myhre et al., 2013) in which the GWP value for fossil methane has been updated to 36 on a 100-year time horizon, including climate carbon feedbacks. In general, use of the AR5 instead of AR4 GWP data would result in approximately 5% higher GHG emissions from flaring, 21-44% higher GHG emissions from venting (on 20- and 100-year time horizons respectively), and negligibly different GHG emissions for diesel combustion. The legacy IPCC 2nd Assessment Report (IPCC, 1996) was specified by the United Nations Framework on Climate Change for use in international GHG reporting through to the end of the first commitment period of the Kyoto protocol which ended in 2012 (UNFCCC, 1998), and included 100-year time horizon GWP values for CH_4 and N_2O of 21 and 310 respectively.

[ψ] For all CAPP numbers it is assumed that the average UWI count per well in Canada in 2000 was approximately 1.

[a] Based on interviews during a site visit to witness a hydraulic fracturing operation in Dawson Creek, British Columbia

[b] Derived using a reported 890 kt CO_2e of reported flaring and 92 kt CO_2e of reported venting in (CAPP, 2004a) and assuming a flaring efficiency of 98% and gas composition data from (Johnson and Coderre, 2012)

[c] Reported in (CAPP, 2004a) under flaring from well testing 878 kt CO_2 and 568 t CH_4

[d] Reported in (CAPP, 2004a) under venting reported from well testing 4364 t CH_4

[e] Based on 109777 liters of diesel fuel per 8 well leg Marcellus shale well pad, Table 2.11.

[f] Calculated using CO_2, CH_4 and N_2O emissions for large diesel engines sources from U.S. EPA AP-42 Section 3.4 (US EPA, 1995a).

[g] The reported emission factor of 173.3 t CH_4/UWI unconventional (US EPA, 2013a) and 0.71 t CH_4/UWI conventional (US EPA, 2010) are converted to an Alberta natural gas volume at 15 degrees C and 101.325 kPa assuming a methane mean content of 85.79%, (Johnson and Coderre, 2012). A flared and vented volume is calculated using the flaring to venting ratio for Alberta tight gas in row one of the table.

[h] Reported as potential methane emissions in Table SI-6 from 27 measured well-completions. The average potential emission is 8210137.04 scf CH_4/completion or 158 t CH_4/completion. Comparable flared and vented volumes calculated assuming a volume at 15°C and 101.325 kPa with a Alberta-relevant mean CH_4 content of 85.79% (Johnson and Coderre, 2012) and flaring to venting ratio (value for tight gas in row 1 of the table).

5.5.3 A Comparison of Liquid Unloading Emission Factors

Liquid unloading has the potential to be the largest source of emissions over the production life of a natural gas well. In the 2010 US National GHG Inventory, liquid unloading was assumed to occur at 41% of conventional wells and at 0% of unconventional wells, but still accounted for 51% of the US EPA estimated methane emissions from natural gas production (U.S. EPA, 2012a, Table A-129).

During the course of this study new liquid unloading activity data for unconventional wells has been reported by the API/ANGA survey of upstream US natural gas producers, as outlined in Section 2.3, and more recently, direct measurements of 9 manual liquid unloading events were reported for a field study conducted by (Allen et al., 2013a). As a direct consequence the US EPA changed the methodology for estimating national greenhouse gas emission in the 2011 National Inventory. In particular, the US EPA now applies a liquid unloading factor to both conventional and unconventional wells,

> *"The methodological update for liquids unloading required updated activity data for use with the new emission factors. The API/ANGA data showed that both wells with and without hydraulic fracturing can have liquids unloading issues, while the Inventory previously only included wells without hydraulic fracturing in its estimates for liquids unloading. This year's Inventory applies liquids unloading emission factors to both wells with and without hydraulic fracturing, using the percentages of wells venting for liquids unloading with plunger lifts, and wells venting without plunger lifts in each region, from the API/ANGA data."* (US EPA, 2013a),

and has updated the liquid unloading emission factor relating to the use of plunger lifts,

> *"This year's Inventory included an update to emission factors for liquids unloading. Region- and unloading technology- specific emission factors were developed based on API/ANGA 2012. API/ANGA 2012 collected survey data on liquids unloading from over 50,000 wells. The data showed far more widespread use of control technologies than EPA was previously capturing in its Inventory, and also presented calculated emissions from liquids unloading for wells with and without plunger lifts. Using the API/ANGA data and regional methane contents, EPA developed liquids unloading emissions factors for wells with and without plunger lifts for each NEMS region. In this new methodology, the emission factors used for liquids unloading are not potential factors, but are factors for actual emissions because control technologies are taken into account through the use of separate emission factors for wells with and without plunger lifts."* (US EPA, 2013a).

