CERIN
Canadian Emissions Reduction
Innovation Network

CANADA EMISSIONS REDUCTION INNOVATION NETWORK (CERIN) PUBLIC REPORT

1. PROJECT INFORMATION:

Project Title:	**St. Fx / UofC Methane Emission Technology Deployment**
Emissions Reduction Scope/Description:	Technology abatement pathways assessment for tank methane emissions from Alberta's oil and gas sector
Applicant (Organization):	University of Calgary
Project Completion Date:	March 31 2023

2. EXECUTIVE SUMMARY:

Canadian methane emissions reduction targets for the oil and gas sector are currently aiming for a 40%

Canadian methane emissions reduction targets for the oil and gas sector are currently aiming for a 40% to 45% reduction from 2012 levels by 2025 and furthermore, a 75% reduction by 2030. In anticipation of such increasingly stringent methane reduction targets, the oil and gas sector in Canada is evaluating methane emissions mitigation pathways from the major emission sources at operating facilities, including production tank methane vents which are estimated to account for 19% of total onsite emissions. While tank methane emissions represent a considerable contribution to the total methane emissions, there remains a knowledge gap on the current opportunities and barriers to methane reduction from production tanks. The Tank Methane Mitigation Technology Deployment Study aims to address this knowledge gap by evaluating tank methane emissions and available tank methane abatement technologies through an economic and emissions reduction model.

This study determines the levelized costs of methane abatement technologies based on 2022 Alberta oil and gas production site performance and operations. Facility and technology data was acquired from the public domain to explore the availability and quality of data within these categories. Within the model, various configurations of flaring/incineration, gas pipeline tie-in, and gas capture and onsite storage technologies are assessed for economic feasibility and GHG reduction potential. While the focus of the study is on tank methane emissions, the technologies described above would also apply to other methane vent sources, therefore the model evaluates the methane abatement potential of each technology based on methane emissions across *all* onsite emission sources. Designing the model in this manner would reflect realistic technology applications as operators would likely maximize methane emissions capture where possible.

The results of the economic and emissions reduction assessment model suggest approximately 0.1 $MtCO_2e$ per year can be reduced at no-net cost, with an average negative cost (i.e., a positive revenue resulting from methane gas capture and sale) of $1.2 CAD/$tCO_2e$ without carbon pricing programs. At a carbon price of $50 CAD/$tCO_2e$ set for 2022 in Alberta, upwards of 3.2 $MtCO_2e$ per year can be achieved at no-net cost. The methane emissions reductions shown on the methane abatement cost curve (see Figure 3 of the report) represent methane emission reductions from approximately 8400 facilities across Alberta with reported venting in 2022, totalling to approximately 3.5 Mt CO_2e per year of methane emissions reduction through all modelled applications of casing gas flares, casing gas tie-ins, and grid- or generator-powered VRU with vapour combustors. A sensitivity analysis identified methane vent volumes, methane GWP factors, and methane concentrations in produced gas would have the largest influence on levelized costs.

Due to the limited quality and availability of input data for the model, the results determined in this study are high-level estimates of methane abatement costs associated with tank methane technologies. There remain knowledge gaps within the Canadian oil and gas methane mitigation space which prevent detailed discussions on tank methane emission reduction. Gaps such as operational practices, facility design limitations of production tanks, and detailed economic parameters associated with respective methane technologies are identified as the major factors that can substantially affect the modelled levelized costs and technology deployment potential.

3. KEY WORDS

Methane abatement, upstream oil and gas, technology deployment, emissions reduction, greenhouse gas

4. APPLICANT INFORMATION:

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6. PROJECT PARTNERS

N/A

A. INTRODUCTION

Methane is an increasingly prevalent area of interest in the discussion of greenhouse gas (GHG) emissions reduction in the Canadian oil and gas landscape. With current methane reduction targets aimed for a 40% to 45% reduction from 2012 levels by 2025 in Canada and discussions underway to increase targets to a 75% reduction by 2030, the oil and gas industry is incentivized to further explore and evaluate methane mitigation technologies for addressing the primary emission sources [1]. Pneumatic devices (38%) and tank (19%) methane emissions were the largest emission sources from Alberta's oil and gas facilities in 2018, representing methane emissions in the order of 7.3 and 3.2 $MtCO_2e$, respectively [2]. While pneumatic device vents have been investigated through industry and government-driven research, tank methane mitigation pathways have yet to be explored with the same rigor.

Tank methane emissions can be addressed through a variety of technologies, including, but not limited to, vapour recovery units, tie-ins to natural gas pipelines, and onsite gas destruction such as incineration or flaring [3]. The applicability of each type of equipment can vary depending on production conditions, operational parameters, and existing facility infrastructure and equipment. This report explores tank methane reduction technologies for Alberta's oil and gas facilities using publicly available economic and operational data. The resulting methane abatement cost curve provides operators and stakeholders with insight into the economic viability of mitigation technologies given Alberta's current methane emissions inventory. A sensitivity analysis is included in this report to investigate the effects of differing facility (i.e., methane vent rate, global warming potential, gas compositions) and technology parameters on economic and emissions reduction performance.

The scope of work of this project was originally designed to explore pathways and barriers of mitigating methane vent and fugitive emissions from production tanks in 2019. As the project progressed, the scope was narrowed to explore specifically pathways of tank methane vent abatement and identifying knowledge gaps in tank methane mitigation. This change was primarily driven by the limited data availability in the public domain to complete a detailed analysis of fugitive emissions and operator-specific barriers. The current knowledge gaps that exist in the tank methane mitigation space are discussed in detail in this report.

B. METHODOLOGY

Alberta emissions inventory

To evaluate the potential deployment of tank methane mitigation technologies in the province, an inventory of the current methane vent volumes and existing equipment counts in Alberta is first established through an evaluation of public facility records from Petrinex and datasets from the Alberta Energy Regulator (AER) [4], [5]. Total facility vent emissions and associated facilities details used for this project are obtained through these data sources for 2022. AER facility subtypes that are included in this analysis with supplemental information on facility counts and reported venting volumes for 2022 are described in Table 1 and Table 2. Furthermore, only operating facilities within the selected subtypes are included in this study.

