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Opportunities for CO_2 equivalent emissions reductions via flare and vent mitigation: A case study for Alberta, Canada

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ABSTRACT

Global flaring and venting of gas associated with petroleum production is a significant source of greenhouse gas emissions and airborne pollutants that has proven difficult to mitigate. This work examines the technical and economic potential for flaring and venting mitigation in a mature oil and gas producing region of the world. Using detailed monthly production data spanning the years 2002–2008 for 18,203 active production facilities, combined with geographic information system pipeline data, reservoir gas composition data, and cost data derived from industry sources, a case study was constructed to explore the technical and economic viability of further mitigation of flaring and venting associated with upstream oil and gas production in Alberta, Canada. Calculations were performed to evaluate the feasibility of mitigation via collection and compression of gas into pipelines to connect into existing pipeline networks. Four main calculation scenarios were considered, and for each, a series of Monte-Carlo analyses were performed to evaluate uncertainties and sensitivities to key calculation parameters. In all scenarios, the results reveal potentially significant opportunities for economically viable flare and vent mitigation that would yield substantial reductions in CO_2 equivalent emissions. Because of the highly skewed distribution of gas volumes flared and vented at individual facilities, the results also show that solutions for comparatively small numbers of the largest facilities can offer large reductions in overall emissions from the sector. These results suggest that in a concerted effort to minimize carbon emissions in the upstream oil and gas industry, there is potential for significant near-term reductions using existing technology while research and development continues on more advanced methods such as carbon capture and storage.

1. Introduction

In the global petroleum industry, flaring of unwanted flammable gases via combustion in open atmosphere flames is a significant environmental concern. Recent estimates from satellite data suggest that more than 139 billion m^3 of gas are flared annually (Elvidge et al., 2009), an amount equivalent to 4.6% of world natural gas consumption which totalled 3011 billion m^3 in 2008 (BP, 2010). This amount of flaring produces approximately 281 million tonnes of CO_2 emissions annually (Johnson and Coderre, 2011). Flaring can also be a source of pollutants such as particulate soot (Pohl et al., 1986; Johnson et al., 2011; McEwen and Johnson, 2012), sulphur dioxide (in cases where the flare gas contains sulphur compounds such as hydrogen sulphide, H_2S), unburned fuel (Johnson et al., 2001a,b; Johnson and Kostiuk, 2000), and other undesirable by-products of combustion (Strosher, 2000).

In addition to flaring, direct venting of gas is a significant source of emissions during oil production, especially during production of heavier oils when casing gas is directly vented to atmosphere at the well-head (Clearstone Engineering Ltd., 2002). In the context of the present work vented volumes are limited to potentially capturable sources of gas related to the active production of oil resources and are considered exclusive of additional uncontrolled fugitive releases or leaks from potential sources such as compressor seals, pipelines, well restimulation, and natural gas processing facilities that are considered in other recent works (e.g. GAO, 2010; U.S.E.P.A, 2010; Hayhoe et al., 2002; Reshetnikov et al., 2000). To the authors' knowledge, reliable estimates of global venting of gas associated with oil production do not exist. Nevertheless, recent work analyzing production data for Alberta, Canada – a large, mature oil producing region with extensive gas pipeline networks and a high (>93%) rate of associated gas[2] conservation – has shown that

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[2] Associated gas in this context is primarily comprised of hydrocarbon gases that are originally dissolved in the oil at formation pressures (also referred to as "solution gas") but are released as the oil is brought to the surface and the pressure is reduced from formation to atmospheric. In general, the term associated gas refers to the combination of solution gas and gas that exists separate from the oil within the underground formation, which together may be brought to the surface as a byproduct of oil production.

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industry-wide total volumes of gas vented at primary production facilities are similar to those being flared (ERCB, 2009a; Johnson and Coderre, 2011). Given that the principle constituent of associated gas from oil production is methane, and that methane has a 25 times greater global warming potential than CO_2 on a mass basis (IPCC, 2007), it is expected that global greenhouse gas emissions from venting would be even larger than those from flaring.

In recent years, there has been an international push to reduce gas flaring and venting through the World Bank global gas flaring reduction (GGFR) partnership[3] and the global methane initiative (GMI – formerly called methane-to-markets).[4] Several countries are now signatories on the GGFR partnership's voluntary standard for flare and vent mitigation (World Bank, 2004a), and both the GGFR partnership and GMI actively promote demonstration projects to reduce flaring and venting. However, satellite data for flaring suggest that to date these initiatives have not yet made a significant impact. Although flaring levels decreased from 2005 to 2008, very recent data quoted by the GGFR suggest global flaring actually increased by 6% from 2008 to 2009 (World Bank, 2010). In fact, over the 15 year period from 1994 to 2008, global flare volumes were relatively stable within a range of 140–170 billion m^3 per year (Elvidge et al., 2009). This lack of progress reflects the magnitude of the challenge in which different countries have very different levels of infrastructure and opportunities for mitigation. The current trends also raise the question as to whether there may be practical limits to mitigation and what those limits might be.

The purpose of this work is to examine the technical and economic potential for flare and vent mitigation in a mature oil and gas producing region of the world. A case study was constructed using production and pipeline data for Alberta, Canada. The key objective of this study was to assess what realistic opportunities for further mitigation might exist. More specifically, given that mitigation requires capital investment and infrastructure, objectives of this study were to assess the level of investment required to achieve specific reductions in flaring and venting, the fraction of production sites that might be technically and economically amenable to mitigation measures, and how might the costs of these measures compare to other proposed methods of reducing greenhouse gas (GHG) emissions in the upstream oil and gas industry.

1.1. Mitigation of flaring and venting

The decision by an operator to continuously flare and vent gas associated with oil production is driven primarily by economic factors, and this is reflected in international standards and management practices. The World Bank voluntary standard recommends that alternatives to gas flaring be assessed in "a process through which alternatives are evaluated based on economic feasibility" (World Bank, 2004a). Similarly in Alberta, Canada, "Directive 60" (ERCB, 2006) of the Energy Resources Conservation Board (ERCB) specifies an economics driven decision process to permit continuous flaring or venting in the upstream oil and gas industry. However, Directive 60 is considerably more prescriptive in outlining how the economic analysis is to be performed, as further discussed below.

In principle, there is a range of alternatives for dealing with surplus associated gas that would otherwise be directed to a flare (World Bank, 2002, 2004b; Buzcu-Guven et al., 2010; Thomas and Dawe, 2003). These can include collection and compression of gas into pipelines for processing and sale; generation of electricity or co-generation of heat and electricity using conventional gas turbines, microturbines, or other gas-fired engines; and compression and reinjection of the gas back into an underground reservoir. For very large volumes of remotely located associated gas, gas-to-liquid (GTL) conversion of natural gas into more valuable and more easily transported liquid fuels, or production of liquefied natural gas (LNG) to facilitate transport to distant markets, are also potential options (e.g. Dong et al., 2008; Buzcu-Guven et al., 2010). However, in a mature oil and gas producing region such as Alberta, Canada, where most upstream flaring and venting is distributed among many smaller sites (Johnson and Coderre, 2011), most of these options are not viable and are rarely, if ever, exercised. Both GTL and LNG options require enormous capital investments of infrastructure and must process very large volumes of gas to be economic. Even at the smallest scales under development (Bao et al., 2010; Hall, 2005), proposed GTL technology would still require gas volumes well beyond what would be available at sites typical of the upstream industry in Alberta (Johnson and Coderre, 2011). While re-injection has been successfully used at several sites in Alberta to dispose of residual "acid-gas" (primarily hydrogen sulphide, H_2S, and CO_2 with traces of hydrocarbons) from gas sweetening plants where the costs of reinjection are less than the costs of sulphur removal (Bachu and Gunter, 2005; Wong et al., 2003), in Alberta at least there is generally insufficient return on investment for re-injecting raw associated gas from oil production. The use of associated gas in engines or microturbines to generate electricity for on-site use is a demonstrated option, but this approach is not always economic and can be limited by the on-site demand for electricity (California Oil Producers Electric Cooperative, 2008). In Alberta, larger scale, grid-connected electricity generation projects have not yet proven economically viable; since 1998 in Alberta, only a single grid-connected electricity generation project using flare gas was attempted (Alberta Energy, 2011a), and it is no longer operational (AESO, 2011).

