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TECHNICAL REPORT

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Study to Investigate Fugitive and Venting Emissions from Aboveground, Fixed-Roof Storage Tanks.

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EXECUTIVE SUMMARY

Researchers assert that a significant portion of methane emissions are from a small number of large, temporally-dynamic emitters (Zavala-Araiza et al, 2018; Lyon et al., 2016; and Lavoie et al., 2017) that may be understated in national inventories. Gas carry-through to storage tanks due to leakage past drain valves into tank inlet headers, inefficient gas-liquid separation in upstream vessels, malfunctioning level controllers or leakage past the seat of level control valves, or unintentional storage of high vapour pressure liquids in atmospheric tanks are observed to be noteworthy sources at some sites and can be temporally-dynamic. Because uncontrolled storage tanks are designed to vent, Fugitive Emission Management Programs (FEMP) typically classify emissions as 'process vents' and **do not trigger remedial action**.

To inform mitigation efforts, this study investigates root-causes of fugitive (unintentional) as well as venting (intentional) emissions from fixed-roof storage tanks facilities located in Alberta and British Columbia. The work highlights the importance of fugitive emission diagnosis to enables effective repairs. Outcomes include a proposed troubleshooting decision tree for use during leak detection and repair (LDAR) surveys; a critical review of gas flashing estimation methods; and techno-economic assessments for ten storage tank emission mitigation options.

This study focuses on condensate, light crude oil and medium crude oil production at well sites. Cold heavy oil production (CHOP) is excluded because tank venting is driven by well behavior and beyond the scope of this project.

Methodology

Desktop investigations focused on fixed-roof storage tanks where infrared camera videos suggested fugitive and venting emissions were greater than the ECCC facility venting limit of 42 m^3/day (GC, 2018). Candidate tanks were selected from 2018 and 2019 field data collected during Energy Efficiency Alberta Baseline Opportunity Assessments and the British Columbia methane emissions field study. Participating companies voluntarily provided relevant site-specific and confidential data items that included:

- Tank and emission details collected during 2018 or 2019 field campaigns.
- Site process flow diagram (PFD)
- Storage tank piping and instrumentation diagram (P&ID). If P&IDs are not available, provide the maximum and minimum allowable working pressure for the subject tank (a photo of the tank nameplate is ideal).
- Operating pressure and temperature of vessel(s) immediately upstream of subject tank.
- Oil and gas disposition volumes relevant to the survey month.
- If the site has a treater, the pump rate (m^3/hr) for recycling slop oil.

- Laboratory analysis of relevant oil/condensate and gas streams.
- An explanation or copy of spreadsheet currently used to estimate storage tank emissions.

Based on these details, desktop reviews identified possible root-causes and defined specific questions for site operators to investigate for 47 tanks. In some cases, laboratory analysis of pressurized samples plus separator pressure, temperature and hydrocarbon liquid throughput were available and enabled quantification of flashing losses (using a process simulator). Comparing calculated emission rates to IR videos provided a qualitative indicator of whether the observed plume was strictly due to separator liquid flashing or whether other, unintentional mechanism(s) contributed.

Operators provided repair details, process data and/or equipment conditions that confirmed specific mechanism responsible for emissions observed by the IR camera. These mechanisms are broadly categorized by the following root-causes.

- Volatile liquid flashing (typically defined as venting emissions)
- Tank-top equipment component leaks (typically defined as fugitive emissions)
- Unintentional gas carry-through (typically defined as fugitive emissions)

Volatile Liquid Flashing Root-Cause Observations

Fixed-roof tanks located at primary production facilities are intended to store volatile hydrocarbon liquids from separators and treaters. Therefore it's not surprising that, of the tank emissions investigated by operators, approximately half were attributed to volatile liquid flashing. Provincial directives specify methods for quantifying gas flashing that provide reasonably representative emission rates for tanks not experiencing unintentional gas carry-through. For example, AER Directive 017 specifies the following to determine Gas-to-Oil Ratio (GOR) factors (that are multiplied by stock tank oil production for monthly associated gas volume accounting).

1. 24 hour test may be conducted such that all the applicable gas and oil volumes produced during the test are measured. The gas volume is divided by the oil volume to result in the GOR factor.
2. A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis should be based on the actual pressure and temperature conditions that the oil sample would be subjected to downstream of the sample point, including multiple-stage flashing. The GOR factor is calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.
3. A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional

analysis can be conducted. A computer simulation program may be used to determine the GOR factor based on the compositional analysis.

Some circumstances permit operators to use correlations listed in the 2002 Canadian Association of Petroleum Producers (CAPP) Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities are also permitted. (CAPP, 2002). These correlations are desirable for predicting flashing loss contributions to emission inventories. However, correlations are unable to account for sample specific analyte fractions; stock tank liquid heating (that has an upward influence on GOR); or backpressure imposed by emission control overhead piping (that has a downward influence on GOR). Thus, correlations may be appropriate for estimating average emissions from a large number of tanks while more rigorous process simulation or direct measurement should be employed when accurate determination of site-specific venting is required (e.g., for designing vapour recovery systems or compliance with Directive 017).

In general, the accuracy of flash gas factors improves with modelling sophistication and process data granularity. Input data requirements for methods investigated by this study are indicated in Table ES-1. The AER 'Rule-of-Thumb' is the simplest and only requires knowledge of upstream pressure while process simulations are complex and require detailed process knowledge.

Table ES-1: Input process data required for selected flash gas estimation methods.

Input Parameter	Correlations			Simulation
	AER 'Rule-of-Thumb'	Vazquez and Beggs	Valko and McCain	VapourSIM
Stock tank oil density (API gravity)		X	X	X
Stock tank oil temperature				X
Stock tank oil RVP				X[1]
Local atmospheric pressure				X[1]
Stock tank vapour molecular weight		X		
Upstream separator pressure	X	X	X	X
Upstream separator temperature		X	X	X
C_1 to C_{30} analysis of pressurized liquid sample				X

[1] *Simulation users select flashing end point of interest (atmospheric pressure or RVP)*

To spot check how well Directive 017 site testing requirements align with correlations, flash gas factors are determined according to the methods presented in Table ES-1 and described in Appendix Sections 6.3.1 to 6.3.1. For example, GOR is calculated for a light crude oil (API Gravity 43.4°) over the range of separator pressures observed in the field dataset (and constant separator temperature of 10° C). Figure ES-1 presents GOR as a function of pressure and an insert of the pressure distribution. GOR determined by correlations are represented by trend lines. GOR determined by field measurements are plotted as brown boxes while GOR determined by VapourSIM are plotted as cross markers and used to spot check correlation results. Red font markers indicate a flash end point equal to atmospheric pressure and stock tank temperature (representative of instantaneous venting when pressurized liquid enters the tank). Green font markers indicate a flash end point equal to sales oil Reid Vapour Pressure (RVP) and representative of total venting due to instantaneous flashing plus weathering over a longer period of time. The difference between red and green simulated GOR is the contribution from working and breathing losses (i.e., weathering) that occurs over the entire period oil is stored in the tank (e.g., days, weeks or months).

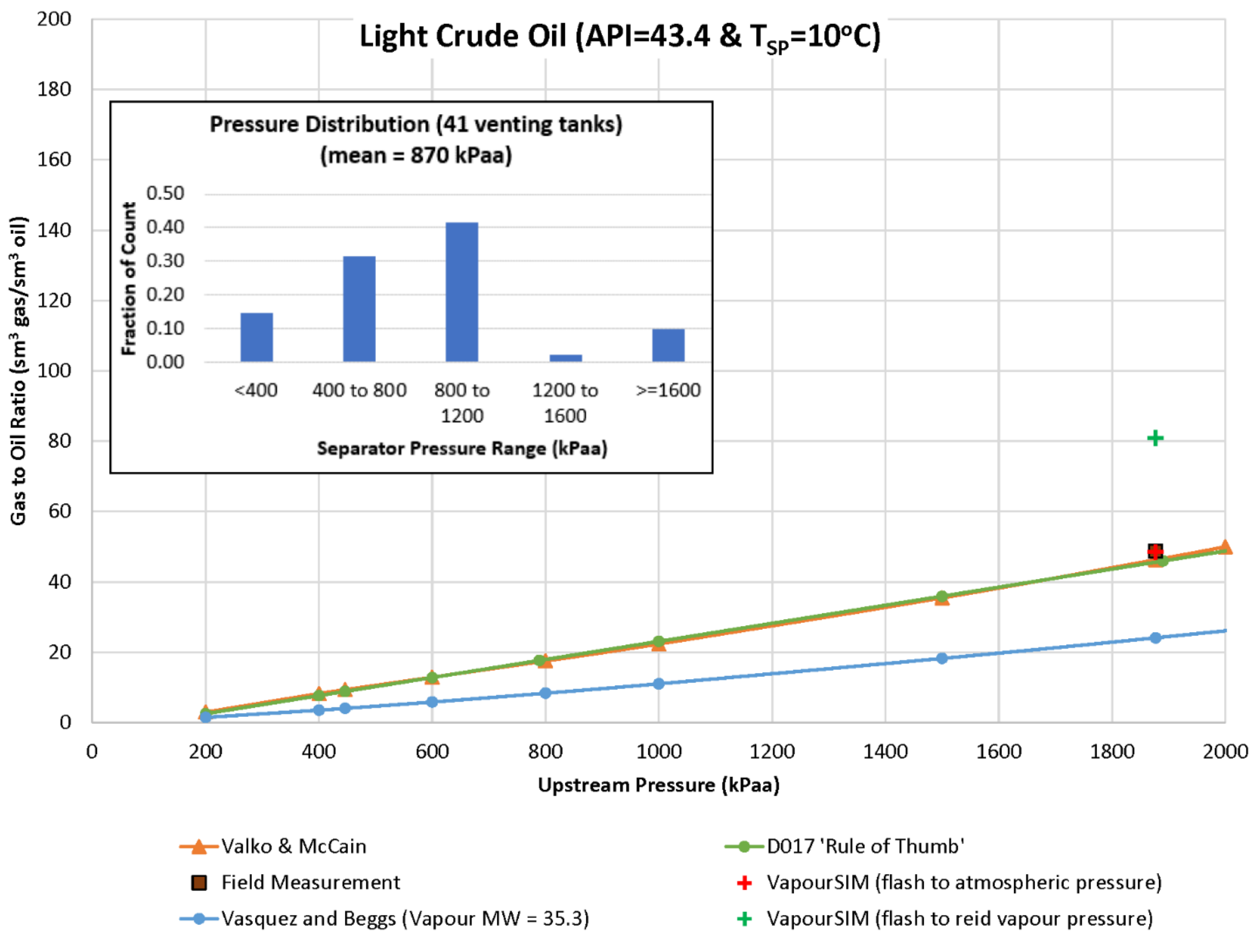

Figure ES-1: GOR correlation estimates over separator pressure range of 200 to 2,000 kPaa for light crude oil with API = 43.4° and separator temperature = 10 °C.