One of the challenges of modelling the application of methane abatement technologies is determining which facilities have methane conservation or destruction equipment already installed. Within this study, the assumption of which facilities have flares or tie-in infrastructure was based on Petrinex datasets [4]. Facilities are assumed to have existing gas tie-in infrastructure if gas disposition activities are recorded in Petrinex. Similarly, facilities are assumed to have existing flares if flaring activities are recorded. The block flow diagrams shown on Figure 1 provide a simplified depiction of the four types of facility configurations assessed in this study: a) facilities that have existing capture and destroy gas through flare equipment, b) facilities that have existing gas capture and conserve (i.e., tie-in) equipment, c) facilities that have both existing tie-in and flare equipment, and d) facilities that vent all methane emissions to the atmosphere.

While vent mitigation activities such as flares or tie-ins can be established from public records, there is greater difficulty in determining site-specific tank emissions due to variability in facility design, production trends, and operating practices. Directive 015 from the Alberta Energy Regulator provides guidance for determining storage tank emissions, however, there is insufficient data in the public domain to complete site-specific calculations, which would require tank and inlet stream temperature and pressure data [6]. Alternatively, Clearstone Engineering's study determined average tank equipment counts and associated emission factors for select facility subtypes in Alberta, however, the emission factors do not differentiate between facilities with existing mitigation technologies and those without (e.g., flare vs. no flare) [7]. Furthermore, the number of tanks at each facility can vary depending on production volumes and operational practices which are difficult to capture within the parameters discussed by Clearstone Engineering.

Table 1: 2022 operating facility counts of each existing mitigation equipment associated with facility subtypes evaluated in this study. Facility details are obtained from Petrinex [4].

	Crude oil facilities			Gas facilities					Total
Facility Subtype Code	311	321	322	351	361	362	363	364	
Facility Subtype Name	Single-Well Battery	Multiwell Battery	Multiwell Proration Battery	Single-Well Battery	Multiwell Battery	Multiwell Effluent Battery	Multiwell Proration Battery (various regions)		
No disposition, no flare	1625	98	143	29	9	2	0	0	1906
Disposition, no flare	1970	193	791	3434	1804	238	263	419	9112
No disposition, flare	366	46	292	6	3	1	0	0	714
Disposition and flare	119	33	612	137	189	117	3	20	1230

Table 2: Averaged monthly 2022 operating facility configurations vent volumes (e^3m^3 gas/month) associated with the facility subtypes evaluated in this study. Facility details are obtained from Petrinex [4].

	Crude oil facilities			Gas facilities					Total (e^3m^3 gas/month)
Facility Subtype Code	311	321	322	351	361	362	363	364	
Facility Subtype Name	Single-Well Battery	Multiwell Battery	Multiwell Proration Battery	Single-Well Battery	Multiwell Battery	Multiwell Effluent Battery	Multiwell Proration Battery (various regions)		
No disposition, no flare	2374.9	203.5	370.6	3.8	43.9	0.7	0	0	2997.4
Disposition, no flare	1176.7	267.5	1542.8	1858.9	6644.0	1040.0	104.2	751.5	13385.6
No disposition, flare	334.2	42.8	430.2	1.5	14.4	2.9	0	0	826
Disposition and flare	129.5	55.8	2000.6	131.2	2208.8	2355.7	8.9	71.0	6961.5

a) 714 facilities with flaring only

c) 1230 facilities with tie-in and flare

b) 9112 facilities with tie-in only

d) 1906 facilities without tie-in or flare

Figure 1: Block flow diagrams of facility configurations and total configuration counts in AB in 2022

Methane mitigation technologies

Within this study, the economic and emissions reduction feasibility assessment of tank methane emissions reduction technologies is based on resources and literature available within the public domain. A summary of the independent technologies and equipment scoped for this work are discussed in Table 3 and Table 4. Economic data for the technologies primarily reference Canadian studies and are supplemented by US data where needed. Historical capital, installation, and operating costs are converted to 2022 Canadian dollars from reference currencies to represent current cost estimates. The model assessed facilities-specific cases of methane emissions reduction through the adoption of methane mitigation systems consisting of various combinations of independent technologies (listed in Table 3) and auxiliary equipment (listed in Table 4). This method of evaluation is designed to represent realistic greenfield or retrofit projects which would utilize different technologies for each stage of the onsite methane abatement (i.e., capture, destruction or conservation, energy supply). For clarity, Table 5 provides a summary of the methane mitigation systems which utilize independent methane abatement technologies. Further details on the systems assessed in this study are discussed in Section 0.

Methane mitigation technology deployment assessment

Tank methane emissions technologies are assessed within an economic and emissions reduction feasibility model to evaluate the methane mitigation potential and associated abatement costs for oil and gas facilities in Alberta. Facility details acquired from the Alberta Energy Regulator (AER) and Petrinex include facility tie-in and flaring infrastructure, facility surface locations, natural gas pipeline proximities and maximum allowable operating pressures, and facility vent, production, and flare volumes [4], [5]. Facilities and natural gas pipeline proximities are estimated using ArcGIS Pro embedded tools to identify the nearest pipeline from each site [8]. Configurations of tank methane mitigation systems evaluated in this study are comprised of one or more independent technologies are described in Table 5. Where there is demand for electricity, both cases electricity grid tie-in and onsite generators are evaluated and the lower cost option is selected. Due to data limitations, a fixed distance of 10km for accessing the electricity grid (to estimate the grid tie-in cost) is assumed for all facilities. The grid tie-in distance was an educated assumption based on the spatial distribution of high voltage electricity grid and wellsite locations in AB [9]. The application of the described methane mitigation systems is based on existing facility equipment, facility vent volumes, and technology throughput limitations (described in Table 3).

