Environmental Science & Technology

Article

pubs.acs.org/est

Emission Factors for Hydraulically Fractured Gas Wells Derived Using Well- and Battery-level Reported Data for Alberta, Canada

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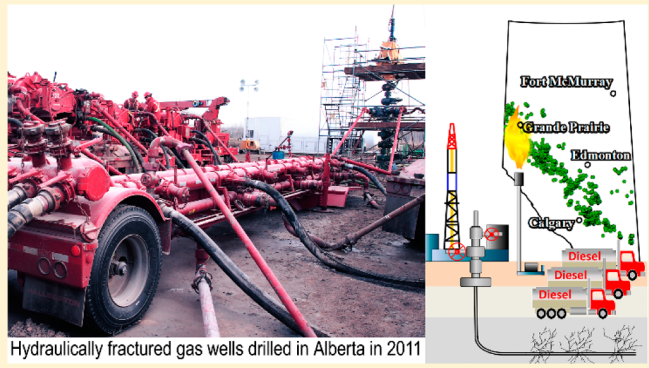
Ⓢ *Supporting Information*

ABSTRACT: A comprehensive technical analysis of available industry-reported well activity and production data for Alberta in 2011 has been used to derive flaring, venting, and diesel combustion greenhouse gas and criteria air contaminant emission factors specifically linked to drilling, completion, and operation of hydraulically fractured natural gas wells. Analysis revealed that in-line ("green") completions were used at approximately 53% of wells completed in 2011, and in other cases the majority (99.5%) of flowback gases were flared rather than vented. Comparisons with limited analogous data available in the literature revealed that reported total flared and vented natural gas volumes attributable to tight gas well-completions were ~6 times larger than Canadian Association of Petroleum Producers (CAPP) estimates for natural gas well-completion based on wells ca. 2000, but 62% less than an equivalent emission factor that can be derived from U.S. EPA data. Newly derived emission factors for diesel combustion during well drilling and completion are thought to be among the first such data available in the open literature, where drilling-related emissions for tight gas wells drilled in Alberta in 2011 were found to have increased by a factor of 2.8 relative to a typical well drilled in Canada in 2000 due to increased drilling lengths. From well-by-well analysis of production phase flared, vented, and fuel usage natural gas volumes reported at 3846 operating tight gas wells in 2011, operational emission factors were developed. Overall results highlight the importance of operational phase GHG emissions at upstream well sites (including on-site natural gas fuel use), and the critical levels of uncertainty in current estimates of liquid unloading emissions.



INTRODUCTION

Upstream emissions from hydraulically fractured gas wells have received significant attention in several recent lifecycle and emission studies[1−8] and have been identified as a large source of uncertainty in recent greenhouse gas inventories.[9,10] The overall emission estimates in these studies are heavily influenced by activity data (i.e., usage and frequency of specific practices and equipment) and emission factors relating to well-completions, liquid unloading, and workovers (recompletion). Despite the myriad of studies in the literature, comprehensive sources of activity data and emission factors specific to hydraulically fractured natural gas wells are extremely limited. The majority of existing analyses rely on well-completion emission factors for potential methane emitted from hydraulically fractured natural gas wells calculated by the U.S. EPA during development of the U.S. National GHG Inventory.[11,12] While these data are a vital source of information, they have in general been derived from aggregated data, including presentation material from U.S. EPA Gas STAR Workshops.[13,14] Recent field measurement studies[15] are a significant source of new information, but there remains a critical need for well-level analysis of emissions data from a broader range of operations. In addition, from the perspective of constructing future policy and emission inventories for the natural gas sector in Canada, it is desirable to have access to activity and emission factors derived using jurisdiction-specific upstream oil and gas data.

The development of oil and gas resources in the province of Alberta is governed by Alberta Energy Regulator (AER), which has authority over drilling applications, infrastructure requirements, reporting and operational compliance, and decommissioning of oil and gas assets as set out in the Alberta Oil and Gas Conservation Act.[16] In the present work, a comprehensive analysis of the AER's provincial well database and raw petroleum registry (PRA) production data was used to identify and study emissions patterns of hydraulically fractured natural gas wells in Alberta in 2011. The analysis was based on data submitted by industry to meet regulatory requirements and provides a snapshot of the current operating practices in Alberta where 92% of new natural gas wells drilled in 2011 were hydraulically fractured. In particular, this analysis makes use of individual well-by-well monthly volumetric data (i.e., produced, flared, vented, dispensed, and fuel usage volumes of natural gas

Received: June 10, 2014
Revised: November 9, 2014
Accepted: November 17, 2014
Published: November 17, 2014

   dx.doi.org/10.1021/es502815b | Environ. Sci. Technol. 2014, 48, 14772−14781

at 15 °C, 101.325 kPa), which in general is only available publically in aggregate form as yearly provincial and/or industry totals.[17] This resolution of data not only provides a proper representation of average well emissions and information on the wide variance in emissions among individual wells, but also enables derivation of emission factors for different natural gas well types. Using these volumes in combination with information from other sources where necessary including Canadian Association of Petroleum Producers' (CAPP) technical reports and selected privately shared industry data used in the development of the Canadian National Greenhouse Gas inventory,[18] sets of flaring, venting, natural gas fuel use, and diesel combustion emission factors linked to drilling, completion, and operation of hydraulically fractured gas wells were developed. In addition, usage rates in Alberta in 2011 of inline green-completions, where potential flowback emissions are routed into a gas gathering system as an alternative to flaring and venting, were estimated. Each derived emission factor is compared to available relevant sources such as the U.S. EPA,[12] the American Petroleum Institute (API)[9] and the direct measurement study from Allen et al.[15] Supporting Information (SI) to this manuscript provides significant additional detail and statistical information on the derived results. The relative importance of the various sources considered is also examined in terms of greenhouse gas emissions and estimated particulate matter ($PM_{2.5}$) and oxides of nitrogen (NO_x) emissions. In addition to being a valuable new source of emission factor data for comparison, the present results are thought to be the first publically available analysis derived for gas wells in Alberta.