These changes had a significant impact on the total liquid unloading emissions for the year 2010 and resulted in the overall reduction in estimates of liquid unloading CH_4 emissions (calculated in terms of equivalent CO_2 emissions) from 85.6 Tg CO_2e to 5.4 Tg CO_2e (US EPA, 2013b). The dramatic change of 80.2 Mt CO_2e in overall estimated emissions illustrates the importance of obtaining accurate measurements and/or estimates of liquid unloading emissions.

However, there is a great deal of uncertainty as to which types of gas wells require liquid unloading, the resulting emissions from liquid unloading, the variability of emission volumes, and the frequency of liquid unloading events. Indeed, the US EPA continues to monitor and update liquid unloading emissions, as discussed below, by evaluating data gathered through external sources, as well as through the implementation of the Greenhouse Gas Reporting Program (GHGRP) via 40 CFR Part 98 subpart W. The US EPA reports that initial GHGRP data suggests that "highly variable" liquid unloading emissions and frequencies are possible and that this activity may still not be fully captured with the updates to the 2011 inventory (US EPA, 2013b).

Table 5.25 compares data for "unreported venting" for fractured Alberta tight gas wells (calculated using the CAPP methodology as detailed in Section 5.4, which includes liquid unloading due to "blowdowns") with a number of relevant liquid unloading emission estimates, including those from the direct measurement study (Allen et al., 2013b) and estimates provided during a 2012 Natural Gas STAR workshop (Robinson, 2012). The estimated venting emissions of 9.2 to 25.8 m^3/well per month for liquid unloading at fractured Alberta tight gas wells, obtained via application of the CAPP methodology, are significantly lower than other reported emission factors. The estimated range maximum of 25.8 m^3/well per month is between 23 and 45 times lower than the extents of the range 590-1150 m^3/well per month derived from the API/ANGA survey data on unconventional wells (Shires and Lev-On, 2012). The breadth of the ranges even in the industry reported data from API/ANGA data and direct measurement data from (Allen et al., 2013a) highlights both the current level of uncertainty in liquid unloading emission factors and the likely importance of this activity to overall emission rates. This comparison also suggests that caution is warranted when using current estimates of unreported venting for Alberta tight gas wells derived in accordance with the procedures in (CAPP, 2004c) to calculate overall provincial emissions.

Table 5.25: A comparison of estimated monthly venting emission factors for liquid unloading

<table>
<tr><th rowspan="2"></th><th colspan="2">Fraction of wells requiring liquid unloading [%]</th><th colspan="2">Monthly Vented Gas Volume [1000 m^3 / well-month]</th><th colspan="4">Monthly Greenhouse gas (GHG) emission factors using a 100-year time horizon [t CO_2e /well-month]</th></tr>
<tr><th>Conven-tional</th><th>Unconven-tional</th><th>Conven-tional</th><th>Unconven-tional</th><th colspan="2">(IPCC, 1996)‡</th><th colspan="2">(IPCC, 2007)‡</th></tr>
<tr><td colspan="9">Current Analysis†</td></tr>
<tr><td>Estimate for Alberta tight gas wells derived using CAPP method</td><td>65[a]</td><td>68[a]</td><td>n/a</td><td>0.009-0.026</td><td colspan="2">0.11-0.32</td><td colspan="2">0.13-0.38</td></tr>
<tr><td colspan="9">Available estimates of liquids unloading that can be derived from other sources (see footnotes)</td></tr>
<tr><td>US EPA 2010 Inventory
(US EPA, 2012c)</td><td>41[b]</td><td>0</td><td>2.06-4.47[c]</td><td>0</td><td colspan="2">24.3-54.7</td><td colspan="2">30.1-65.1</td></tr>
<tr><td rowspan="2">US EPA 2011 Inventory
(US EPA, 2013a)</td><td colspan="2" rowspan="2">n/a [d]</td><td colspan="2">0.23-6[e]</td><td colspan="2">2.9-73.5</td><td colspan="2">3.4-87.5</td></tr>
<tr><td colspan="2">0.009-3.53[f]</td><td colspan="2">0.1-43.2</td><td colspan="2">0.1-51.4</td></tr>
<tr><td rowspan="3">API/ANGA
(Shires and Lev-On, 2012)</td><td colspan="2" rowspan="3">58.7[g]</td><td colspan="2">0.76[h]</td><td colspan="2">9.33</td><td colspan="2">11.1</td></tr>
<tr><td>0.25[i]</td><td>1.15[i]</td><td>3.02</td><td>14.0</td><td>3.59</td><td>16.7</td></tr>
<tr><td>2.30[j]</td><td>0.59[j]</td><td>28.2</td><td>7.24</td><td>33.5</td><td>8.61</td></tr>
<tr><td>(Allen et al., 2013a)</td><td>n/a</td><td>n/a</td><td>n/a</td><td>0.0048-3.29[k]</td><td colspan="2">0.06-40.3</td><td colspan="2">0.07-47.9</td></tr>
<tr><td>ICF International (Robinson, 2012)</td><td>n/a</td><td>n/a</td><td colspan="2">0.15-1.8[l]</td><td colspan="2">1.8-22</td><td colspan="2">2.2-26.2</td></tr>
</table>

