Supporting Information

A Techno-Economic Analysis of Methane Mitigation Potential from Reported Venting at Oil Production Sites in Alberta

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S1 Breakdown of Upstream Oil and Gas Methane Emissions in the Alberta in 2014 to 2016

Analogous to Figure 1 in the manuscript, Figure S1 to Figure S3 show the estimated breakdown of methane emission sources in the Alberta upstream oil and gas sector (excluding oil sands mining and upgrading) for 2014 through 2016. These figures have been derived from the current Environment and Climate Change Canada (ECCC) National Inventory Report (NIR) data but, as noted in the manuscript, actual industry reported flaring and venting data has been substituted for values in the NIR that instead are based on forward projections from 2011 data. Methane emissions from other sources, i.e. methane from unreported venting and fugitive emissions are otherwise estimated as in the ECCC NIR.

The breakdown in emissions is similar across all three years, with methane from reported venting and flaring representing 20-28% of total estimated methane emissions. Reported venting at oil and heavy oil sites is the dominant source of methane from directly reported sources. Total estimated methane emissions have decreased during 2014-2016, driven by a decrease in reported venting volumes at oil and heavy oil sites[1]. This trend should be interpreted with some caution however. Recent airborne[2] and ground-based[3,4] measurements show that observed methane emissions are consistently higher than what reported venting and flaring sources would suggest, and at heavy oil sites in particular, there is evidence of significant mis-measurement and/or under-reporting[2,3]. As further summarized in Section S6.1, comparison of airborne measurements with inventory estimates in the Lloydminster heavy oil production region of Alberta[2] suggests that reported whole gas venting volumes would need to be increased by ~4.9 times to account for difference between inventory methane estimates and measured data. Figure S4 shows that if reported venting data are corrected upward accordingly, then the contribution of methane emissions from directly reportable venting and flaring sources increases significantly (rising to ~49% of total methane emissions in 2015). As discussed in the context of Figures 6 and 7 in the manuscript, this significantly improves the economics of mitigation.

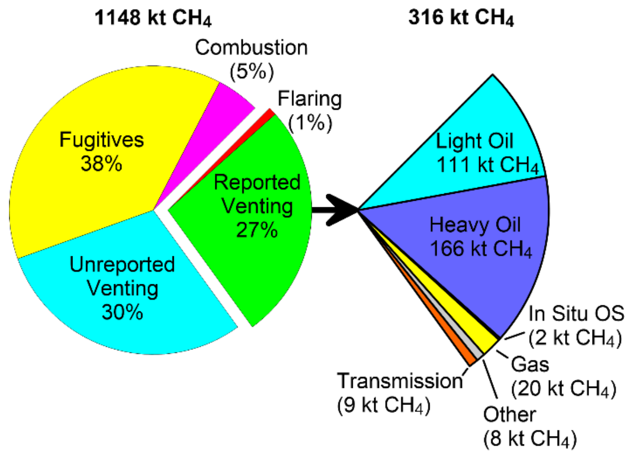

Figure S1:Updated 2014 inventory estimates of methane emissions in the Alberta upstream oil and gas sector.

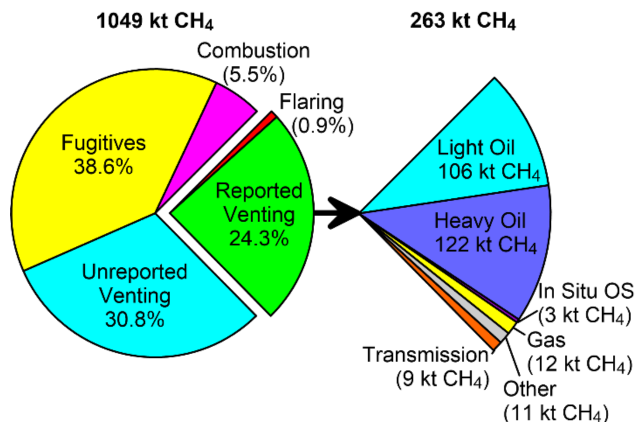

Figure S2:Updated 2015 inventory estimates of methane emissions in the Alberta upstream oil and gas sector.

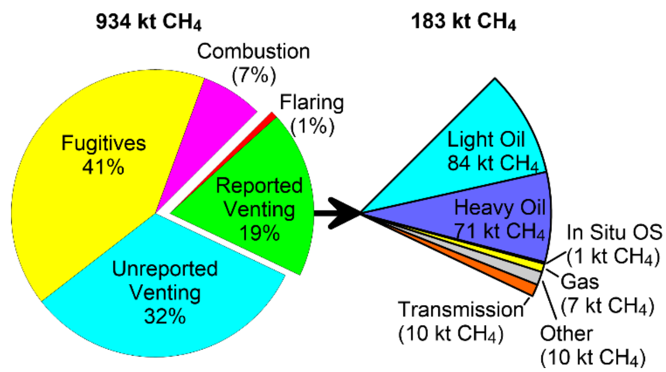

Figure S3:Updated 2016 inventory estimates of methane emissions in the Alberta upstream oil and gas sector.

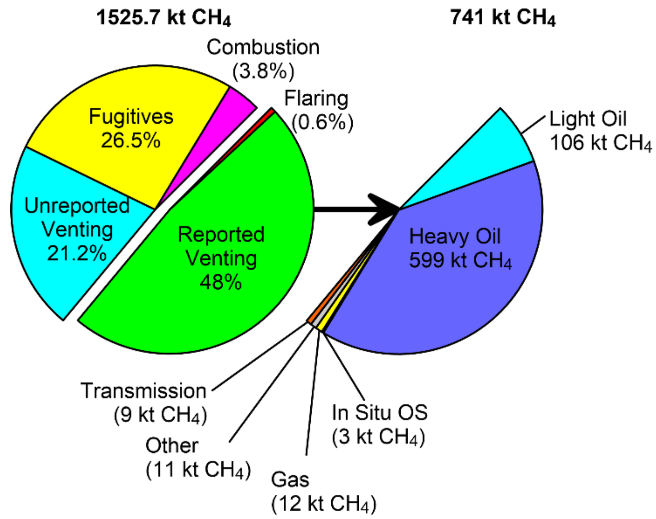

Figure S4: 2015 inventory estimates of methane emissions in the Alberta upstream oil and gas sector where reportable vented volumes at heavy oil sites have been augmented to agree with recent airborne measurements.

S2 Reference Case Economic Parameters

The reference scenario techno-economic input parameters are summarized in Table S1 and Table S2. Values for inflation rate, discount rate, natural gas and propane price projections, and tie-in operating costs were obtained from sources recommended in AER Directive 60[5]. Operating costs for flaring and mitigation technology specific to heavy oil sites were chosen to match those presented by Clearstone Engineering[6].

Table S1: Reference case economic parameters for methane mitigation analysis

Parameter	Specified Value in Reference Case Analysis	Source / Reference
Inflation rate	1.3%	http://www.stats.gov.sk.ca/
Discount rate	5.7% (prime rate + 3%)	https://www.atb.com/rates/
Operating costs	Applied yearly at each site as a percentage of the capital cost. The percentage for each mitigation scheme is as follows: • 10% for tie-in; • 7.6% for flaring; • 6.5% for Auxiliary Burner and Heat Trace; • 8.0% for Catalytic Conversion; • 8.0% for Catalytic Line Heaters; and • 7.0% for Vapour Combustor	Directive 60[5] Clearstone Engineering Ltd.[6]
Gas price projections	Table S2	GLJ Petroleum Consultants[7]
Propane price projections	Table S2	GLJ Petroleum Consultants[7]
Gas composition	Site specific composition estimates	Derived from the Alberta Energy Regulator's Individual Well Gas Analysis file
100-year global warming potential (GWP) of CH_4	25	IPCC[8]
Gas production decline rate at oil sites	$\exp(-dt)$ where $d = \begin{cases} 0.000, & \text{heavy oil} \\ -0.055, & \text{otherwise} \end{cases}$ See Figure S11 (a) and (b)	Derived from 2015 production reporting data provided by the Alberta Energy Regulator
Project duration	10 years	
Capital asset value after 10 years	$0 CAD	

Table S2: GLJ Petroleum Consultants projected propane price and gas price data at the plant gate

Year	Projected ARP Gas Price at the Plant Gate [$ CAD/MMBtu]	Projected Edmonton Propane Price [$ CAD/bbl]
2017	2.78	22.26
2018	2.74	22.57
2019	2.91	25.38
2020	3.08	25.88
2021	3.25	26.35
2022	3.44	27.59
2023	3.62	28.82
2024	3.82	30.06
2025	3.9	31.29
2026	3.98	32.48
2027+	+2.0%/year	+2.0%/year

S3 Assumed Project Duration

Project duration and residual asset value assumptions necessary for a net present cost (NPC) calculation were conservatively taken as 10 years and $0 CAD respectively in the reference case. A common fixed project duration for all oil sites ultimately results in a conservative mitigation estimate for two key reasons. First, positive revenues from any mitigation projects extending beyond the project duration were neglected, and any projects that cease to be profitable earlier than the prescribed project duration (e.g. due to production decline) were forced to continue at a loss for the full project duration. Additionally, mitigation options such as auxiliary burners and catalytic line heaters that required a minimum volume of gas were only evaluated if there was sufficient gas for the full project duration.

The effects of different project durations were further explored through additional analysis summarized in Figure S5. Reference case calculations were repeated for assumed project durations of 4, 5, 6, 7, 8, 9, 10, 11, or 12 years as plotted left to right in each group of bars in the figure. While individual operators may prefer to run their economic calculations using project durations shorter or longer than 10 years, the effects on the annual methane mitigation are minimal. At a maximum cost of $30 CAD/t$CO_2$e at any one site, and an overall average cost of $5.78 CAD/t$CO_2$e, the annual methane mitigation potential is 0.173 Mt/y in the reference case of a 10-year project duration. At the same maximum cost per site of $30 CAD/t$CO_2$e but with a 6-year duration, a nearly identical annual methane mitigation of 0.176 Mt/y is possible at a still modest overall average cost of $9.33 CAD/t$CO_2$e. For a longer 12-year project duration, the annual mitigation potential is again very close at 0.168 Mt/y with a lower overall average cost of $4.70 CAD/t$CO_2$e. These results show that the assumed project duration does not significantly affect the achievable mitigation potential. The impact of all other economic parameters, i.e. capital cost, commodity pricing and production decline fluctuations were investigated through Monte-Carlo simulations as discussed in Section S12. As part of this Monte Carlo analysis, Figure S34 shows that the overall confidence limits in the costs to achieve 45% methane reductions are comparable for project durations of 8, 10, and 12 years.

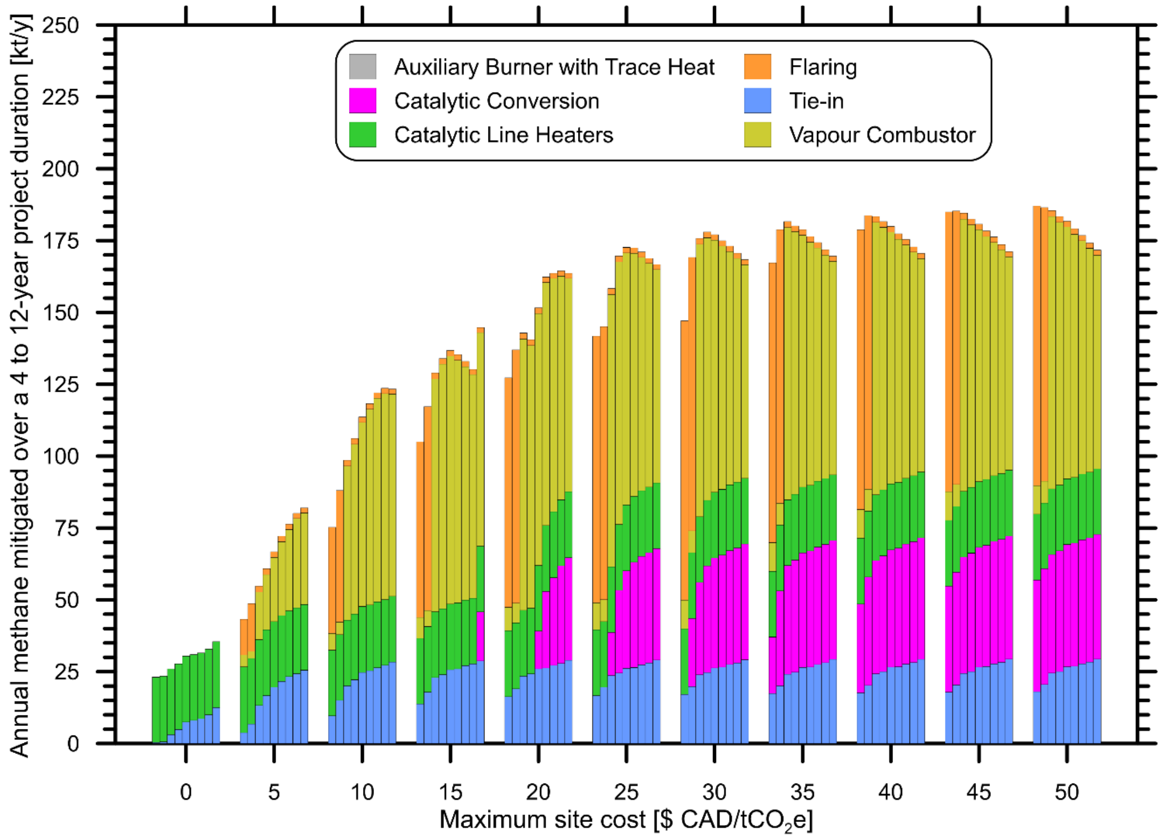

Figure S5: The average annual methane mitigation potential varying project durations from 4 to 12 years (left to right) at different maximum site mitigation cost in \$ CAD/tCO_2e.

S4 Cost Models

All Capital cost models included complete equipment, material, engineering, construction, installation, and regulatory costs for winterized operation in Alberta. The reference case capital cost estimates for flaring systems, catalytic conversion units, internal vapour combustors, catalytic line heaters, and auxiliary burners with heat tracing were sourced from a recently published in a report by Clearstone Engineering Ltd. based on quotes obtained from industry vendors[6]. These capital cost estimates are inline with those reported by Sentio Engineering and New Paradigm Engineering Ltd.[9,10] The reference case pipeline and compressor costs associated with tie-in follow those proposed by Johnson and Coderre[11]. As further detailed below, a review of the limited number of more recent publicly available estimates for pipeline and compressor costs suggests the reference case models are likely to be conservatively high. This range of capital cost estimates was used to bound the underlying cost variations assumed for the Monte Carlo uncertainty analysis in Section S13.

S4.1 Pipeline Cost Models

The capital cost models for compression and pipeline installation developed by Johnson and Coderre[11] integrated detailed cost data obtained from Clearstone Engineering Ltd. into a linear regression model similar to those used by Rahim[12]. The pipeline costing data considered steel pipeline gathering systems and included data or estimates for all associated costs such as shipping, installation, land agent fees, right-of-way, surveying, engineering, and regulatory approval costs. These raw data are plotted in Figure S6(a) along with other relevant steel pipe cost estimates found from a search of journal and conference proceedings / presentations [13–18]. The linear model:

$$\text{Pipeline Cost}\,[\$\ \text{CAD}] = \frac{\$86000}{\text{km}} \cdot \text{distance[km]} \tag{1}$$

is a good fit (R^2=0.95) to the original source data from Clearstone Engineering Ltd. and the additional cited sources. Since the development of equation (1) , the technological advances and certification of high density polyethylene (HDPE) pipeline, composite, and other reinforced plastics for high pressure oil and gas gathering systems has reduced material and installation costs[17]. Non-steel pipeline costing data, Figure S6(b), gleaned from case studies[13–15,17], conference proceedings[11], technical magazine articles[18], and public quotations[19] suggest that plastic pipeline systems are significantly cheaper than steel pipeline systems with a reduction in estimated installed cost of 24% to 38%. Thus, the $86000 CAD per km pipeline installation cost used in the reference case economic analysis is likely to be conservatively high. The Monte Carlo analysis detailed in Section S13.1 considered a range of higher and lower pipeline costs (including lower costs approaching those shown in Figure S6(b)) and demonstrated that these costs do not strongly influence the overall methane mitigation potential.