By contrast, the collection and compression of gas into pipelines for processing and sale is a well-established and proven approach to mitigating flaring and venting. Of the 9.72 billion m^3 of associated gas produced during production of oil and heavy oil in Alberta in 2008, 72% was captured and sold into pipelines. An additional 21% was used for onsite fuel (e.g. for process heaters or to drive natural gas fired compressors), although it is worth noting that the ERCB has stated that "[t]his fuel gas use is large and represents a significant opportunity for companies in terms of both improvement in efficiencies and savings" (ERCB, 2010). The remaining 7% of gas at upstream oil and heavy oil sites (0.69 billion m^3 in 2008) was flared or vented (Johnson and Coderre, 2011). Thus, in practice, collection and compression of associated gas for transport in pipelines has proven to be the lone option for significant mitigation of continuous flaring and venting in Alberta.

Given these facts, the question arises whether there is potential for further mitigation of flaring and venting via tie-in to pipelines, or whether technical or economic limits are being reached. Furthermore, from a policy standpoint, is it possible that in a mature production region, such as Alberta, costs of mitigation in marginally economic cases might still be less than other options for CO_2 equivalent emissions reduction? Although flaring and venting levels at upstream sites in Alberta have decreased from the highs of the late 1990s (Johnson et al., 2001a; ERCB, 2009a), CO_2 equivalent emissions in 2008 still approached 8 million tonnes (6.4 Mt from battery sites alone) (Johnson and Coderre, in press), suggesting they remain an important target for mitigation efforts.

2. Materials and methods

Alberta, Canada is a mature oil and gas producing region in which non-oil sands production of oil and heavy oil was dispersed among roughly 50,000 wells in 2008 (ERCB, 2009b). These wells are

[3] http://go.worldbank.org/NEBP6PEHS0.
[4] http://www.globalmethane.org/.

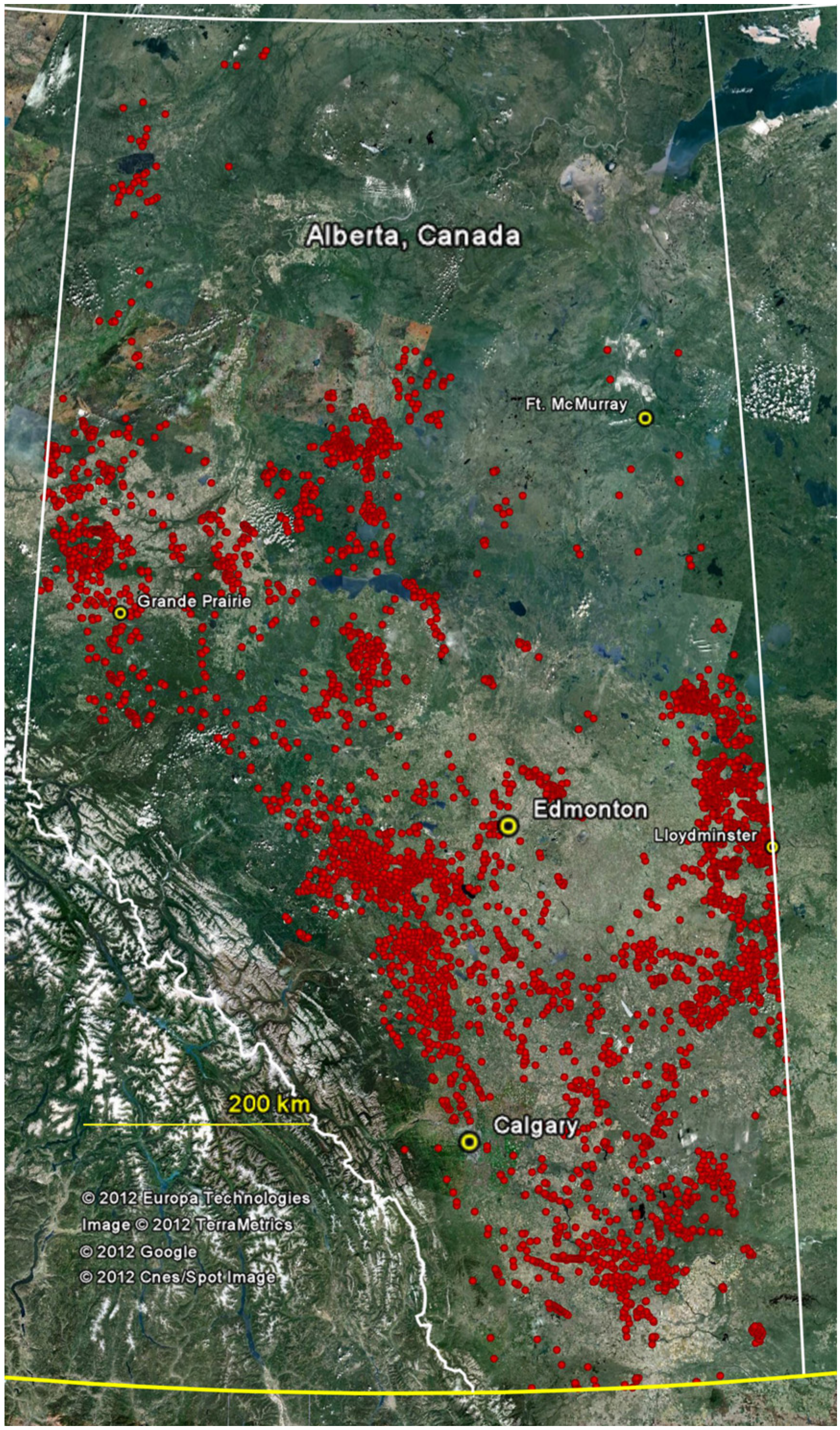

Fig. 1. Google Earth satellite image of Province of Alberta, Canada with superimposed red dots indicating locations of 5945 active battery sites that reported any amount of flaring and/or venting in 2008.

tied to primary production facilities known as "batteries", where primary separation of oil, water, and associated gas (more commonly referred to as "solution gas" in Alberta) takes place. Surplus gas deemed uneconomic to process is typically flared or vented at these batteries. In 2008, the latest year for which data were available, there were 11,028 active oil and bitumen batteries in Alberta (the term "bitumen" is equivalent to "heavy oil" in this context), which produced 14.8 billion m^3 of associated gas. Approximately half (5945) of these batteries reported flaring and/or venting activity, totalling 0.687 billion m^3. Fig. 1 shows a Google Earth satellite image of the Province of Alberta, Canada with superimposed red dots locating the 5945 active battery sites that reported any amount of flaring and/or venting in 2008. As can be seen active production in Alberta spans a very large area. A more complete discussion of upstream flaring and venting trends in Alberta was presented in previous work (Johnson and Coderre, 2011).