The VapourSIM (flashed to atmospheric pressure) and measured GOR results are reasonably aligned with Valko and McCain results for the light crude oil example presented in Figure ES-1. This is expected because the pressure, temperature and API gravity of the subject oil stream is within the range of conditions the correlation was derived from. Similar observations are made for a medium oil example (API Gravity 30.1^{o}) but not for condensate examples. This is attributed to the condensate API gravity (66.4^{o}) being greater than the maximum API gravity (56.8^{o}) used to derive the Valko and McCain correlation.

Techno-Economic Assessment of Mitigating Actions

Tanks not experiencing unintentional gas carry-through but still exceeding provincial or federal methane regulation limits may require controls to reduce emissions. Design memorandums are developed for the ten mitigation approaches listed in Table ES-2 and broadly grouped into two categories: tank top versus flash vessel vapour capture. Storage tanks certified with a minimum and maximum allowable working pressure rating can be fitted with overhead piping that can capture 100 percent of tank-top vapours. However, many tanks are not rated for pressure or vacuum service and at risk of failure if tank-top vapour capture piping is installed. Therefore, options to install a flash vessel between separators and non-certified tanks are investigated. The applicability of each case depends on whether the subject site is connected to a natural gas gathering system; power distribution system; and or features sufficient lease area; certified tanks or a suitable well/reservoir for gas lift. Most UOG facilities operating in western Canada will satisfy one or more of the site requirements summarized in Table ES-2.

Table ES-2: Site features required for deployment of mitigating technologies.

Case # and Description	Connection to electric grid	Connection to gas gathering system	Certified tanks	Sufficient lease area	Well and reservoir suitable for gas lift
#1 Tank Top to Existing High Pressure Flare	X		X		
#2 Tank Top to Low Pressure Flare			X	X	
#3 Tank Top to Booster Compressor for Gas Lift	X		X	X	X
#4 Tank Top to Vapour Combustor	X		X		
#5 Flash Vessel to Electrical Generators	X			X	
#6 Tank Top to Electrical Generators	X		X	X	
#7 Flash Vessel to Existing High Pressure Flare					
#8 Flash Vessel to Vapour Combustor					
#9 Tank Top to VRU for Gas Sales	X	X	X	X	
#10 Flash Vessel to VRU for Gas Sales	X	X		X	

A description of installed equipment; process flow diagrams (PFD), total installed capital cost (TICC) details; and annual GHG emission reductions are developed for each mitigation case investigated. These are used for calculating Net Present Value (NPV with sensitivity analysis) and indicate whether an investor can expect to recover their capital and earn a nominal rate of return. Average abatement costs (in present value terms) are also developed to show the total lifecycle cost incurred by an operator (net of any revenue) to avoid the release of one tonne of CO_2E. As shown in Table ES-3, all options except case #3, have a negative NPV under the base venting rate of 500 m^3 per day and would not normally be implemented because there is no economic benefit to facility owners. Sensitivity analysis indicates all actions are highly sensitive to the monetization of GHG emission reductions. When re-calculated using the current federal carbon price (levelized value of $46 per t CO_2E), NPV is positive for all cases but #8 and #10.

Table ES-3: Summary of TICC, NPV, GHG reduction and average abatement costs for options to mitigate of 500 m^3 per day tank venting.

Case # and Description	TICC	NPV	GHG reduction over 10 years	Average Abatement Cost ($/t CO_2E)
#1 Tank Top to Existing High Pressure Flare	$195,000	-$311,000	11,180	28
#2 Tank Top to Low Pressure Flare	$155,000	-$245,000	11,180	22
#3 Tank Top to Booster Compressor for Gas Lift	$780,000	$283,000	17,500	16
#4 Tank Top to Vapour Combustor	$235,000	-$363,000	11,275	32
#5 Flash Vessel to Electrical Generators	$245,000	-$122,000	8,055	15
#6 Tank Top to Electrical Generators	$300,000	-$113,000	11,275	10
#7 Flash Vessel to Existing High Pressure Flare	$125,000	-$123,000	9,535	15
#8 Flash Vessel to Vapour Combustor	$200,000	-$307,000	8,055	38
#9 Tank Top to VRU for Gas Sales	$430,000	-$461,000	17,522	26
#10 Flash Vessel to VRU for Gas Sales	$525,000	-$620,000	12,517	50

Tank-Top Equipment Leaks Root-Cause Observations

Tank-top equipment leaks are the second root-cause category and are only relevant to controlled storage tanks where vapours are directed to a conservation or destruction system (but leak from associated equipment). Their root-cause can be malfunctioning equipment components or incorrectly set, undersized or blocked components that cause tank ullage pressures to exceed relief set-points. Tank-top equipment leaks are detected during LDAR surveys. Repairing components installed on controlled tanks typically requires a full or partial site shut-down and therefore aligned with other maintenance work or downstream facility outages (which can exceed some regulatory timelines). It involves planning the shutdown, emptying the tank, isolating (lock-out) the tank; purging with an inert gas (e.g., nitrogen); accessing with a manlift; disassembling/replacing/repairing the component; purging the tank with natural gas; removing lock-out and returning the tank to service.

Repair costs depend on materials (ranging from almost zero to thousands) and labour (ranging from $200 to thousands)) which depend on the nature of the problem and number of people involved. Valuing the cost of a site shut-down depends on throughput, current commodity prices and view on whether down time should be included in the repair cost.

Unintentional Gas Carry-Through Root-Cause Observations

Unintentional gas carry-through is the third root-cause category and of most interest because it presents low-cost methane reduction opportunities and may help explain discrepancies between bottom-up emission inventories and top-down observations.

The most common cause observed is from leakage of process gas or volatile product past valve seats connected to the product header leading to storage tanks. Hard substances (e.g., sand, wax or other debris) can deposit on a valve seat and prevent the disk fully sealing with its seat, as indicated in the Figure ES-2 globe valve example. The seat or disk can also be scoured or damaged to the point where a full seal is not possible. The most common instance of these problems are on liquid (hydrocarbon or water) control valves immediately downstream of separators or scrubbers (commonly referred to as 'dump-valves'). Other instances of this leak type are observed on manual by-pass valves that result in direct connection between high-pressure production fluids and atmospheric tanks. It's also possible for level controllers to malfunction and send a false output signal that keeps the dump-valve open (and passing gas to the storage tank). Malfunctioning can be due to a 'hung-up' float assembly or change in liquid density that prevents the assembly from returning to its expected level.

Overall, costs reported by operators to repair a passing dump-valve ranged from zero to $7,500 depending on the nature of the problem and number of people involved.

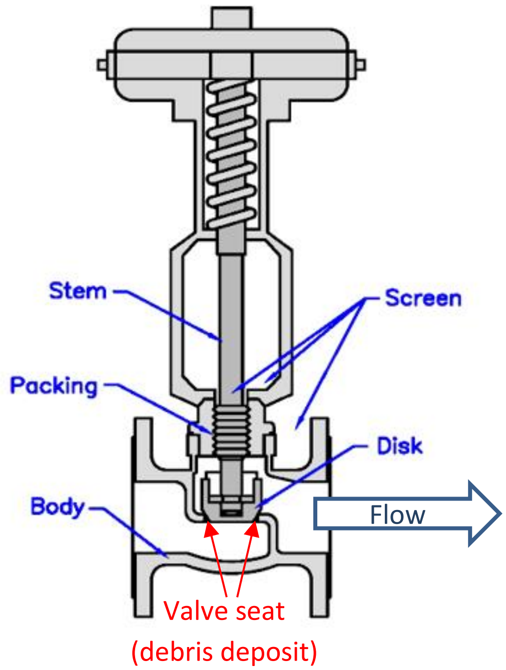

Figure ES-2: Globe control valve with debris deposit area indicated.

Inefficient separation of gas and liquid phases upstream of the tanks allowing some gas carry-through, by entrainment or in solution, to the tanks. Sustained high liquid levels in the separator will initiate frequent signals for the dump-valve to open resulting in continuous flow of pressurized hydrocarbon liquids to the storage tanks. This condition reduces residence time for separation of gas from the liquid phase and may cause storage tank flashing to exceed solution gas losses predicted by a simulator or correlation (strictly based on the subject liquid properties and separator conditions).

Although considered infrequent and not observed in the study dataset, piping anomalies can result in unintentional placement of gas or high vapour pressure product in tanks not equipped with appropriate vapour controls. Examples include:

- Liquids from 2nd and 3rd compression stage scrubbers being tied into storage tanks instead of recycled back to the 1st stage scrubber inlet.
- Recombining separator gas, after metering, into the liquid line connected to a tank.
- Purge gas supplied to a separator liquid line and connected to a storage tank.
- Oil well production casing connected to a storage tank.