† Calculated using the "unreported venting" estimation methodology for liquid unloading published in (CAPP, 2004c) and applied to 3846 tight gas wells as detailed in Section 5.4. Results of this comparison suggest CAPP methodology may need updating.
[a] Assuming shallow gas wells of less than 1000 m have insufficient pressure to self-unload (CAPP, 2004c); there are 12259 of 18924 producing gas wells without a fracture code and 56567 of 83098 producing gas wells with a fracture code in the 2011 volumetric data that have at least one UWI of less than 1000m.
[b] Assuming 179391 "LU wells" vented for liquid unloading, the sum over all National Energy Modeling System regions. "LU wells" make up 41% of the conventional well count in 2010 (US EPA, 2012c).
[c] Reported as 690440 to 1491925 scf CH_4/well-year vented in the US EPA Nation Inventory over the National Energy Modeling System regions (US EPA, 2012c), assumes a methane content of 78.8%.
[d] Although the US EPA methodology support document states that liquids unloading emissions factors were applied *"to both wells with and without hydraulic fracturing, using the percentages of wells venting for liquids unloading with plunger lifts, and wells venting without plunger lifts in each region, from the API/ANGA data."* (US EPA, 2013a) there were insufficient data within table A-127 to compute the fraction of wells requiring liquid unloading.
[e] Reported for wells without plunger lifts as 77900 to 2003373 scf CH_4/well-year vented in the US EPA Nation Inventory over the National Energy Modeling System regions (US EPA, 2013a), assumes a methane content of 78.8%.
[f] Reported for wells with plunger lifts as 2856 to 1177705 scf CH_4/well-year vented in the US EPA Nation Inventory over the National Energy Modeling System regions (US EPA, 2013a), assumes a methane content of 78.8%.
[g] Reported as 36% of gas wells have a plunger lift, 13.4% of gas wells have an artificial lift and 9.3% of wells without a lift vent to the atmosphere for liquid unloading (Shires and Lev-On, 2012).
[h] A weighted average of emissions per well per year reported in Table C1, C2, C3 and C4 (Shires and Lev-On, 2012).
[i] A weighted average of emissions per well per year reported for wells, conventional in Table C1 and unconventional in Table C3, without plunger lifts (Shires and Lev-On, 2012).
[j] A weighted average of emissions per well per year reported for wells, conventional in Table C2 and unconventional in Table C4, with plunger lifts (Shires and Lev-On, 2012).
[k] Derived using reported volumes and event frequencies from Table S3-2 (Allen et al., 2013a). Emitted methane per event ranged from 950 to 191000 scf (average 57000 scf). The frequency of liquid unloading events per year ranged from 1 to 12 (average 5.9).
[l] This range assumes a methane content of 78.8% and uses liquid unloading estimates of 50000-600000 scf CH_4/well-year vented from (Robinson, 2012). There is no distinction made for conventional or unconventional wells
‡ Refers to the source for CH_4 global warming potential (GWP) data used to calculate CO_2 equivalent GHG emissions.