■ OVERVIEW OF ALBERTA NATURAL GAS WELLS

In 2011 in the province of Alberta, there were 12 800 well legs drilled (i.e., licensed drilling events), each defined by a unique well identifier (UWI) within the AER well database.[19] A further analysis of fluid codes identified 2989 (23%) as natural gas well legs, of which 2735 were subsequently hydraulically fractured. A fractured UWI and the date of each stage fracture are distinguished in the AER data by a specific treatment code. These 2735 fractured natural gas well legs were distributed among 1934 unique well structures, where a well structure or well is defined as one or more UWIs sharing a common surface hole. The majority of these natural gas wells were tight gas (1334 of 1934, or 69%) and coalbed methane (580 of 1934, or 30%) related lithology, with the remaining 1% consisting of 20 shale gas wells. This breakdown is similar to that reported in a recent survey of wells in U.S. basins,[9] where 70% of identified wells were labeled tight gas, 19% as shale gas, and 11% as coalbed methane (CBM). Although there are some multileg 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, CBM, and shale formations in Alberta are roughly 70% vertical, 100% vertical, and 85% horizontal, respectively.[20]

The present analysis was based on available reported volumetric data for the 2011 study year, where a UWI was considered to be completed in 2011 if it had a fractured date recorded in 2011. By this criterion, in 2011 there were 2252 fractured UWIs contained within 1579 well structures. Table 1 shows the distribution of UWIs drilled and/or completed in 2011 by fluid type as derived from the AER well database. These data, combined with petroleum registry production data, form the base sets used in subsequent sections to calculate well-type specific flaring, venting, and diesel combustion greenhouse gas emission/intensity factors on a per UWI basis for hydraulically fractured natural gas wells in Alberta. As might be expected, but is not generally acknowledged in the existing literature, the present analysis illustrates that the different natural gas well types can have different emissions characteristics.

Table 1. Hydraulically Fractured UWIs Drilled and/or Completed in 2011

natural gas well type[a]	no. of well structures drilled	no. of UWIs drilled	no. of well structures completed	no. of fractured UWIs completed
tight gas	1334	1888	1143	1576
CBM hybrid	498	723	372	591
CBM	81	103	44	65
CBM shale other	1	1	1	1
shale gas	20	20	19	19
Total	1934	2735	1579	2252

[a]Tight gas is natural gas found in low permeability rock including sandstone, siltstones, and carbonates that requires "stimulation" such as hydraulic fracturing to produce; CBM = coalbed methane (natural gas contained in coal); Shale gas is natural gas locked in fine-grained rock; CBM hybrid refers to a well completed in both coal(s) and other lithology (e.g., sandstone); CBM shale other refers to a well competed in coal(s), shale(s), and other lithology (e.g., sandstone).[21,22]

■ DERIVATION OF EMISSION FACTORS FOR WELL-COMPLETION FLARING AND VENTING

In Alberta, well-completion flaring and venting is regulated under AER's Directive 060,[23] which specifies that all monthly flared, incinerated or vented gas volumes (i.e., raw natural gas volume at 15 °C and 101.325 kPa) of 100 m^3/month or greater must be reported to the PRA. However, Directive 060 states that if production data "are not routinely submitted for a facility, as is sometimes the case for well-completions, and if total volumes are ... less than 0.5×10^3 m^3 in total, the (AER) Technical Operations Group may waive the reporting requirement."[23] To ensure data integrity, electronic data submissions are automatically verified to be arithmetically correct so that total facility receipts match total facility dispositions.[22] AER Directive 017 further prescribes measurement requirements and acceptable uncertainties[24] and AER Directive 019 outlines compliance assurance processes.[25]

Quantification of well-completion emissions using AER and PRA data required the development of criteria to relate relevant reported monthly flared and vented volumes to identifiable well-completion activities at the well-head. Currently, the flowback interval for a UWI is not tracked as a specific event within the AER well activity data. However, the activity data do contain the date of each fracture stage associated with a UWI. Thus, by linking the fracture date for each UWI with monthly reported flared and vented volumes within the PRA, the associated well-completion related emissions could be estimated. In practice, two different criteria were used to identify relevant well-completion volumes from available monthly data depending on whether flared and vented volumes for a particular UWI were reported at the well- or battery-level (since both options are possible within the reporting system). A gas battery is an upstream facility where raw effluent from one or more gas wells is initially collected, and gas, water, and oil are separated for measurement and sometimes basic pretreatment (e.g., dehydration and dew-point control), prior to disposition into a gathering system.

For well-level reported data, supported by Figure S1 in the SI, flared natural gas volumes reported during the month of fracture or in the following month were clearly distinguishable from any subsequent reported emissions. The majority, 89.9%, of the UWIs that reported flaring volumes in SI Figure S1(a) reported under a single month (i.e., either in the month of fracture or in the following month). Of the remaining UWIs that reported flaring over two reporting months, all but one had fracture dates within 2 weeks of the next reporting month. Thus, for well-level reported data, any monthly flared and vented natural gas volumes reported during the month of the fracture date and in the following month were summed to accommodate well-completions reported in either month and those overlapping two reporting periods.