Python is a programming language which can be utilized to perform efficient calculations and aid in large-scale data processing [10]. Given the scale of the dataset and the complexity of the calculations, the economic and emissions reduction assessment model within this study is designed and run on Python. Within the model, each facility is evaluated for tank methane mitigation systems where only non-existing equipment is assumed to be feasible. For example, a tied-in facility would omit methane mitigation systems involving further tie-in activities. The remaining possible mitigation systems are further narrowed respective to each facility based on the vent volumes and technology throughput maximum and minimum limits. Facilities with vent volumes exceeding the maximum throughput limits are assessed based on multiple counts of technologies where applicable, such as flares or vapour combustors. The methane mitigation systems assessed in the model are generally not applied exclusively to address production tank emissions (e.g., VRUs would capture methane from multiple onsite sources) and therefore, all vent volumes from the facility are assumed to be reduced within the model. The flowchart shown in Figure 2 provides a visual representation of the decision process incorporated in the model. Each technology's methane reduction potential is also integrated into the calculations using a methane global warming potential of 28 times larger than CO_2 based on IPCC's 5th Assessment Report [11]. For flaring and incineration processes, CO_2 emissions are estimated based on a stoichiometric ratio resulting from the complete combustion of methane.

Table 3: List of independent methane mitigation technologies with economic and performance details

Independent Tank Methane Mitigation Technologies								
		CAPEX ($CAD 2022)	**Installation ($CAD 2022)**	**OPEX ($CAD 2022)**	**Maximum Flowrate (e^3m^3/day)**	**Minimum Flowrate (e^3m^3/day)**	**Methane Reduction Potential**	**Source**
VRU **(based on throughput capacity)**	25 Mcf/d	$64,296		$0	$13,255	0.71	95%	ICF Intl. Report, EPA Gas STAR program [12], [13]
	50 Mcf/d	$82,890		$0	$15,147	1.42*	95%	
	100 Mcf/d	$99,893		$0	$18,177	2.83*	95%	
	200 Mcf/d	$133,898		$0	$21,207	5.66*	95%	
	500 Mcf/d	$187,033		$0	$30,296	14.16*	95%	

Flares	Gas-ignition flare	$112,803		$0	$10,795	2.00*	98%	SRC Report, ICF Intl. Report [12], [14]
Casing Gas	Casing Gas Flare (Large)	$83,549	$59,856	$1,247	0.90	0.05	95%	Delphi Report [3]
	Casing Gas Flare (Small)	$19,952	$73,573	$345	0.50	0.05	95%	
	Casing Gas Tie-in (Large)	$52,374	$197,025	$7,981	0.90	0	95%	
	Casing Gas Tie-in (Small)	$26,187	$24,940	$6,235	0.50	0	95%	
Vapour combustor	Enclosed vapour combustors (Large)	$74,077	$0	$0	2.83	0.0	99%	PTAC Handbook [15]
	Enclosed vapour combustors (Small)	$29,631	$0	$0	0.57	0.0	99%	
Gas Bladder	Gas bladder	$1,182	$0	$0	0.90	0.0	99%	SRC Report [14]
Onsite Gas Storage	Onsite gas storage trailer (Large)	$167,915	$0	$0	4.00	0.0	99%	
	Onsite gas storage trailer (Small)	$131,934	$0	$0	4.00	0.0	99%	

Table 4: List of auxiliary equipment with economic details

Auxiliary Equipment		**CAPEX**	**Units**	**Installation**	**Units**	**OPEX**	**Units**	**Source**
	Electric grid connection	$23,650	$CAD 2022	$11,825	$CAD 2022/km	$0	$CAD 2022/km	Delphi Report [3]
	Generator	$40,000	$CAD 2022	$0	$CAD 2022	$0	$CAD 2022	
	Gas Pipeline *(for all tie-in options, except for casing gas)*	$103	$CAD 2022/m	$0	$CAD 2022/m	$10	$CAD 2022/m	Tyner and Johnson, 2018 [16]
	Compressor *(for all tie-in options, except for casing gas)*	$\$224{,}802 + \text{Emission Rate } x \ \frac{\ln(P_{MOP})}{\ln(PR_{stages})} \ x \ \$18{,}885$ $PR_{stages} = \mathit{Stage\ Pressure\ Ratio} = 1.5$ $P_{MOP} = \mathit{Nearest\ tie\ in\ maximum\ operating\ pressure\ (kPa)}$ $P_{atm} = \mathit{Atmospheric\ pressure\ (kPa)}$				10% of CAPEX	$CAD 2022	

Table 5: Tank methane mitigation systems comprising of independent methane mitigation technologies (Table 3) and auxiliary equipment (Table 4)

Flaring Configurations	VRU with Flare and Grid Electricity	VRU sizing and number of flare units based on vent rate
	VRU with Flare and Generator Electricity	VRU sizing and number of flare units based on vent rate
	Casing Gas Flare	Fixed costs due to limited data
Gas Tie-in Configurations	VRU with Tie-in and Grid Electricity	VRU sizing based on vent rate, pipeline distance based on determined tie-in proximity
	VRU with Tie-in and Generator Electricity	VRU sizing based on vent rate, pipeline distance based on determined tie-in proximity
	Casing Gas Tie-in	Fixed costs due to limited data
Vapour Combustion Configurations	VRU with Vap. Combustors and Grid Electricity	VRU sizing and number of combustor units based on vent rate
	VRU with Vap. Combustors and Generator Electricity	VRU sizing and number of combustor units based on vent rate
Gas Capture and Storage	Gas bladder with onsite gas storage via truck trailer	Gas bladder count and truck transport based on vent rate

The net present costs of each technology application are assessed based on a 10-year lifetime and a 10% discount rate. Revenue from gas sales for methane conservation technologies such as tie-in and onsite gas storage is estimated to be $3.90 CAD in 2022 based on the AECO-C gas price benchmark for Western Canada [17]. Carbon pricing is not incorporated in the model calculations to provide an opportunity to evaluate technologies in other jurisdictions with varying or no carbon credit programs. The resulting GHG reduction (tCO_2e) achieved for each technology is determined based on the degree of methane reduction and any GHG emissions occurring as a result. From determining the net present costs and the associated GHG reductions, the levelized cost of methane abatement of potential methane mitigation pathways respective to each facility is determined using the equation provided below. Levelized costs are used in this study to compare various technologies as these costs represent the average net present costs of an assessed system or product over its lifetime [18]. Given the range of technology costs and the methane abatement potentially achieved via each technology, levelized costs provide a normalized economic measure to fairly compare between methane mitigation systems assessed in this study.