Field Troubleshooting Decision Tree

To support first attempts at field level troubleshooting and root-cause identification, the decision tree depicted in Figure ES-3 is proposed. It is intended to identify equipment components or process conditions responsible for continuous venting from uncontrolled storage tanks. The decision tree is a systematic process for determining whether tank venting may be due to component malfunction (that can be repaired) or inherent to the pressurized hydrocarbons stored. The decision tree can be integrated into FEMP and completed by LDAR survey technicians (equipped with an IR camera and portable acoustic leak detector). It is applicable to continuous venting, observed by IR camera (or other detection method), from uncontrolled tanks storing hydrocarbons and/or water. It is **not** applicable to tank venting that occurs at an intermittent frequency corresponding to the separator dump frequency because this is an indicator of equipment components operating according to their design.[1] It is **not** applicable to tanks equipped with emission controls that conserve or combust the vapours.

Using the decision tree begins at the offending tank and involves tracing pipe to the upstream vessel(s) responsible for delivering liquids (or walking directly to the vessel(s) if predetermined from P&IDs or identified by the site operator). These vessels can be separators, treaters, scrubbers, or drain sumps. If equipped with a level gauge, the vessel liquid level and dump-frequency can be monitored as follows.

- Sustained high-liquid level and frequent/continuous dump events are an indicator of inlet liquid flows greater than separator design capacity. Under these conditions, there may be insufficient residence time for gas to fully disengage from liquids before delivery to the tank.
- Sustained low-liquid level (or empty vessel) and frequent/continuous dump events are an indicator of a malfunctioning level controller. Under these conditions, the controller may be sending a false signal for the dump valve to remain open.
- Sustained mid-liquid level or rising/descending levels (that align with dump frequency) are an indicator of sufficient separator capacity and intended level control. Under these conditions, the offending component may be the dump-valve. This is checked with an acoustic leak detector by placing a probe on the valve body. If liquids or gas are passing through the closed valve, vibrations (noise) are generated and an acoustic signal is observed by the instrument. An empirical correlation is then used to estimates the leak rate based on the signal strength, valve type and pressure differential across the valve.

If these troubleshooting steps don't identify a root-cause then the subject vessel is unlikely to be the source of continuous venting. The same steps should be repeated for all other vessels

[1] When viewed by an IR camera, intermittent tank venting should appear as a large plume; associated with instantaneous flashing when pressurized liquids enter the tank; that decreases in magnitude until the next dump event. The plume may not decrease to 'zero' because of residual weathering of oil between dumping events. If dumping events are infrequent (e.g., occurring once per hour or more), a very small or zero plume may be observed which is an indicator of intermittent venting.

connected to the tank. Locating connected scrubbers and drain sumps can be more difficult than identifying upstream separators or treaters. It requires patient pipe walks and/or consultation with site operators and P&IDs (especially if pipe racks are insulated). If all connected vessels are checked and no problems identified, then the root-cause may be due to an abnormal piping configuration or the flashing of volatile liquid hydrocarbons.

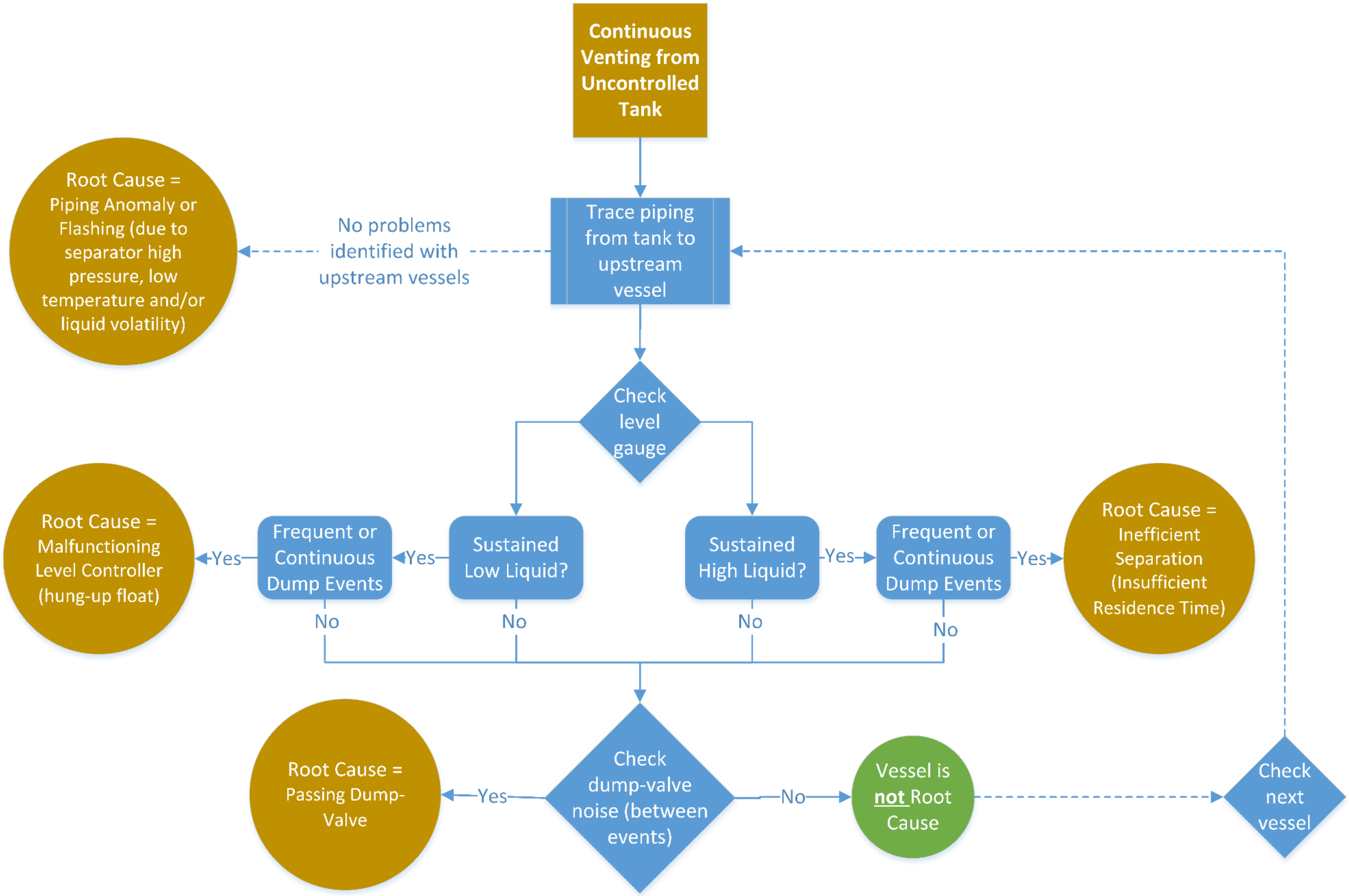

Figure ES-3: Decision tree for troubleshooting the root-cause of continuous venting from uncontrolled storage tanks.

Key conclusions and recommendations from this study include the following:

- Evidence collected by this study indicates separator and scrubber dump-valve leakage is contributing to fugitive emissions from storage tanks. However, this source is not accounted in provincial or national inventories. To resolve this data gap, a field measurement campaign should be implemented to develop component counts and population-average emission factors.
- A decision tree for identifying the root-cause of venting from uncontrolled storage tanks is proposed as a first troubleshooting attempt during LDAR surveys. Outcomes are intended to alert maintenance personal to equipment that may be malfunctioning and unknowingly contributing to tank venting.
- The key benefit of correlations is their simplicity and minimal input data requirements. However, they are unable to account for sample specific analyte fractions; stock tank liquid heating (that has an upward influence on GOR); or backpressure imposed by emission control overhead piping (that has a downward influence on GOR). When accurate determination of peak venting is required (e.g., for designing vapour recovery systems or compliance with Directive 017), more rigorous process simulation should be applied to account for site specific conditions.
- To improve laboratory analysis data reliability the steps recommended by Colorado regulators (described in Section 6.3.1), when performing and verifying flash gas liberation analysis on pressurized liquid hydrocarbon samples, should be considered (CAPCD, 2017).
- For emission inventory purposes, the Valko and McCain correlation is recommended when determining flash gas factors for crude oils within the range of parameters stated in Table 20. This is based on alignment with GORs determined with VapourSIM (flashed to atmospheric pressure) and measured spot checks plus its use in Colorado for determining flash gas factors (SLR, 2018). The Valko and McCain correlation is not recommended for lighter condensates with API gravity greater 56.8^o. Instead, the Vasquez & Beggs and D017 'Rule of Thumb' correlations provide more reasonable GOR estimates for condensates with API gravity greater 56.8^o.
- Techno-economic assessments are completed for ten storage tank emission mitigation options. Results indicate all but one option have a negative NPV when venting equals 500 m^3 per day. Unless alternative revenue opportunities (e.g., offset credits, royalty credits, energy efficiency incentives, etc) are available, current commodity prices and limited economic benefit to facility owners will challenge implementation of mitigation options. Of particular vulnerability are existing sites that require retrofits and may be forced to shut-in if incentives are not available. This outcome diminishes economic activity and Canada's capacity to implement climate solutions.