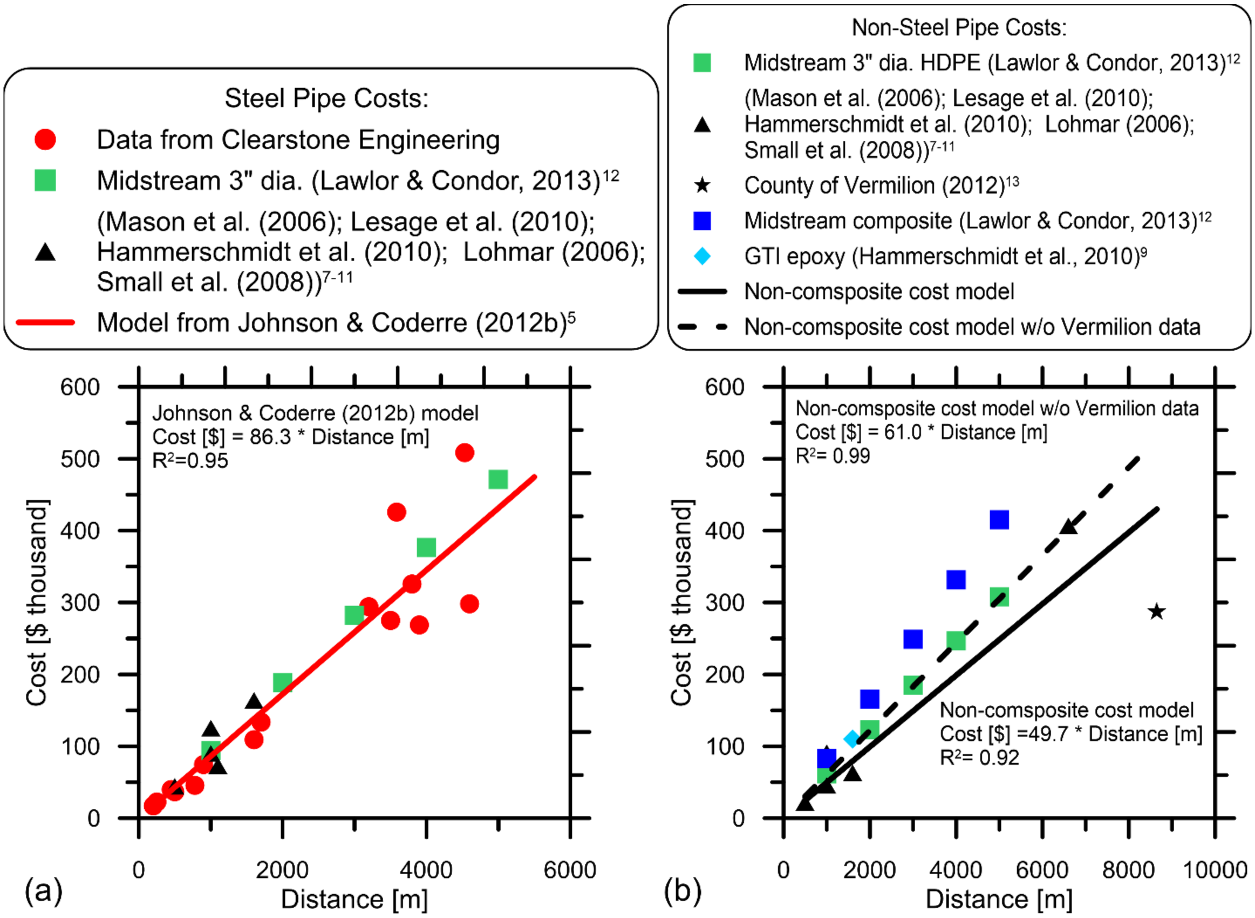

Figure S6: A comparison of steel and non-steel pipeline cost estimates: (a) Steel pipeline estimates from Clearstone Engineering Ltd. compared to other sources; (b) Non-steel pipeline estimates from industry case studies and conference proceedings.

S4.2 Compression Cost Models

The compressor cost estimates shown in Figure S7 – originally sourced from Clearstone Engineering Ltd. and used in the model of Johnson and Coderre[11] – show much greater spread than the pipeline cost data of Figure S6. This spread precluded the derivation of an independent pressure/volume model from the data alone. However, there were sufficient data to perform a regression model for the compression costs using the functional form originally proposed by Rahim[12] which gave the result used by Johnson and Coderre[11] as shown in Equations (2) and (3).

$$\text{Compression cost [\$ CAD]} = \$187430 + \left[\$15746 \cdot \text{volume}\left(\frac{10^3\text{m}^3}{\text{d}}\right) \cdot \text{stages}\right], \tag{2}$$

The number of required compressor stages in (2) was determined via Eq. (3),

$$\text{stages} = \frac{\ln\left(\frac{P_{\text{MOP}}}{P\text{atm}}\right)}{\ln(\text{stagePR})}, \tag{3}$$

where P_{MOP} is the maximum operating pressure of the intended of gas gathering pipeline, P_{atm} is the atmospheric pressure, and stagePR is the stage pressure ratio. This model conservatively assumes that gas to be captured must be raised from P_{atm} all the way to P_{MOP}. The maximum operating pressures within the oil and gas gathering infrastructure in British Columbia, Alberta, and Saskatchewan (cross provincial pipeline tie-in was allowed since this could be the best option in border regions) were obtained using geographic pipeline infrastructure data from Geomatics Data Management Inc. (GDM). In cases where the maximum operating pressure was not specified within the GDM data, the average pressure from the candidate pipeline sections for the relevant transported product was substituted. For the present analysis, it was assumed that tie-in locations were permissible in the subset of pipeline segments carrying the specific product types outlined in Table S3.

Table S3: Average maximum operating pressure of candidate pipelines

GDM product type	Average of maximum operating pressure [kPa]
Fuel Gas	2032
HVP Products	9388
Miscellaneous Gases	10007
Natural Gas	5060
NGL	9928
Oil Emulsion	3450
Oil Well Effluent	5453
Sour Natural Gas	5737
Sour Oil Well Effluent	4999
Sweet Gas	9800

To assess the effect of capital cost variations on the overall mitigation potential, additional compressor cost data were obtained from US EPA’s Natural Gas STAR program reports as summarized in Table S4. These data similarly suggest that installed costs are primarily driven by the required outlet pressure.

Table S4: US EPA Natural Gas STAR program compressor cost estimates

Source	Compressor type	Maximum outlet (pipeline) pressure [kPa]	Operating Flow Rate [1000 m^3/day]	Capital & Installation cost [$ USD/ $ CAD]
US EPA Natural Gas STAR Program[20]	Rotary	689.3	5.1	31,250/40064
US EPA Natural Gas STAR Program, Spring 2010 Partner Update[21]	Scroll	2378.0	0.4 to 5.7	60,000/76923
	Rotary screw	1033.9	0.4 to 56.6	55,000/70513
	Rotary vane	482.5	0.1 to 70.8	50,000/64103

The flow rates specified in the compressor cost data obtained from Clearstone Engineering Ltd. ranged from 3.6 m^3/day to 3263.5 m^3/day and were generally much lower than those form the Gas STAR program data shown in Table S4. Thus, the cost data could only be directly compared in terms of the maximum operating pressure, and even then, only two of the Clearstone data points overlapped with the Gas STAR data as shown in Figure S7. For these two points the Gas STAR compressor costs were approximately 3.5 times lower. This suggests that the compressor cost model used in the reference case analysis is also likely to be conservatively high, especially given that approximately one third of the candidate tie-in locations in this analysis have a maximum operating pressure less than or equal to 2400 kPa.

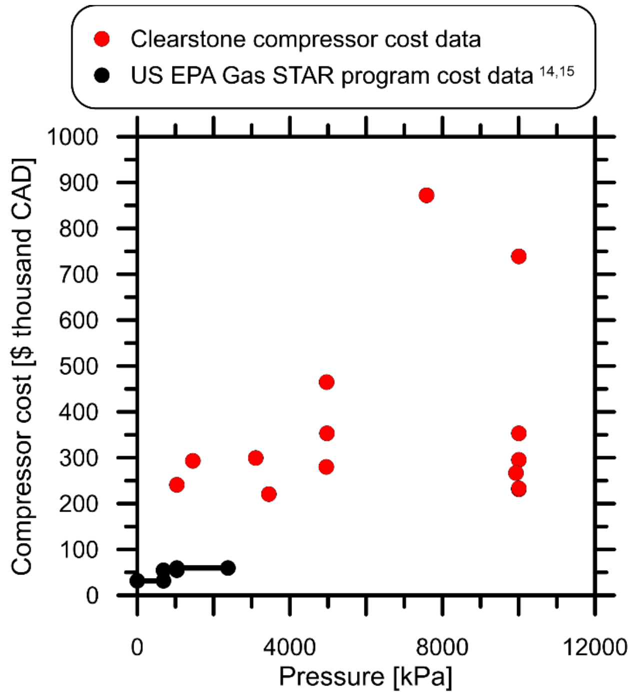

Figure S7: Compression cost estimates obtained from Clearstone Engineering Ltd. compared with US EPA compression cost estimates.

S5 Locations of Oil Production Sites

Geographic coordinates of oil production sites (i.e. batteries and/or wells) were necessary when calculating distances to nearest pipelines and when determining required setback distances from nearby infrastructure or residences. For single well batteries and oil wells associated with paper batteries (comprising 62% of the analyzed sites), the GPS coordinates of the surface hole locations could be extracted from the AER's general well file. For multi-well batteries, locations were either obtained using geographic information system (GIS) facility data when available from GDM Inc. as supplied by IHS Cera Ltd. or derived from Dominion Land Survey (DLS) data available from AER[22]. The DLS system locates facilities to the resolution of a legal subdivision (LSD), a 402 m x 402 m land parcel. In cases where DLS data were used, the multi-well battery location was assumed to be at the center of an LSD such that the actual location was at most offset by 284.3 m.

Heavy oil sites could only be distinguished based on their designated sub-type code, since oil density is not tracked in the AER/Petrinex data. More specifically, within designated oil sands areas (See Figure S8), AER's volumetric reporting manual states that heavy oil wells must be linked to crude bitumen or paper batteries[23]; however "heavy oil wells outside an AER-designated oil sands area must be linked to and reported as part of a crude oil battery". Thus, in the present analysis, the number of heavy oil wells is conservatively underestimated. Wells outside of the designated area were necessarily considered to be light/medium crude oil wells, in line with AER reporting practices, and were not considered eligible for potential methane mitigation technologies applying specifically to heavy oil facilities as further discussed below.

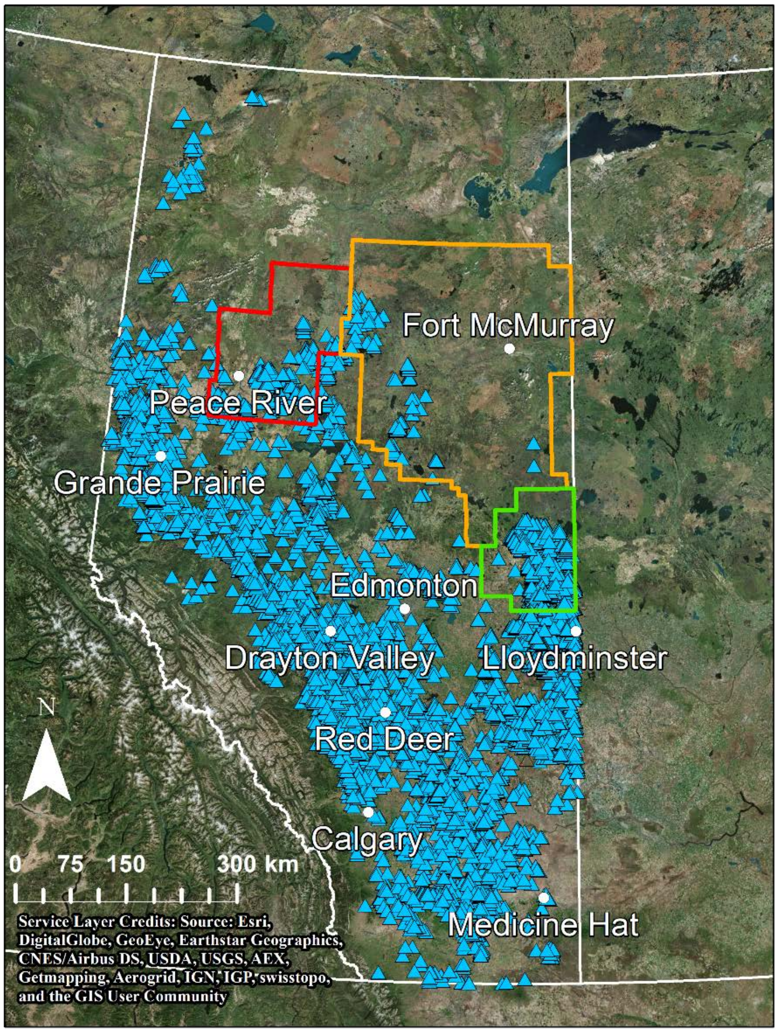

Figure S8: AER Peace River (red), Athabasca (orange), and Cold Lake (green) Oil Sands Administrative Boundaries and locations of the 9422 active oil batteries or oil wells associated with paper batteries that reported flaring and/or venting in 2015.

S6 Volumetric Data Reported at Oil Production Sites

In 2015, 27,249 upstream oil and gas facilities reported 110 million m^3 of oil production, 129.5 billion m^3 of gas production, 25.6 billion m^3 of gas used as on-site fuel, 763 million m^3 of gas flared, and 388.4 million m^3 of gas vented. Included in these data were 9053 active oil batteries (i.e. oil and heavy oil batteries as identified by facility subtype codes within AER's complete list of provincial facilities[22], but excluding in-situ oil sands sites) that reported some amount of flaring and/or venting. Volumes at 116 paper batteries with reported flaring and venting activity were disaggregated to their associated 485 wells, prorating by natural gas production reported at the well where necessary. Historically paper batteries were mainly associated with cold heavy oil production with sand (CHOPS) operations in the Lloydminster area of Alberta. Although the use of paper batteries in reporting is decreasing, these sites still accounted for 6.4% (22.8 million m^3 of 353.3 million m^3) of the total reported natural gas vented from Alberta oil batteries. For comparison, in 2008 paper batteries accounted for 35.7% of vented volumes reported at oil batteries[24].

Figure S9 plots the geographic distributions of reported flaring (a) and venting (b) volumes at oil production sites in Alberta in 2015. Sites within the superimposed yellow, ~100 km × 230 km box near Lloydminster accounted for 66% of all reported venting in the Province of Alberta in 2015. This region is dominated by CHOPS production. Although there is similar CHOPS development in the Peace River area, as noted in the manuscript, region specific regulations (i.e. "play-based regulations")[25] to control odours set by AER prohibit venting of tank top and casing gas in the area. Relative to reported volumetric data for 2008[24], it seems that by 2015 nearly all of the reported venting volumes near Peace River had been replaced by flaring. As apparent on the map, four townships north of Peace River had the highest flaring intensities in Alberta in 2015.

Figure S9 shows histograms and cumulative distributions of reported flared and vented volumes at upstream oil production sites in Alberta in 2015. Most (82%) of sites flare less than 328,800 m^3/y (equivalent to 900 m^3/day), but the remaining 18% of sites account for more than 77% of the total flare volume at upstream oil sites in the province. The distribution of vented volumes is less skewed with a lower median site volume (11,900 m^3/y of venting vs. 59,600 m3/y of flaring), but still spans several orders of magnitude. However, 8219 oil production sites reported venting in 2015, while only 1998 sites reported flaring. Among the venting sites, 98% vented less than 328,800 m^3/y, while the top 2% of sites vented nearly one quarter (23.1%) of the total reported venting at upstream oil production sites. Overall, 9422 sites reported either flaring or venting with a median total volume of 17,350 m^3/y. Approximately 95% of these sites had reported total flare and vent volumes of less than 328,800 m^3/y, while the top 5% of sites accounted for nearly 55% of the total provincial volumes.

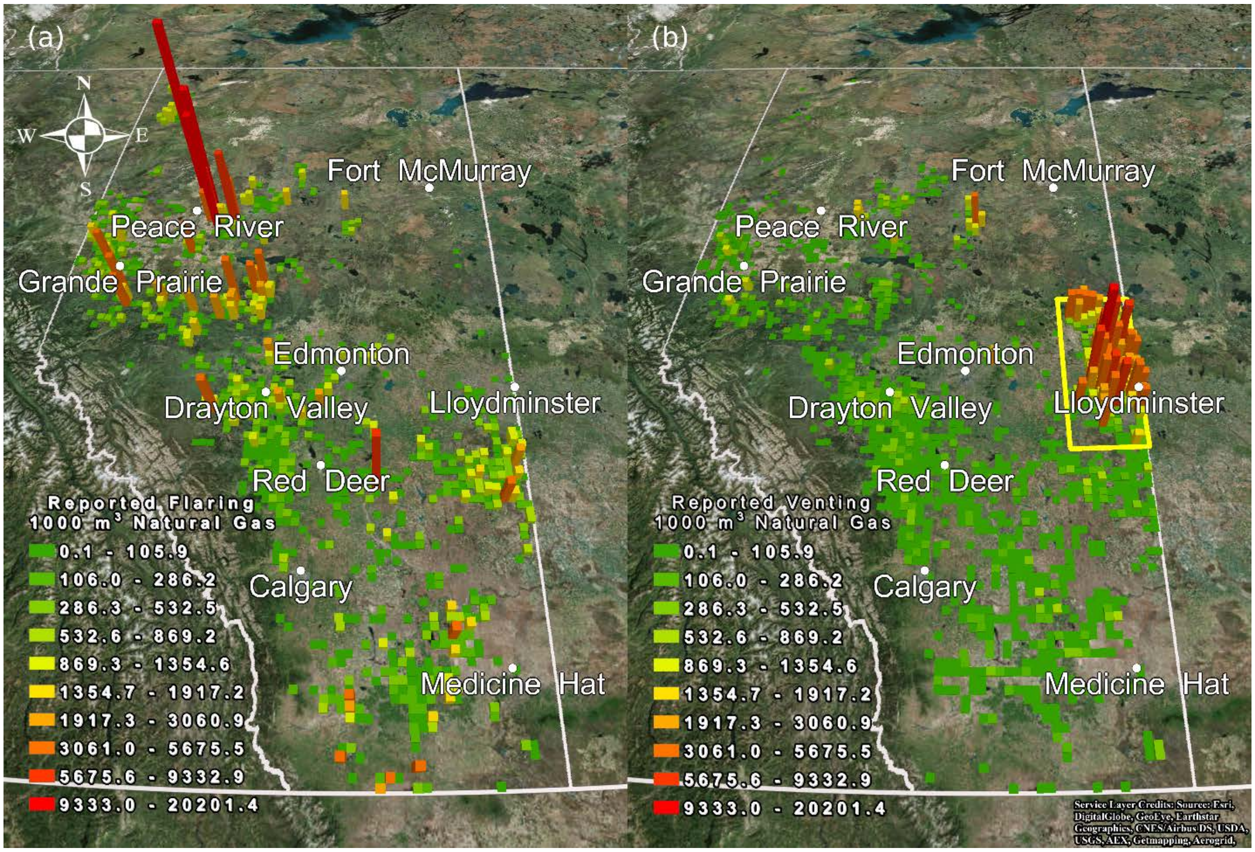

Figure S9: Distribution of reported (a) flaring and (b)venting volumes in Alberta in 2015. Grid resolution is 9.7 km × 9.7 km corresponding to Alberta's township system. ~Sites within the highlighted yellow, 100 km × 230 km box near Lloydminster accounted for 66% of all reported venting in the Province of Alberta in 2015