For battery-level reporting, where the produced gas volume is reported under a UWI and the subsequent fate of that gas such as flaring, venting, and/or other gas uses such as fuel are reported under a separate battery code, the relevant completion month 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 by tracking receipts in the production accounting, was then identifiable as a well-completion related emission. Although "green-completions", defined here as in-line completions, are not specifically identified in the AER well activity data, it was still possible to estimate their prevalence by tracking cases where under the criteria noted above no well- or battery-level flaring or venting was reported, and reported well-level gas production volumes exactly matched battery-level dispositions into gathering systems. In some cases (e.g., at multiwell batteries other than "gas-test batteries") ambiguities in the available PRA framework preclude definitive attribution of reported flared and vented volumes back to individual UWIs. Data reported at these multiwell batteries were necessarily excluded during the derivation of well-completion flaring and venting emission factors, although it was still possible to estimate the rate of in-line completions at these sites. A detailed description of well-completion volumes, well counts, and reporting modes found in the 2011 PRA volumetric data are available in Tyner et al.[20]

The distribution of reported well-completion flared and vented volumes and apparent green-completions by battery type is shown in Figure 1. Of the 1579 unique well structures in Alberta that each contained one or more UWIs that were hydraulically fractured in 2011, slightly less than one-quarter (371 of 1579, or 23.5%) were not identifiable within the available PRA data, having been excluded by AER for confidentiality reasons. New wells may be deemed confidential according to their Lahee class (e.g., if the Lahee class corresponds to "wild cat" wells in new fields or seeking new pools, or to a well that is part of an AER approved experimental scheme), or if the well penetrates an AER-designated confidential pool.[26] In general, the minimum initial confidentially period is one year from the completion of drilling but a well may be maintained confidential for a period considered appropriate by AER.[16] A significant number of well-completions, 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 subsequent use and disposition into gathering systems and there was no well-

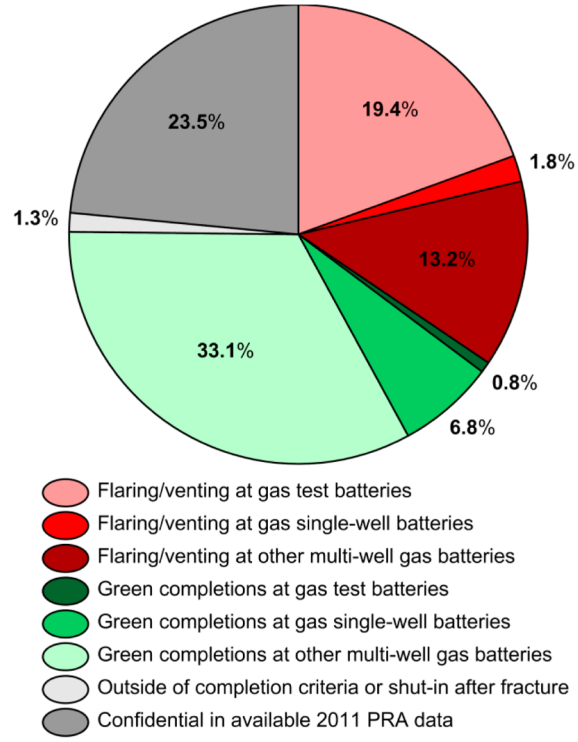


Figure 1. Percentage breakdown of how flaring and venting data associated with fractured gas well-completions could be tracked within the confines of the available AER and PRA data for Alberta in 2011.

level flaring or venting. Finally, 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 the breakdown of the nonconfidential 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 (in-line completions).

Well-completion flaring and venting emission factors were calculated from the available nonconfidential volumetric data from the PRA representing 1208 unique well structures. Flared and vented volumes for each well structure were normalized by the number of contributing fractured UWI within that well structure, and these data were subsequently averaged by natural gas well type. As summarized in Table 2, reported flare volumes attributable to well-completions are much greater for tight gas wells than CBM hybrid or CBM wells, and reported venting volumes are comparatively negligible.

Associated greenhouse gas emission factors on both 100- and 20-year time horizons, calculated using global warming potential values from the two most recent Intergovernmental Panel on Climate Change (IPCC) assessment reports (AR4 and AR5) are presented in Table 2. Emission factors for individual species of interest (e.g., particulate matter (PM), oxides of nitrogen (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), and total hydrocarbons (THC)) derived using results of Table 2 in conjunction with published emission factor data are included as SI to this paper.

Table 2 also includes comparison to relevant GHG emission factors for flaring and venting during well-completion that can be derived from other sources.[11,12,27,28] To enable this comparison, and as further detailed in the footnotes to Table 2, emission estimates presented in terms of "potential methane

Table 2. Comparison of Mean[a] Emission Factors for Wells Reporting Flaring and Venting during Well-Completion

	flared volume [1000 m^3/UWI]	vented volume [1000 m^3/UWI]	greenhouse gas (GHG) emission factors using a 100-/20-year time horizon [tCO_2e/UWI]			
			IPCC AR4[b]		IPCC AR5[c]	
			flaring	venting	flaring	venting
Current Analysis of Alberta Data for 2011[a]						
tight gas (407[d] UWIs)	113.2	0.6	271.6/331.6	8.9/26.2	286.2/351.6	12.9/31.0
CBM hybrid (291 UWIs)	0.9	n/a	2.1/2.6	n/a	2.2/2.7	n/a
CBM (30 UWIs)	2.7	n/a	6.5/7.9	n/a	6.8/8.4	n/a
Available Estimates that can be Derived from Other Sources (See Footnotes)						
CAPP[27]	18.8[e]	0.4[e]	43.4[f]/44.7[f]	5.3[g]/15.3[g]	43.7[f]/45.1[f]	7.3[g]/18.5[g]
U.S. EPA[12] *unconventional*	296.1[h]	1.6[h]	710.8/867.7	23.1/67.9	749.3/920.1	33.3/80.4
U.S. EPA[11] *conventional*	1.2[h]	0.006[h]	2.9/3.6	0.1/0.3	3.1/3.8	0.1/0.3
Allen et al.[28]	269.6[i]	1.4[i]	633.3/789.8	20.8/61.8	682.0/837.5	30.3/73.2