To analyze technical and economic barriers to flaring and venting mitigation, production and pipeline data for each of these 5945 batteries were separately analyzed and calculations were performed to assess the potential economics of mitigation via collection and compression of gas into pipelines, under different scenarios. As explained with the results, these different scenarios considered potential inclusion of carbon credits and different approaches for parsing aggregated data. Necessary data were gathered from a variety of sources as detailed below, and consolidated into a large database for scripted queries and analysis. A separate economic analysis was performed for each battery on a net present value basis, using gas price, inflation, and borrowing cost data from sources specified in ERCB Directive 60 (ERCB, 2006). The four key data components of the analysis are discussed under the headings that follow.

2.1. Flare and vent volume data

Operators in Alberta are required to report monthly oil and gas production data (including flaring and venting volume data) at batteries on a monthly basis.[5] In cooperation with the ERCB, these data were obtained for all 18,203 batteries that operated at any point during the 84-month period spanning January 2002–December 2008. The data were then linked with location information and imported into a database for subsequent analysis. A very significant complication arose because of the use of “paper batteries” for data reporting by industry, as permitted by ERCB. Paper batteries exist on paper only, and represent aggregated reporting of data from a number of physically disconnected wells as if they were a single entity. Although only 213 of the 5945 batteries reporting flaring or venting in Alberta in 2008 were paper batteries, these 3.6% of sites were responsible for 35.7% of the total venting from all batteries (Johnson and Coderre, 2011). To overcome this difficultly, working with the ERCB it was possible to identify locations of individual wells tied to the various paper batteries in the Province, essentially all of which were concentrated in the Lloydminster region of the Province and associated with heavy oil production. Reported volumes at paper batteries could then be distributed among the associated wells for analysis. Subsequent calculations were conducted in two bounding scenarios assuming either that the paper batteries existed as single entities (and hence that costs associated with low pressure gas collection from the wells through plastic piping would be insignificant compared to other costs) or that paper batteries were actually a series of individual wells (and hence each well would require an individual compressor and high-pressure pipeline to connect into the nearest appropriate tie-in point on the existing pipeline network). The implications of these two scenarios are discussed along with the results of the final economic analysis.

2.2. Estimating gas composition at battery sites

Composition of gas being flared or vented is important for assessing its economic value and for matching it with suitable pipeline infrastructure for transport. The value of the gas is based primarily on its heating value. For transport in the upstream pipeline network, the key consideration is the H_2S content of the gas. Gas is considered sour if it contains 10 mol/kmol H_2S or more (Province of Alberta, 2005). Unfortunately, operators in Alberta are not required to report composition of gases flared or vented and there is no central source for these data. However, the ERCB was able to provide a large collection (66 k+) of well gas samples, as well as a partial listing (for ~9 k batteries) of the associations between batteries and wells. The well gas sample data also listed the geologic formation, or pool, from which each well produced. This information, along with the assumption that solution gas compositions would be reasonably consistent and stable within a particular pool, allowed measured solution gas compositions to be linked to 5819 batteries, including approximately half (3241) of the batteries that flared or vented in 2008. The remaining batteries, lacking sufficient data, were estimated based on their geographic proximity to batteries with known compositions. A detailed description of this procedure and accompanying analysis of the derived composition data are discussed in related work (Johnson and Coderre, in press).

2.2.1. Greenhouse gas emission factors

The greenhouse gas impact of solution gas disposal depends on the composition of the gas and the means of disposal. Emission factors for flared gas were calculated based on ideal combustion, i.e. complete conversion of hydrocarbons to CO_2. For vented gas, methane content and existing CO_2 content were the parameters of interest. As mentioned above, methane contributes 25 times the greenhouse effect of CO_2 on a mass basis, making vented gas of particular concern. Many batteries reported both flaring and venting activity; the individually calculated GHG emissions for these batteries accounts for the proportions of each.

2.3. Location and evaluation of site specific pipeline infrastructure

Geographic information system (GIS) data for the entire Western Canadian high-pressure pipeline network were obtained in collaboration with IHS Energy Inc. These data included precise location data for each small linear segment of the pipeline network (as short as several meters), as well as specific information on maximum operating pressures, pipeline construction, and gas service (i.e. sweet or sour). The pipeline GIS data were manipulated using ArcGIS software (ESRI Inc.) and linked with location data for each battery (or well tied to a paper battery) obtained from ERCB. Using queries scripted in Python, an initial list of at least 15 potential pipeline tie-in points were identified for each battery, or well linked to a paper battery, within the Province of Alberta. These 15 candidate tie-in points comprised the closest locations along the nearest 10 distinct sweet- and 5 distinct sour-pipeline sections. Because the mitigation costs varied with both the distance to a pipeline and the compression equipment required to feed into that pipeline as discussed below, the initial screening approach allowed the economic modeling to be decoupled from the pipeline location calculations. The capital costs of mitigation for each candidate tie-in point for each battery could then be calculated to find the cheapest option. Although the cheapest option most often corresponded to the closest potential tie-in point, this was not universally true, demonstrating the utility of this approach.

2.4. Economic modeling

Alberta’s ERCB Directive 60 provides general guidelines for the methodology that operators are required to use to perform their own economic analysis of solution gas conservation options, and states that the gas must be conserved if it is economic to do so on a net present value (NPV) basis (ERCB, 2006). For the NPV calculation, Directive 60 prescribes the sources of the gas price forecast, inflation rate, and discount rate to be used, as well as guidelines for estimating the annual operating costs as a percentage of capital costs. Thus, the operator need only determine the capital cost of installation and the rate of decline in production expected over the lifetime of the battery.

[5] Directive 60 of the Alberta ERCB specifies that “[o]perators of oil, bitumen, and natural gas production and processing facilities (including well tests) must report volumes of gas greater than or equal to 0.1 10^3 m^3/month (adjusted to 101.325 kPa(a) and 15 °C) that is flared, incinerated, or vented” through the Petroleum Registry of Alberta (PRA), along with their regular monthly production reports. The ERCB conducts inspections of facilities and ERCB Directive 19 outlines compliance assurance processes. Although detailed audit data on reported flaring and venting volumes are not currently available, it is generally understood that industry response rates are very good.