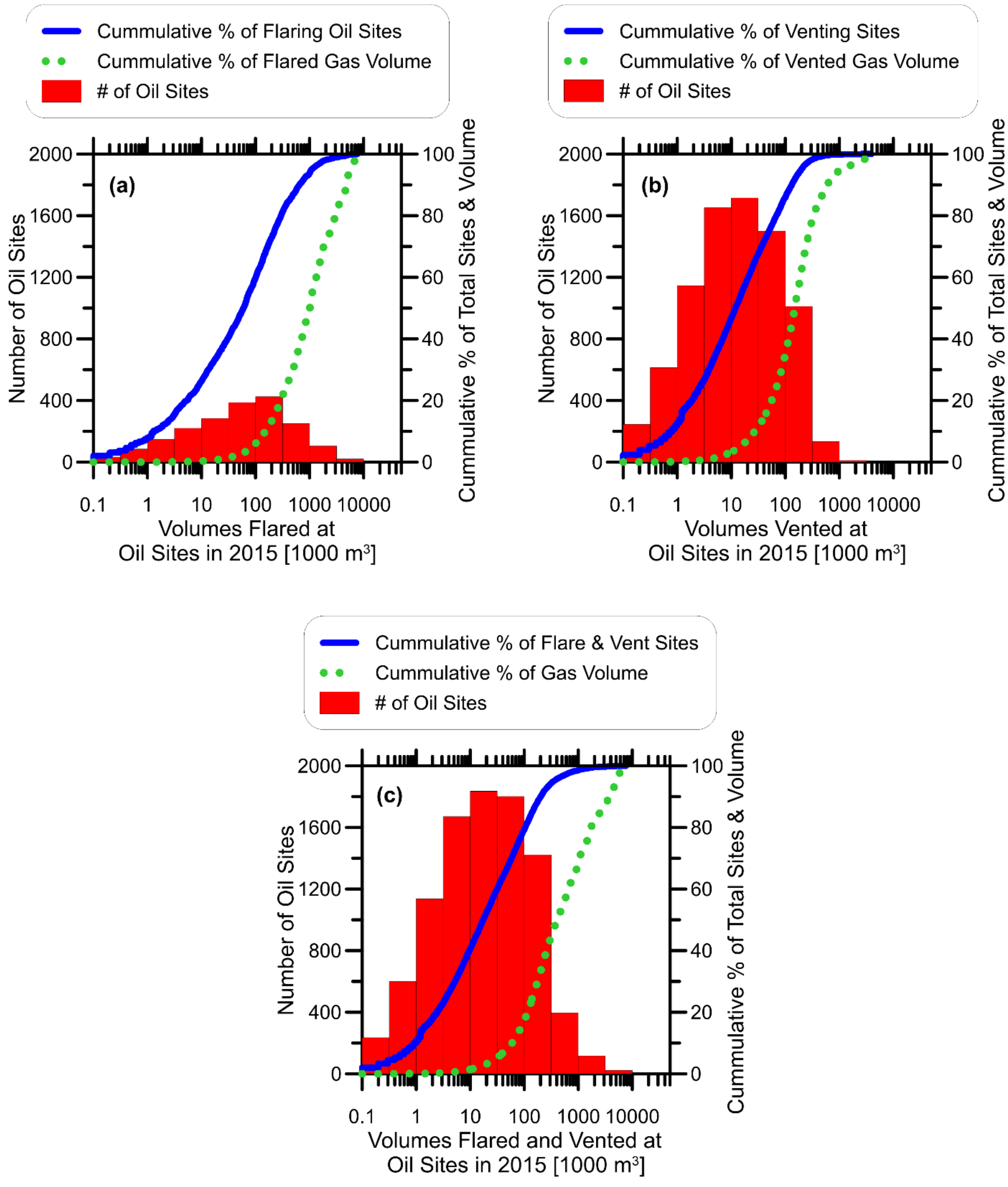

Figure S10: Distributions of reported flare and vent volumes at upstream oil production sites in Alberta in 2015. (a) reported flared volumes, (b) reported vented volumes, (c) total reported flared and vented volumes.

S6.1 Potential for Higher Reported Venting Volumes at CHOPS sites and fraction of emissions likely captured by current reporting

A recently published comparison of airborne measurements of methane flux with updated, regionally-resolved, inventory estimates for two distinct regions of Alberta has highlighted limits and discrepancies in currently reported vent volume data.[2] In a heavy oil production region near Lloydminster, Alberta, dominated by cold heavy oil production with sand (CHOPS) sites, airborne measurements suggested "significant under-reporting or under-estimation of methane emissions" attributed to excess venting of casing gas that may be difficult to accurately measure using current gas-oil ratio measurement guidelines. Measurements in a second region near Red Deer, Alberta found general agreement between measured emissions and inventory estimates. Nevertheless, these latter results also verified that most methane emissions in this region originate from "unreported" sources that are estimated in the national inventory but not directly captured in current industry reporting as mandated by the Alberta Energy Regulator (AER). Specifically, only 6% of the inventory methane sources in the Red Deer region were from flaring and venting as reported to AER, while 94% of methane emissions were other sources such as unreported venting (53%) and fugitives (19%).

In the Lloydminster region, actual emissions as measured by aircraft were 3-5 times higher after accounting for biogenic sources than federal inventory estimates, and 4-7 times higher than reported emissions values as captured by current industry reporting requirements to AER (see Figure 5 in Johnson et al.[2]). Given the notional agreement between airborne measurements and inventory estimates in the Red Deer region, this suggested that the significant discrepancies in the Lloydminster region were attributable to unique operating practices in that area – i.e. casing gas venting from CHOPS sites. For inventory estimates to agree with airborne measurements in the Lloydminster CHOPS production region, methane emissions from reported venting would need to be increased from 4.6 t/h to 22.0 t/h to make up for the 17.4 t/h difference between airborne measured emissions (24.1 t/h) and current inventory estimates (6.7 t/h)[2]. Factoring in the mean methane fraction of 97.2% in this region, reported whole gas venting volumes would need to be increased by ~4.9 times to account for the measured difference. The assertion that casing gas venting at CHOPS sites is the primary reason for the discrepancy with airborne measurements is supported by subsequent ground-based measurements at 5 CHOPS sites[3]. Given the dominant contribution of CHOPS production to total reported venting volumes in the province of Alberta, the airborne measurement results suggest that if CHOPS venting throughout Alberta were adjusted upward to match airborne measurements, without adjusting any other sources, then actual methane emissions in Alberta would be 25-50% higher than current inventories suggest[2].

S7 Facility-level Gas Composition Estimates

Raw gas composition can vary significantly across the Province of Alberta[26] and has the potential to swing the economics of any one oil site. For this analysis, individual gas compositions were assigned to each oil site using 316,917 raw gas samples obtained from AER's Individual Well Gas Analysis file (current as of November 2016). Each composition consists of molar fractions for 10 carbon groups (CO_2, C1, C2, C3, IC4, NC4, IC5, NC5, C6, C7+), hydrogen sulphide (H_2S), nitrogen (N_2) and two trace species (He, H_2). The composition at well sites was assigned using direct samples where available or when necessary a local spatial pool averaging was applied using an inverse distance weighted mean for each species from surrounding bottom hole samples. By determining a composition at all conventional Alberta oil well sites, the combined raw gas composition at the battery level was then assigned using a produced gas weighted mean of all feeder well compositions. The majority (97.8%, 9213 of 9422 oil sites) of the economic test oil sites were considered sweet with a H_2S molar fraction less than or equal to 1%. The bulk of sour oil sites are in the Red Deer, Drayton Valley, and Grand Prairie areas with a mean H_2S molar fraction of 2.9%. The molar fraction of methane at the 485 heavy oil well test sites concentrated in the Lloydminster area ranged from 89.4% to 99.3% which is consistent with Johnson and Coderre[26] and the mean heavy oil compositions used by Clearstone Engineering to develop the National Inventory[27]. At light/medium oil batteries, the molar fraction of methane varied widely between 63.6% and 98.8%.

S8 Analysis of Decline Rates

Representative yearly median gas decline rates were derived for heavy and non-heavy oil batteries using reported monthly gas and oil production data, spanning January 2003 to December 2015. Gas production trends for 9053 oil batteries that reported some level of flaring and/or venting in 2015 were analyzed using monthly reported gas and oil production data. For each individual oil battery, a continuous yearly gas production curve was derived as follows. First, monthly gas production data was trimmed to the first month in which oil production was reported. This removes potential gas produced while bringing the battery online that is not representative of typical production operations. Additionally, any gas production reported in months without oil production (possibility attributable to maintenance and/or shut-ins) were removed. This created a continuous monthly gas production set for each battery. Yearly gas production data was formed by summing on 12-month intervals, starting from the initial production month.

It was observed that gas production trends for individual batteries do not typically follow a simple exponential model. A subsequent study of gas production trends among battery types (e.g. single well, multi-well, light oil, heavy oil etc.) suggested gas decline at light oil and heavy oil sites are fundamentally different in character. In general gas production trends at light oil sites showed an overall decline with time, whereas trends at heavy oil sites pointed to potential significant increases in produced gas over a battery's production lifetime. These observations are consistent with the analysis of Johnson and Coderre[11] that suggested gas production increased by 11% per year at heavy oil sites in the Lloydminster area.

A bootstrapping procedure was used to generate representative median gas decline rates and 95% confidence intervals for both light/medium oil and heavy oil batteries. These are plotted as solid lines in Figure S11(a) and (b) respectively. These data were subsequently fitted with exponential decline curves that were used to bound the range of possible declines in the Monte Carlo analysis (Section S13). For the reference case analysis, light/medium oil sites were assumed to decline at 5.5% per year. As apparent in Figure S11(b), gas production at heavy oil batteries does not follow a simple trend. The median and 95% confidence intervals show that gas volumes in years 1-6 actually rise beyond the initial rate of production, before subsequently starting to decline. Although the fitted median exponential decline curve arguably shows 0.5% growth, in the reference case gas production at heavy oil sites was conservatively modelled with a 0% decline.

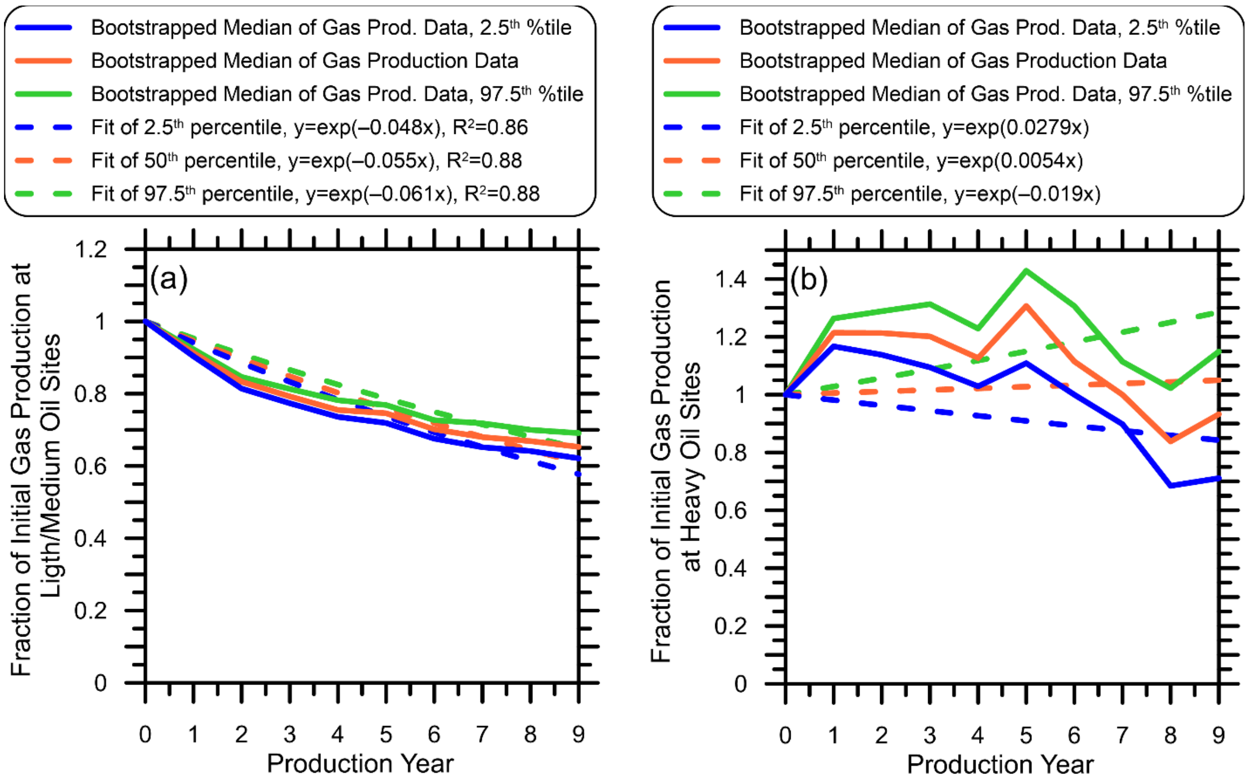

Figure S11:(a) Gas production decline and exponential fits at light/medium oil batteries (b) Gas production decline and exponential fits at heavy oil batteries

S9 Flaring and Incineration Setbacks

Under AER Directive 60, vapour combustors and flare stacks are subject to minimum setback requirements from built-up infrastructure and residences. In general flaring and incineration equipment located at oil production sites in Alberta must be setback at least 100 m from the nearest surface improvements and/or surface developments such as residences, permanent farm buildings, schools, and places of business as defined by AER Directive 56[5,28]. Additionally, sites flaring or incinerating greater than 900 m^3/d require a setback of at least 500 m from a residence, otherwise under Directive 60 the site must conserve the gas regardless of economic considerations[5]. These constraints form the basis of the decision tree shown in Figure S12 which was used to determine which of the 9422 oil sites in the economic analysis are eligible to install a vapour combustor or flare stack (for the subset of sites that reported only venting).

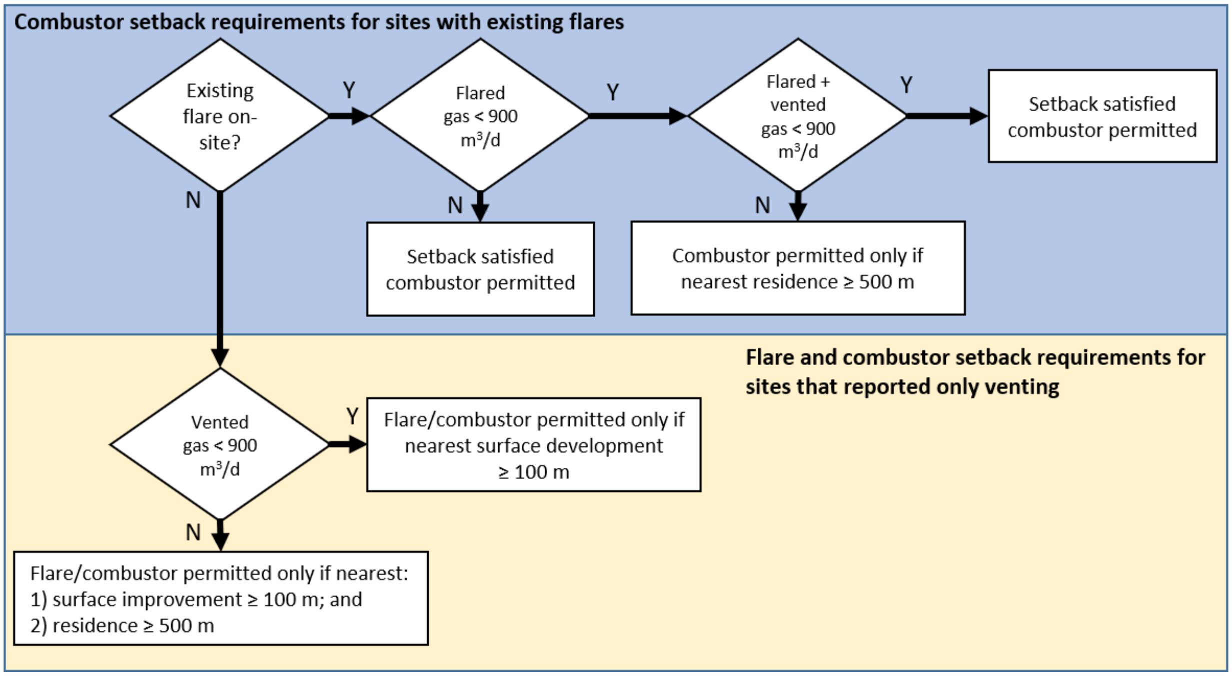

Figure S12:Flare and combustor setback requirements based on AER's Directive 60

For oil sites with an existing flare (i.e. reported some amount of flaring) it was assumed that the site complies with set back requirements in Directive 60. Thus, a vapour combustor could be added to these sites and only triggered the need to review additional setback requirements if the new total volume of vented gas to be incinerated and flared rose from below to above the 900 m^3/d threshold. For oil sites that were assumed not to have an existing flare (i.e. based on having reported only venting), required setback distances were verified in all cases regardless of the vented volume to be incinerated.

Distances from oil production sites to surface developments and improvements were estimated using publicly available GIS data generated by the Alberta Biodiversity Monitoring Institute as part of the 2014 Human Footprint Inventory (HFI) dataset[29]. The HFI estimates land use by enclosing structures and transportation infrastructure found in SPOT6 satellite imagery and other information sources using a multi-vertex polygon following boundaries such as roads, property lines, and fences. Surface developments and improvements in the HFI that were considered in the present analysis included gravel or paved roads with 2 or more lanes, active railway lines, canals, industrial sites (excluding upstream oil and gas facilities), feed and high-density livestock facilities, and rural and urban residences (includes farm structures, rural dwellings, and residential areas in cities, towns, villages, hamlets etc.). To determine whether flaring/incineration would be permissible at an oil site, the minimum distance to the closest surface improvement was compared to the setback distance prescribed by the decision tree in Figure S12. For surface developments such as rural residences where the enclosing polygon follows the property boundary, these minimum distances are conservative estimates. For example, in some cases, as depicted in Figure S13, an oil site will fall within a residence's land boundary and thus obtain a minimum distance of zero meters whereas the actual location is greater than 100 m from the property's associated dwelling.