[a]Note: mean rate data are correctly calculated as the average 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. Additional statistics are provided in tables included with the online SI. [b]Calculated using global warming potential (GWP) data from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report[30] which specifies 100- and 20-year time horizon GWP values for methane of 25 and 72 respectively. [c]Calculated using GWP data from the IPCC 5th Assessment Report.[31] Calculations were performed including climate-carbon feedbacks with 100- and 20-year time horizon GWP values for fossil methane of 36 and 87 respectively (which include further increments due to oxidation of methane to CO_2). [d]388 of the 407 sites reported flared volumes. Only 20 of the 407 sites reported venting volumes. [e]Derived using a reported 890 $ktCO_2e$ of reported flaring and 92 $ktCO_2e$ of reported venting at 20 566 wells[27] and assuming a flaring efficiency of 98% and gas composition data from Johnson and Coderre[29] [f]Reported as flaring at 20 566 wells from well testing 878 $ktCO_2$ and 568 t CH_4[27] [g]Reported as "venting reported" at 20 566 wells from well testing 4364 t CH_4[27] [h]The reported emission factors of 173.3 t CH_4/UWI unconventional[12] and 0.71 t CH_4/UWI conventional[11] are converted to an Alberta natural gas volume at 15 °C and 101.325 kPa assuming a methane mean content of 85.79%.[29] An equivalent flared and vented natural gas volume is determined using the mean proportion of natural gas flared and vented at tight gas well-completions in Alberta in 2011 (i.e., 99.5%, 113 200 m^3 of 113 800 m^3, of the flowback natural gas is flared). [i]Reported as potential methane emissions in SI Table SI-6 from 27 measured well-completions. The average potential emission is 8 210 137 scf CH_4/completion or 158 t CH_4/completion. An equivalent flared and vented natural gas volume was determined as in footnote g.

release" by the U.S. EPA[11,12] and Allen et al.[28] were converted to relevant flared and vented natural gas volumes based on an Alberta-relevant mean methane content of 85.79%[29] and operational practices at tight gas wells in Alberta in 2011 where 99.5% of emitted natural gas volumes were flared.

Relative to CAPP emission factors[27] for well-completion based on wells drilled in 2000 (which would be expected to be dominated by conventional wells), the combined flaring and venting GHG emission factors for fractured tight gas wells derived in the present work from analysis of well- and battery-level data are 5.75−6.0 times higher. However, the present tight gas factors are also approximately 2.5 times smaller than comparable factors that can be derived from the U.S. EPA[11,12] and Allen et al.,[28] These differences may be attributed to differences in formation geology (e.g., reservoir pressures and porosity) and well type (e.g., tight gas vs shale gas), variability associated with sample size, differences in methodology (e.g., high-level analysis of aggregated well data, direct field measurements of smaller numbers of sites, and well-level analysis of reported data), and inherent inaccuracies in source data or measurements.

Total greenhouse gas emissions from flaring and venting during well-completions in Alberta in 2011 can be estimated assuming that nonconfidential fractured UWIs are representative of the UWIs held confidential by AER, such that the proportions of green-completions and flaring and venting rates are consistent.[20] Considering IPCC AR5 greenhouse gas emission factors derived for Alberta in Table 2, this yields an estimated total GHG emission from flaring and venting during tight gas well-completions in 2011 of 147.2 $ktCO_2e$.

■ DERIVATION OF EMISSION FACTORS ASSOCIATED WITH DIESEL COMBUSTION

Diesel Combustion Emissions During Well Drilling. Atmospheric emissions associated with drilling of hydraulically fractured natural gas wells are predominately due to diesel combustion and are governed by the overall drilled length. The move toward hydraulically fractured wells has in general coincided with increased drilling depths and overall lengths over the past decade. In Alberta, the average length of 8089 tight gas UWIs drilled in the year 2000 and active in 2011 was 1034.7 m, and ~2% of these were horizontal. By comparison, the average length of 1888 tight gas UWIs drilled in 2011 and subsequently fractured was nearly three times longer (2958.2 m), with approximately 30% of these being horizontal. These included 263 tight gas UWIs that extended to lengths in excess of 4000 m.

Length-weighted emission factors for well drilling were derived by relating reported data in the 2005 CAPP National GHG Inventory[27] for total CO_2 emission volumes from fuel combustion during drilling with drilling length data for 2000 and 2011 derived using AER well files. As reported in Table A,[27] total CO_2 emissions of 1247 kt were attributable to fuel combustion from drilling of 20 566 wells in Canada in 2000. This equates to a well drilling GHG intensity factor of 60.6 t CO_2/UWI-drilled-in-2000, based on an average UWI count per well in Canada in 2000 of approximately 1. Assuming all reported CO_2 from well drilling is a product of diesel combustion during drilling[32] and considering an emission factor of 2709.8 $kgCO_2/m^3$-of-combusted-diesel for large diesel engines,[33] 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 dividing by the average distance drilled for a natural gas UWI in 2000. Since the CAPP