2.4.1. Capital cost model

The capital cost of such an installation can be broken into two parts: the high-pressure pipeline running from the battery to the tie-in point, and the compression equipment needed to move the gas. The actual installed costs of each of these two parts will vary somewhat due to the particular circumstances of the installation. Estimating costs of pipeline construction, especially in the context of developing large-scale transmission infrastructure for CO_2 transport for carbon capture and storage, has been the subject of a number of recent studies (e.g. McCoy and Rubin, 2008; Schoots et al., 2011; Doctor et al., 2005; Essandoh-Yeddu and Gülen, 2009). However less data are available on the costs of smaller branch or distribution pipelines as appropriate for comparatively local collection of flared and vented gas. In work submitted to the Clean Air Strategic Alliance (CASA), Rahim (2004) presented linear capital cost models for collection of associated gas at battery sites in Alberta "derived from New Paradigm Engineering's Heavy Oil Gas Utilization Option Sheet and cost estimates from several industry sources". At first glance, Rahim's model, reproduced in Eqs. (1) and (2), seemed somewhat simplistic; pipeline costs scaled only with distance, while compression costs varied with pressure ratio (expressed as the required number of compression stages) and flow rate, with different slopes for sweet and sour gas. In an attempt to improve on this model for use in the current study, additional project costing data were obtained in collaboration with ERCB and Clearstone Engineering Ltd. From ERCB, anonymous "authority for expenditure" (AFE) estimates for flare and vent tie-in costs submitted to the ERCB by industry operators were obtained. The quality of data in these AFEs was highly variable however, and they were mostly useful as a secondary check on the developed model. Formal (also anonymous) project cost estimates graciously supplied by Clearstone Engineering Ltd. proved much more useful. These reports were originally prepared by Clearstone Engineering for industry operators, and included specific data/estimates on all associated project costs, such as shipping and installation, land agent fees, right-of-way, surveying, and engineering and regulatory approval costs. Although these cost data showed significant variability among individual projects that precluded regression into a more detailed multivariable model, wider trends were indeed discernable, and ultimately it was found that the somewhat simplistic linear models of Rahim provided the best approach to capture these trends. Thus, the present model follows the form of that used by Rahim (2004), where the additional detailed data collected were regressed to obtain new scaling parameters, as given in Eqs. (3) and (4). Since the available cost data for sour gas installations fell within the cost range of the sweet gas installations (and were all slightly cheaper than what was predicted by the derived linear model), it was deemed more conservative to use a single model. It is further noted that the capital cost estimates obtained using the current model significantly exceed those obtained with Rahim's model, implying further conservatism.

$$\text{Pipeline cost}_{\text{Rahim}} = \$70,000 \quad \text{distance} \quad (\text{km}) \tag{1}$$

$$\text{Compression cost}_{\text{Rahim}} = \$20,000 + \left[\text{volume}\left(\frac{10^3\text{m}^3}{\text{d}}\right)\cdot\text{stages} \cdot \begin{pmatrix}\$15,000\text{ if sweet}\\ \$20,000\text{ if sour}\end{pmatrix}\right], \quad \text{Caveat: minimum compression cost of } \$50,000 \tag{2}$$

$$\text{Pipeline cost} = \$86,000 \cdot \text{distance} \quad (\text{km}) \tag{3}$$

$$\text{Compression cost} = \$187,430 + \left[\text{volume}\left(\frac{10^3\text{m}^3}{\text{d}}\right)\cdot\text{stages}\cdot\$15,746\right] \tag{4}$$

Estimation of the number of compression stages required an assumption of a stage pressure ratio; 1.5 was chosen in this case. However, note that since the scaling factor of $15,746 was obtained via regression, the actual value of this assumption is somewhat immaterial. It was conservatively assumed that the compression equipment would need to boost the gas from atmospheric pressure to the maximum operating pressure of the pipeline. The number of required stages was then determined as follows:

$$\text{Stages} = \frac{\ln(P_{\text{MOP},\alpha}/P_{\text{atm}})}{\ln(\text{stagePR})}, \tag{5}$$

where stagePR is the stage pressure ratio, $P_{\text{MOP},\alpha}$ is the maximum operating pressure of the pipeline to be tied into, in absolute terms, and P_{atm} is the atmospheric pressure. The accuracy of the cost model and its potential influence on results is further considered in the Monte-Carlo uncertainty analysis discussed below.

This capital cost model, outlined in Eqs. (3)–(5), was also used to estimate costs of tying in individual wells associated with paper batteries, even though the actual costs to do so are expected to be much lower. It is recognized that this is overly conservative, but in the absence of separate cost data for low-pressure gas collection systems to link individual wells, this was deemed a reasonable way of obtaining an upper bound cost estimate. Informally reported case-study data from industry (Mann, 2002) suggest actual low-pressure gas collection costs are likely much lower (by more than a factor of 3) than what is conservatively predicted with the current model. Separate calculation cases were also considered in which paper batteries were treated as single entities, to obtain a corresponding lower bound estimate (effectively assuming that the costs associated with low-pressure gas collection from associated wells is comparatively negligible).

2.4.2. Production decline rate

The production trend of a battery is, again, specific to its particular circumstances. Several attempts were made to model decline rates on a per-battery basis, based on each battery's reported oil and gas production history, as well as its flaring and venting history. The expected logarithmic declines due to pressure reduction were only rarely observed, and production trends were as likely to increase in time as decrease in time, indicating that production rates at individual locations were dominated by other factors. Overall trends in production were subsequently examined, both on an absolute (total) and per-battery basis, for the entire data set and for subsets of the data based on age of facility or location in the Province. Previous work (Johnson and Coderre, 2011) has shown that the bulk of the recent increases in production between 2005 and 2008 have occurred in the Lloydminster region of the Province, so decline rates were examined in this region separately from the rest of the Province. In an effort to examine only batteries with sufficient historical data to identify trends, batteries that first reported activity before 2005 were also examined separately from newer ones. Within the Lloydminster region, monthly and annualized oil and gas production were both found to be increasing by all measures. The per-battery oil and gas production increases for batteries within this region that existed before 2005 were found to be approximately +10% and +11% per year, respectively. This is a clear indication that production rates are at least partially determined by the operators (e.g. through operational controls, decisions to alter production based on oil prices, investments in technology, through tying in of new wells to existing batteries, etc.) rather than by the physical limitations of reduced formation pressure. Outside the Llyodminster region, producing batteries that existed prior to 2005 also showed an annualized increase in per battery oil production (+2.7% per year), while gas production per battery decreased by 2.4% per year. The corresponding averages for the entire Province showed a 6% annualized increase in per battery oil production and a 0.2% annualized decrease in associated gas production. These aggregate trends support the results found when fitting data for individual batteries, and suggest that production decline rates are not likely to have a significant influence on tie-in economics. However, these assumptions were further examined in the Monte-Carlo analysis presented below in which decline rates ranging from 0 to 2.5% were considered. For the reference case calculation, the Province-wide mean decline rate of 0.2% per annum calculated for currently producing batteries with at least three years of data was used.

2.4.3. Net present value calculation: gas pricing, inflation, and borrowing cost parameters

To objectively assess tie-in economics over the lifespan of a potential project, all calculations were performed on a net present value (NPV) basis. ERCB Directive 60 (ERCB, 2006) prescribes sources to obtain the inflation and discount rates necessary for an NPV calculation, as well as the source of gas price projections (Herchen, 2010). At the time of data processing, the long-term inflation rate was 1%, the prescribed discount rate was 6%, and the initial gas price was $4.19/mmbtu. The influence of these values on NPV calculations was further examined as part of the Monte Carlo analysis presented in the discussion.

Directive 60 also states that the “economic life of a conservation project is defined as the period from the start of the project to the time when annual expenses exceed annual revenue” (ERCB, 2006). However, this is strongly dependent on the individual decline rates experienced by each battery, as well as on the capital cost of implementation. Instead, a standard lifetime of 10 years was applied to each battery. This assumption is quite conservative since a battery with only a few profitable years will be deemed uneconomic, and batteries with many more profitable years will have truncated revenue streams, making them appear less profitable. It was also conservatively assumed that the equipment and connecting pipelines retained no salvage value afterward. Finally, for the purpose of calculating GHG emissions reductions, it was assumed that batteries reporting both flaring and venting would continue to do so in the same proportions.