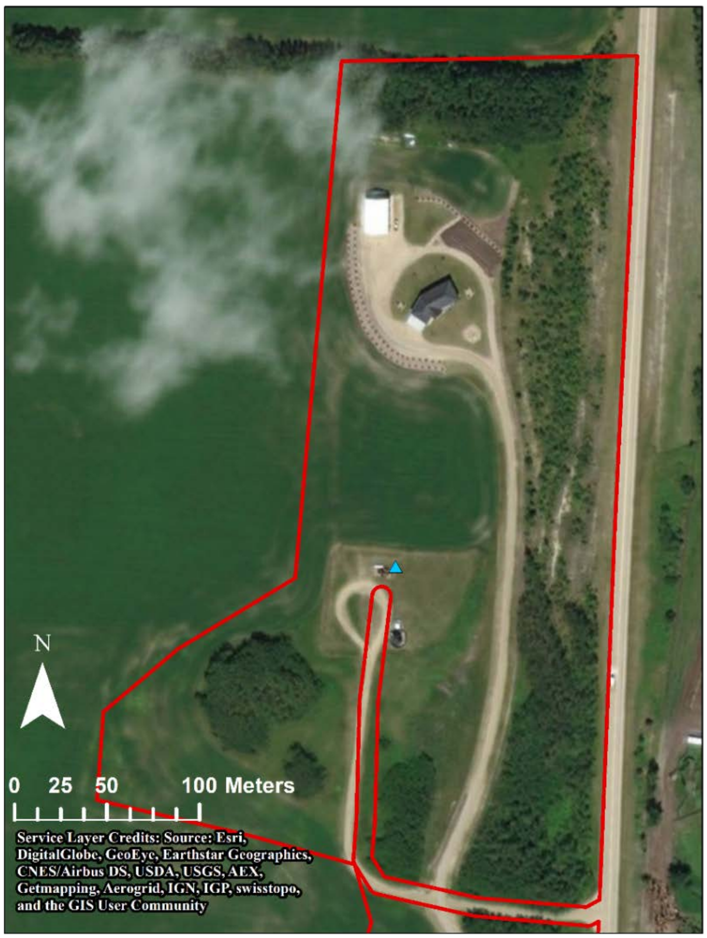

Figure S13: Example of an oil site that would be assigned a distance of zero (as it is located within an HFI rural residence polygon) whereas the actual distance to major roadways and residential dwellings is greater than 100 m.

Of the 9244 oil sites considered in the economic analysis, 7% were estimated to be within 100 m of a surface improvement, and 32% were within 500 m of a residence. The potential close proximity of oil sites to rural residences is illustrated in Figure S14.

Figure S14: An example map illustrating the potential close proximity of oil production sites (blue triangles) to rural residences (red HFI polygon) in Alberta

S10 Estimated Propane Use at Heavy Oil Sites

To assess the economic feasibility of a catalytic line heating or an auxiliary burner scheme as presented by Clearstone Engineering[6], it was assumed that the heavy oil sites in this study (2718 heavy oil batteries, 485 heavy oil wells) used a mix of natural gas and propane as on-site fuel to operate pump(s) and/or heat storage tank(s). Following the approach used by Clearstone, onsite energy requirements were calculated based on assumed thermal efficiencies, load and operating requirements, and output power ratings as summarized in Table S5.

Table S5: Assumed energy requirements for pump engines and tank heaters at heavy oil sites

Unit	Rated Power [kW]	Thermal Efficiency [%]	Load [%]	Operating [h/d]	Fuel [GJ/d]
Pump Jack Engine	45	35	60	24	6.67
Tank Heater	220	80	60	12	7.13
Total					**13.8**

As outlined in the Clearstone report[6], one challenge of using produced gas for on-site fuel use is the potential for freeze up (due to hydrate formation in the lines) during the colder months of the year. In their report, Clearstone assumed a "typical" heavy oil site used casing gas as fuel for 7 months of the year (when temperatures would be warm enough to prevent potential line "freeze-offs" that might interrupt oil production) and used purchased propane in the other 5 months. The present analysis considered this concept, but rather than defining a single "typical" site, the operating characteristic of each site was considered individually. As on-site propane use is not tracked in the production accounting data, propane use was inferred from on-site energy demands in Table S5 together with reported natural gas volumes used as fuel gas at each site. A detailed decision tree to infer propane use is presented in Figure S15.

The present techno-economic model assumed heavy oil sites used propane to meet all heating and pumping requirements if no natural gas fuel use was reported, or if the amount of reported fuel use was less than the amount required for at least 7 months of pump operation from Table S5. If the amount of reported fuel use was sufficient to operate a pump for at least 7 months, but not enough to also operate tank heaters, then it was assumed that propane was used to operate pumps during the five coldest months and for all tank heating. In this case, piping from the wellhead to the pump was assumed to already exist and this was discounted from the capital cost when considering the catalytic line heating and auxiliary burner and heat tracing schemes as detailed in the decision trees outlined in Figure S20 and Figure S22. Finally, if the amount of reported fuel use was more than the estimated amount required to operate pumps and tank heaters for at least 7 months per year, then it was conservatively assumed there were no additional opportunities to use produced gas as fuel on site. Heavy oil sites falling in this latter category were then analyzed considering only the same options available to non-heavy sites.

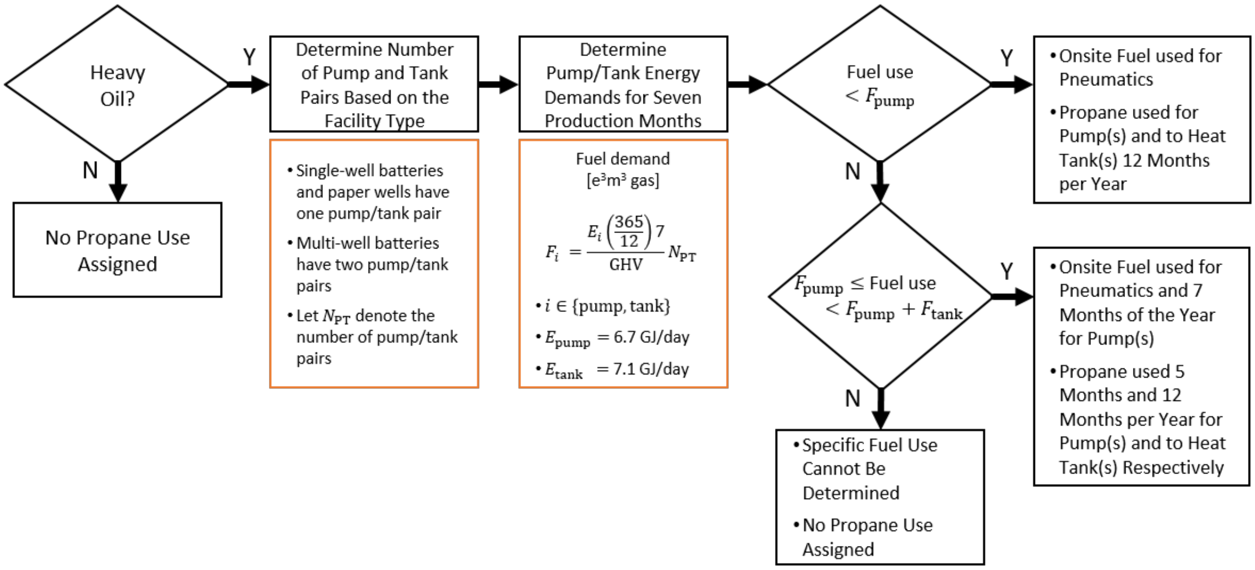

Figure S15: Decision tree to infer fuel gas and propane use at heavy oil sites

S11 Detailed Mitigation Scheme Flowcharts

Figure S16 through Figure S23 outline the details to determine the capital cost, mitigated methane and CO_2e, revenue and costs for each mitigation technology.

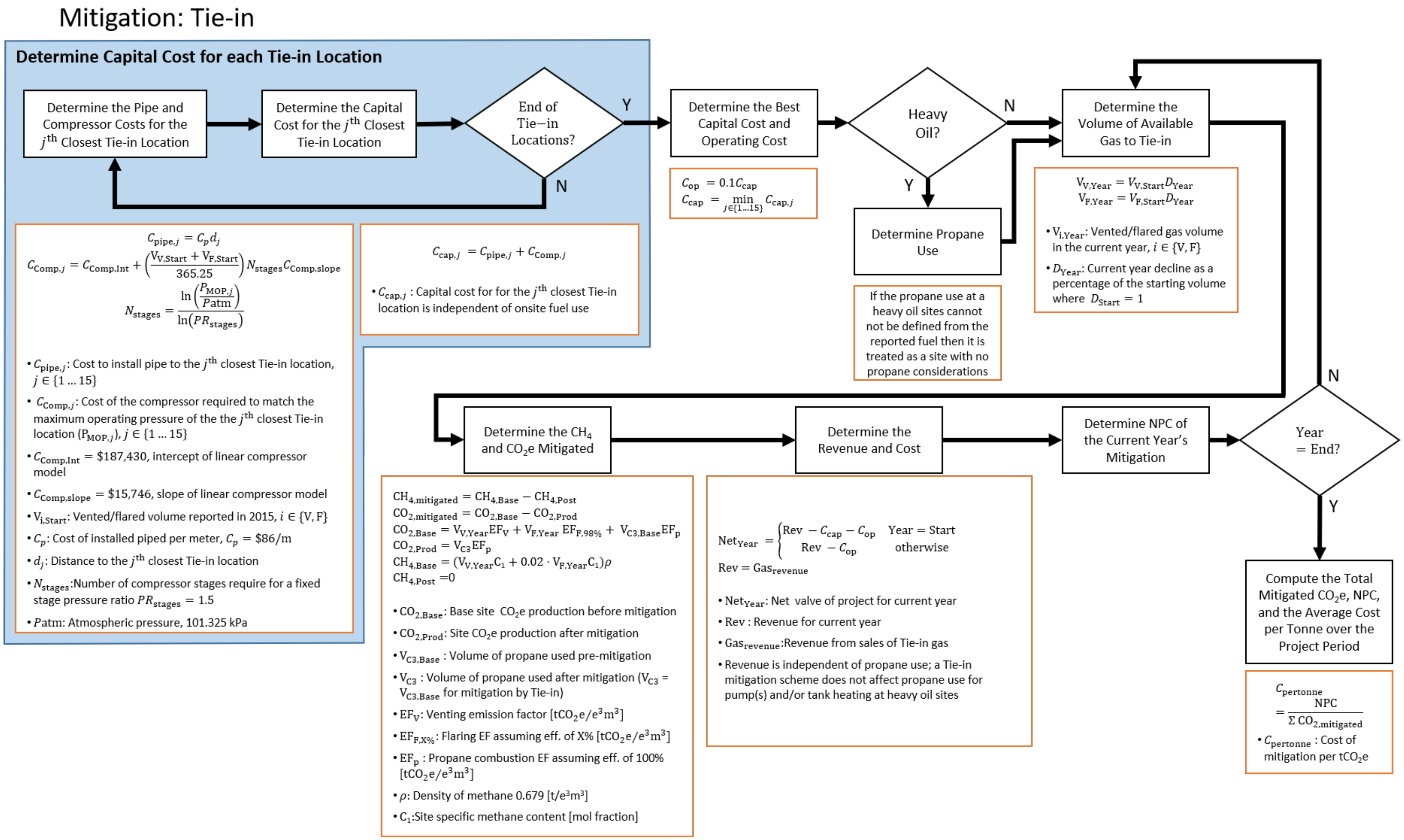

Figure S16: Detailed flow chart to determine applicability of mitigation of methane by routing gas into a pipeline and assess associated project costs (NPC and cost per tonne CO_2e mitigated)

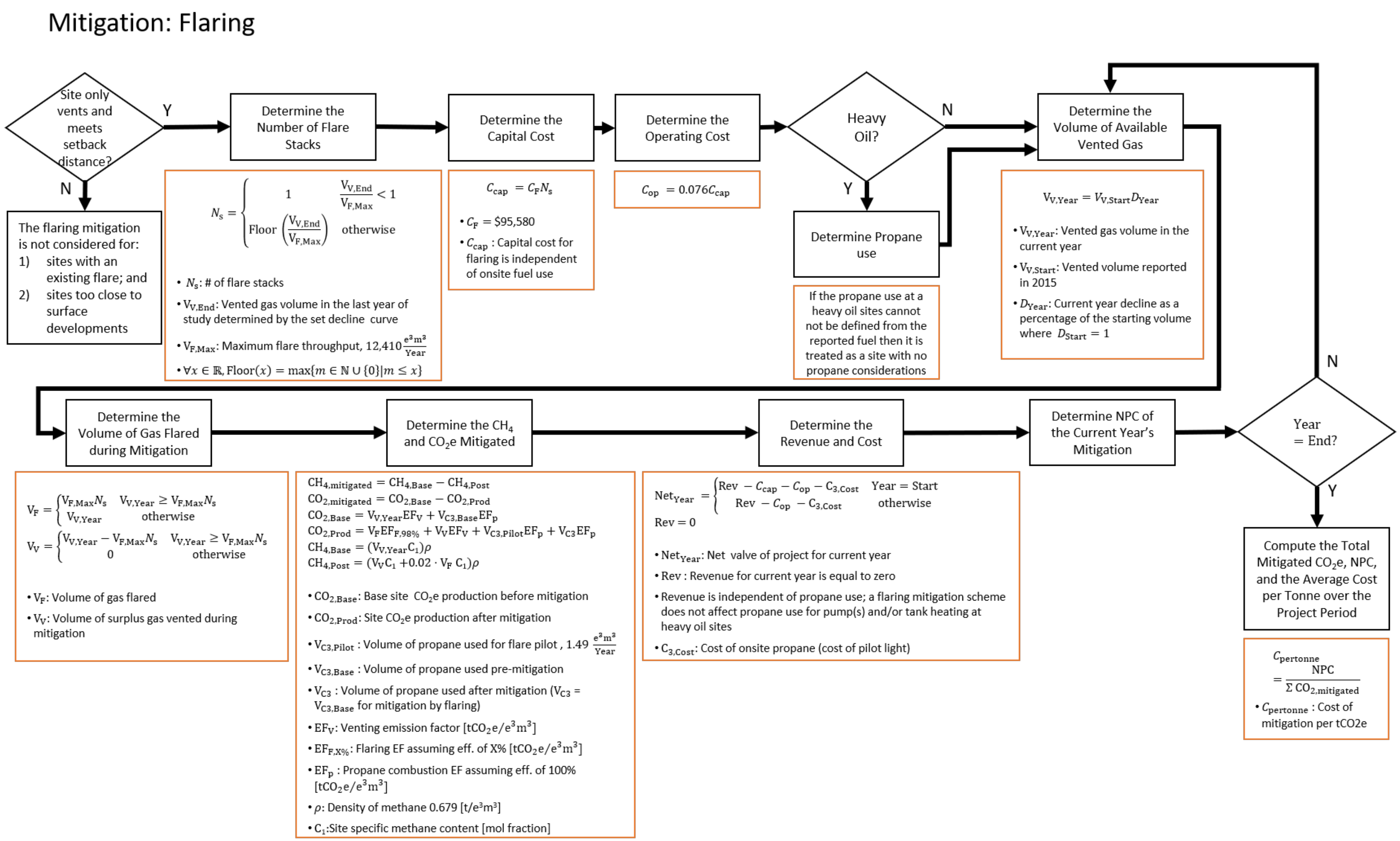

Figure S17: Detailed flow chart to determine applicability of mitigation of methane by flaring and assess associated project costs (NPC and cost per tonne CO_2e mitigated)

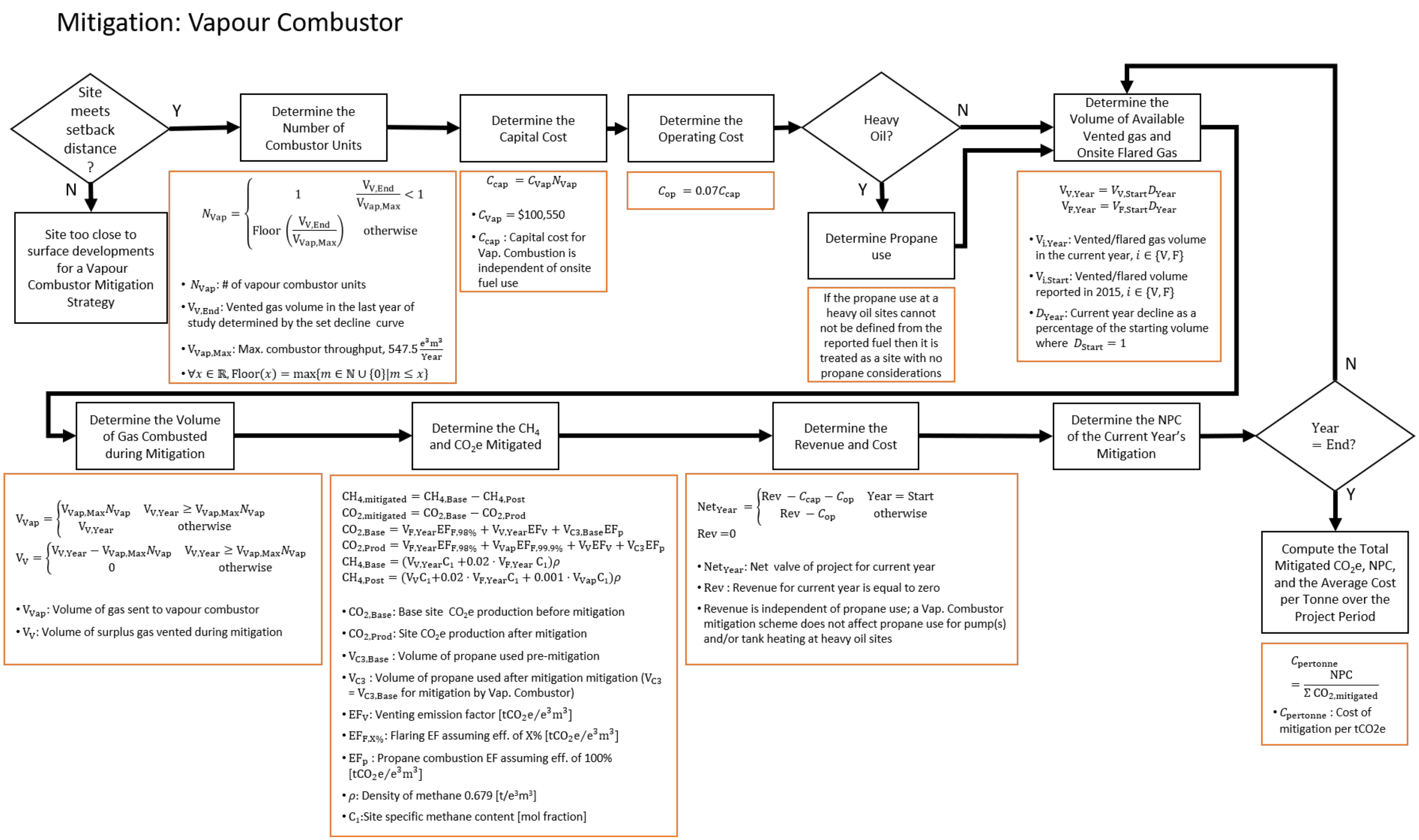

Figure S18: Detailed flow chart to determine applicability of mitigation of methane using a vapour combustor and assess associated project costs (NPC and cost per tonne CO_2e mitigated)