$$Levelized\ Cost\ of\ Methane\ Abatement = \frac{NPV_{Technology}}{NPV_{MethaneAbated}} = \frac{\sum_{t=0}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{A_t}{(1+r)^t}}$$

$I_t = Investment\ expenditures\ in\ year\ t\ (\$CAD)$
$M_t = Operations\ and\ maintenance\ expenditures\ in\ year\ t\ (\$CAD)$
$F_t = Fuel\ expenditures\ in\ year\ t\ (\$CAD)$
$A_t = Methane\ abatement\ in\ year\ t\ (tCO_2e)$

Key model assumptions

- Various model assumptions are embedded within the model. A summary of the key assumptions is provided below:
- Methane mitigation systems can address methane emissions from multiple sources (i.e., compressors, pneumatics, glycol dehydrators) and therefore the economic and emissions reduction calculations are based on vent volumes associated with all emission sources at each facility rather than only tank sources.
- Tanks are assumed to have the ability to handle pressure changes resulting from the operation of vapour recovery units.
- Existing onsite flares are assumed to destroy gas to the maximum allowable volume defined by the AER even if additional flaring can theoretically occur based on venting volumes at the facility [19].
- Natural gas tie-in costs are based on direct facility-to-pipeline distances calculated from ArcGIS Pro and additional distance required to accommodate intersecting pipelines or other existing infrastructure is not considered.
- Equipment requiring pilot gas is assumed to utilize fuel gas (i.e., onsite casing gas) and no additional propane supply and equipment is considered.
- Electricity grid tie-in distances are assumed to be approximately 10 km for all facilities due to data required for site-specific calculations being unavailable. This is an educated estimate based on AECO high-voltage grid mapping and AB wellsite spatial densities [5], [9].
- Gas compositions are assumed to be approximately 91.9 mol% methane [20].
- Diesel generators are assumed to have an emission factor of 1.15 $lbCO_2$/hp hour (or 0.0125 tCO2/HP day) [21].
- VRU O&M costs are assumed to include fuel costs, based on EPA's Gas Star report [13].
- Casing gas tie-in economics are acquired from reports assessing the Lloydminster region, and the tie-in costs are assumed sufficiently represent other producing regions in Alberta [22]. The costs adopted from this reference provide economic data as an aggregated value of onsite casing gas capture and tie-in equipment, therefore site-specific tie-in cost variability could not be assessed for this technology.
- Alberta electricity grid intensity is assumed to be 590 gCO_2e/kWh [23].