6 SUMMARY AND CONCLUSIONS

Using the Alberta Energy Regulator (AER) general well data file (GENWELL) (current up to January 31, 2012) and a year 2011 volumetric facility activity report from the Petroleum Registry of Alberta (PRA), detailed well activity and emission factor data associated with unconventional gas well development have been derived. In 2011 in the province of Alberta, there were 12800 well legs drilled, each identifiable by a unique well identifier (UWI). Analysis of available data identified 2989 (23%) of these as natural gas well legs, of which 2252 were also hydraulically fractured in 2011. These 2252 fractured well legs were distributed among 1579 unique well structures, each of which consisted of one or more UWIs sharing a common surface hole. The majority of these wells were tight gas and coalbed methane related lithology. Although there are some multi-leg well structures in Alberta, most tend to consist of one to two UWIs, which is true for all natural gas types. Drilled wells in tight gas, coalbed methane and shale formations in Alberta are roughly 70% vertical, 100% vertical and 85% horizontal respectively. As might be expected, but is not generally acknowledged in the existing literature, the present analysis has revealed that the different well types can have quite different emissions characteristics.

Emissions associated with drilling of unconventional natural gas wells are predominately due to diesel combustion and are governed by the overall drilled length of each UWI. The move toward hydraulically fractured wells has in general increased drilling depths and length over the past decade. Within the set of active natural gas wells in Alberta in 2011, those with a spud date in the year 2000 have an average drilled length of roughly 750 m to 1035 m depending on the well type (see Table 4.11 for further details). By comparison, the average drilled length in 2011 in Alberta ranged from 761.9 m for CBM UWIs to 2958.2 m for tight gas UWIs, and there were 263 tight gas UWIs and 3 shale UWIs that extended to lengths in excess of 4000 m. These average drilling lengths, combined with the calculated diesel usage factor of 0.022 m^3 diesel / m-drilled derived in Section 4.3, yield diesel usage factors for fractured gas wells on a per UWI basis ranging from 16.6 m^3 diesel / CBM-UWI to 64.6 m^3 diesel / tight gas-UWI. This implies a factor of 2.8 increase in diesel fuel combustion per tight gas UWI drilled in 2011 relative to a typical well drilled in 2000. This increase in diesel combustion per drilled UWI is also associated with increases in GHG and CAC emissions on a per drilled UWI basis. In Section 5.2, mean and standard deviation emission factors for specific GHGs and CACs emitted via diesel combustion during unconventional well drilling in Alberta in 2011 were derived using relevant emission factor data for large diesel engine sources published in U.S. EPA AP-42 Section 3.4 (US EPA, 1995a).

The available data did not permit the estimation of flaring and/or venting emissions during well drilling such as those from kickbacks or the degasing of drilling mud. However, these emissions are expected to be similar to those for conventional wells, and negligible relative to the emissions associated with diesel usage during drilling. The analysis of drill stem test submissions presented in Section 5.5.1 revealed that flaring and/or venting from drill stem tests is not a significant emission source for hydraulically fractured wells in Alberta. Indeed, there has been steady decline in the number of conducted drill stem tests over the last decade with only 1 fractured UWI reporting a drill stem test in 2011.

Several different procedures were developed to correctly attribute reported flaring and venting volumes to well-completions of specific UWIs. Although it was initially expected based on discussions from industry representatives and from the ERCB reporting guidelines that most well-completion emissions would be reported at the well-level by UWI at gas-test batteries (sub-type 371), only 6.6% (105 of 1579) of well sites actually reported in this mode. Deeper analysis of the PRA and GENWELL data revealed flaring and venting attributable to well-completion reported at the battery-level for a range of single- and multi-well battery subtypes. This significantly complicated analysis but procedures were successfully developed that could directly attribute reported flaring and venting volumes to well-completions of specific UWIs in most cases, except where UWIs were connected to multi-well batteries that reported flaring or venting volumes less than the total gas delivered from all associated UWIs.