Four separate NPV calculations were performed using the reference case cost and economic parameters outlined above. These included calculations where paper batteries were treated as physical sites (i.e. neglecting costs associated with low-pressure collection of gas from associated wells), where wells associated with paper batteries were treated as separate sites requiring individual high operating-pressure tie-in infrastructure, and for each case with and without a carbon credit of $15/tonne for mitigated CO_2 equivalent emissions. The $15/tonne value corresponds to the current carbon price ceiling specified in the Alberta greenhouse gas reduction program (Province of Alberta, 2007; Alberta Environment, 2011a), which requires the very largest emitters (>100,000 tonnes of CO_2 equivalent emissions per year) in the Province to reduce emissions intensities, purchase offset credits, or pay into a Climate Change and Emissions Management Fund (Alberta Environment, 2011b). Subject to project approval, this credit could offer an additional revenue stream besides gas revenues in calculating NPV tie-in costs.

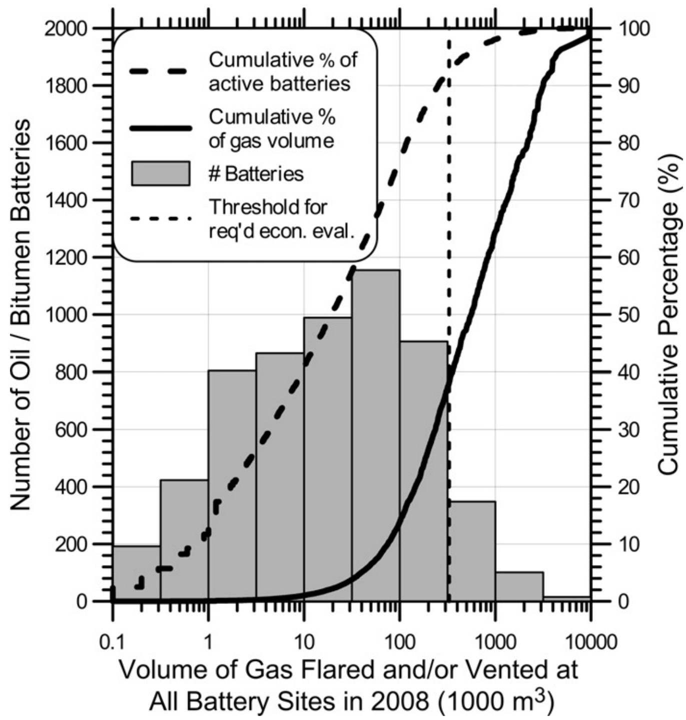

Fig. 2. Distribution of volumes flared and/or vented at individual batteries in 2008. Left vertical axis shows number of batteries that in 2008 each reported combined flared and vented gas volumes in the range indicated by the greyed bars.

3. Results

Fig. 2 shows the distribution of reported flare and vent volumes at battery sites in the Province of Alberta. The logarithmic scale of the horizontal axis highlights more than 5 orders of magnitude variability in gas volumes at individual facilities. The cumulative percentage of battery sites flaring/venting at or below the volume indicated on the horizontal axis is shown by the dashed curve on the figure, whereas the solid curve indicates the cumulative percentage of the total Provincial volume handled by these sites. The vertical dashed line indicates the current regulatory threshold specified in ERCB Directive 60 (ERCB, 2006), above which operators are supposed to perform annual economic evaluations to assess viability of conservation. Interpreting these curves, it is apparent that 92.5% of sites fall below the ERCB threshold of 328.5×10^3 m^3 per year of flared and vented gas. Conversely, while only 7.5% of sites are above the threshold, these same sites handle 62% (261×10^3 m^3) of the total Provincial flaring and venting at oil and bitumen batteries in the upstream sector. A key observation from these trends is that mitigation of only a small fraction of the largest sites could have significant impacts in terms of total reduction in flared and vented volumes (Johnson and Coderre, 2011). Recognition of this trend was a key motivation for pursuing the present analysis.

Access to pipeline infrastructure is as critical as gas volume in determining feasibility of gas recovery. Fig. 3 shows the distribution of distances from each battery in the Province to its most economic tie-in point determined using the procedures described above. Even though active production regions span a very wide geographic area covering much of the Province (Johnson and Coderre, 2011), the histogram reveals an extensive pipeline network that passes relatively near to a majority of batteries currently reporting flaring and venting. As indicated by the cumulative distribution curves plotted in Fig. 3, 81% of these sites (and 77% of the total gas flared or vented at these sites) are within 1 km of a potential pipeline tie-in point. Nevertheless, it is apparent from the logarithmic scale

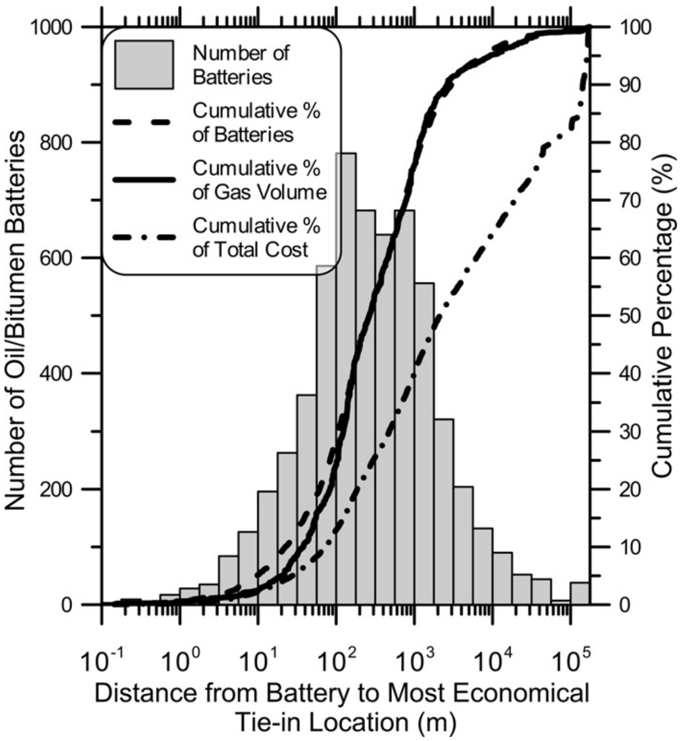

Fig. 3. Histogram of distances from batteries reporting flaring and/or venting to their corresponding most economical tie-in points along the existing pipeline network.