Table 3. GHG Emission Factors for Diesel Combustion during Drilling of Hydraulically Fractured Wells in Alberta in 2011

					greenhouse gas (GHG) emission factors [tCO_2e/UWI][a]			
					100-year time horizon		20-year time horizon	
			length drilled [m/UWI]	diesel consumption [m^3/UWI]	IPCC AR4[b]	IPCC AR5[c]	IPCC AR4[b]	IPCC AR5[c]
well type	no. of wells	no. of fractured UWIs	mean (std dev)[d]	mean (std dev)	mean (std dev)	mean (std dev)	mean (std dev)	mean (std dev)
Current Analysis of Alberta Data for 2011								
tight gas	1334	1888	2958.2 (1154.1)	64.6 (25.2)	182.9 (71.3)	183.0 (71.4)	183.1 (71.4)	182.6 (71.3)
CBM hybrid	498	723	1040.0 (186.8)	22.7 (4.1)	64.3 (11.5)	64.3 (11.6)	64.4 (11.6)	64.2 (11.5)
CBM	81	103	761.9 (293.5)	16.6 (6.4)	47.1 (18.1)	47.1 (18.2)	47.1 (18.2)	47.0 (18.1)
CBM shale other	1	1	1081.0 (n/a)	23.6 (n/a)	66.8 (n/a)	66.9 (n/a)	66.9 (n/a)	66.7 (n/a)
shale	20	20	2172.9 (1107.7)	47.5 (27.5)	134.3 (68.5)	134.4 (68.5)	134.5 (68.5)	134.2 (68.4)
Available Estimates that can be Derived from Other Sources (See Footnotes)								
CAPP	6100	9418[e]	1023.9 (729.3)	22.4 (15.9)[f]	63.3 (45.1)	63.3 (45.1)	63.4 (45.1)	63.2 (45.0)
Wood et al.[4]	AB 2011 well count	AB 2011 UWI count	AB 2011 drill lengths	14.2–55 (5.5–21.5)[g]	40.1–155.7 (15.5–60.8)	40.1–155.8 (15.5–60.8)	40.1–155.9 (15.5–60.8)	40.1–155.5 (15.4–60.7)
Sonoma Technology Inc.[34]	AB 2011 well count	AB 2011 UWI count	AB 2011 drill lengths	14.7–56.9 (5.7–22.2)[h]	41.5–161.2 (16.0–62.9)	41.5–161.3 (16.0–62.9)	41.6–161.3 (16.0–62.9)	41.5–161.0 (16.0–62.8)

[a]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.[33] Following CAPP,[32] N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2.[35] [b]Calculated using global warming potential (GWP) data from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report[30] which specifies 100- and 20-year time horizon GWP values for methane of 25 and 72, and for N_2O of 298 and 289 respectively. [c]Calculated using GWP data from the IPCC 5th Assessment Report.[31] Calculations were performed including climate-carbon feedbacks with 100- and 20-year time horizon GWP values for methane of 34 and 86 (which exclude further increments due to oxidation of methane to CO_2 since this is already incorporated into the calculation of direct CO_2 emissions), and N_2O of 298 and 268 respectively. [d]The standard deviation (std dev) is a resultant of the variation in drill length. [e]Alberta UWIs with a spud date in the year 2000 which may or may not have been fractured [f]Calculated based on a reported intensity factor of 60.6 tCO_2e/well[27] and an emission factor of 2709.8 $kgCO_2e$/ m^3-of-combusted-diesel for large diesel engines from U.S. EPA AP-42 Section 3.4.[33] [g]Based on their reported value of 18.6 m^3-diesel/m-drilled in Table 3.2[4] applied to the average drill length for each natural gas well type drilled and fractured in Alberta in 2011. [h]Based on their reported value of 1.55 gal-diesel/ft-drilled applied to the average drilled length for each natural gas well type drilled and fractured in Alberta in 2011.

Table 4. Mean GHG Emission Factors for Diesel Combustion during Hydraulically Fractured Well-Completions in Alberta

well type	no. of well structures	no. of fractured UWIs	diesel consumption [m^3/UWI]	GHG emission factors 100-/20-year time horizon [tCO_2e/UWI][a]	
				IPCC AR4[b]	IPCC AR5[c]
tight gas	12	12	31.7	89.6/89.7	89.7/89.5
tight gas (Dawson Creek, BC)	1	1	36[d]	101.9/102.0	101.9/101.8
Wood et al.[4]	n/a	n/a	13.7[e]	38.8/38.8	38.8/38.7

[a]GHG emission factors were calculated using CO_2, CH_4 and N_2O emission factor data derived from diesel fuel consumption factor using emission factor data for large diesel engine sources from U.S. EPA AP-42 Section 3.4.[33] Following CAPP,[32] N_2O emissions are calculated using an emission factor for diesel stationary combustion sources found in Table C2.[35] [b]Calculated using global warming potential (GWP) data from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report[30] which specifies 100- and 20-year time horizon GWP values for methane of 25 and 72, and for N_2O of 298 and 289 respectively. [c]Calculated using GWP data from the IPCC 5th Assessment Report.[31] Calculations were performed including climate-carbon feedbacks and use 100- and 20-year time horizon GWP values for methane of 34 and 86 (which exclude further increments due to oxidation of methane to CO_2 since this is already incorporated into the calculation of direct CO_2 emissions), and N_2O of 298 and 268 respectively. [d]Based on interviews during a site visit to witness a hydraulic fracturing operation in Dawson Creek, British Columbia, Canada. [e]Based on a citation of a total of 109 777 L of diesel fuel used "for hydraulic fracturing on eight horizontally drilled wells in the Marcellus Shale".[4]