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AEP	Alberta Environment and Parks
AER	Alberta Energy Regulator
API	American Petroleum Institute
AR4	IPCC Fourth Assessment Report
AR5	IPCC Fifth Assessment Report
BC OGC	British Columbia Oil and Gas Commission
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resources Board
CHOPS	Cold Heavy Oil Production with Sand
CO_2E	Carbon Dioxide Equivalent
CSA	Canadian Standards Association
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
GJ	Gigajoule
GIS	Gas in Solution Ratio
GOR	Gas to Oil Ratio
IPCC	Intergovernmental Panel on Climate Change
NPV	Net Present Value
PFD	Process Flow Diagram
P&ID	Piping & Instrumentation Diagram
PRV	Pressure Relief Valve
PSAC	Petroleum Services Association of Canada
PTAC	Petroleum Technology Alliance of Canada
PVRV	Pressure/Vacuum Relief Valve
TICC	Total Installed Capital Cost
QA	Quality Assurance
QC	Quality Control
UNFCCC	United Nations Framework Convention on Climate Change
UOG	Upstream Oil and Gas
VOC	Volatile Organic Compound
VRU	Vapour recovery Unit

GLOSSARY

API Gravity An inverse measure (expressed in degrees) of a petroleum liquid's specific gravity. Hence, if a petroleum liquid is less dense than another, then it has a greater API gravity. Most values are in the range of 10˚ to 70˚. The formula used to determine API gravity is:

API Gravity = (141.5/SG at 60°F) - 131.5

Where, SG is the specific gravity of the fluid.

Associated Gas Natural gas that was in contact with oil in the reservoir.

Backpressure Valve A valve designed to control flowrates in such a manner that upstream pressure remains constant. This type of valve may be operated by a diaphragm, spring or weighted lever.

Blanket Gas - Storage tanks are equipped with gas blanket systems to reduce vapour emissions (especially when the vapours are sour) and to ensure that oxygen does not enter the vapour space of the tank when it is connected to a flare system or vapour recovery unit. The blanket gas is usually fuel gas but any other inert gas could be used.

Storage tanks with gas blanket systems are usually connected to a flare or vapour recovery system, but in some cases (if the gas is not sour) the tank vapours and blanket gas may be released untreated to the atmosphere through a vent system.

Breather Pressure Setting – The pressure set-point at which the breather will begin to open to relieve pressure by venting gases from the tank vapour space to the atmosphere.

Breather Vent Vacuum Setting - The vacuum set-point at which the breather will begin to open to allow ambient air to flow into the tank vapour space to relieve a vacuum condition.

Condensate: Hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and that remains a liquid at standard reference conditions. Condensate density is less than 800 kg/m^3**.**

Crude Bitumen - A naturally occurring viscous mixture consisting of hydrocarbons heavier than pentane and other contaminants, such as sulphur compounds, which in its natural state will not flow under reservoir conditions or on the surface. Bitumen occupies the lower end of the range of heavy crude oils and is sometimes referred to as ultra-heavy crude oil.

Crude Oil A mixture of mainly pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen. The following crude oil types are defined by the AER (https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/appendix-and-glossary#h):

Light crude oil density ranges from 800 to 850 kg/m^3.
Medium crude oil density ranges from 850 to 900 kg/m^3.
Heavy crude oil density ranges from 900 to 925 kg/m^3.
Ultra-Heavy crude oil density is 925 kg/m^3 and greater.

Fixed-Roof Storage Tank Storage tank that consists of a vertical, cylindrical steel shell with a permanently affixed roof. The roof may be a conical, dome or flat design and supported by a central column and the external cylindrical shell. This study considers aboveground, atmospheric storage tanks that do not exceed maximum internal design pressure specified in API Standard 650 Appendix F (e.g., up to 17 kPa gauge).

Fugitive Emission Management Program (FEMP) A program established by duty holders to plan and support the systematic detection and management of fugitive emissions. FEMP document internal (e.g., individual staff, groups, departments) and external (e.g., contractors) resources allocated to develop, implement, maintain, and update the program, with their specific responsibilities identified, such as surveying, screening, repairing, tracking, reporting, and training.

Flash Gas-in-Solution Factor (GIS)

The flash gas factor is the amount of flash gas liberated per unit of oil produced (sm^3/m^3 of oil) when oil from a pressurized source is flashed to a particular set of conditions. For determining the peak instantaneous flash gas liberation rates, the flash gas factor is normally determined at the operating temperature and pressure (e.g., local barometric pressure) of the stock tank.

For the purposes of determining the total amount of flash gas liberated from the product, the flash gas factors (sm^3/m^3 of oil) is determined at the reported RVP of the sales oil.

If the flash gas factor is determined by flashing the gas to standard conditions of 1 atmosphere and 60°F (e.g., in a laboratory), the result is referred to as flash GOR (scf/bbl oil).

Flash Gas-to-Oil Ratio (GOR)

The gas factor (sm^3/m^3 oil) determined by flashing a pressurized oil sample to standard end conditions of 1 atmosphere (101.325 kPa) and 60°F (15.6°C) (e.g., in a laboratory). In AER Directive 017, GOR is inclusive of all gas produced at the subject facility.

Flare

An open flame used for routine or emergency disposal of waste gas. There is a variety of different types of flares including flare pits, flare stacks, enclosed flares and ground flares.

Flow Line

The pipe through which well effluent flows from the oil well to the field processing facility.

Fully-Speciated Substance

A fluid or chemical mixture that has been adequately characterized in terms of its dominant constituents to allow prediction of the rheological and thermodynamic properties of the substance, and in terms of any trace constituents to satisfy the application-specific needs of the user. Trace constituents may be of particular interest or concern because of their market value, health-risk properties, adverse environmental effects, catalysing or inhibiting properties, etc. In reality, no substance is ever fully speciated; even a highly purified substance may contain hundreds or more trace constituents, most of which are of no consequence or concern at the concentrations they occur. For a fully-speciated fluid, the developed composition profile is normalized so that the mol and mass fractions of the quantitated components sum to a value of 1.

Greenhouse Gas (GHG) Gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of thermal infrared radiation emitted by the Earth's surface, the atmosphere itself, and by clouds. This property causes the greenhouse effect. Water vapor (H_2O), carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4) and ozone (O_3) are the primary greenhouse gases in the Earth's atmosphere. Moreover, there are a number of entirely human-made greenhouse gases in the atmosphere, such as the halocarbons and other chlorine- and bromine-containing substances dealt with under the Montreal Protocol. Beside CO_2, N_2O and CH_4, the Kyoto Protocol deals with the greenhouse gases sulphur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs).

Hydrocarbons - All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.

Knock-out Drum A vapor-liquid separator for removal of entrained liquids from gas flows.

Leak Detection And Repair (LDAR) A work practice designed to detect unintentional loss (leak) of process fluid past a seal, mechanical connection or minor flaw at a rate that is in excess of normal tolerances allowed by the manufacturer or applicable health, safety and environmental regulations. Leaking equipment components are repaired to minimize or eliminate atmospheric emissions.

Nonroutine flaring, venting, incineration AER Directive 060 defines “Nonroutine” as intermittent and infrequent flaring, venting, or incineration events. There are two types: planned and unplanned

PIG A device inserted into a flow line with normal flow for the purpose of cleaning out accumulations of wax, scale and debris and into gas pipelines for the purpose of displacing liquids from the pipeline (e.g., water or condensate). The pig used in flow lines cleans the pipe walls by means of blades or brushes attached to it. The pig used in gas pipelines is usually a neoprene displacement spheroid.

Pressure Relief Valve (PRV) A safety device to protect against structural damage to piping and vessels that can result from over-pressurization. The PRV's set point for opening must be set low enough to prevent over-pressurization from occurring, but high enough to exceed the rang operating pressures experienced during normal operations (i.e., to avoid unintended venting or simmering conditions).

Produced Water Water that is extracted from the earth from a crude oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Reduced Sulphur Compounds (RSCs) - Any compounds containing the sulphur atom in its reduced oxidation state. These are taken to be any sulphur-containing compounds except SO_x.

Reid Vapour Pressure (RVP) A measure of the volatility of a hydrocarbon liquid (i.e., crude oil and petroleum refined products) at 37.8˚C (100˚F) as determined by Test Method ASTM-D-323. Because of the presence of air in the vapor space within the test method's sample container, as well as some small amount of sample vaporization during the warming of the sample to the test temperature, the RVP differs slightly from the TVP of the sample at this temperature.

Routine flaring, venting, incineration AER Directive 060 defines "Routine" as continuous or intermittent flaring, venting, or incineration that occurs on a regular basis due to normal operation. Examples of routine flaring include glycol dehydrator reboiler still vapour flaring, tank vapour flaring, flash tank vapour flaring, and solution gas flaring. Routine venting can include gas from

- production casing vents,
- process vents,
- tank vents,
- blanketing,
- online gas analyzer purge vents,
- pneumatic devices, and
- desiccant dehydrator regeneration vents and membrane dehydrator purge vents.

Scrubber A vessel used to knock out entrained droplets and/or dust particles in gas flow (usually having high gas-to-liquid ratios) to protect downstream rotating or other equipment or to recover valuable liquids from the gas. Scrubbers commonly are used in conjunction with dehydrators, extraction plants, instruments, or compressors.

Separator A vessel used to separate multi-phase flow into its constituent phases (e.g., gas, hydrocarbon liquid, water and solids) by gravity settling and/or centrifugal action. A separator may be either two-phase (e.g., gas/liquid), three-phase (e.g., (gas/hydrocarbon liquid/water) or four-phase (e.g., gas/hydrocarbon liquid/water/sand). Separators can have incidental added heat, but if the heat added or removed is more than incidental then the vessel falls in the family of "heaters/treaters".

Slug Flow A liquid-gas flow in which the gas phase exists as large bubbles separated by liquid slugs. Oscillations in pressure and flowrates may occur within the piping due to slug flow.

Standard Reference Conditions - Most equipment manufacturers reference flow, concentration and equipment performance data at ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 percent relative humidity.

Stock Tank Vapours - The small volume of dissolved gas present in the oil storage tanks that may be released from the tanks.

Solution Gas Natural gas dissolved in crude oil and held under pressure in the oil in reservoir.

Synthetic Crude Oil - A high quality, light, usually sweet, crude oil derived by upgrading heavy crude oil, particularly bitumen, through the addition of hydrogen or removal of carbon. It comprises mainly pentane and heavier hydrocarbons.