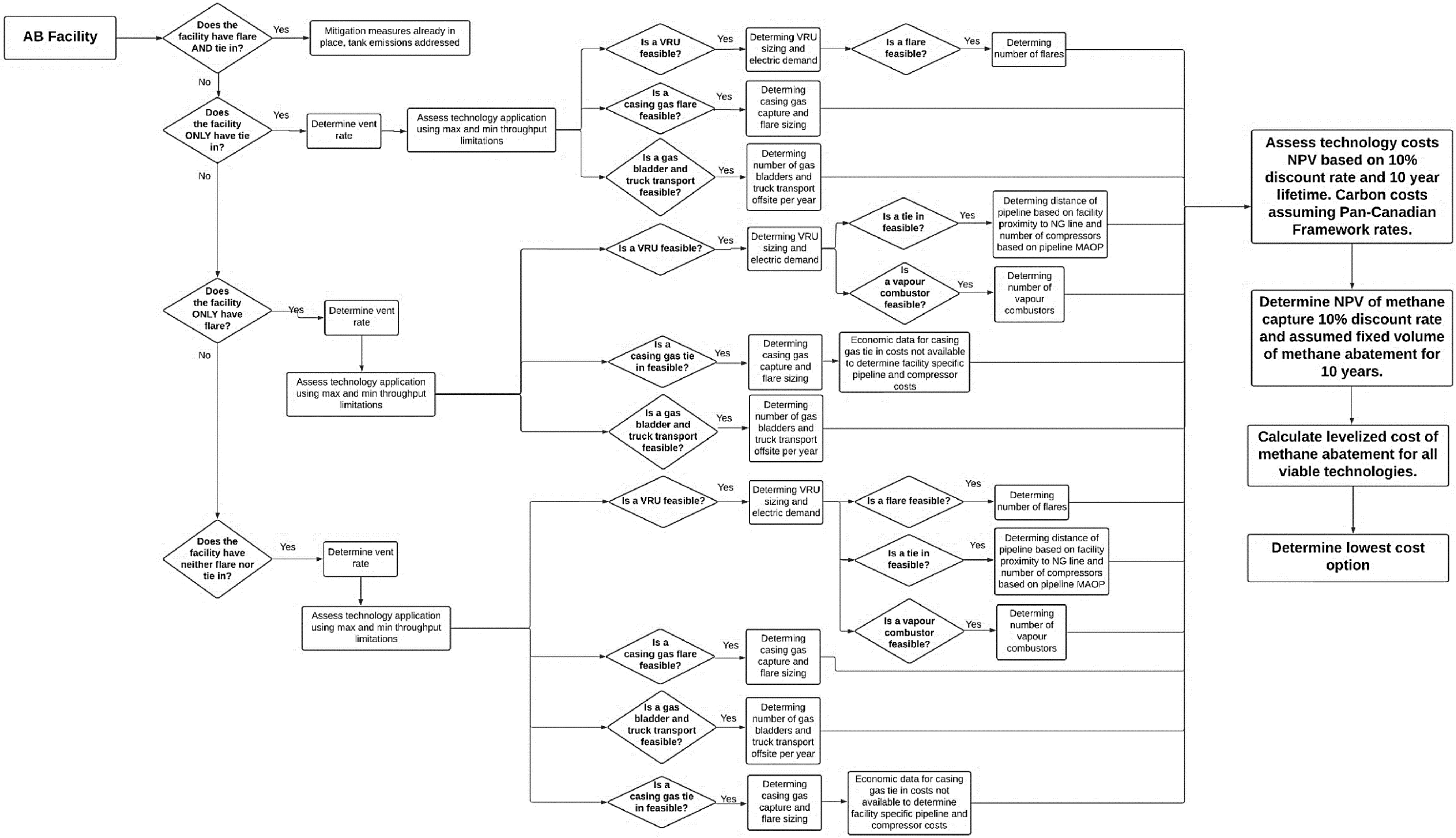


Figure 2: Decision flowchart embedded in the tank methane abatement model

C. PROJECT RESULTS AND KEY LEARNINGS

Tank methane mitigation technologies are considered for each facility based on existing infrastructure, applicability, and overall methane abatement costs. Out of the available methane mitigation systems assessed for this study (described in Table 5), the lowest cost technology options were determined to be grid-powered VRU with vapour combustion, generator-powered VRU with vapour combustion, casing gas tie-in, or casing gas flares. Figure 3 is a methane abatement cost curve generated using the estimates of methane abatement costs and annual methane reduction potentials based on 2022 Alberta operations over a lifetime of 10 years and a discount rate of 10%. Methane abatement cost curves visually describe the costs of methane reduction technologies respective to the volume of methane reduction potential of each technology. The cost curve sorts technologies from highest to lowest cost to identify the most economically feasible methane reduction opportunities in units of 2022 Canadian dollars per tonne of CO_2e worth of methane reduction ($CAD 2022/ tCO_2e). Along the x-axis of the figure, the volume of methane reduction is represented by the width of the columns in units of megatonnes of CO_2e per year ($MtCO_2e/y$). From the model, a methane abatement potential of approximately 0.1 $MtCO_2e$ per year is estimated to be achievable at negative costs (or positive revenue) for select facility applications of casing gas capture and tie-in. These specific scenarios have an average negative cost of $1.4 CAD/$tCO_2e$ resulting from vent gas capture and sales. When considering the 2022 carbon price of $50 CAD/$tCO_2e$ in Alberta, the methane reduction potential increases to approximately 3.2 $MtCO_2e$ per year through applications of casing gas flaring, casing gas tie-ins, and grid- or generator-powered VRU with vapour combustors [24]. The methane emissions reductions shown in Figure 3 represent potential technology applications addressing 80% (or 3.5 Mt CO_2e per year) of methane emissions from approximately 8400 facilities across Alberta with reported venting. The remaining 20% of methane venting remains unresolved due to existing methane mitigation infrastructure, such as tie-ins (16%) or both tie-ins and flares (4%) which have been omitted from the analysis based on the decision flowchart (see Figure 2).

While the methane abatement cost curve provides an overview of tank methane abatement via four main technology pathways, the high-level analysis incorporates assumptions and generalizations that do not capture the unique operating conditions and limitations of each facility. The economic data embedded in the calculations are based on historical data and adjusted to 2022 Canadian dollars but do not reflect cost variabilities resulting from other factors such as economies of scale, demand, supply, etc. Factors that have yet to be considered in the model include royalties, flaring limits, and a detailed analysis of fuel costs associated with VRUs which would impact the resulting levelized costs and technology applications for the facilities included in the analysis. Due to limited data availability, the results also do not capture seasonal operational changes (i.e., open thief hatches during winter) which can impact the vent volumes and, subsequently, tank methane abatement costs. Production tanks designed for minimal pressure change may not be suitable for VRU operation, however, details on the fraction of tanks within this category are not available to the public and therefore not considered in the assessment. Table 6 provides a qualitative summary of the data quality associated with various model parameters utilized in this study.