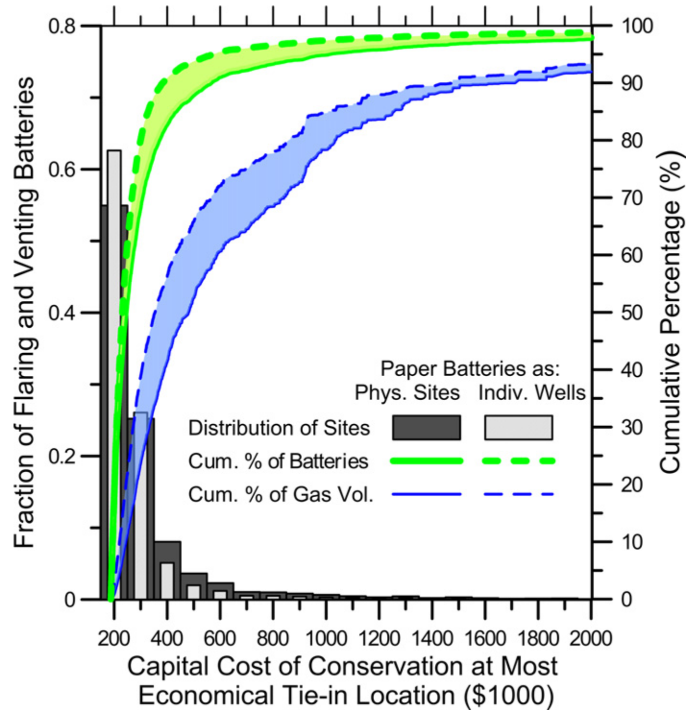

Fig. 4. Distribution of capital costs required to tie-in batteries to the existing pipeline network.

on the horizontal axis, that a small number of sites are still quite remotely located. Closer inspection of the data has shown that most of these more remote sites handle gas with higher H_2S concentrations, which restricts potential tie-in points to a subset of pipelines capable of handling sour gas. The cumulative cost curve included on the figure shows that the potential costs of attempting mitigation at these sites via connection into the existing pipeline network would be disproportionately high.

Gas flow and composition information as well as suitable pipeline location and operating pressure data were separately determined for each battery or well-site. Total capital costs to install suitable compression and pipeline infrastructure necessary to capture gas and compress it into the pipeline network were then calculated, as plotted in Fig. 4. Because the ERCB permits aggregated data reporting of some sites as paper batteries as discussed above, this and all subsequent calculations needed to consider two different scenarios. The dashed lines in Figs. 4–6 indicate calculations performed assuming paper batteries were disaggregated into a collection of individual wells, where each well needed to be separately tied-in to a suitable point along the pipeline network. The corresponding solid lines show results of the alternate assumption, in which paper batteries were treated as physical entities that could be tied-in as a unit (i.e. assuming low-pressure gas collection costs from the individual wells were negligible by comparison), and the shading between the curves indicates the range within the bounding assumptions. Fig. 4 shows that regardless of the assumed scenario, typical capital costs for a facility are less than $1 million. In the most cost-conservative (i.e. expensive) scenario, in which wells associated with paper batteries are treated individually, the dashed-line cumulative distribution curves show that 90% of sites and 54% of the total gas volume could be recovered at a capital cost of less than $384 thousand per battery. Conversely, a small number of sites can be comparatively very expensive to mitigate, as evidenced by the long-tail of the histogram toward higher capital costs, and the non-linear trends of the cumulative curves. Up to 2.1% of sites would cost more than $2 million each to mitigate, with some remotely located individual facilities costing more than $10 million.

To evaluate the economic feasibility of mitigation, calculations were performed to compare total lifetime project costs on a net present value basis, using flare and vent volume data from 2008 as a starting point (the most recent year available). Net costs or revenues for mitigation were calculated under four main scenarios as summarized in Fig. 5: with paper batteries considered as single sites or disaggregated wells, with and without a $15/tonne carbon credit for mitigated CO_2 equivalent emissions. The first surprising results of these calculations is a small number of sites currently flaring or venting appear to have positive net present values – i.e. these sites should be profitable to mitigate under current conditions even without additional revenue in the form of carbon offset credits. Even more significantly, this small collection of sites is responsible for significant fractions of the total flaring and venting at battery sites. As shown in Fig. 5a, for the most conservative scenario (i.e. with each well linked to a paper battery considered individually), the present calculations suggest that 190 sites and 32.6% of the total flared and vented volume should be profitable to mitigate. If paper batteries are considered as physically aggregated sites, then 263 sites handling 48.2% of the total flared and vented should be profitable to mitigate. As shown in Fig. 5b, these numbers rise even further if a revenue stream from carbon offset credits is considered. The finding that significant benefit can be derived from mitigation of a relatively small number of battery sites is not surprising given the highly skewed flare and vent volume distribution discussed in Fig. 2. However, it is quite significant that economics appear to be favorable for many of these cases, and that the cumulative trend lines for all scenarios in Fig. 5 show a near vertical rise for net present values between 0 and −$500,000. This indicates that many sites are close to being economic to mitigate and that small changes in economic conditions or regulatory frameworks might allow for large changes in the number of sites flaring or venting on a

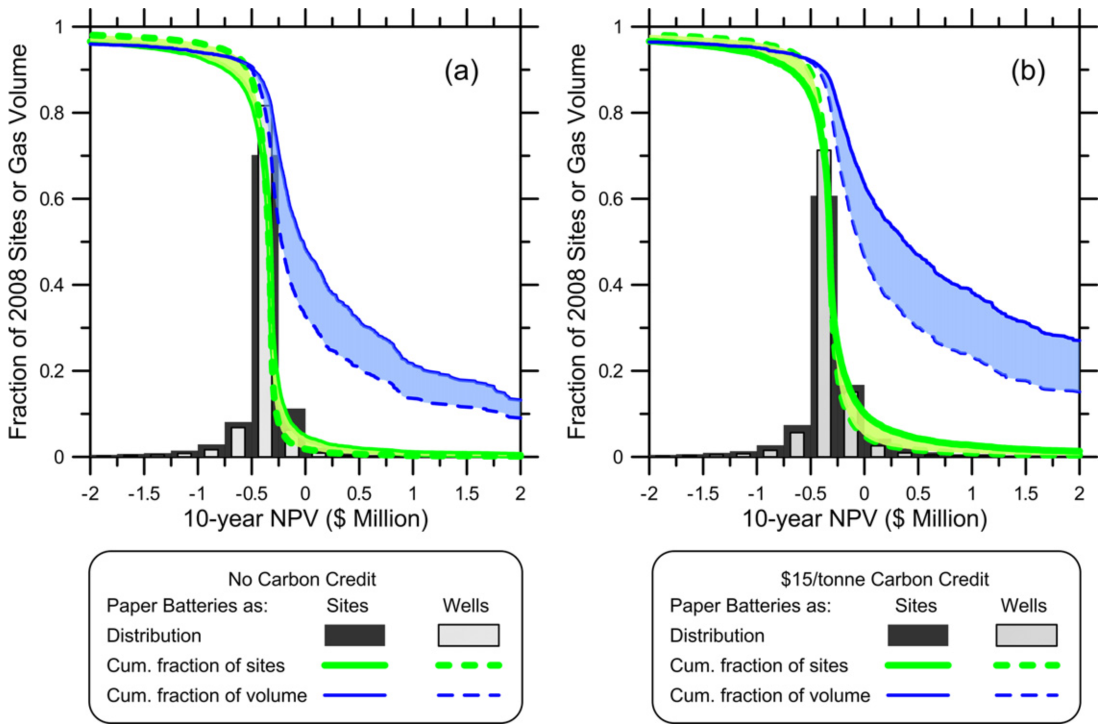

Fig. 5. 10-year net present value histograms calculated assuming (a) no carbon credit, (b) carbon credit of $15/tonne.

continuous basis. The influence of several of these factors is further discussed in the Monte-Carlo analysis results presented below.