data do not delineate between natural gas well types, the average length of 1023.9 m combining natural gas types drilled in 2000 was used to compute a diesel usage factor of 0.022 m^3-diesel/m-drilled. As presented in Table 3, by taking into account variations in drilling lengths among different types of hydraulically fractured gas wells obtained using AER well files, diesel usage factors for fractured natural gas wells drilled in 2011 on a per UWI basis can be derived, which range from 16.6 m^3-diesel/CBM-UWI to 64.6 m^3-diesel/tight gas-UWI. To the authors' knowledge, the only other directly comparable estimates of diesel usage on a per drilled length basis were estimated as 0.0186 m^3-diesel/m-drilled in New York State shale formations,[4] and 0.0192 m^3-diesel/m-drilled (reported as 1.55 gal/ft) for wells drilled in California's Santa Barbara and Kern counties.[34] Applying these factors to Alberta well-depths yields a diesel usage range of 14.2−56.9 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 apparent variability in tight gas drilling lengths is partially a consequence of horizontal drilling. The average fractured horizontal tight gas UWI was approximately 950 m 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 three shale gas wells had substantially longer drill lengths of 4400, 4557.3, and 5157 m and were part of the Second White Speckled Shale formation.

Using the IPCC AR5 greenhouse gas emission factors derived for Alberta in Table 3, the total GHG emissions from the combustion of diesel attributed to tight gas well drilling in 2011 (1888 UWI) were estimated to be 345.5 $ktCO_2e$. The potential impact of dual-fuel engine technology (i.e., natural gas and diesel) on GHG drilling emissions is considered in the SI. Although there are clear potential benefits to this technology, estimated usage rates of dual-fuel rigs in Alberta in 2011 were insufficient to affect overall GHG drilling emissions.

Diesel Combustion Emissions during Well-completion. Diesel consumption associated with pumping of fracturing fluids; 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 Alberta 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. Using privately shared diesel fuel volume data obtained through collaborative work supporting development of the 2012 Canadian National Greenhouse Gas Inventory, a mean diesel usage of 31.7 m^3-diesel/UWI (standard deviation of 15.4 m^3-diesel/UWI) was derived for a set of 12 tight gas wells in western Canada that were completed during 2011−2012. This is consistent with the on-site estimate of 36 m^3 for a tight gas well-completion near Dawson Creek, BC provided by operators during a well-site visit by the authors. The present factor differs from the diesel fuel use estimates in the 2012 Canadian National Greenhouse Gas Inventory,[36] which were made based on the assumption that on-site fuel use scales linearly with the total volume of fracturing fluid used during a well-completion. Under this assumption a scaling factor of 0.0245 m^3-diesel/m^3-injected-fracturing-fluid was derived from 22 completion jobs that occurred in western Canada. However, this scaling factor was assumed to be independent of well-type with the intent that it be used on broad well populations. In particular, the data set includes gas and oil wells, and two of the injected volumes used in the calculation had initial reporting/data entry errors that when corrected revise the factor to 0.030 m^3-diesel/m^3-injected-fracturing-fluid. Considering only tight gas wells, an average injected volume of 838.2 m^3 can be obtained for the eight wells with reported load injection data from the present set of 12 tight gas wells. The relevant tight gas scaling factor based on these wells is 0.0378 m^3-diesel/m^3-injected-fracturing-fluid.

A comparison of all available diesel consumption and GHG emission factors for hydraulically fractured well-completions is provided in Table 4. Additional statistical information and derived emission factor data for individual criteria air contaminants (CAC) and other species of interest are included as SI. Based on the IPCC AR5 emission factors derived in Table 4, the estimated total emission of GHGs, on a 100-year time horizon, associated with diesel combustion during completion of hydraulically fractured tight gas UWIs in Alberta in 2011 was calculated to be 141.3 $ktCO_2e$.

■ ESTIMATION OF WELL OPERATION EMISSION FACTORS

Well operation emissions over the lifetime production period of a well may include onsite fuel (natural gas) combustion, as well

Table 5. Comparison of Estimated Monthly Venting Emission Factors for Well Operation/Liquid Unloading

		fraction of wells that report venting during operation or liquid unloading [%]		monthly vented gas volume at wells that vent [1000 m^3/well-month]		monthly GHG emission factors using a 100-year time horizon [tCO_2e/well-month] IPCC AR4[b]		IPCC AR5[c]	
		conventional	unconventional	conventional	unconventional	conventional	unconventional	conventional	unconventional
Current Analysis of Reported Vented Volumes during Operation of Natural Gas Wells in Alberta in 2011[a]									
estimate for Alberta tight gas wells based on reported data		n/a	5.9	n/a	0.345[d]	n/a	5.1[e]	n/a	7.3[f]
Available Estimates of Liquid Unloading that can be Derived from Other Sources (See Footnotes)									
U.S. EPA 2010 inventory[39]		41[g]	0	2.06−4.47[h]	0	30.1−65.1	0	43.8−94.7	0
U.S. EPA 2011 Inventory[12]	all venting wells	see API/ANGA[i]		0.681[j]		10.0		14.4	
	w/o plunger lift	see API/ANGA[i]		0.23−6[k]		3.4−87.5		5.0−127.2	
	with plunger lift	see API/ANGA[i]		0.009−3.53[l]		0.1−51.4		0.2−74.8	
API/ANGA[9]	all venting wells	13.5[m]		0.63[n]	0.82[n]	9.2	12.0	13.4	17.5
	w/o plunger lift	6.0[m]		0.25[o]	1.15[o]	3.59	16.7	5.22	24.3
	with plunger lift	7.6[m]		2.30[p]	0.59[p]	33.5	8.61	48.8	12.5
Allen et al.[28]		n/a	n/a	n/a	0.0048−3.29[q]	n/a	0.07−47.9	n/a	0.1−69.7
ICF International[37]		n/a	n/a	0.15−1.8[r]		2.2−26.2		3.2−38.1	