Tank A device designed to contain liquids produced, generated, and used by the petroleum industry. Tanks are constructed of impervious materials, such as concrete, plastic, fiber-reinforced plastic, or steel, and are designed to provide adequate structural support for the intended contents, and satisfy specific pressure and vacuum limits as well as wind and snow loads. Design standards such as API 620 and 650 and API Specification 12B, 12D, 12F and 12P, establish the applicable design procedures and set default pressure and vacuum values in the absence of specific requirements by the purchaser.

Thief Hatch A hinged cover on an opening located on the top of the tank through which liquid sampling or liquid-level measurements are manually performed. The hatch features an integral safety device for pressure-vacuum relief or simply pressure relief, depending on the design of the safety device and the application requirements.

Treater A process unit for separating gas, oil and water from emulsified well streams by gravity and enhanced means of breaking emulsions such as heating, chemical and/or coalescing sections.

True Vapour Pressure (TVP) - A measure of the equilibrium partial pressure exerted by a liquid at a specified temperature. The TVP of an organic liquid may be determined using Test Method ASTM D 2879.

Uncontrolled Emissions The emission rate that would occur in the absence of a control device or during periods when a control device is not operational.

Unintentional Gas Carry-through Natural gas can be unintentionally carried through to a storage vessel during a liquid delivery event (e.g., due to gas entrainment caused by inefficient gas/liquid separation as a result of an undersized separator, or due to the formation of a vortex at the entrance to the liquid outlet line) or through a delivery valve that is stuck in an open or partially-open position (i.e., where a valve failed to properly reseat).

Vapor Recovery Tower (VRT) A tall or elevated vertical separator installed immediately upstream of a storage tank; it is used to recover flash gas from oil at pressures slightly above local atmospheric pressure. Oil is dispensed from a separator or treater into the VRT and flows by gravity from the VRT into the storage tank. Use of a VRT captures flash gas without risk of the vapors being contaminated with air, while greatly reducing the amount of flashing occurring in the storage tanks.

Vapor Recovery Unit (VRU) A specialized compressor package (e.g., rotary vane, rotary screw, vapor jet or eductor) designed to capture low-pressure wet-gas streams from oil and condensate tanks and compress the gas into the suction of a gas conservation compressor or into a low-pressure gas gathering system.

Volatile Organic Compounds (VOC) - Organic substances that can photo-chemically react in the atmosphere to form secondary particulate matter and ground-level ozone. For NPRI purposes, the definition for VOCs comes from the "Order" adding toxic substances to Schedule 1 of the Canadian Environmental Protection Act, 1999, Section 1" published in the Canada Gazette, Part II, July 2, 2003. This excludes methane, ethane, methylene chloride, methyl chloroform, acetone, many fluorocarbons, and certain classes of per fluorocarbons specified as exclusions in Section 65 of Schedule 1 of the List of Toxic Substances established under CEPA 1999 (for the list of excluded substances, see www.laws.justice.gc.ca/eng/acts/C-15.31/page-124.html#h-115).

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1 INTRODUCTION

Researchers assert that a significant portion of methane emissions are from a small number of large, temporally-dynamic emitters that include storage tanks (Zavala-Araiza et al, 2018; Lyon et al., 2016; and Lavoie et al., 2017). This study investigates possible root-causes of fugitive and venting emissions from aboveground, fixed-roof, storage tanks at upstream oil and gas facilities located in Alberta and British Columbia. A field troubleshooting decision tree is proposed for determining whether tank emissions are due to malfunctioning equipment that can be repaired or process conditions (e.g., gas flashing) that can be controlled. Common component malfunctions are identified and the range of repair costs discussed. A critical review of gas flashing quantification methods is undertaken with results spot-checked with available field measurements. Finally, techno-economic assessments are completed for ten storage tank emission mitigation options.

This study is funded by Alberta Upstream Petroleum Research Fund Program (AUPRF) managed by Petroleum Technology Alliance Canada (PTAC) and directed by the Air Research Planning Committee (ARPC). The report is prepared by Clearstone Engineering Ltd. with support from Greenpath Energy Inc and Vanguard Engineering Inc.

The methodologies for collecting study data, completing root-cause analysis and quantifying flashing losses are described in Section 2. Root-cause observations, a troubleshooting decision tree and evaluation of empirical correlations used to estimate gas flashing are presented in Section 3. An economic assessment of actions to mitigate tank venting is presented in Section 4 while conclusions and recommendations are in Section 5. All references cited herein are listed in Appendix Section 6 along with cost details and drawings for mitigating actions investigated.

1.1 BACKGROUND

Fixed-roof tanks are the primary equipment for storing hydrocarbon liquids in the UOG industry. **Venting emissions** from fixed-roof, atmospheric tanks include contributions from three different types of losses: breathing/standing, working (i.e., filling and emptying) and flashing. Breathing and working contributions are small relative to flashing losses. Flashing losses occur at production sites where unstable products (i.e., products that have a vapour pressure greater than local barometric pressure) are produced into storage tanks. When an unstable product first enters a tank, a rapid boiling or flashing process occurs as the liquid tends towards a more stable state (i.e., the volatile components vapourize). The material that vapourizes during flashing is called solution gas and flow rates are typically estimated using the Peng-Robinson equation of state (and a commercial process simulator) or empirical correlations (that can be implemented in a spreadsheet).

Ideally, associated gas is captured and conserved or disposed via a flare or vapour combustor. **Fugitive emissions** may occur from pressurized components associated with vapour capture systems (i.e., equipment leaks) or unintentional gas carry-through from upstream vessels. An illustration of how tank vapours are collected (at almost atmospheric pressure); piped through a separator to remove free liquids (suction scrubber); and delivered to a sales pipeline is presented in Figure 1. An electric drive rotary screw compressor is typically used to deliver gas into a gathering pipeline and downstream reciprocating compressor (with minimum suction pressure of about 344 kPag or 50 psig). Blanket fuel gas is supplied to the ullage space and to ensure tank pressure is maintained above its minimum allowable working pressure during unloading periods. Subject tanks are also equipped with a pressure vacuum relief valve as a secondary precaution against implosion and to ensure the tank does not exceed maximum allowable working pressure.

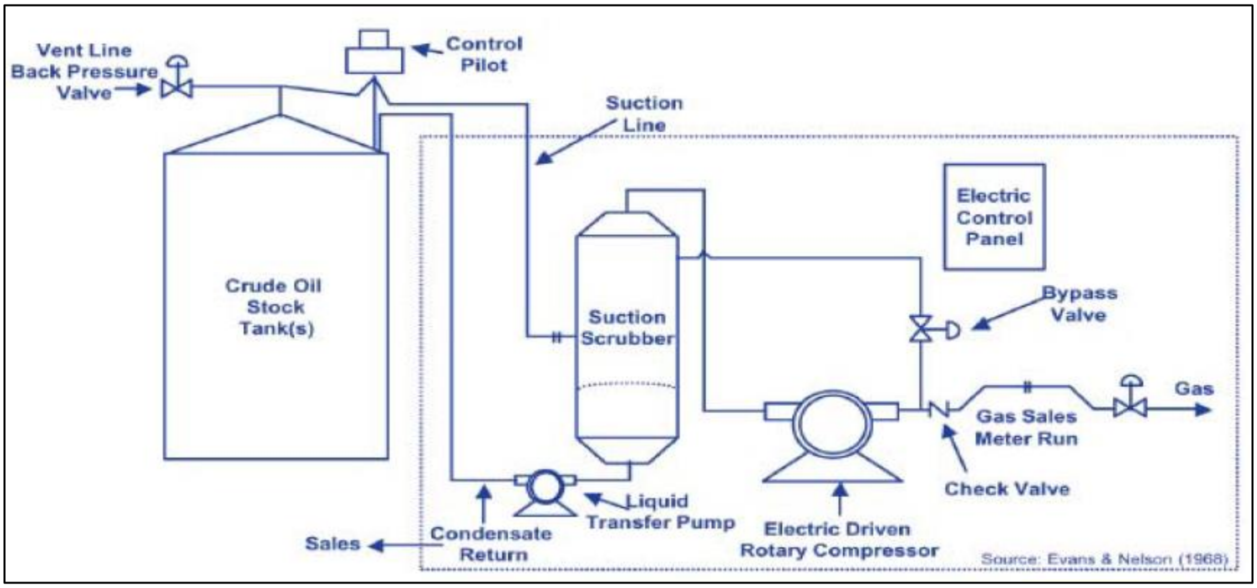


Figure 1: Schematic of a fix-roof storage tank and vapour recovery system (Evans and Nelson, 1968).

Researchers assert that a significant portion of methane emissions are from a small number of large, temporally-dynamic emitters (Zavala-Araiza et al, 2018; Lyon et al., 2016; and Lavoie et al., 2017) that may be under stated in national inventories. Gas carry-through to storage tanks due to leakage past drain valves into tank inlet headers, inefficient gas-liquid separation in upstream vessels, malfunctioning level controllers or leakage past the seat of level control valves, or unintentional storage of high vapour pressure liquids in atmospheric tanks are observed to be noteworthy sources at some sites and can be temporally-dynamic. Because these losses are from storage tanks designed to vent, Fugitive Emission Management Programs (FEMP) typically classify them as 'process vents' with **no remedial action required**. Therefore this study will endeavor to provide a troubleshooting decision tree that can be incorporated into FEMP and leak detection and repair (LDAR) surveys.

In Alberta, Directive 060 will require sites commissioned **before** January 1, 2022 not to exceed a site-wide 'overall vent gas' (OVG) limit[2] of 15,000 m^3 (or 9 tonnes methane) per month while sites commissioned **after** January 1, 2022 cannot exceed a 'defined vent gas' (DVG) limit[3] of 3,000 m^3 (or 1.8 tonnes methane) per month (AER, 2018a). Because the methane fraction of tank vapour is typically much less than produced natural gas, the methane mass limit will likely determine which tanks are controlled in Alberta. The British Columbia methane regulations are more aggressive with storage tanks at sites commissioned **before** January 1, 2022 limited to 9,000 m^3 natural gas per month while sites commissioned **after** January 1, 2022 are limited to 1,250 m^3 natural gas per month (BC OGC, 2018a). Federal methane regulations (that apply to jurisdictions without equivalent regulation) require all facilities that receive or deliver more than 60,000 m^3 of gas per year not to exceed a site-wide limit of 1,250 m^3 per month (GC, 2018). Because the effectiveness of regulatory limits depends on reliable quantification of tank losses, a critical review of quantification methods and comparison to field measurements is undertaken by this study.