Fig. 6 shows the aggregate greenhouse gas mitigation potential assuming 10-year project lifetimes, calculated in terms of total project costs per tonne of CO_2 equivalent emissions abated. As before, the dashed and solid lines in the figure indicate the bounding scenarios in which paper batteries are treated as disaggregated wells or as physical sites respectively. The shaded areas between these curves then represent the bounded range of potential costs for mitigation. For a specified cost per tonne indicated on the horizontal axis, the corresponding total CO_2 equivalent mitigation potential over a 10-year project lifetime is indicated for each curve on the vertical axis. Two main scenarios are plotted: the green curves show total mitigation potential at or below a specified cost per tonne (i.e. for a specified maximum cost per tonne, the total GHG mitigation potential is shown). The grey curves show results in terms of the average cost per tonne of CO_2 mitigated. This latter calculation implicitly implies a regulatory framework or corporate management scenario in which more profitable sites are used to subsidize less profitable sites to achieve maximum GHG reduction potential.

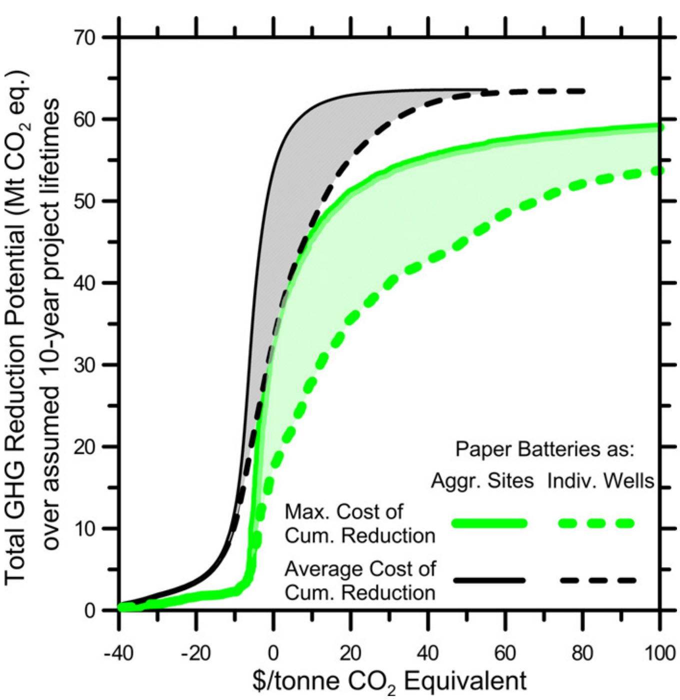

Fig. 6. Total net present value project costs per tonne of CO_2 equivalent mitigated over 10-year project lifetimes. Data shown are for reference case with 6% discount rate, 1% inflation, and 4.19$/mmbtu initial gas price.

Based on 2008 volume data, and considering only profitable or full-cost recovery cases (i.e. lifetime NPV mitigation costs of less than $0/tonne), Fig. 6 shows the remarkable result that between 17 and 33 Mt of CO_2 equivalent GHG emissions ($MtCO_2e$) could potentially be mitigated over a 10-year period, depending on the cost range associated with tying-in flaring and venting at paper batteries. If a $15/tonne threshold is instead chosen (i.e. corresponding to the potential carbon offset credit value under the Alberta regulatory system), then the results suggest that between 28 and 46 $MtCO_2e$ are potentially available at some profit. In the most optimistic scenarios, for a framework designed to maximize GHG reductions at zero total net cost, calculations suggest that between 33 and 53 $MtCO_2e$ could potentially be mitigated over a 10-year period based only on the value of the gas, or as much as 47–61 $MtCO_2e$ assuming a carbon offset credit of $15/tonne.

4. Discussion

4.1. Monte-Carlo analysis of model sensitivity and uncertainty

As noted several times above, the calculation of NPV GHG mitigation costs requires inputs and data that are necessarily uncertain, or may be subject to economic fluctuations. To manage data limits

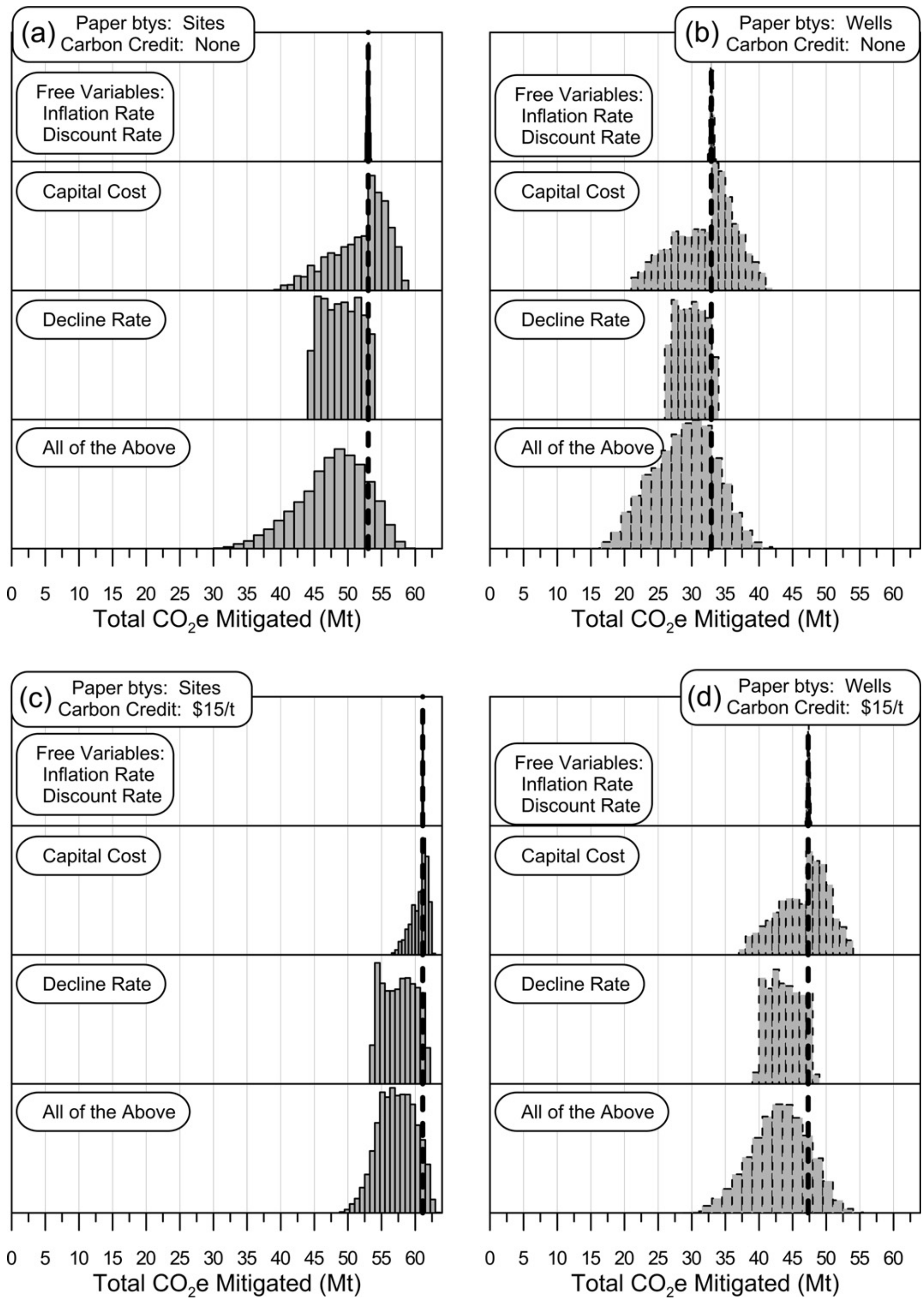

Fig. 7. Results of the Monte Carlo analysis plotted in terms of CO_2e mitigation potential at net-zero cost for the four reference calculation scenarios: (a) paper batteries treated as regular batteries, no carbon offset credit; (b) paper batteries treated as a collection of individual wells, no carbon credit; (c) paper batteries treated as regular batteries, with a carbon offset credit of $15/tonne of CO_2 equivalent; and (d) paper batteries treated as a collection of individual wells, with a carbon credit of $15/tonne.