[a]Derived from production phase vented natural gas volumes reported at the 225 of the 3846 tight gas wells in Alberta that reported venting to the PRA in 2011. [b]Calculated using global warming potential (GWP) data from the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report[30] which specifies 100- and 20-year time horizon GWP values for methane of 25 and 72 respectively. [c]Calculated using GWP data from the IPCC 5th Assessment Report.[31] Calculations were performed including climate-carbon feedbacks with 100- and 20-year time horizon GWP values for fossil methane of 36 and 87 respectively (which include further increments due to oxidation of methane to CO_2). [d]Includes all reported venting during operations (i.e., reported vented volumes may include venting due to facility upsets, maintenance activities, liquid unloading, etc.). [e]14.6 on a 20-year horizon. [f]17.7 on a 20-year horizon. [g]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.[39] [h]Reported as 690 440 to 1 491 925 scf CH_4/well-year vented in the U.S. EPA Nation Inventory over the National Energy Modeling System regions,[39] assumes a methane content of 78.8%. [i]The U.S. 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.".[12] [j]A weighted average of the emissions for all well reported in the U.S. EPA Nation Inventory over the National Energy Modeling System regions[12] presented on a per month basis, assumes a methane content of 78.8%. [k]Range for wells without plunger lifts reported as 77 900 to 2 003 373 scf CH_4/well-year vented in the U.S. EPA Nation Inventory over the National Energy Modeling System regions,[12] assumes a methane content of 78.8%. [l]Range for wells with plunger lifts reported as 2856 to 1 177 705 scf CH_4/well-year vented in the U.S. EPA Nation Inventory over the National Energy Modeling System regions,[12] assumes a methane content of 78.8%. [m]Reported as 36% of gas wells have a plunger lift (Table 5)[9], 21.1% of plunger lift gas wells vent (Table 6)[9] and 9.3% of wells without a plunger lift vent to the atmosphere for liquid unloading (Table 6).[9] [n]A weighted average of the emissions per well per year reported in Table C1, C2 for conventional, C3 and C4 for unconventional[9] presented on a per month basis. The weighted average of all wells 0.76 × 1000 m^3/well-month. [o]A weighted average of emissions per well per year reported in Table C1 and C3 for conventional and unconventional wells, without plunger lifts[9] presented on a per month basis as indicated. [p]A weighted average of emissions per well per year reported in Table C2 and C4 for conventional and unconventional wells with plunger lifts[9] presented on a per month basis as indicated. [q]Calculated using reported volumes and event frequencies found in SI Table S3−2.[28] Emitted methane per event ranged from 950 to 191 000 scf (average of 57 000 scf). The frequency of liquid unloading events per year ranged from 1 to 12 (average of 5.9). [r]This range assumes a methane content of 78.8% and uses liquid unloading estimates of 50 000−600 000 scf CH_4/well-year vented.[37] There is no distinction made for conventional or unconventional wells

as venting and flaring occurring after well-completion that may occur during liquid unloading (i.e., well cleanup or blowdown treatments to remove accumulated liquids in the wellbore), during equipment maintenance (e.g., separator tanks, compressors, etc.), and/or during required work to service/repair down-hole equipment. An analysis of production phase fuel usage, flared, and vented natural gas volumes reported to the PRA in 2011 was completed using data from 3846 tight gas wells tied to single-well gas batteries, which had fracture dates between January 1, 2000 and December 31, 2011. Note that the reported venting volumes do not include estimates of fugitive leaks (e.g., compressor seals) at upstream facilities and these sources are not considered in this paper. The analysis of monthly reported volumes (excluding volumes attributable to well-completions) revealed that while 56% of these wells (2151 of 3846) reported fuel usage data during 2011 totaling 54.8 million m^3, only 6.9% reported flaring (55 of 3846, totaling 642100 m^3) and/or venting (225 of 3846, totaling 1.14 million m^3). The total fuel volume is equivalent to 0.66% of the 2011 production from these 3846 wells (8.25 billion m^3) and 1.1% of the 2011 production from the 2151 wells (5.18 billion m^3) reporting fuel usage. For the 56% of wells that report fuel usage, a mean fuel usage rate of 2123 m^3/well-per-month was derived. Similarly, a mean flared natural gas volume of 973 m^3/well-per-month was derived for the 1.4% of wells that report flaring, and a mean vented natural gas volume of 345 m^3/well-per-month was derived for the 5.9% of wells that reported venting (excluding a single outlier reporting vented volumes more than 4.1 times greater than the second largest site and more than 51 times greater than the average of the remaining sites). Plots of these distributions are included as SI.