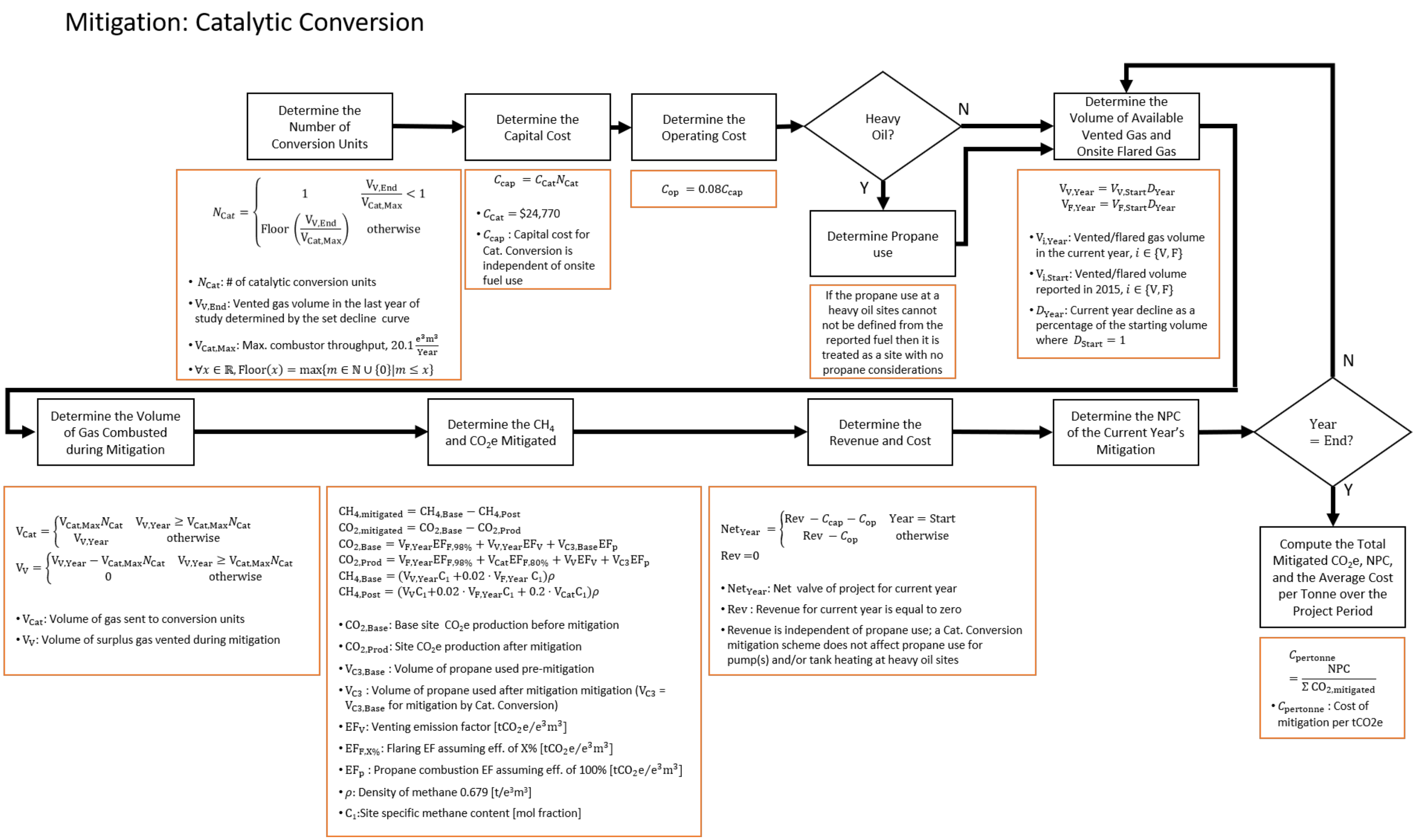

Figure S19: Detailed flow chart to determine applicability of mitigation of methane by catalytic conversion and assess associated project costs (NPC and cost per tonne CO_2e mitigated)

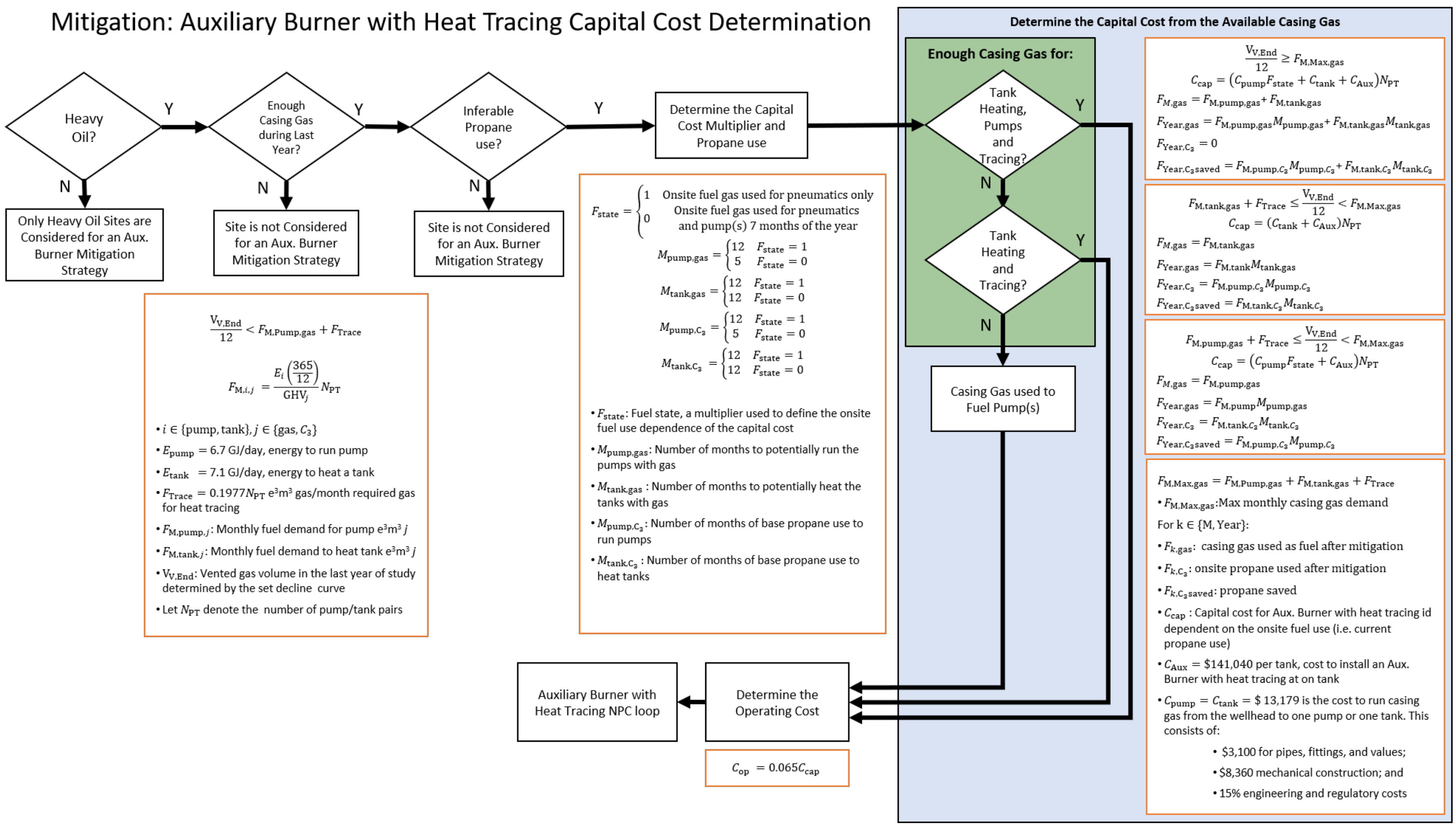

Figure S20: Detailed flow chart to determine applicability of the capital cost of installing an auxiliary burner with heat tracing and assess associated project costs (NPC and cost per tonne CO_2e mitigated)

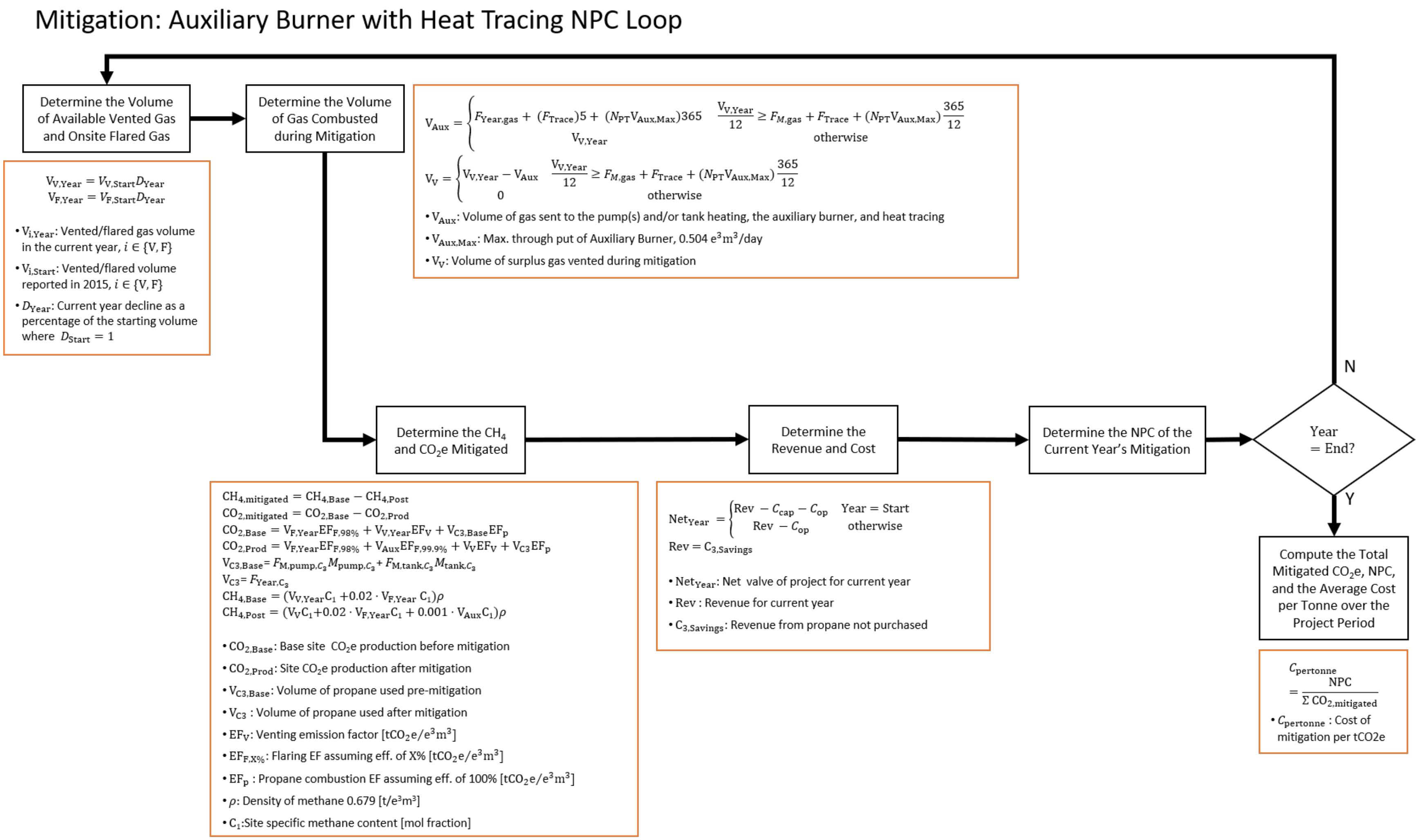

Figure S21: Detailed flow chart to determine applicability of mitigation of methane using an auxiliary burner with heat tracing and assess associated project costs (NPC and cost per tonne CO_2e mitigated)

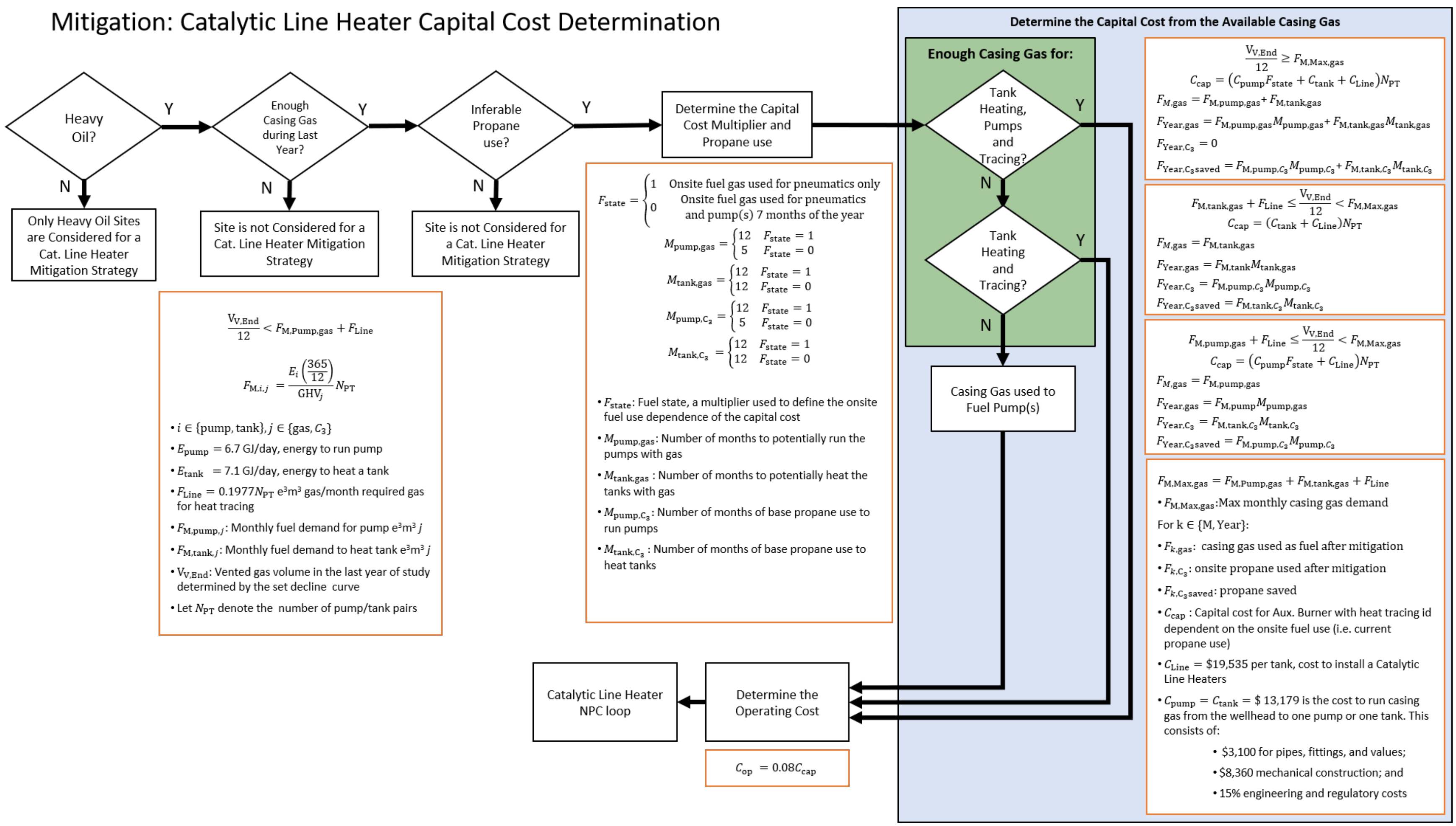

Figure S22: Detailed flow chart to determine applicability of installing catalytic line heating and assess associated project capital costs