imposed by the use paper batteries, and to contain the uncertainty in potential revenues from carbon credits, bounding calculations were performed using the four different reference scenarios to elucidate the potential range of results. Model uncertainties and sensitivities to other key variables were explored via Monte-Carlo simulations. In these simulations, the calculation procedure for all 5945 active batteries reporting flaring and/or venting was automated and repeated several thousand times to determine the total volume of CO_2 mitigated at the break-even point (i.e. at an average cost of $0), while the input data for capital cost, the decline rate, the long-term inflation rate, and the discount rate were randomly varied following prescribed probability distributions.

The capital cost was varied between 75% and 150% of the reference modeled value specified by Eqs. (3) and (4), in a triangular probability distribution where equal weight was placed on either side of the mode (peak) at unity. The annual decline rate was varied between 0 and 2.5% in a uniform distribution, as further explained in Section 2.4.2. The inflation rate was varied between 0.5% and

1.5%, using a triangular distribution centered at 1%. Similarly, the discount rate was varied between 5.5% and 6.5% in a triangular distribution centered at 6%. For each of the four reference scenarios, Monte Carlo simulations were run varying each variable individually and all variables simultaneously. Individual variable simulations ran for 2000 iterations, and the full simulations ran for 10,000 iterations. Natural gas price was not explicitly included in the Monte Carlo analysis for three main reasons. A review and analysis of recent quarterly official price projections using the source prescribed by ERCB Directive 60, revealed essentially no variability in predicted price increases, which have been fixed at 2% anticipated annual growth in all recent projections. Secondly, broader consideration of influencing factors on natural gas pricing suggests that the glut of natural gas related to development of new shale gas resources is likely to keep prices stable near historic lows for the foreseeable future. In this context, the present analysis using current prescribed price projection data is believed to be accurate but also conservative. Finally, the effects of gas price variability on the NPV calculation have the same net effect as varying the capital cost estimate which was explicitly tested over a wide range. Thus the data as presented still provide insight into the scenario where gas price might deviate from recent projections.

Fig. 7 plots results of the Monte-Carlo simulations performed for four different reference scenarios. In all cases the influence of inflation rate and discount rate on the calculations is negligible. For the zero carbon credit reference cases, the results are modestly sensitive to relatively large variations in capital cost, although the net CO_2 mitigation potential is still substantial in all cases. With an additional revenue stream from carbon credits considered (Fig. 7c and d), the influence of capital cost variation is reduced. The decline rate shows a more consistent influence on the mitigation potential for all four reference cases, although the effect is again limited within the probable range of decline rates suggested by the available battery-level production data. Finally, allowing all input parameters to vary (bottom panels in Fig. 7a–d), the Monte-Carlo simulation results show that the main conclusions are unchanged – for all scenarios, independent of the model uncertainties as tested, the results reveal significant potentially economic CO_2 mitigation opportunities. There are other factors not explicitly considered in the present analysis that could affect results, including possible costs at individual sites for terrain challenges such as road and rail crossings, opportunities for cooperation among closely located sites to share infrastructures costs, and uncertainties associated with estimating gas composition (especially in cases where H_2S content could be above or below the threshold requiring direction into sour gas pipelines). Of these however, the available industry cost data suggest that the first, when relevant, is not likely to be a significant component of overall costs; the second would only lead to increased mitigation opportunities; and the third could lead to increased or decreased viability of individual sites but should not bias results of the aggregate calculations. Finally, it may be the case that some sites identified as economically viable for flaring and venting mitigation are new or expanded facilities that have been brought to production in advance of economic evaluations and subsequent implementation of suitable gas conservation measures that could be in progress. Although this is impossible to elucidate without specific knowledge about the management of individual facilities, it is noted that 95% of the sites identified as potentially economic to mitigate had been in operation for more than one year, and 47% had been in operation for all seven years considered in the analysis.

4.2. GHG mitigation potential and projected cost comparison

The results of Figs. 5–7 reveal potentially significant opportunities for economically viable GHG emissions reductions via flaring and venting mitigation in the Alberta upstream oil and gas industry. The trends also suggest that much of the GHG reduction opportunities could come from implementing gas conservation solutions at a comparatively small number of sites, and that there is a trend toward diminishing returns with additional investment. As larger total reductions are considered by involving greater numbers of sites, overall costs per tonne of CO_2 eq. eliminated increase significantly. Nevertheless, even these higher costs might be acceptable in the context of still greater costs associated with other proposed GHG reduction strategies such as carbon capture and storage (CCS) (Alberta Energy, 2009, 2011b,c,d; Athabasca Oil Sands Project, 2010). For Alberta, the magnitudes of economically viable CO_2 eq. reductions via flaring and venting mitigation are potentially greater than what would be available with currently proposed CCS projects (Alberta Energy, 2011b; Athabasca Oil Sands Project, 2010), and at similar levels of provincial investment, the data suggest it should be potentially possible to eliminate nearly all continuous flaring and venting at upstream oil and gas facilities in Alberta, thus preventing the release of an estimated 57–63 $MtCO_2e$ over a 10-year period. Overall, the present results suggest that short-term investment in additional infrastructure, employing mature, reliable technologies, has the potential to immediately reduce GHG emissions from the upstream oil and gas sector without necessarily drawing funding away from other projects for the longer term.

5. Conclusions

Using detailed monthly production data spanning the years 2002–2008 combined with current GIS pipeline data for the Province of Alberta, Canada, a comprehensive analysis of GHG mitigation potential in a mature oil and gas producing region via upstream flaring and venting reduction has been performed. Focusing on mitigation via compression of gas into pipelines for connection into existing pipeline networks, the analysis has revealed potentially significant opportunities for GHG emissions reductions, in some cases at a profit. Monte-Carlo analyses to assess calculation uncertainty and sensitivity to input parameters have shown that, while the exact magnitudes of the reduction potential vary with different input data scenarios, they appear to be significant in all cases considered. Added incentives to mitigate, such as revenue from carbon offset credits or cooperation among sites to pool costs and potential gas revenues, can dramatically improve the economics, leading to increased participation and further mitigation. It is noted that despite efforts to err on the side of conservatism in developing the estimated flare and vent gas conservation costs, there may still be situations where, due to site-specific considerations (e.g., the remoteness of the facility and difficult terrain such as muskeg resulting in the need for winter construction), the estimated costs are non-conservative. Implementation solutions for individual sites would thus need to be re-evaluated on a case by case basis. Nonetheless, the models presented herein for the industry as a whole suggest that investment in CO_2 equivalent reductions from upstream flaring and venting is likely to be much more economically viable in the near-term than other possible strategies for achieving similar reduction magnitudes. In principle, this type of analysis could be extended to any mature oil and gas production in the world with existing pipeline infrastructure on which to build.

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