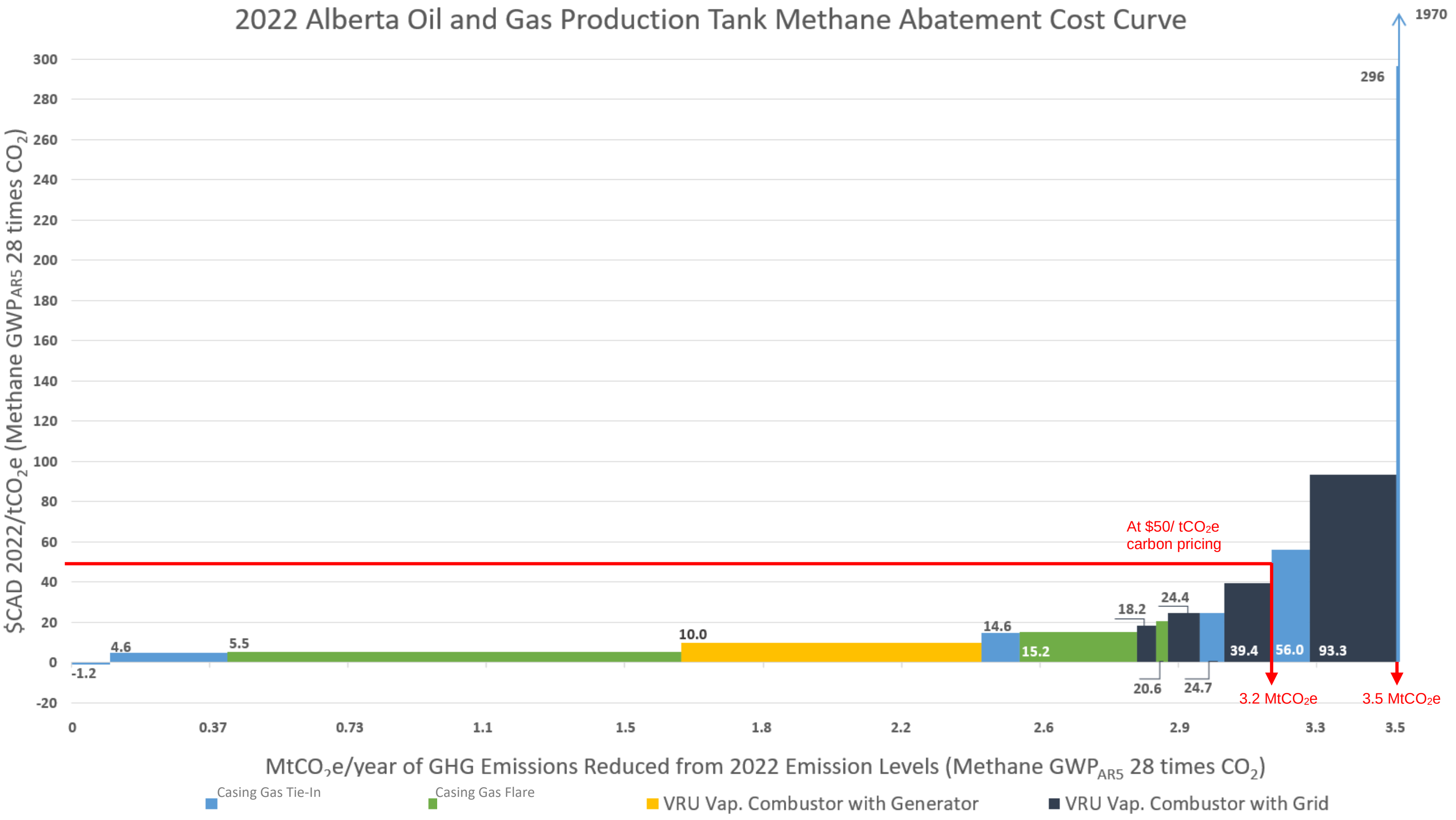


Figure 3: Alberta oil and gas production tank methane abatement cost curve based on 2022 facility data and technology economics.

Table 6: Data quality matrix evaluating model input parameters.

	RELIABILITY OF SOURCE	COMPLETENESS	ACCURACY	SUGGESTED IMPROVEMENTS
Modelling parameters				
Fraction of methane emissions from tanks	Poor	Poor	Poor	Industry data collection, disclosure, expert knowledge
Pressure-change handling capabilities of tanks	Poor	Poor	Poor	
Seasonal operational change	Poor	Poor	Poor	
Facility gas compositions	Good	Poor	Good	Availability of a comprehensive site-level dataset
VRU operation frequency	Poor	Poor	Poor	Expert knowledge
Grid intensities	Excellent	Excellent	Excellent	N/A
Existing equipment	Excellent	Good	Poor	Operator input on the model assumptions
	RELIABILITY OF SOURCE	**COMPLETENESS**	**Accuracy**	**Suggested improvements**
Mitigation Technology Costs				
Flares	Good	Poor	Good	Expert knowledge, vendor disclosure/ feedback
VRU	Excellent	Excellent	Good	
Casing gas flare	Good	Poor	Poor	
Casing gas tie-in	Good	Poor	Poor	
Tie-in pipeline	Excellent	Excellent	Good	
Tie-in compressors	Excellent	Excellent	Good	
Vapour combustors	Excellent	Good	Excellent	
Generator	Good	Poor	Poor	
Gas bladder	Good	Poor	Good	Industry feedback on the applicability of this technology
Onsite gas storage	Good	Poor	Good	
Electric grid connection	Good	Poor	Poor	Increased public availability of electricity grid spatial data

Sample facility cost breakdown

A detailed cost breakdown of a sample facility utilizing the methane mitigation system of a grid-connected VRU, and vapour combustion is shown in Table 7 to provide insight into the calculations embedded in the Python-based model. To clarify, Table 6 is not an output from the model but rather a tabulated version of the model calculations and results for this specific sample case.

The facility vents approximately 7.73 e^3m^3 of gas per month across all components and equipment on site, which is captured by a vapour recovery unit and combusted via an enclosed vapour combustor. The methane mitigation system for the sample case results in a levelized cost of \$63.3 CAD 2022/tCO_2e. Equipment capture and combustion efficiencies are assumed to be approximately 95% and 99% for the VRU and vapour combustor, respectively, as defined by manufacturing and research sources [13], [15]. Note that the provided sample facility cost breakdown does not include fuel or electricity costs due to the assumption that it is included in the VRU operating and maintenance costs. Future iterations of the model will explore this component in further detail.

Sensitivity analysis using sample facility as the base case

Figure 4 represents the results of a sensitivity analysis investigating the impact of various input parameters for the sample case shown above. The facility vent rate has the largest impact on the levelized cost of methane abatement where the upper bound is represented by the high vent rate observed (27.9 e^3m^3/month) and the lower bound is represented by the lowest, non-zero vent volumes observed (3.63 e^3m^3/month) across all the facilities in 2022. The upper and lower vent rate tested in the sensitivity analysis resulted in levelized costs ranging from \$17.3 to \$138 CAD/tCO_2e, respectively. The global warming potential of methane also impacts the levelized cost of abatement depending on the timeframe of assessment and the year of assessment report. The resulting levelized costs can range from \$20.9 CAD/tCO_2e to \$71.0 CAD/tCO_2e for methane GWP of 84 times larger (AR5 20-year) and 25 times larger (AR4 100-year) respectively, as compared to \$63.3 CAD/tCO_2e based on methane GWP of 28 times larger (AR5 100-year) [11], [25]. The sensitivity analysis capturing methane concentrations in gas compositions ranging from 60% to 100% resulted in upper and lower levelized costs of \$97.8 CAD/tCO_2e and \$58.1 CAD/tCO_2e, respectively. The remaining tested input parameters result in minimal change in levelized costs, ranging from \$54.4 CAD/tCO_2e to \$74.6 CAD/tCO_2e.