This study focuses on condensate, light crude oil and medium crude oil production at well sites. Cold heavy oil production (CHOP) is excluded because tank venting is driven by well behavior and beyond the scope of this project. Moreover, the data available for this study does not support determination of population-average factors or how frequent components malfunction.

[2] The OVG limit includes all venting sources at a site.

[3] The DVG limit includes routine venting except pneumatics, compressor seals and dehydrators which have their own requirements. Thus, the primary contributor to DVG is storage tank losses.

2 METHODOLOGY

This study is based on field observations and data relevant to UOG facilities located in Alberta and British Columbia. A description of data collection activities, root-cause analysis and candidate methods for quantifying flashing losses is presented in the following subsections.

2.1 FIELD OBSERVATIONS

This study leverages storage tank operating conditions and infrared (IR) camera videos collected during BC and AB field campaigns completed by GreenPath Energy Ltd. (GreenPath) in 2018 and 2019. Subject datasets were screened by GreenPath to identify 117 tanks where fugitive and venting emissions appeared greater than the ECCC facility venting limit of 42 m^3/day (GC, 2018 effective January 1, 2023). A request for operators to participate in this tank study and provide the following details was issued by GreenPath to preserve data confidentiality.

- Tank and emission details collected during 2018 or 2019 field campaigns.
- Site process flow diagram (PFD)
- Storage tank piping and instrumentation diagram (P&ID). If P&IDs are not available, provide the maximum and minimum allowable working pressure for the subject tank (a photo of the tank nameplate is ideal).
- Operating pressure and temperature of vessel(s) immediately upstream of subject tank.
- Oil and gas disposition volumes relevant to the survey month.
- If the site has a treater, the pump rate (m^3/hr) for recycling slop oil.
- Laboratory analysis of relevant oil/condensate and gas streams.
- An explanation or copy of spreadsheet currently used to estimate storage tank emissions.

To highlight the importance of tank research, the request for industry participation was endorsed by Petroleum Technology Alliance Canada (PTAC), BC Oil and Gas Commission (BC OGC), Climate Action Secretariat (CAS), Alberta Energy Regulator (AER), Explorers and Producers Association of Canada (EPAC) and Canadian Association of Petroleum Producers (CAPP) via letters presented in Section 6.2. Industry responded with voluntary participation of 9 companies representing 63 storage tanks.

2.1.1 BC FIELD CAMPAIGNS

The Province of BC and ECCC sponsored a study to estimate the number and types of equipment and components that may release methane to the atmosphere during operation. GreenPath technicians surveyed 266 BC locations operated by 21 different companies during September 2018. Of the sites visited in the study, storage tanks were estimated to have the second greatest source of natural gas venting after pneumatics (Cap-Op, 2019). It's estimated 38 percent of BC tank venting is from tanks labelled to contain water with vapour confirmed to be composed of hydrocarbons (not steam). Because the BC study did not collect vapour samples for laboratory analysis, the methane concentration of water and hydrocarbon storage tanks losses could not be confirmed.

The BC data was screened to identify candidate tanks and solicit companies for participation in the current study. 9 of the 63 storage tanks investigated are located in BC.

2.1.2 AB FIELD CAMPAIGNS

Energy Efficiency Alberta (EEA) provides incentives for AB industry to improve productivity, save energy and reduce emissions. In 2018, EEA announced incentives for Baseline Opportunity Assessments (BOA) and LDAR surveys as part of a methane emission reduction program. These incentives resulted in BOA/LDAR surveys and collection of emission and process equipment (including storage tanks) data for thousands of small UOG facilities. The AB BOA data was screened to identify candidate tanks and solicit companies for participation in the current study. 38 of the 63 storage tanks investigated are located in AB.

2.2 ROOT-CAUSE ANALYSIS

2.2.1 DESKTOP REVIEWS

Desktop reviews were completed for 47 of 63 fixed-roof tanks storing produced hydrocarbons and/or water. 16 tanks were not investigated because emission plumes were small or insufficient site data was available to support meaningful outcomes. The minimum information required is the site measurement schematic, separator operating conditions, stored liquid type and IR video. Based on these details, reviewers could identify possible root-causes and define specific questions for site operators to investigate. Possible root-causes were informed by 30 years of environmental consulting experience relevant to storage tank fugitive and venting emissions. Operators provided repair details, process data and/or equipment conditions that confirmed specific mechanism responsible for emissions observed by the IR camera. These mechanisms are described in Section 3.1 and broadly categorized by the following root-causes.

- Volatile liquid flashing (typically defined as venting emissions)
- Unintentional gas carry-through (typically defined as fugitive emissions)
- Tank-top equipment component leak (typically defined as fugitive emissions)

In some cases, laboratory analysis of pressurized samples are available for the subject hydrocarbon liquids. This knowledge plus separator pressure, temperature and hydrocarbon liquid throughput enables quantification of flashing loss rates using a process simulator or empirical correlation described in Section 2.3. Comparing calculated emission rates to IR videos provides a qualitative indicator of whether the observed plume is strictly due to separator liquid flashing or whether other, unintentional mechanism(s) contributed.

2.3 QUANTIFICAITON OF FLASHING LOSSES

Whenever a hydrocarbon liquid is placed in contact with a gas at pressurized conditions, it will absorb some of the gas. If that liquid is subsequently dispensed to a storage tank, the dissolved gases will be released as flashing losses, which is a rapid form of evaporation (e.g., a boiling event). Flashing losses occur at production facilities and potentially at some downstream oil and gas facilities. The schematic depicted in in Figure 2 is an example of associated gas flashing out of solution due to the pressure drop between the upstream vessel (e.g. a separator) and downstream vessel (e.g., stock tank).

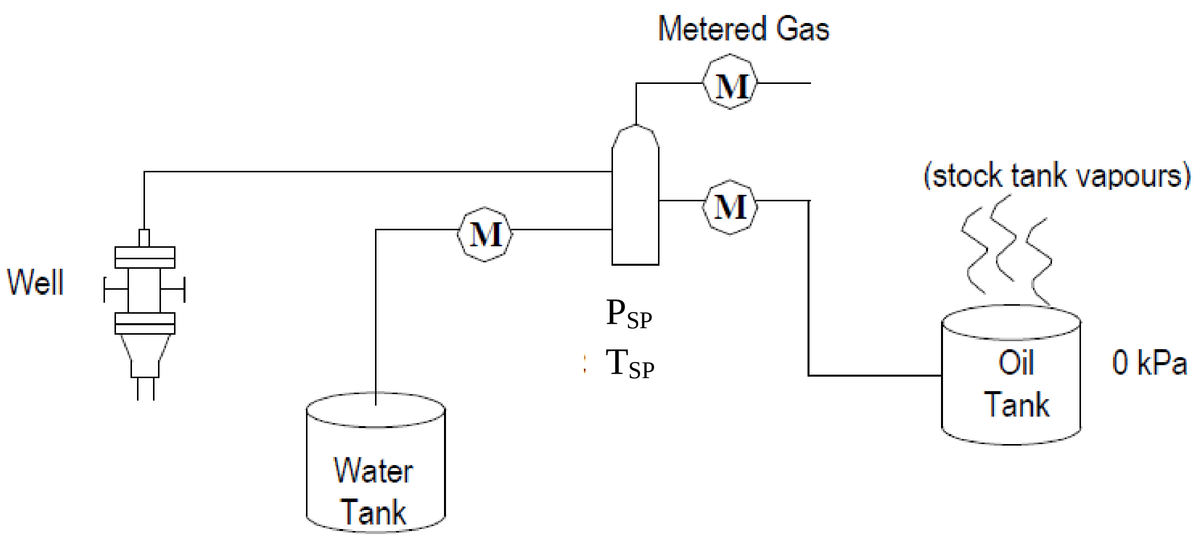


Figure 2: Oil well schematic with 3-phase separation and metering (source: AER Directive 017).

Gas-in-solution (GIS) and gas-to-oil ratio (GOR) factors are used to determine the quantity of flash gas released per unit of stock tank oil produced. When flash gas factors are determined at stock tank reference pressure and temperature they are referred to as GIS. When flash gas factors are determined at standard conditions of 101.325 kPa and 15.6 ºC they are referred to as GOR. The magnitude of these factors depends on the separator and stock tank hydrocarbon fluid composition; separator pressure; separator temperature; local barometric pressure and stock tank oil temperature. The impact of vessel pressure and temperature on flash gas generation was the subject of a recent US study and generally described as follows (Southern Petroleum, 2018):

- Flash gas **increases** with **higher** separator pressure because larger fractions of volatile compounds partition to the liquid phase in the separator at higher pressures, and subsequently flash in the tank.
- Flash gas **increases** with **lower** separator temperature because larger fractions of volatile compounds partition to the gas phase in the separator at higher separator temperatures.
- Flash gas **increases** with **higher** tank temperature because larger fractions of volatile compounds partition to the gas phase in the tank at higher temperatures.
- Flash gas **increases** with **lower** tank pressure because smaller fractions of volatile compounds partition to the gas phase in the tank at higher pressures. This has little impact on flash gas from atmospheric storage tanks.
- Flash gas **increases** with **lower** liquid hydrocarbon density because lighter oils contain more volatile hydrocarbons.

Ideally flash gas factors are determined based on product specific field samples for representative operating conditions according to the following requirements stated in AER Directive 017 (or equivalent in other provinces).