Within the context of well operation emissions, recent studies have implicated liquid unloading as a potentially significant source of GHG emissions.[15] During routine operation, produced liquids are separated inline and gas is delivered to the gathering pipeline. Liquid unloading is required in wells where the downhole pressure and wellbore velocities are insufficient to prevent liquids from collecting in the wellbore. These liquids can be cleared by removing the back pressure of the gathering system by diverting the flow at the wellhead to an atmospheric pressure separation vessel. Gas from this vessel may be vented directly to atmosphere or flared. These types of emission are typically not metered in Alberta and any reported monthly venting data would be expected to be based on engineering estimates.[23]

Table 5 compares the well operations emission factors derived using reported vented volume data for Alberta with available liquid unloading emission factor data in the literature. Although the present data would be expected to include additional venting from operations activities other than liquid unloading, the emission factor is nevertheless roughly half those derived from the API/ANGA survey data[9] and U.S. EPA,[12] and at the low end of the wide emission factor ranges provided during a 2012 Natural Gas STAR workshop[37] and from the direct measurement study of Allen et al.[15]

A potential explanation for this difference may be that some estimates of liquid unloading emissions fall below the monthly minimum reporting threshold of 100 m^3/month. Indeed, volume 3 of the CAPP National Inventory of Greenhouse Gases[38] contains procedures for separately estimating liquid unloading emissions at shallow-depth natural gas wells to augment reported data. This estimation procedure is further summarized in the SI. From the perspective of an operator trying to estimate vented volumes during liquid unloading, given an absence of widely accepted emission factor data, the CAPP unreported venting methodology[38] or similar procedures might be used as a guide, where vented volumes are estimated based on normal well production and an assumed duration and frequency of liquid unloading procedures. For the specified average duration of 0.79 h and event frequency of 0.24 times per month (based specifically on shallow gas wells predominantly in southern Alberta),[38] monthly venting volumes of 47.1 m^3/well might be expected, which on their own are below reporting thresholds. Further analysis of the present reported data for the set of 3846 tight gas wells in Alberta noted above reveals that only 5.9% reported any venting in 2011 (as compared to 13.5% that might be expected based on API/ANGA activity factor data), and of these, 42.9% reported average monthly volumes over the year that were less than or equal to the 100 m^3/month reporting threshold (see SI Figure S5(b) for plotted distributions). All of these considerations would support the notion that liquid unloading emissions may not be well-captured in the monthly flared and vented volume data as it is currently reported. The breadth of the ranges even in the industry reported data from API/ANGA data[9] and direct measurement data[28] highlights both the current level of uncertainty in liquid unloading emission factors and their potential significance.

Considering the set of tight gas wells completed in 2011 in Alberta, the presently derived well operation emission factors (including reported fuel usage, flaring, and venting) based on 2011 production data would suggest total GHG emissions over a 20-year production life of 811.1 $ktCO_2e$ (calculated over a 100-year time horizon using the fossil methane IPCC AR5 GWP of 36 as further detailed in the SI). By contrast, if we instead apply the API/ANGA activity and emission factors for liquid unloading at unconventional wells in conjunction with the presently derived natural gas fuel usage emission factor, this would imply total GHG emission of 1342.3 $ktCO_2e$ over the projected 20-year production life (similarly calculated over a 100-year time horizon using the fossil methane IPCC AR5 GWP of 36).

RELATIVE CONTRIBUTIONS OF WELL-COMPLETION, DRILLING, AND OPERATION EMISSIONS

The overall relative significance of each of the various tight gas well emission sources considered in this paper were compared using the mean GHG results of the previous sections and the mean CAC results in the form of NO_x and $PM_{2.5}$ totals derived in the SI. The GHG results (first including well operation GHG estimates based on the reported data for 2011) applied to the 1143 hydraulically fractured tight gas wells completed in Alberta in 2011 suggest that over a nominal 20-year production life, total equivalent greenhouse gas emissions of approximately 1384.0 $ktCO_2e$ would be expected (evaluated using IPCC AR5 data on a 100-year time horizon). The reader is reminded that this total considers only those emissions sources examined in this paper and, for example, excludes fugitive leaks. Of these total GHG emissions, roughly 49% would be attributable to natural gas fuel use over the nominal production life of the well, 21% to well drilling diesel combustion emissions, 11% to well-completion flaring and venting, 10% to well-completion diesel combustion emissions, and 9% to well operation flaring and venting emissions. Alternatively, using current results in conjunction with liquid unloading related data from the API/ANGA survey[9] would suggest total GHG emissions of 1915.2 $ktCO_2e$ from the sources considered in this paper, where up to 34% would be attributable to liquid unloading. These two calculation scenarios highlight both the importance of operational phase GHG emissions at upstream well sites (including on-site natural gas fuel use), and the critical levels of uncertainty in current estimates of liquid unloading emissions.

Comparison of CAC emission sources (see details of calculations in SI), suggests that production phase natural gas fuel use is a similarly significant source, contributing 68% of lifetime NO_x and 26% of lifetime $PM_{2.5}$ emissions. However, in contrast to GHG emission patterns, the majority of $PM_{2.5}$ emissions are from the large one-time emission events of drilling and completion. These results present a regulatory dichotomy in that the major sources of GHG and CAC emissions may differ. Overall these results represent an important source of new information for estimating impacts of well-completions (i.e., flaring, venting and diesel combustion), drilling (i.e., diesel combustion), and well operations (i.e., flaring, venting, and on-site fuel usage) from hydraulically fractured natural gas wells.

ASSOCIATED CONTENT

Supporting Information

Supporting Information contains several tables and figures with additional statistical information on the derived emission factors, detailed tables with derived emission factors for specific CACs and GHGs, a figure supporting the criteria used for identifying reported flaring during well-completion, additional analysis on the use and current impact of dual-fuel drilling technologies, and further details of calculations of relative magnitudes of GHG and CAC emission sources at tight gas wells. This material is available free of charge via the Internet at http://pubs.acs.org/.

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Notes

The authors declare no competing financial interest.

ACKNOWLEDGMENTS

We are grateful for valuable input from David Picard and Yori Jamin of Clearstone Engineering as well as support of Natural Resources Canada CanmetENERGY (Devon; project manager Michael Layer), Petroleum Technology Alliance of Canada (PTAC), Natural Sciences and Engineering Research Council (NSERC), Environment Canada, Encana, and the Alberta Energy Regulator.

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