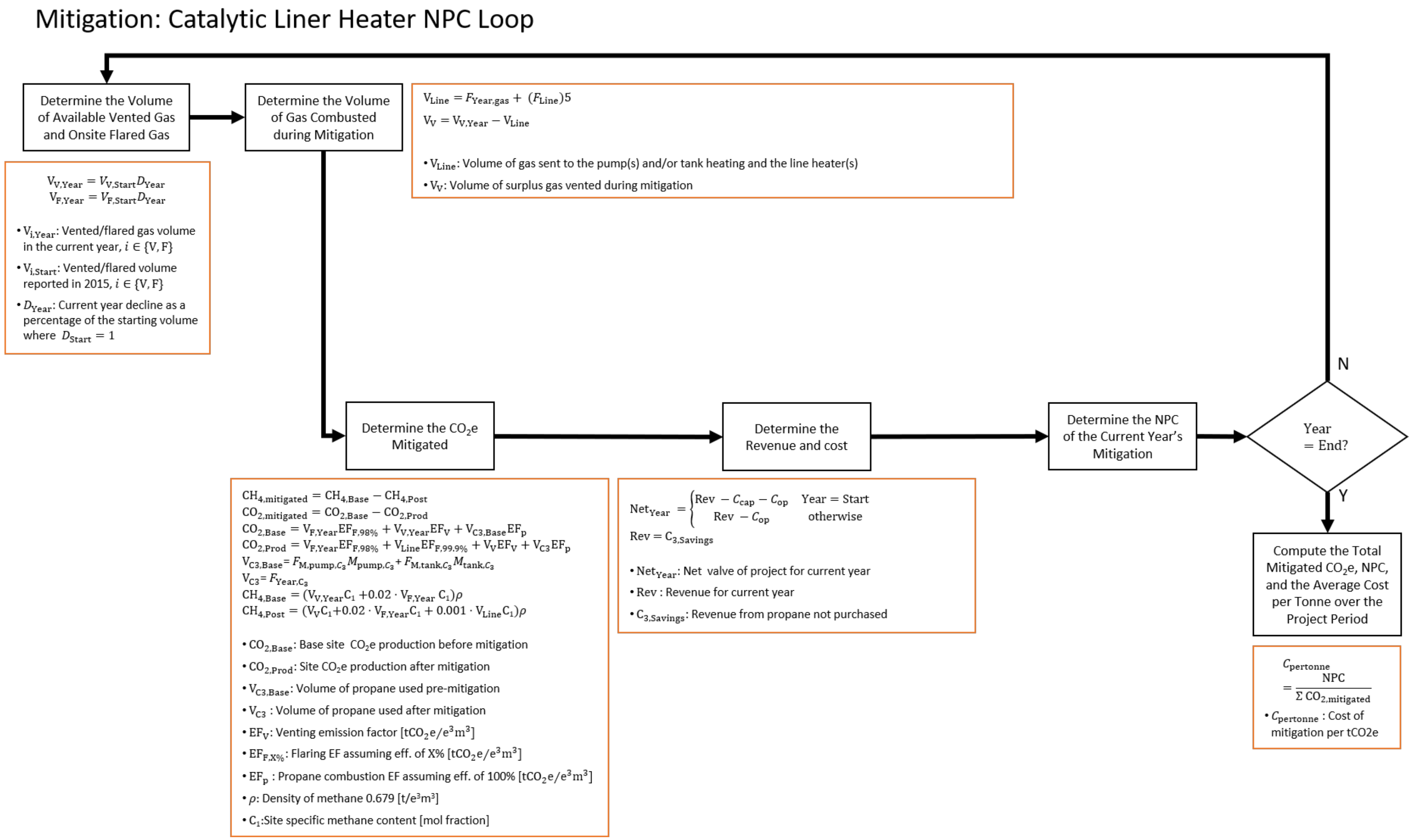

Figure S23: Detailed flow chart to determine associated project costs (NPC and cost per tonne CO_2e mitigated) when installing catalytic line heating to mitigate methane by enabling its use as onsite fuel

S12 Additional Economic Results

S12.1 General Locations of Profitable Sites

In the reference economic scenario, 4% of the analyzed oil sites had a profitable (NPC≤0) mitigation option. Most of these sites are located in a heavy oil production region near Lloydminster bounded north-south by the 65th and 42nd township and east-west by the 1st and 10th range as outlined in yellow in Figure S24. As noted above, this ~100 km × 230 km region accounts for 66% of all reported venting in the Province of Alberta in 2015.

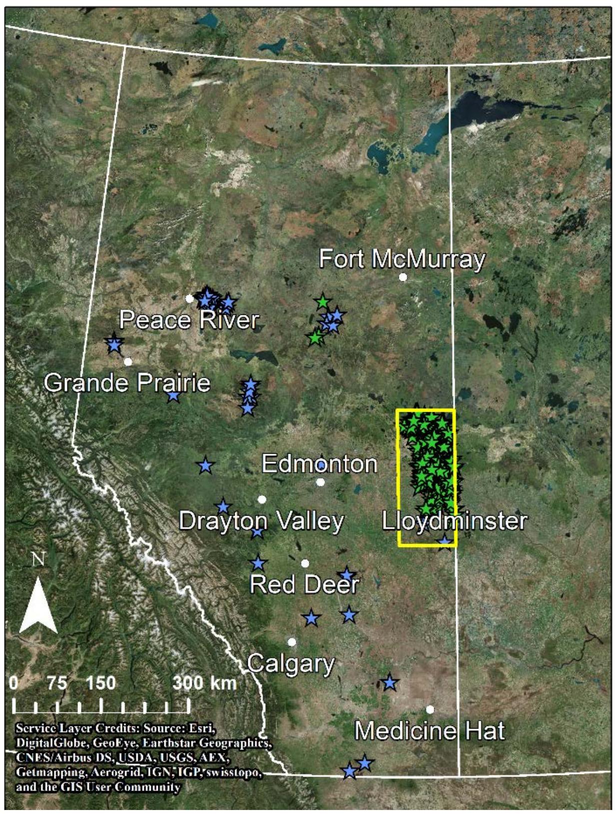

Figure S24: Locations of 355 profitable sites where 304 heavy oil sites (green stars), mainly located in the Lloydminster region, use with casing gas to meet on-site fuel demands by employing catalytic line heaters. Outside of Lloydminster, the economics at 51 oil sites (blue stars) are driven by natural gas prices where economic sites conserved large volumes (>800,000 m^3/y) of gas through tie-in that would be otherwise flared.

S12.2 Reference Case results with Site Count and Capital Cost

Figure S25 provides additional capital cost, site count, and average cost data for the techno-economic analysis results presented in Figure 5 of the manuscript. Figure S25(b) presents the impact of a hypothetical tie-in clause whereby a site is required to tie-in to a pipeline if the derived cost per tCO_2e to tie-in is less than a specified maximum (e.g. \$30 CAD/tCO_2e). While the hypothetical tie-in cause has almost no effect on the total number of sites contributing to the potential methane mitigation at each maximum site cost, the upfront total capital cost is increased by 1.2 to 2.1 times over the range of maximum site costs from \$5 CAD/tCO_2e to \$50 CAD/tCO_2e. However, over this same range the overall estimated mitigation is increased by 16 $ktCO_2e$ to 1158 $ktCO_2e$.

In each panel of Figure S25 the number of sites using flaring or incineration (i.e. combustion without energy recovery in flares, vapour combusters, or catalytic conversion units) as a method to mitigate methane is represented by a red dashed line. In all scenarios the tie-in clause effectively reduces the number of sites flaring or incinerating. In panel (a) the the average mitigation cost for flaring or incineration, defined as the total net present cost (NPC) divided by the total mitigated CO_2e, is provided in red above each bar. Over a range of maximum site costs of \$5 CAD/tCO_2e to \$50 CAD/tCO_2e the average cost to flare or incinerate methane ranged from \$3.40 CAD/tCO_2e to \$11.09 CAD/tCO_2e. This range of average costs is similar to the approximately \$7 CAD/tCO_2e estimated in a recent study considering flaring of stranded gas at oil wells in Alberta.[30]

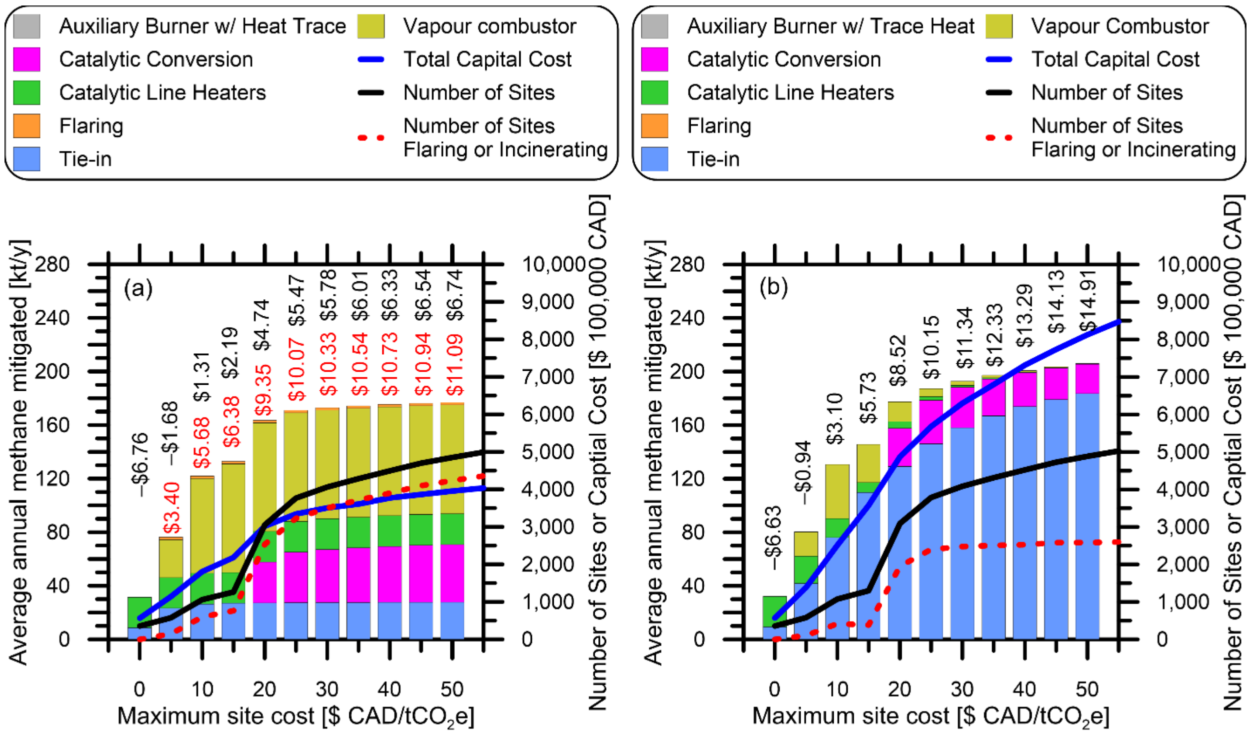

Figure S25: (a) Annual methane mitigated using the least costly technology at each oil site while capping the maximum site cost to range of \$0 CAD/tCO$_2$e to \$50 CAD/tCO$_2$e as indicated on the horizontal axis (b) Methane mitigated under a hypothetical tie-in clause whereby sites must tie-in to a pipeline if the associated cost is less than the specified maximum site cost. Aggregate average mitigation costs for all sites and for sites flaring or incinerating in each bar is written in black and red respectively on the graph. Data are for 9422 oil-sites in Alberta that reported flaring and venting in 2015 and are calculated assuming a 10-year project duration.

Figure S26 recasts the estimated average annual methane mitigation presented in Figure S25 as a percentage reduction of methane emissions from reported flaring and venting at upstream oil sites and as a percentage of Alberta's total upstream oil and gas methane inventory (see Figure S2). The reference case results indicate a 45% cut in methane emissions from reported flaring and venting at upstream oil sites is obtainable for near zero average net cost over ~800 sites where no site pays more than \$7.41 CAD/tCO$_2$e. This could be accomplished with an initial capital investment of \$150 million CAD (Figure S25a).

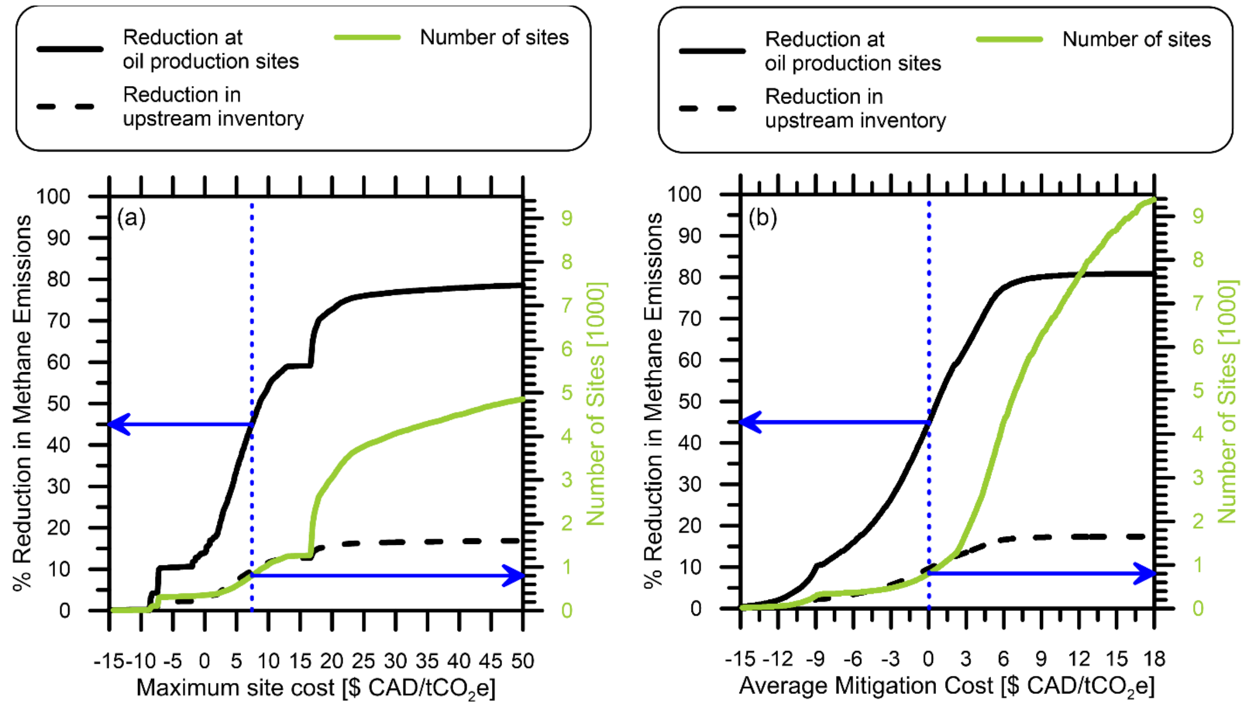

Figure S26: Percent reductions in methane emissions achieved via mitigation of reported flaring and venting at oil sites over a range of a) maximum site costs and b) average mitigation costs. Solid black lines show achieved reductions as a percent of reported flaring and venting volumes. Dashed black lines show achieved reductions as a percentage of all upstream inventory sources of methane. Solid green lines indicate the number of sites over which the reduction is achieved

S12.3 Reference Case without Catalytic Conversion Units as an Option

The results from the techno-economic analysis results presented in Figure 5 of the manuscript suggest that catalytic conversion units may be a frequent choice of mitigation technology along with vapour combustors, especially as the maximum allowable site cost is increased beyond \$20 CAD/tCO_2e. In the reference case, the methane destruction efficiency of catalytic conversion units is assumed to be 80% as originally assumed in the report by Clearstone Engineering Ltd.[6] and incorporated in the detailed flow chart (Figure S19) above. However, it is expected that the final ECCC regulations will stipulate a minimum destruction efficiency of 95% for technology used to destroy methane. While the manufacturer of these catalytic conversion units (Scottcan Industries Ltd.) suggested in a discussion with the corresponding author that higher destruction efficiencies should be easily achieved, they acknowledged that there has been little commercial interest in these units to date. To assess the potential impact of these factors, an additional analysis was completed where catalytic conversion units were excluded as an available option. Figure S27 shows that the excluding catalytic conversion units has negligible overall impact on the results. In general, sites that had chosen catalytic conversion units instead choose vapour combustors. The overall mitigation potential increases slightly (as the replacement technologies achieve higher destruction efficiencies) and the average costs are marginally higher. For example, in the reference case, at a maximum site cost of \$30 CAD/tCO_2e, the achievable methane mitigation is 173 kt/y at an average cost of \$5.78 CAD/tCO_2e. With catalytic conversion units excluded as an option, these values rise to 176.5 kt/y and \$5.95 CAD/tCO_2e respectively.