4. A 24 hour test may be conducted such that all the applicable gas and oil volumes produced during the test are measured. The gas volume is divided by the oil volume to result in the GIS factor.
5. A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis should be based on the actual pressure and temperature conditions that the oil sample would be subjected to downstream of the sample point, including multiple-stage flashing. The GIS factor is calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.
6. A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the GIS factor based on the compositional analysis.

Some circumstances permit operators to use correlations listed in the 2002 Canadian Association of Petroleum Producers (CAPP) Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities are also permitted. (CAPP, 2002). These correlations are also used to predict flashing losses for emission inventory purposes. To spot check how well Directive 017 site testing requirements align with correlations, flash gas factors are determined according to the methods presented in Table 1 and described in Appendix Section 6.3.1 to 6.3.1. Results of this assessment are presented in Section 3.2.

In general, the accuracy of flash gas factors improves with modelling sophistication and process data granularity. Input data requirements for each of the methods are indicated in Table 1. The

AER ‘Rule-of-Thumb’ is the simplest and only requires knowledge of upstream pressure while process simulations are complex and require detailed process knowledge.

Table 1: Input process data required for selected flash gas estimation methods.				
Input Parameter	**AER ‘Rule-of-Thumb’**	**Vazquez and Beggs**	**Valko and McCain**	**VapourSIM**
Stock tank oil density (API gravity)		**X**	**X**	**X**
Stock tank oil temperature				**X**
Stock tank oil RVP				**X**[1]
Local atmospheric pressure				**X**[1]
Stock tank vapour molecular weight		**X**		
Upstream separator pressure	**X**	**X**	**X**	**X**
Upstream separator temperature		**X**	**X**	**X**
C_1 to C_{30} analysis of pressurized liquid sample				**X**

[1] *Simulation users select flashing end point of interest (atmospheric pressure or RVP)*

Evaporative losses due to tank breathing and working activities are estimated using the ‘Evaporative Loss from Fixed-Roof Tanks’ method (EPA, 2006b) and are not accounted in the flashing methods described in Appendix Section 6.3. Emissions are much less than flashing contributions for the production pressures considered in Section 3.2 and therefore not investigated further. Production casing gas and associated gas produced off the separator are separate and potentially additional contributions to site-wide venting. These solution gas sources are not investigated by this study.

3 RESULTS

Results of the desktop reviews, feedback from site operators and root-cause observations are discussed below. A decision tree for identifying intentional and unintentional contributions to uncontrolled storage tank losses is proposed. Solution gas flashing determined by five different quantification methods are presented with method merits and challenges discussed.

3.1 ROOT-CAUSE OBSERVATIONS

Mechanisms responsible for fixed-roof storage tank venting and fugitive emissions are described in the following subsections.

3.1.1 VOLATILE LIQUID FLASHING

Fixed-roof tanks located at primary production facilities are intended to store volatile hydrocarbon liquids from separators and treaters. Therefore it's not surprising that, of the tank emissions investigated by operators, approximately half were attributed to volatile liquid flashing. The observed separator pressure, temperature, throughput and product type resulted in venting rates (predicted by correlation) reasonably consistent with the plumes recorded by IR cameras.

Tank labels are not always a reliable indicator of tank contents or venting rates. A number of 'water' tanks were observed to release gas and could be attributed to 'unintentional gas carry-through' described in Section 3.1.2. However, incomplete separation is also possible. This results in hydrocarbons being entrained with water and flashing in the 'produced water' tank. Confirmation and the quantity of hydrocarbons in produced water is typically available from the company handling water disposals.

Colorado based investigation of gas flashing from produced water concluded with a static estimate of 0.7 m^3 gas per m^3 produced water (SLR, 2018). Moreover, because hydrocarbon liquids are less dense than water, they float and can form a thin layer on top of water in a storage tank. These hydrocarbons will evaporate into the tank vapour space and be released to the atmosphere during working and breathing periods.

Storage tanks connected to oil treaters will vent more than determined from stock tank production volumes. Recycle volumes should also be included in the volume multiplied by the flash gas factor. Heavier hydrocarbons (and water) that settle to the bottom of tanks is often referred to as 'slop' and typically recycled to the treater inlet. When recycled slop enters the treater it re-absorbs gas at the treater operating conditions which is flashed when delivered back into the storage tank.

Other process conditions that increase gas flashing are investigated in more detail in Section 3.2.

3.1.2 TANK TOP EQUIPMENT LEAKS

Tank-top equipment leaks are only relevant to controlled storage tanks where vapours are directed to a conservation or destruction system (but leak from associated equipment). Their root-cause can be malfunctioning equipment components or incorrectly set, undersized or blocked components that cause tank ullage pressures to exceed relief set-points.

Examples of malfunctioning equipment components include the following and can be repaired through routine maintenance work.

- Thief hatches are installed on most fixed-roof tanks to provide access for level gauging, sampling and overpressure/vacuum protection. Over time gasket material can deteriorate or be damaged so that it no longer provides a complete seal between the hatch and seating face. An imperfect seal provides a pathway for tank vapours to leak into the atmosphere. Moreover, thief hatches may open during overpressure events and may remain partially open until an operator closes the hatch.
- Level gauge assemblies installed on controlled fixed-roof tanks are typically digital systems for measuring liquid level, internal pressure and internal temperature. These instruments are mounted on a manway cover by flange or threaded connection. Wear and tear or improper installation can cause the connections to leak. Level gauges can also be mechanical systems but are typically only installed on uncontrolled tanks because they provide a venting pathway (e.g., A float resting on the liquid surface is connected, by a wire, to an external gauge board. This includes a gauge head pulley system that provides a pathway for tank vapours to vent).
- Pressure relief valves (PRV) and pressure/vacuum relief valves (PVRV) are installed on roof-tops to protect tanks from over/under pressure events. Over time gasket material can deteriorate or be damaged so that it no longer provides a complete seal between the pallet and seating face. An imperfect seal provides a pathway for tank vapours to leak into the atmosphere.

Examples of problems that cause tank ullage pressures to exceed relief set-points include the following.

- If overhead vapour lines are not sloped to a low point and drained (e.g., into a flare knock-out drum), liquids can accumulate and block gas flow. This applies a backpressure on the tank ullage and, when set point pressure is exceeded, will cause the PRV, PVRV and/or thief hatch to open (pop). Once opened, thief hatches remain partially open until an operator closes the hatch.

- If pipe supports are not designed to preclude frost heaves, then the pipe rack can develop low spots where liquids accumulate, produce a flow restriction and cause the relief devices to open.
- If the diameter of overhead vapour lines is too small, back pressure during peak venting periods can cause the relief devices to open.
- Overhead vapour lines fabricated with carbon steel without any internal lining are susceptible to corrosion and fouling. Line blockage resulting from corrosion products can cause back pressure relief devices to open. Vapour line fouling can be detected (and mitigated) by instrumentation that detects pressure drop across downstream flame arrestors. If fouling starts to occur in the vapour collection piping, it usually impacts the flame or destination arrestor first and is detected based on the magnitude of the pressure drop across the arrestor.
- If the blanket gas regulator set point is too close to the pressure set point of the PRV, PVRV and/or thief hatch, small atmospheric or process pressure changes can cause the relief devices to open.

Repairing components associated with a controlled tank typically require a full or partial site shut-down. Therefore, repair timing can be delayed to align with other maintenance work or downstream facility outages. It involves planning the shutdown, emptying the tank, isolating (lock-out) the tank; purging with an inert gas (e.g., nitrogen); accessing with a manlift; disassembling/replacing/repairing the component; purging the tank with natural gas; removing lock-out and returning the tank to service. Material costs range from almost zero (e.g., if repair is limited to cleaning and taping threads with Teflon tape) to a few hundred dollars (e.g., for a gasket kit) or greater depending on the extent of pipe/component requiring replacement. 'Typical' tank-top repairs require two operators and will last 2 to 8 hours so labour costs can range from $200 to $1000. If repairs involve changes to process piping or instrumentation, a 'management of change' process involving engineering and updates to drawings is required. Valuing the cost of a site shut-down depends on throughput, current commodity prices and view on whether the down time should be included in the repair cost.

3.1.3 UNINTENTIONAL GAS CARRY-THROUGH

Unintentional gas carry-through is less recognized, potentially significant and often an unaccounted contribution to atmospheric emissions of methane from storage tanks.

3.1.3.1 PASSING DUMP-VALVES

The most common cause observed is from leakage of process gas or volatile product past valve seats connected to the product header leading to storage tanks. Hard substances (e.g., sand, wax or other debris) can deposit on a valve seat and prevent the disk fully sealing with its seat, as indicated in the Figure 3 globe valve example. The seat or disk can also be scoured or damaged to the point where a full seal is not possible. The most common instance of these problems are on liquid (hydrocarbon or water) control valves immediately downstream of separators or scrubbers (commonly referred to as ‘dump-valves’). Other instances of this leak type are observed on manual by-pass valves that result in direct connection between high-pressure production fluids and atmospheric tanks.

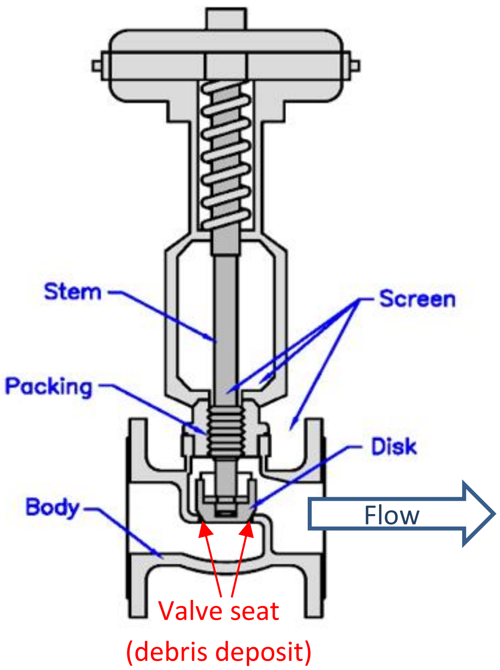


Figure 3: Globe control valve with debris deposit area indicated.