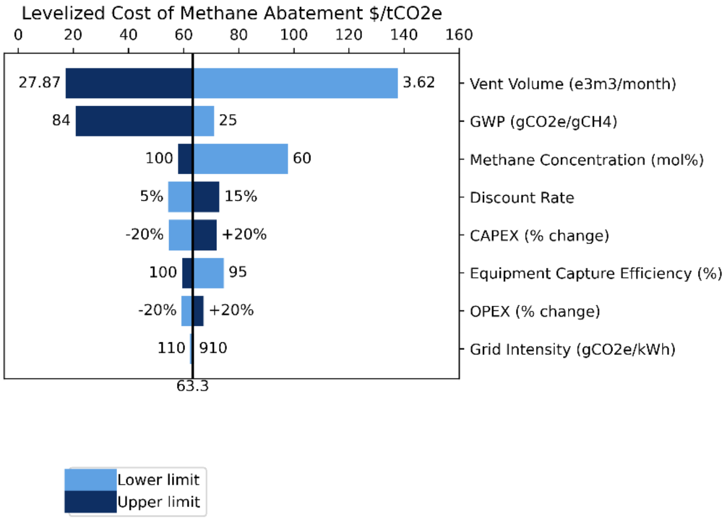
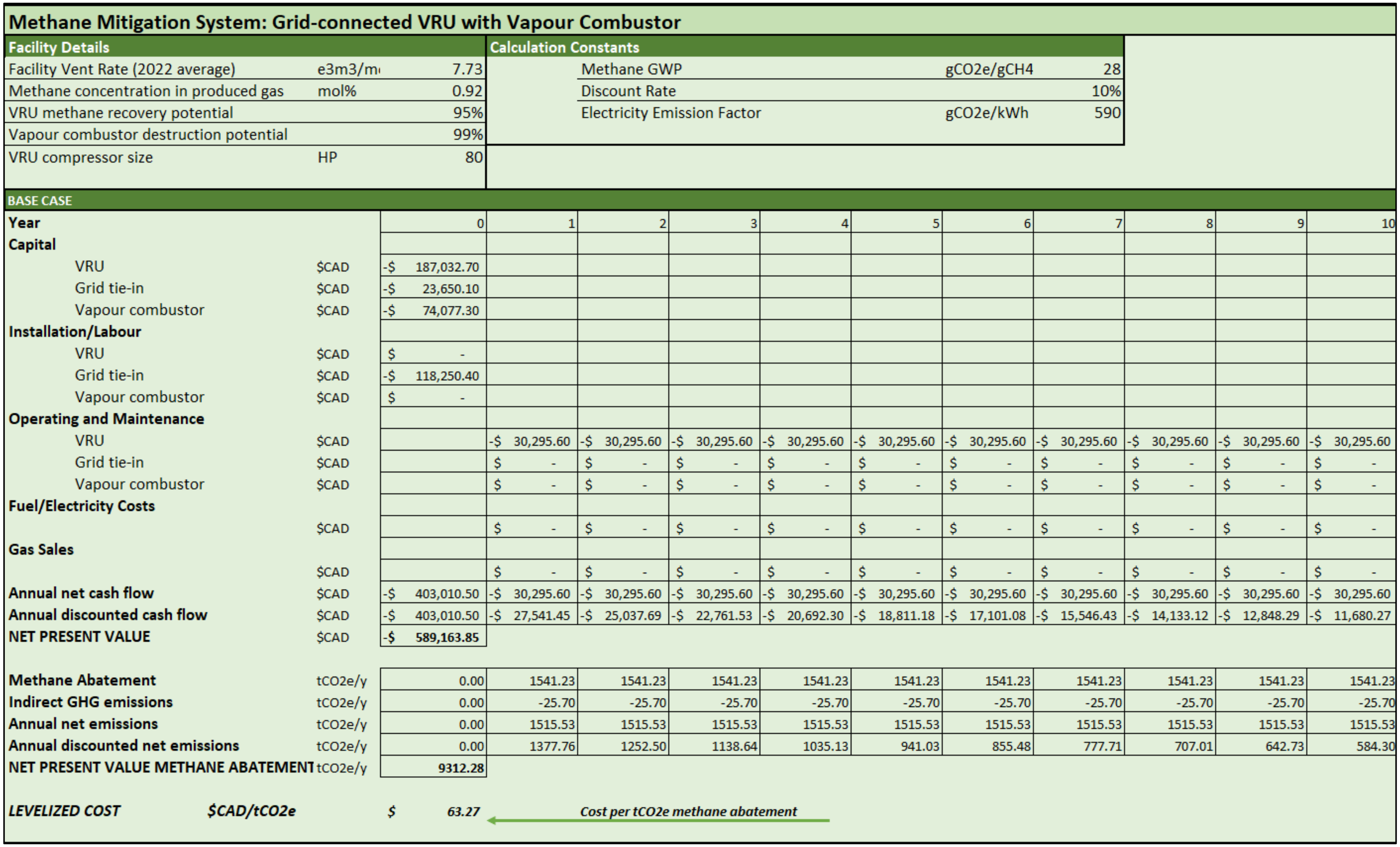


Figure 4: Tornado plot resulting from the sensitivity analysis of input parameters determining levelized cost of abatement using sample facility shown in Table 7.

Table 7: Sample facility detailed cost breakdown showing grid-connect VRU with vapour combustion as the mitigation technology system.