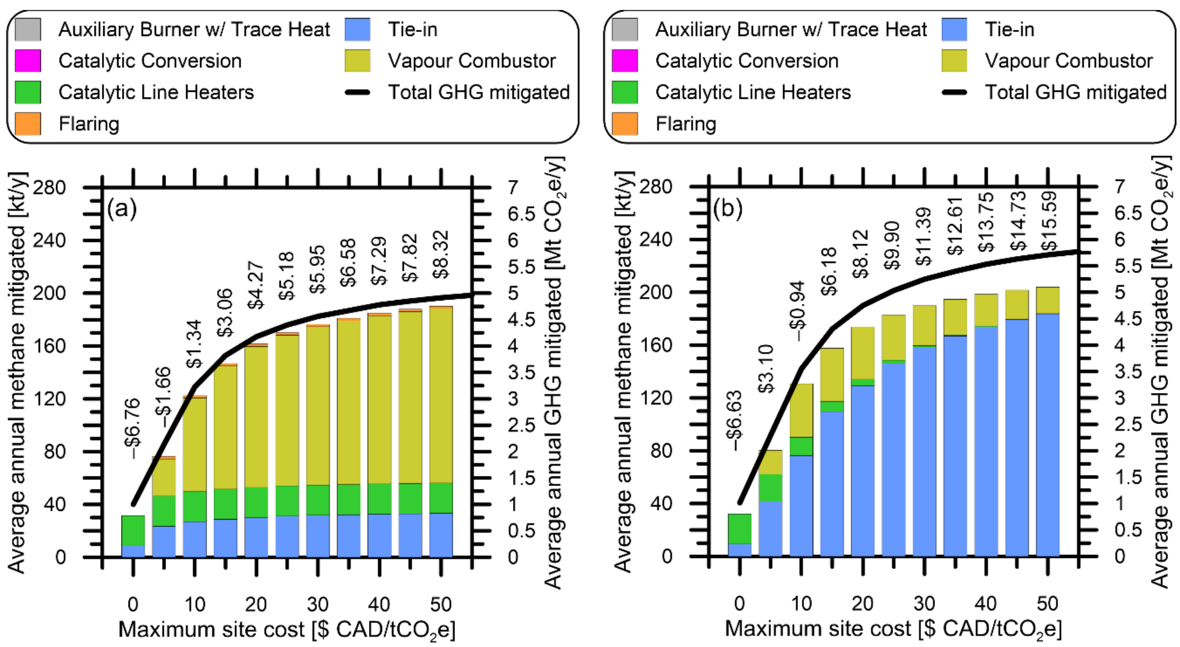

Figure S27: Techno-economic analysis results excluding catalytic conversion of methane as a mitigation option (a) Annual methane mitigated using the least costly technology (excluding catalytic conversion) at each oil site up to a maximum site cost ranging from \$0 CAD/tCO_2e to \$50 CAD/tCO_2e (b) Methane mitigated (excluding catalytic conversion) under a hypothetical tie-in clause whereby sites must tie-in to a pipeline if the associated cost is less than the specified maximum site cost. Aggregate average mitigation costs for sites represented in each bar is written on the graph. Data are for 9422 oil-sites in Alberta that reported flaring and venting in 2015 and are calculated assuming a 10-year project duration

S12.4 Techno-Economic Results Considering Recent Measurement Studies with Site Count and Capital Cost

As discussed in the manuscript and detailed in Section S6.1, recent measurement studies suggest that reported venting volumes at heavy oil/CHOPS sites in Alberta are likely underreported. The results of the techno-economic analysis including the potential for higher than reported vented emissions at heavy oil sites are presented in Figure 6 of the manuscript. Figure S28 provides additional capital cost, site count, and average cost data for this scenario. Site counts and average cost data specific to methane reductions achieved by flaring or incineration are shown in red. Relative to the reference case (See Figure S25), the larger vented gas volumes at heavy oil sites increases the number of profitable sites from 355 to 989 and significantly reduces the average mitigation costs on a cost per tonne basis.

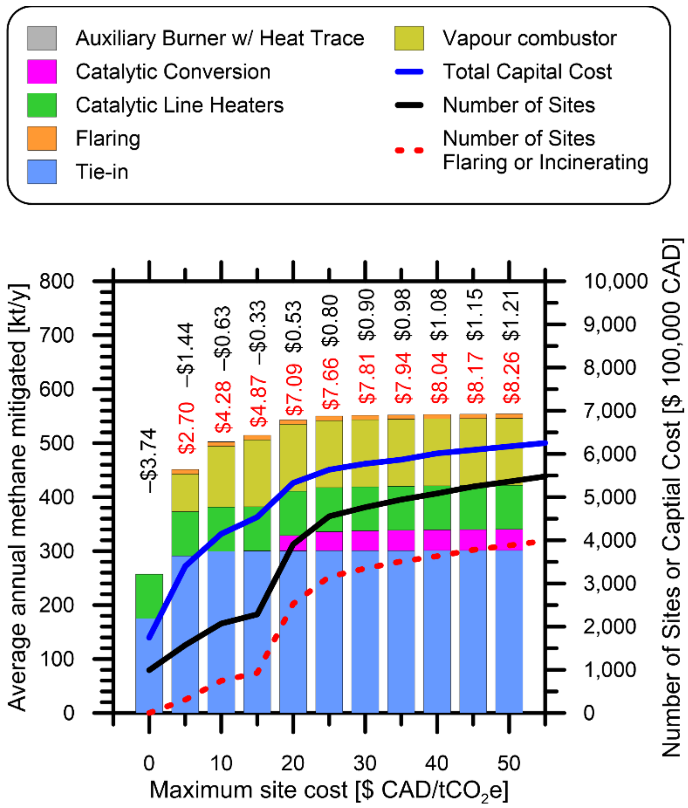

Figure S28: Techno-economic analysis considering the likely much higher actual reportable vented volumes based on recent measurement studies. Aggregate average mitigation costs for all sites and for sites flaring or incinerating in each bar is written in black and red respectively on the graph. Data are for 9422 oil-sites in Alberta that reported flaring and venting in 2015 and are calculated assuming a 10-year project duration.

Adjusting for the potentially larger volume of vented methane at heavy oils sites increases the estimated baseline methane emissions from reported flaring and venting at oil production sites to 746 kt/y. The overall upstream methane inventory for Alberta would correspondingly rise to 1525.7 kt/y (See Figure S4). Relative to this new baseline, Figure S29(a) suggests a 45% reduction in methane emissions from reported flaring and venting at upstream oil sites is possible by considering 1124 of the most economic sites where no site would pay more than $1.21 CAD/t$CO_2$e. This would require an initial capital investment of $238 million CAD (Figure S28).

On average, over a 10-year project duration, these sites could be expected to profit \$2.77 CAD/tCO_2e (Figure S29b) from revenues generated by offsetting propane through the implementation of catalytic liner heaters or conserving natural gas into a pipeline. The overall estimated methane reduction in Alberta's upstream inventory is provided by the red dashed lines in Figure S29. By considering 2831 of the most economic sites, a 34% reduction in the provincial upstream methane inventory is achievable for a near zero average net cost with no site paying more than \$16.90 CAD/tCO_2e. The initial capital investment to achieve this outcome would be \$484 million CAD (Figure S28)

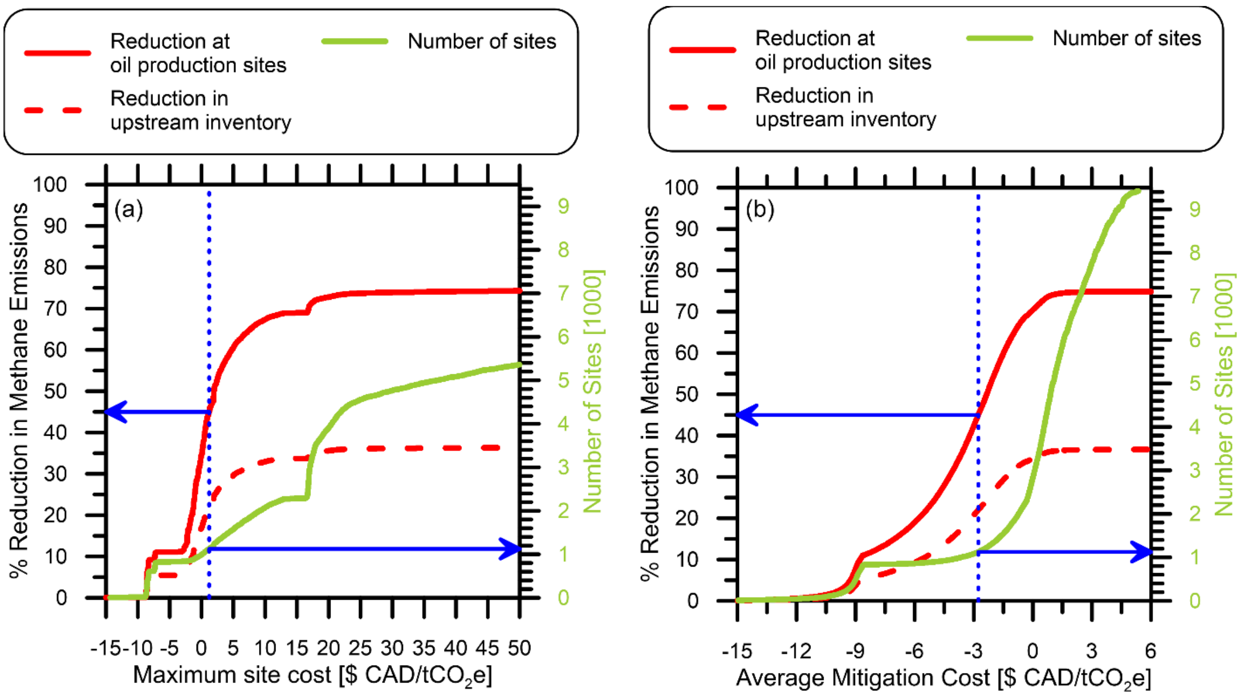

Figure S29: Techno-economic analysis considering the likely much higher actual reportable vented volumes based on recent measurement studies. Percent reductions in methane emissions achieved via mitigation of estimated reportable flaring and venting at oil sites over a range of a) maximum site costs and b) average mitigation costs. Solid red lines show achieved reductions as a percent of reportable flaring and venting volumes. Dashed red lines show achieved reductions as a percentage of all upstream inventory sources of methane (augmented in line with the estimated increase in reportable venting based on airborne measurements). Solid green lines indicate the number of sites over which the reduction is achieved

S12.5 Potential Increases in Flared and Incinerated Gas Volumes

The presented techno-economic analysis, both in the reference case and in the scenario considering augmented levels of reported venting consistent with recent airborne measurements[2], suggests that for most sites the least costly methane mitigation option will involve flaring or incineration. For the scenario with higher levels of reportable venting based on airborne measurements (Figure 6 of the manuscript), results suggest an overall 8% increase in total flaring and incineration at oil sites could be expected. Critically however, this result assumes that operators will seek site-wide solutions to mitigating methane and will always choose to tie-in existing flare systems when possible. Alternatively, faced with regulations focussed on methane mitigation rather overall GHG reduction, industry may choose to prioritize mitigating vented methane while leaving existing flaring systems in place. This scenario would be even more likely when there are additional costs to tie-in existing flare systems.

Figure S30 plots results for a scenario where operators choose to leave existing flaring systems in place while focussing on mitigating the augmented methane volumes consistent with airborne measurements. Results are visually very similar to Figure 6 of the manuscript (where operators are assumed to always include flared gas when tying into a pipeline), but there are important differences. The overall GHG reductions in Figure S30 are slightly lower absent the relatively small reductions from reducing CO_2 from existing flares. Also, the average mitigation costs (written above each bar) are slightly reduced if current flare systems are left in place. Most importantly however, as indicated by the red curve reported on the right axis, there is a potential overall net increase in flaring/incineration of 29–68% from oil sites. As noted in the manuscript, this could potentially exceed the AER's regulated solution gas flaring limit[5] of 670 million m^3.

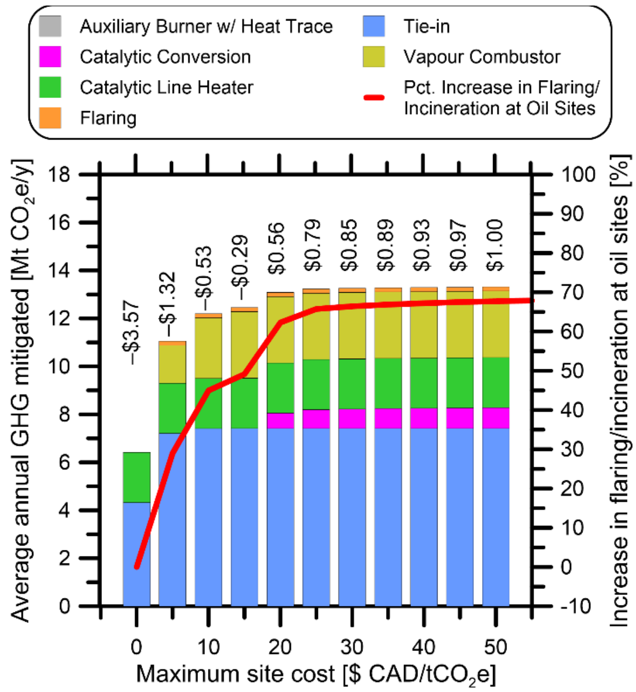

Figure S30: Techno-economic analysis considering the likely much higher actual reportable vented volumes based on recent measurement studies and where industry chooses to leave existing flaring systems in place while focusing on methane mitigation. Colored bars show annual methane mitigation for a specified maximum site cost over an assumed 10-year project duration. Aggregate average mitigation costs for the sites represented in each bar are written on the graph.

S13 Monte Carlo Analysis

The influence of key assumptions, economic parameters, and models used in the techno-economic analysis were evaluated in a Monte Carlo sensitivity analysis. The analysis considered the effects of potential variability in inflation, discount rate, gas production decline rate, gas and propane pricing, and equipment capital costs. Plotted results show the sensitivity of estimated methane mitigation potential at a profit (Figure S32) and at a maximum site cost of \$30 CAD/tCO_2e (Figure S33). Additional simulation results show the average mitigation cost to obtain a 45% cut in reported methane emissions at oil sites when considering different project durations (Figure S34).

S13.1 Monte Carlo Input Parameters

Table S6 summarizes the modeled variability in the techno-economic input parameters used in the Monte Carlo analysis. Potential variability in inflation rate and discount rate were modeled using log normal and normal distributions respectively, with mode and mean values specified to match the reference case. Variability in equipment capital costs were modeled using cost multipliers specified by a triangular distribution with a mode set to 1 and equal weight on either side of the peak. The bounds of each distribution permitted capital costs to be varied low by as much as 33% and high by up to 50% to allow for cost overruns relative to the reference case. For parameters related to pipeline tie-in, the lower bound of this range encompasses the lower cost level achievable using plastic pipe, see Section S4.1, but is conservative relative to the potential lower compressor costs available in Section S4.2. The variability in gas production decline at light and heavy oil sites is modeled by normally varying the exponential median decline rates obtained in Section S5 over a range corresponding to the 95% confidence intervals shown in Figure S11 (a) and (b) respectively.

Table S6: Key parameters and associated distribution characteristics considered in the Monte Carlo sensitivity analysis

Varied parameters and relevant cost/price multipliers	Distributions used to model parameter variability
Inflation Rate [%/year]	Log Normal: Mode = 1.3; Median = 1.47
Discount Rate [%/year]	Gaussian: Mean = 5.7; Standard Deviation = 0.5
Gas production decline	$\exp(-d(i-2017))$ where $i \in \{2017, \ldots, 2026\}$ and $d \sim \begin{cases} \text{Gaussian: mean } 0.0054;\ \text{Std. Dev.} = 0.012, & \text{heavy oil} \\ \text{Gaussian: mean } -0.055;\ \text{Std. Dev.} = 0.0035, & \text{otherwise} \end{cases}$ See Figure S11 (a) and (b)
Gas/Propane price [-]	$1 + \left(\frac{X_j - 1}{2026 - 2017}\right)(i - 2017)$, where $j \in \{\text{Gas, Propane}\}, i \in \{2017, \ldots, 2026\}$, and $X_j \sim N(1, (0.125)^2)$ See Figure S31 (a) and (b)
Pipe cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5
Compressor cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5
Vapour combustor cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5
Catalytic line heater cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5
Catalytic conversion cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5
Flare cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5
Auxiliary burner w/ heat trace cost [-]	Triangular: Mode = 1; Min = 0.667, Max = 1.5

Natural Gas and Propane Price Projections

In the Monte Carlo analysis, natural gas and propane pricing were varied by "fanning" out the base prices in Table S2 using a linear cost multiplier applied to each year's price projection. The spread of gas and propane prices is govern by a normal distribution with the 2.5th and 97.5th percentile of each commodity price shown in Figure S31(a) and Figure S31(b).

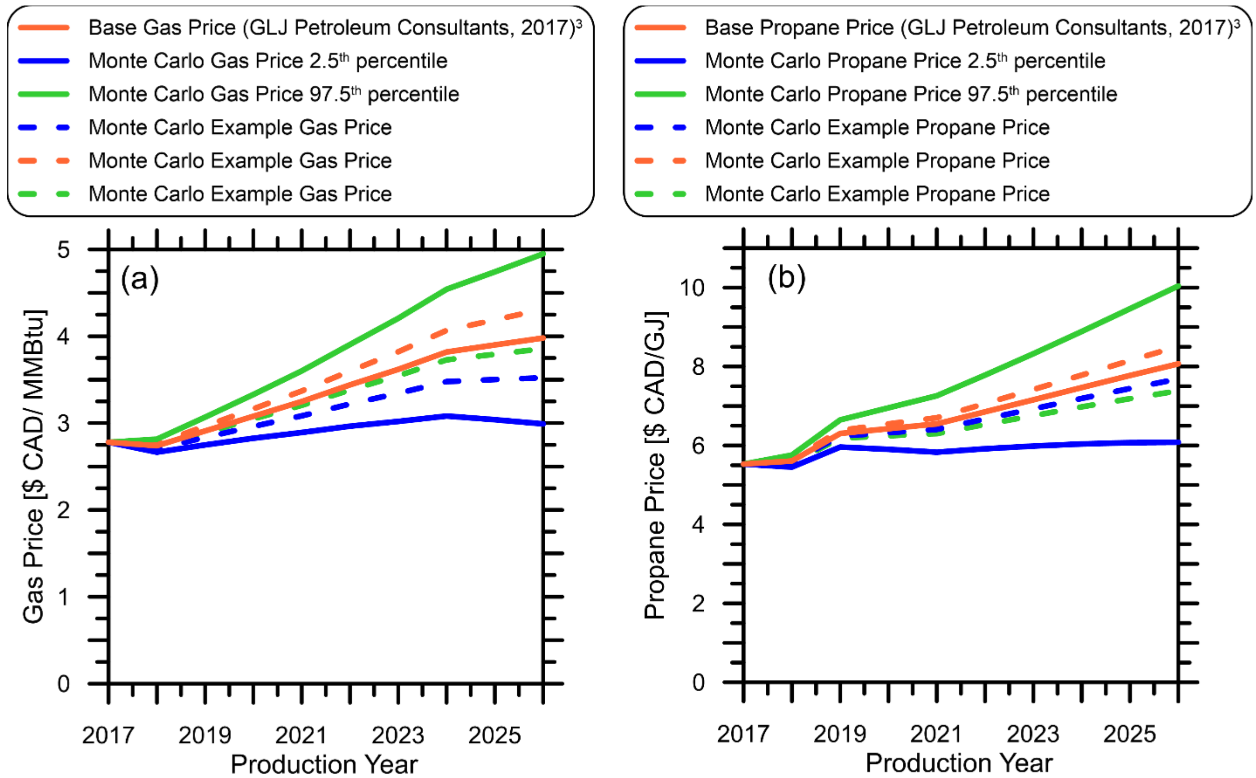

Figure S31: (a) Base natural gas pricing (solid orange) with example pricing variations used in a Monte Carlo simulation (b) Base propane pricing (solid orange) converted to \$ CAD/GJ (assuming 1 bbl = 0.1587 m^3 of liquid propane with a density of 504 kg/m^3 at 15 degrees C and a heating value of 50.3 MJ/kg) with example pricing variations used in a Monte Carlo simulation.