Of the 1579 unique well structures in Alberta that each contained one or more legs (UWIs) that were hydraulically fractured in 2011, slightly less than one-quarter (23.5%) were not identifiable within the PRA data as discussed in Section 4.1.2 and were presumed to have been excluded for confidentiality reasons. Approximately 41% were identified as "green-completions" for which production data were reported that matched battery receipts and no well-level flaring or venting were reported (see Section 4.2.6). Just over a one-third (34.5%) of well structures reported some degree of attributable flaring and venting during well-completion. Assuming 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 a lack of reported flaring and venting and a matching of reported produced gas volumes at the well and received gas volumes at a battery.

New well-completion flaring and venting emission factors were developed using available data for hydraulically fractured gas wells in Alberta in 2011, as presented in Section 5.1. Almost all of the reported gas volumes attributable to well-completions in Alberta were flared. Compared to tight gas wells, flaring and venting from CBM and CBM hybrid wells associated with well-completion was not significant either in total volume or on a per fractured UWI basis. From the available reported data, overall GHG emissions at tight gas wells on a per UWI basis were estimated to be 280.6 t CO_2e/UWI. This emission rate for sites not using green-completions is approximately 5.8 times larger than the CAPP estimate for gas well-completion emissions, based on wells completed in the year 2000, used in the development of the 2005 National Inventory of Greenhouse Gases (CAPP, 2004a). However, this is also less than an equivalent emission factor that can be derived from the revised US EPA data (US EPA, 2010). Assuming that essentially all completion emissions in Alberta in 2011 were flared, which is consistent with the available reported data, then the US EPA unconventional well-completion emission factor of 173.3 t CH_4 produced per completion is equivalent to 296,100 m^3 gas flared /completion with a flaring rate of 99.5%. The present data for Alberta in 2011 imply an overall average flaring rate during well-completion at tight gas wells of 113200 m^3 gas/completion, which is 61.7% less than the comparable US EPA estimate. New CAC emission factors for flaring and venting during well-completions in Alberta in 2011 were also derived, as presented in Section 5.1.

Estimates of diesel fuel consumption and associated GHG and CAC emissions for onsite equipment used during well-completions were also considered. Unfortunately diesel fuel emissions and usage are not currently centrally tracked. However, using privately shared diesel fuel volumes for 22 completion jobs that occurred in western Canada during 2012, and assuming diesel usage was correlated with the volume of fracturing fluid being handled, a scaling factor of 0.0245 m^3 diesel per m^3 of injected fracturing fluid was derived. Analysis of available PRA data revealed that load injected volumes were reported for 164 fractured tight gas UWIs (115 wells) and 5 fractured shale UWIs (5 wells). From these limited data, a tight gas diesel usage factor was estimated at 30.1 m^3 / UWI which enabled calculation of relevant GHG and CAC emission factors and emission volumes for 2011 as discussed in Section 5.2 and 5.3.

Well operational emissions during the production phase of fractured natural wells were also investigated. Working within the confines of the available data, an analysis was completed using data for 3846 tight gas wells tied to single-well gas batteries, which had fracture dates between January 1, 2000 and December 31, 2011 and reported volumetric production data to PRA during 2011. As detailed in Section 4.5, the analysis of monthly reported volumes (excluding volumes attributable to well-completions) revealed that while 56% of these wells reported fuel usage data during 2011, only 6.9% reported flaring and venting volumes. From these data, the calculated mean fuel usage rate of 2200 m^3/UWI per month was found to be equivalent to 0.7% of production. As detailed in Sections 4.5 and 5.4, it appears that the episodic nature of well operations such as liquid unloading is not captured by current reporting requirements. Following the methodology used by (CAPP, 2004c) for estimating unreported liquid unloading emissions, an emission factor range of 9.2 to 25.8 m^3/well per month has been derived for hydraulically fractured wells in Alberta. From the point of view of inventory calculations it should be noted that this derived emission factor range would not capture the possibility of large liquid unloading emissions exhibited by certain wells in the measurement study of (Allen et al., 2013a) and the API/ANGA survey (Shires and Lev-on, 2012). The criteria, whether geographical, geological, and/or some physical well parameter, for identifying or estimating which wells have the potential for large liquid unloading emissions is currently unknown. The fact that liquid unloading has the potential to be the dominant emission source over the production lifetime of a well, indicates a need for closer monitoring and reporting of liquid unloading activities as well as future field studies to quantify liquid unloading emissions for a range of wells typical of a given target region.

The derivation of these new emission factor data represents a significant accomplishment that should help clarify many of the controversial data issues raised in the detailed literature review presented in Section 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.

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