Methane Mitigation System: Grid-connected VRU with Vapour Combustor

Facility Details		
Facility Vent Rate (2022 average)	e3m3/m	7.73
Methane concentration in produced gas	mol%	0.92
VRU methane recovery potential		95%
Vapour combustor destruction potential		99%
VRU compressor size	HP	80

Calculation Constants		
Methane GWP	gCO2e/gCH4	28
Discount Rate		10%
Electricity Emission Factor	gCO2e/kWh	590

BASE CASE

Year		0	1	2	3	4	5	6	7	8	9	10
Capital												
VRU	$CAD	-$ 187,032.70										
Grid tie-in	$CAD	-$ 23,650.10										
Vapour combustor	$CAD	-$ 74,077.30										
Installation/Labour												
VRU	$CAD	$ -										
Grid tie-in	$CAD	-$ 118,250.40										
Vapour combustor	$CAD	$ -										
Operating and Maintenance												
VRU	$CAD		-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60
Grid tie-in	$CAD		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Vapour combustor	$CAD		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel/Electricity Costs												
	$CAD		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas Sales												
	$CAD		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual net cash flow	$CAD	-$ 403,010.50	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60	-$ 30,295.60
Annual discounted cash flow	$CAD	-$ 403,010.50	-$ 27,541.45	-$ 25,037.69	-$ 22,761.53	-$ 20,692.30	-$ 18,811.18	-$ 17,101.08	-$ 15,546.43	-$ 14,133.12	-$ 12,848.29	-$ 11,680.27
NET PRESENT VALUE	$CAD	**-$ 589,163.85**										
Methane Abatement	tCO2e/y	0.00	1541.23	1541.23	1541.23	1541.23	1541.23	1541.23	1541.23	1541.23	1541.23	1541.23
Indirect GHG emissions	tCO2e/y	0.00	-25.70	-25.70	-25.70	-25.70	-25.70	-25.70	-25.70	-25.70	-25.70	-25.70
Annual net emissions	tCO2e/y	0.00	1515.53	1515.53	1515.53	1515.53	1515.53	1515.53	1515.53	1515.53	1515.53	1515.53
Annual discounted net emissions	tCO2e/y	0.00	1377.76	1252.50	1138.64	1035.13	941.03	855.48	777.71	707.01	642.73	584.30
NET PRESENT VALUE METHANE ABATEMENT	tCO2e/y	**9312.28**										

LEVELIZED COST ***$CAD/tCO2e*** ***$ 63.27*** ← ***Cost per tCO2e methane abatement***

Conclusion

Based on the results described in the results section of the report, approximately 80% of methane emissions from facilities in Alberta can be addressed at costs ranging from -$1.21 CAD/tCO$_2$e to $1970 CAD/tCO$_2$e given the current roster of mitigation technologies available for tank methane emissions. When considering the carbon price of $50 CAD/tCO$_2$e in Alberta for 2022, approximately 3.2 MtCO$_2$e/year of methane abatement is achievable at zero or negative cost (i.e., positive revenue) [24]. Facility vent rates are the largest influencing factors of levelized costs, which suggests that facilities with higher vent rates would have greater incentives and better economics when considering methane abatement technologies. The results discussed in this study provide an overview of the methane abatement space in Alberta based on 2022 facility parameters, however, assumptions embedded in the model may not represent operations for all facilities considered [4].

Knowledge gaps exist in the public domain which limit the accuracy of methane abatement modelling results. As previously discussed, operational variabilities such as seasonal methane vent fluctuations, physical facility limitations, and detailed economic variables for each mitigation technology are yet to be incorporated into the methane abatement cost analysis completed for this study. Based on the finding of the sensitivity analysis, the changes in vent volumes resulting from seasonal activities can considerably impact the levelized costs of mitigation technologies. The application of VRU abatement systems will also be affected by site-specific tank pressure limits. Lastly, technology capital, installation, and operational costs adopted from past research may not reflect current pricing affected by external factors, such as supply chain disruptions. Future iterations of methane abatement technology assessments aim to further examine these influencing factors through various methods of analysis including case studies and detailed economic modelling of abatement technologies.

This study provides guidance for where data quality can be improved by both operators and technology vendors to bring greater transparency to methane abatement technology assessments. The methods of analysis developed for this project may also provide a foundational framework to perform case study assessments tailored for specific operators, producing regions, or facility subtypes. As data availability improves, future iterations of assessing methane mitigation technologies will be more representative of the oil and gas industry in Alberta and provide stakeholders with better insight into the methane abatement pathways.

Provided additional funding, the University of Calgary would further develop the methane abatement technology assessment model to include other onsite methane vent sources, such as pneumatic devices, glycol dehydrators, compressors, and fugitive methane emissions. Future work would also assess production facilities in British Columbia and Saskatchewan. The expansion of the methane abatement technology project would contribute to evaluating methane emissions across the major oil and gas producing provinces in Canada and explore the variability of methane emissions reduction opportunities across different regulatory regimes. There would also be opportunities to adapt the current methane assessment model to become a Python-based, open-source tool given additional funding. Where the opportunity may arise, the University of Calgary would be open to collaboration with industry members to conduct methane abatement technology case study assessments.

D. PROJECT AND TECHNOLOGY KEY PERFORMANCE INDICATORS

Organization:	**Current Study**	**Commercial Deployment Projection**
Project cash and in-kind cost ($)	$18,541.65 CAD (CASH) $18,541.65 CAD (in-kind) **TOTAL: $37,083.30 CAD**	N/A
Technology Readiness Level (Start / End):	N/A	N/A
GHG Emissions Reduction (kt CH4/yr):	N/A	N/A
Estimated GHG abatement cost ($/kt CH4)	N/A	N/A
Jobs created or maintained:	2	N/A

E. RECOMMENDATIONS AND NEXT STEPS

The results from this project identify the most cost-effective tank methane mitigation pathways to contribute to Alberta's 75% methane reduction target by systematically considering Alberta's facilities, tank methane emissions, and technology adoption options. Alberta's oil and gas producers, regulatory bodies, technology vendors, and service providers can use the results from this project to accelerate the deployment of tank mitigation technologies, establish incentives targeted to eliminate tank methane mitigation barriers, and determine areas of technology development and optimization. The learnings and findings of this project can contribute to future studies that comprehensively evaluate all methane emission sources and abatement technologies options in Alberta. Next steps would be a similar assessment of all methane reduction technologies available to the Canadian oil and gas industry addressing all sources of methane emissions (pneumatics, valves, meters, seals, compressors, etc.) Given the results of this assessment, stakeholders (such as operators, regulators, etc.) can identify the up-to-date opportunities available to Canadian producers, which technology options are low cost or has large methane reduction potential.

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