S13.2 Monte Carlo Analysis Results

The influence of varying input parameters, detailed in Table S1 and Table S2, on the expected average annual methane mitigated from the reference scenario in Figure 5(a) of the manuscript was studied using Monte Carlo simulations. In particular, four simulations separately varying (i) discount and inflation, (ii) gas production decline, gas pricing, and propane pricing, (iii) technology capital cost multipliers, and (iv) all parameters simultaneously, were considered to assess the sensitivity of the average annual methane mitigated for maximum mitigation costs of \$0 CAD/tCO_2e and \$30 CAD/tCO_2e. In each simulation, 10,000 runs were performed in which a new randomly chosen parameter value was drawn independently for each varied parameter in accordance with the prescribed distributions in Table S6..

Sensitivity of Estimated Profitable Mitigation Potential

Figure S32(a)-(d) shows histograms representing the sensitivity of the expected profitable average annual methane mitigation (i.e. the calculated amount of methane that could be mitigated with a maximum site cost of \$0 CAD/tCO_2e). The vertical dashed line shows the reference case result of 31.5 kt/y of profitable mitigation at an average site cost of –\$6.76 CAD/tCO_2e and maximum site cost of \$0 CAD/tCO_2e. Discount and inflation rate have a negligible influence on the estimated profitable mitigation as shown in Figure S32(a). Natural gas a propane pricing and gas decline rates have a modest and symmetric influence on the profitable mitigation (Figure S32(b)), suggesting both higher and lower amounts are possible at decreasing probability without affecting the central result. The impact of varying the capital cost of each mitigation technology in Figure S32(c) is primarily driven by the compressor cost. As discussed in the manuscript, 85% of profitable sites in the reference scenario are heavy oil sites located in a region between Lloydminster and the Cold Lake area (Figure S24). These sites implemented catalytic line heaters to mitigate vented methane by allowing casing gas to be used as onsite fuel. The economics are driven by a small revenue from offsetting propane use, where the capital cost of a line heater was relatively low compared to other technologies. Thus, the number of sites and the average annual methane mitigation at these sites was mostly unaffected by capital cost overruns. However, the number of profitable sites that tie-in is expected to vary from 14 to 161 with corresponding average annual methane mitigation range of 26 kt/y to 42 kt/y of methane with 95% confidence. Allowing all parameters to vary in Figure S32(d) only slightly increased the 95% confidence interval, of the expected annual methane mitigation to 23 kt/y to 45 kt/y of methane.

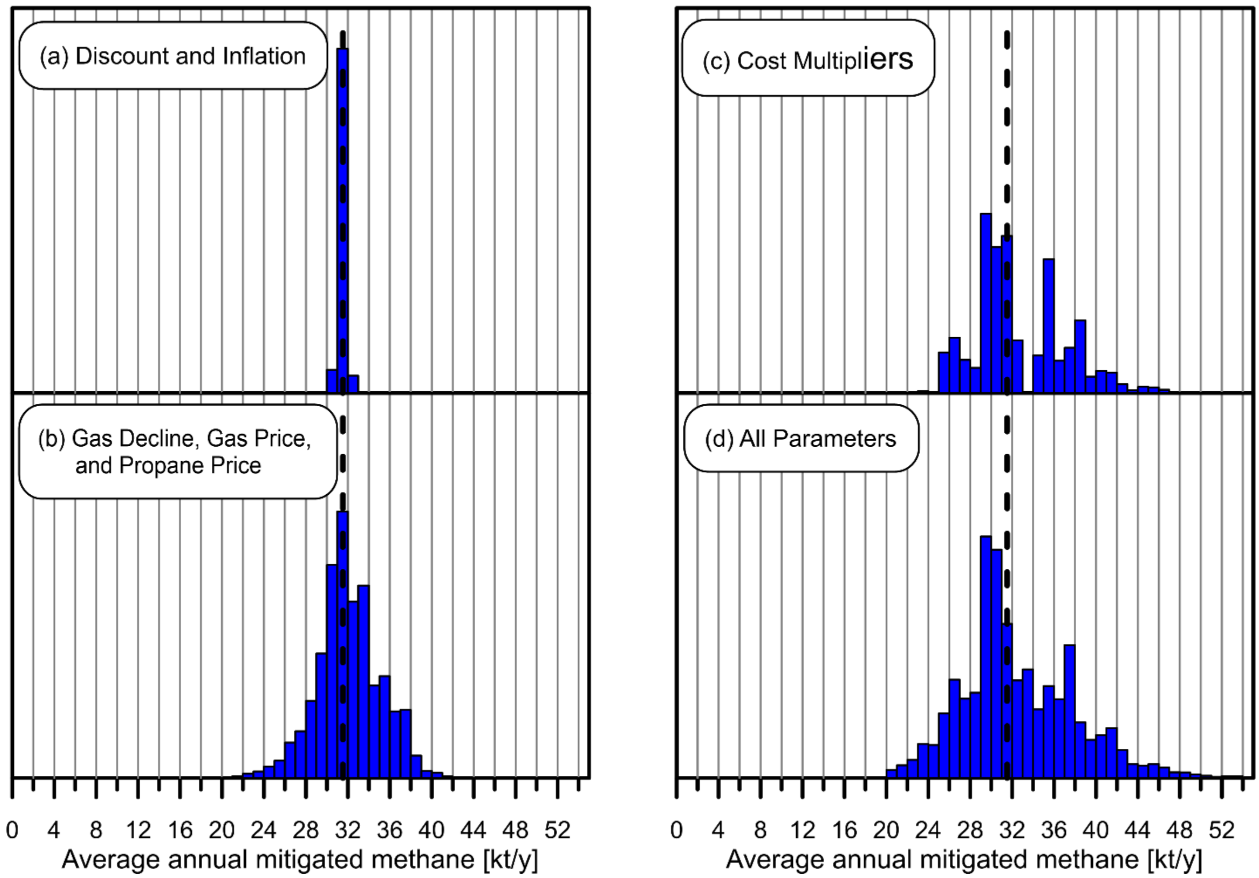

Figure S32: The sensitivity of average annual methane mitigation to (a) discount and inflation rate, (b) gas production decline, gas price, and propane price, (c) capital cost multipliers, and (d) all input parameters for a maximum site cost of $0 CAD/tCO$_2$e. The dashed line at 31.5kt/y represents the average annual profitable methane mitigation in the reference scenario.

Sensitivity of Economic Mitigation Potential at a Maximum Cost of $30 CAD/tCO$_2$e

Figure 5(a) of the manuscript estimates the overall annual average methane mitigation potential from reported venting at oil sites for a range of specified maximum site costs (i.e. maximum cost per tonne of CO$_2$e to be incurred at any one site). In the reference case, for a maximum site mitigation cost of $30 CAD/tCO$_2$e, it is estimated that an average annual methane mitigation of 173 kt/y is readily achievable an average cost of $5.78 CAD/tCO$_2$e. This corresponds to an overall GHG reduction of 4.5 MtCO$_2$e/y, including small contribution from mitigating CO$_2$ from any flares tied into pipelines).

Figure S32 shows the Monte Carlo derived confidence limits in this estimated mitigation potential at a maximum site cost of $30 CAD/tCO$_2$e. Distributions about the central estimate are generally

Gaussian in shape, with narrow width. Discount and inflation rate Figure S32(a) again have negligible influence on the result. Gas pricing and decline rate Figure S32(b) have the strongest influence and are centered at slightly higher mitigation levels the reference case. This supports the suggestion that the reference case results are conservative, perhaps related to current historically low natural gas prices. Varying all parameters in the Monte Carlo analysis simultaneously (Figure S32(d)) suggest that the overall methane mitigation potential is within 159–190 $ktCH_4$/y at costs between \$3.65–7.66 CAD/tCO_2e at 95% confidence. Overall, the Monte Carlo analyses suggest a 15–18% cut in provincial emissions (70–84% cut at oil sites), should be possible in essentially all scenarios.

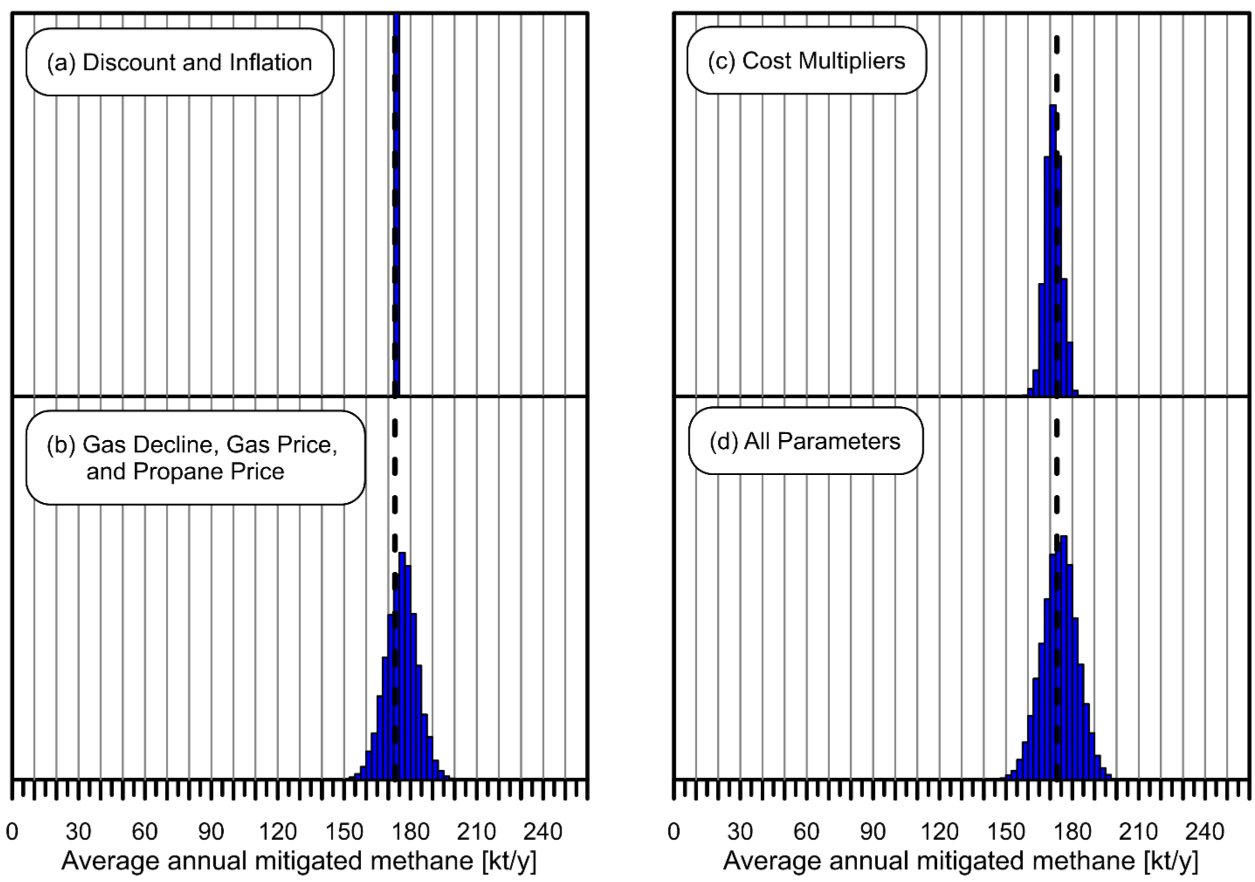

Figure S33: The sensitivity of methane mitigation to (a) discount and inflation rate, (b) gas production decline, gas price, and propane price, (c) capital cost multipliers, and (d) all input parameters for a maximum site cost of \$30 CAD/tCO_2e. The dashed line at 173kt/y represents the average annual methane mitigation at a maximum site cost of \$30 CAD/tCO_2e in the reference scenario.

Sensitivity of the Estimated Costs to Achieve 45% Reduction in Methane Emissions from Reported Venting and Flaring at Oil Sites Considering Different Project Durations

In the reference case, where the project duration was set at 10 years, a 45% reduction in reported methane emissions at oil sites was achievable at an average cost of \$0.05 CAD/tCO_2e with no site paying more than \$7.41 CAD/tCO_2e. The sensitivity of this average cost at fixed project durations of 8,10, and 12 years was examined in additional Monte Carlo simulations. All input techno-economic parameter were again varied as in Table S6 for each case. The results in Figure S34(a)–(c) suggest the average site cost to obtain a 45% cut in reported methane emissions at oil sites can be expected to range between \$–2.98 CAD/tCO_2e and \$2.51 CAD/tCO_2e at 95% confidence as project durations and all techno-economic parameters are varied. This is the range quoted in the abstract of the manuscript. Similarly, Figure S34(d)–(f) show that the maximum cost at any one site while achieving an overall methane reduction of 45% falls between \$4.42 CAD/tCO_2e and \$11.02 CAD/tCO_2e at 95% confidence as the assumed project duration is changed from 8–12 years.

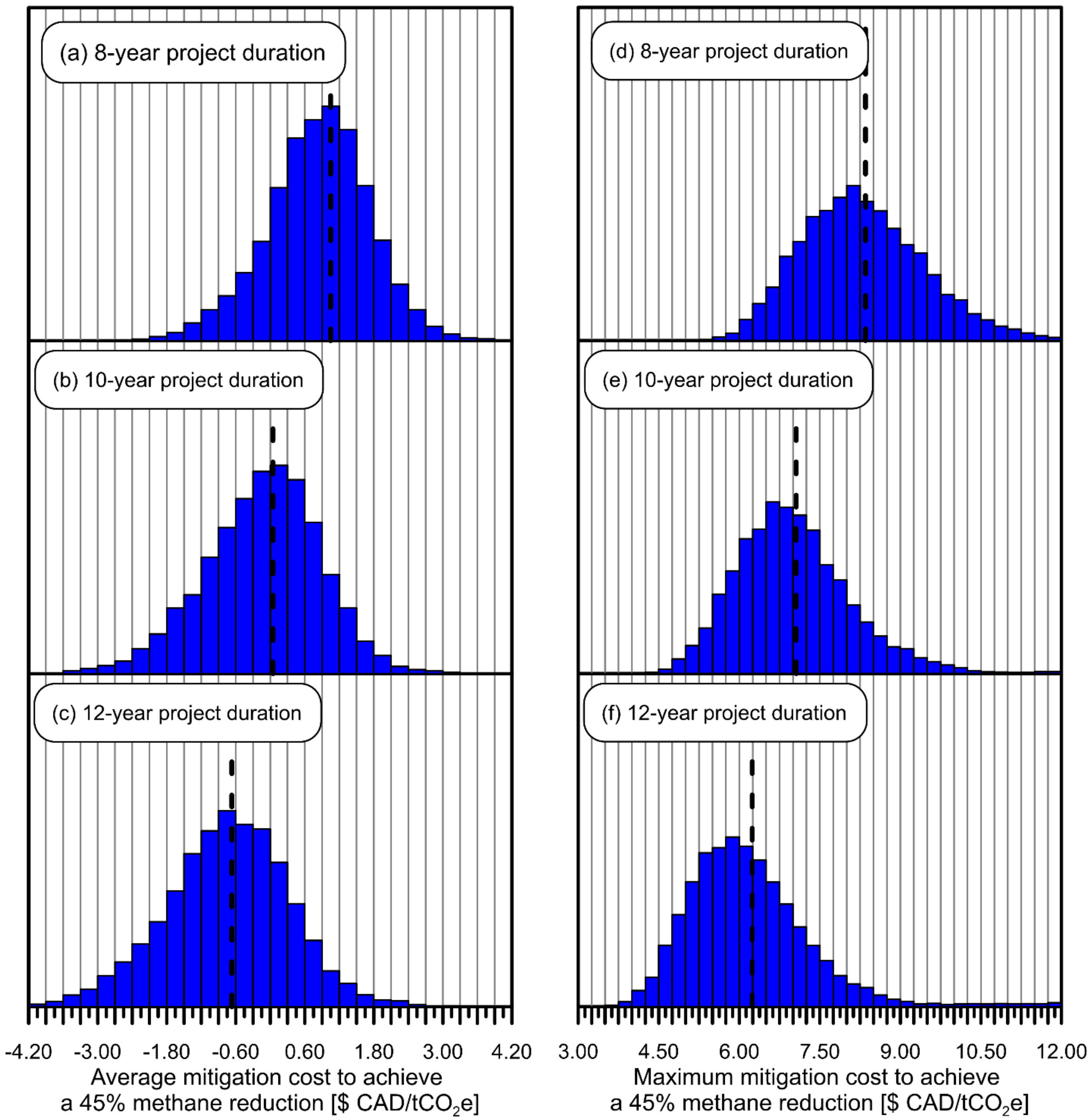

Figure S34: The sensitivity to all techno-economic parameters of the average mitigation cost (a-c) and the maximum site mitigation cost (d-f) to obtain a 45% cut in reported methane emissions at oil sites for project durations of 8, 10, and 12 years respectively. In each plot the dashed line represents the mean average mitigation cost.

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