It’s also possible for level controllers to malfunction and send a false output signal that keeps the dump-valve open (and passing gas to the storage tank). Malfunctioning can be due to a ‘hung-up’ float assembly or change in liquid density that prevents the assembly from returning to its expected level.

Tell-tail indicators of a passing valve include:

- An empty (dry) separator vessel. Operators can confirm control-valve is passing by closing a manual isolation valve and observing whether liquids accumulate in the separator.
- Ice build-up on a ‘closed’ valve. This is caused by large pressure drop and phase change from liquid to gas across the valve body.
- Continuous venting from the downstream tank (detected with an IR camera).
- ‘Noise’ across the valve body (detected with an acoustic leak instrument[4]).

4 Portable acoustic leak detectors (e.g., VPAC™ II) can estimate the internal leakage past the seat of a valve (through valve leakage). These instruments require the operator to enter the valve type, size and differential pressure (pressure upstream vs downstream of the valve), and place a hand held acoustic probe with some gel on the

Operators indicated their first attempt to repair a passing dump-valve involves closing a manual isolation valve downstream of the separator that allows liquids to accumulate. Opening the manual valve to flush the system and dislodge the offending substance (this process may be repeated several times). If this doesn't resolve the problem, a work order is generated to repair or replace the valve.

This type of job involves an operator collecting parts from the area warehouse, isolating the vessel/valve; depressurizing and draining the vessel; disassembling the valve and replacing internal parts (trim[5]) or the entire valve; purge the vessel/valve with natural gas; and return to service. The subject vessel will typically be out of service for an hour or two but this can be prolonged if unforeseen challenges are encountered. If the subject process fluids contain H_2S additional steps to purge the vessel with an inert gas (e.g., nitrogen) and/or conduct repairs with a supplied air breathing apparatus (SABA) are required.

Repair costs range from almost zero if the problem is resolved by flushing the problematic valve or manually resetting the level controller (by opening the instrument cover and temporarily applying force to the span levers or displacer rod). If repairs are limited to replacing valve trim or the entire valve, operator cost estimates range from $500 to $2400 (for materials, equipment and labour) depending on site proximity (i.e., operator travel time from central office or warehouse), valve location (i.e., is a manlift required to access overhead piping), sour service, and type/number of subject valves (i.e., if more than one valve might be leaking, its more efficient to replace control and bypass valves while vessel is out of service). If repairs involve changes to process piping or instrumentation, a 'management of change' process involving engineering and updates to drawings is required.

Overall, costs reported by operators to repair a passing dump-valve ranged from zero to $7,500 depending on the nature of the problem and number of people involved.

3.1.3.2 INEFFICIENT SEPARATION

Inefficient separation of gas and liquid phases upstream of the tanks allowing some gas carry-through, by entrainment or in solution, to the tanks. Sustained high liquid levels in the separator will initiate frequent signals for the dump-valve to open resulting in continuous flow of pressurized hydrocarbon liquids to the storage tanks. This condition reduces residence time for separation of gas from the liquid phase and may cause storage tank flashing to exceed solution

body of the value. The acoustic signal observed by the instrument and valve properties are used to estimate the through valve leak rate from an empirical derived database of laboratory tested valves with known through valve leak rates.

[5] The removable and replaceable valve internal parts that come in contact with the flow medium are collectively termed as Valve trim. These parts include valve seat(s), disc, glands, spacers, guides, bushings, and internal springs. The valve body, bonnet, and packing that also come in contact with the flow medium are not considered valve trim.

gas losses predicted by a simulator or correlation (strictly based on the subject liquid properties and separator conditions). Sustained high liquid levels can be caused by:

- Significant inlet liquid production (e.g., produced water) increase over time resulting in a facility's inlet separators being undersized for current conditions.
- Pipeline pigging operations that accumulate and drive large liquid volumes to inlet separators.
- Unexpected liquid slug production by gas wells.

It is also possible for a vortex to form at the drain of the vessel sending liquids to the storage tank. The cone formed by swirling liquids creates a pathway for gas to enter the liquid dump line. This behavior is difficult to validate because its internal to the separator. However, its not expected to occur very often because vortex breakers are typically installed in separator drains to prevent liquid swirling.

3.1.3.3 PIPING ANOMALIES

Although very few instances were observed in the field data, piping anomalies can occur.

It's possible for piping (or changes to piping) to result in unintentional placement of high vapour pressure product in tanks not equipped with appropriate vapour controls. For example, reciprocating compressor packages are normally deigned to recycle liquids accumulating in 2nd, 3rd and greater compression stage scrubbers back to the 1st stage scrubber inlet. To minimize flashing losses, only the lowest pressure scrubber (1st stage) should deliver liquid to a storage tank[6]. However, there are instances where highly volatile liquids, accumulated in subsequent compression stage scrubbers, are piped directly to atmospheric tanks and cause unnecessary storage tank emissions.

Flashing losses due to scrubber deliveries can be estimated knowing the pressure of each compression stage and condensate risk matrix presented in Figure 12 (or calculated directly from correlations in Section 2.3 if detailed data is available) and volume of liquids dispensed.

Although considered infrequent and not validated by subject operators, other examples of abnormal piping observed during 2017 field surveys (Clearstone, 2018) may be explained by the following piping configurations.

- Recombining separator gas, after metering, into the liquid line connected to a tank. This type of configuration is likely driven by the lack of a gas gathering system.

[6] Alternatively, a blowcase can be used to recombine liquids into the high pressure gas sales line.

- Purge gas supplied to a separator liquid line and connected to a storage tank. It is speculated this is to purge liquids from the dump line and prevent freeze-off.
- Oil well production casing connected to a storage tank. The subject oil battery is not connected to a gas gathering system so casing gas is used for site fuel demands with any excess gas directed to the tank. It is speculated this was done to elevate the release point and promote dispersion.

3.1.4 DECISION TREE

To support first attempts at field level troubleshooting and root-cause identification, the decision tree depicted in Figure 4 is proposed. It is intended to identify equipment components or process conditions responsible for continuous venting from uncontrolled storage tanks. The decision tree is a systematic process for determining whether tank venting may be due to component malfunction (that can be repaired) or inherent to the pressurized hydrocarbons stored. The decision tree can be integrated into FEMP and completed by LDAR survey technicians (equipped with an IR camera and portable acoustic leak detector). It is applicable to continuous venting, observed by IR camera (or other detection method), from uncontrolled tanks storing hydrocarbons and/or water. It is **not** applicable to tank venting that occurs at an intermittent frequency corresponding to the separator dump frequency because this is an indicator of equipment components operating according to their design.[7] It is **not** applicable to tanks equipped with emission controls that conserve or combust the vapours. Unintentional emissions from controlled tanks are due to tank-top component leaks and detected with an IR camera (or other detection method).

Using the decision tree begins at the offending tank and involves tracing pipe to the upstream vessel(s) responsible for delivering liquids (or walking directly to the vessel(s) if predetermined from P&IDs or identified by the site operator). These vessels can be separators, treaters, scrubbers, or drain sumps. If equipped with a level gauge, the vessel liquid level and dump-frequency can be monitored as follows.

- Sustained high-liquid level and frequent/continuous dump events are an indicator of inlet liquid flows greater than separator design capacity. Under these conditions, there may be insufficient residence time for gas to fully disengage from liquids before delivery to the tank.
- Sustained low-liquid level (or empty vessel) and frequent/continuous dump events are an indicator of a malfunctioning level controller. Under these conditions, the controller may be sending a false signal for the dump valve to remain open.

[7] When viewed by an IR camera, intermittent tank venting should appear as a large plume; associated with instantaneous flashing when pressurized liquids enter the tank; that decreases in magnitude until the next dump event. The plume may not decrease to ‘zero’ because of residual weathering of oil between dumping events. If dumping events are infrequent (e.g., occurring once per hour or more), a very small or zero plume may be observed which is an indicator of intermittent venting.

- Sustained mid-liquid level or rising/descending levels (that align with dump frequency) are an indicator of sufficient separator capacity and intended level control. Under these conditions, the offending component may be the dump-valve. This is checked with an acoustic leak detector by placing a probe on the valve body. If liquids or gas are passing through the closed valve, vibrations (noise) are generated and an acoustic signal is observed by the instrument. An empirical correlation is then used to estimates the leak rate based on the signal strength, valve type and pressure differential across the valve.

If the vessel is not equipped with a level gauge, it's more difficult to determine the root-cause but frequent/continuous dumping should motivate a maintenance check of the level controller. If the controller is operating correctly, the vessel may not have sufficient capacity for current throughput. Regardless, the dump-valve should be checked with the acoustic leak detector (between dump events) to confirm whether it is the offending component.

If these troubleshooting steps don't identify a root-cause then the subject vessel is unlikely to be the source of continuous venting. The same steps should be repeated for all other vessels connected to the tank. Locating connected scrubbers and drain sumps can be more difficult than identifying upstream separators or treaters. It requires patient pipe walks and/or consultation with site operators and P&IDs (especially if pipe racks are insulated). If all connected vessels are checked and no problems identified, then the root-cause may be due to an abnormal piping configuration or the flashing of volatile liquid hydrocarbons. As discussed in Section 2.3, the magnitude of gas flashing increases with increasing separator pressure, increasing oil API gravity and decreasing separator temperature.

The decision tree is a first attempt at determining root-cause and alerting maintenance personal to potential equipment problems. Maintenance activities are required to confirm root-causes and repair offending equipment components. When integrated into FEMP, it should sensitize maintenance efforts to equipment that may be malfunctioning and unknowingly contributing to tank venting.

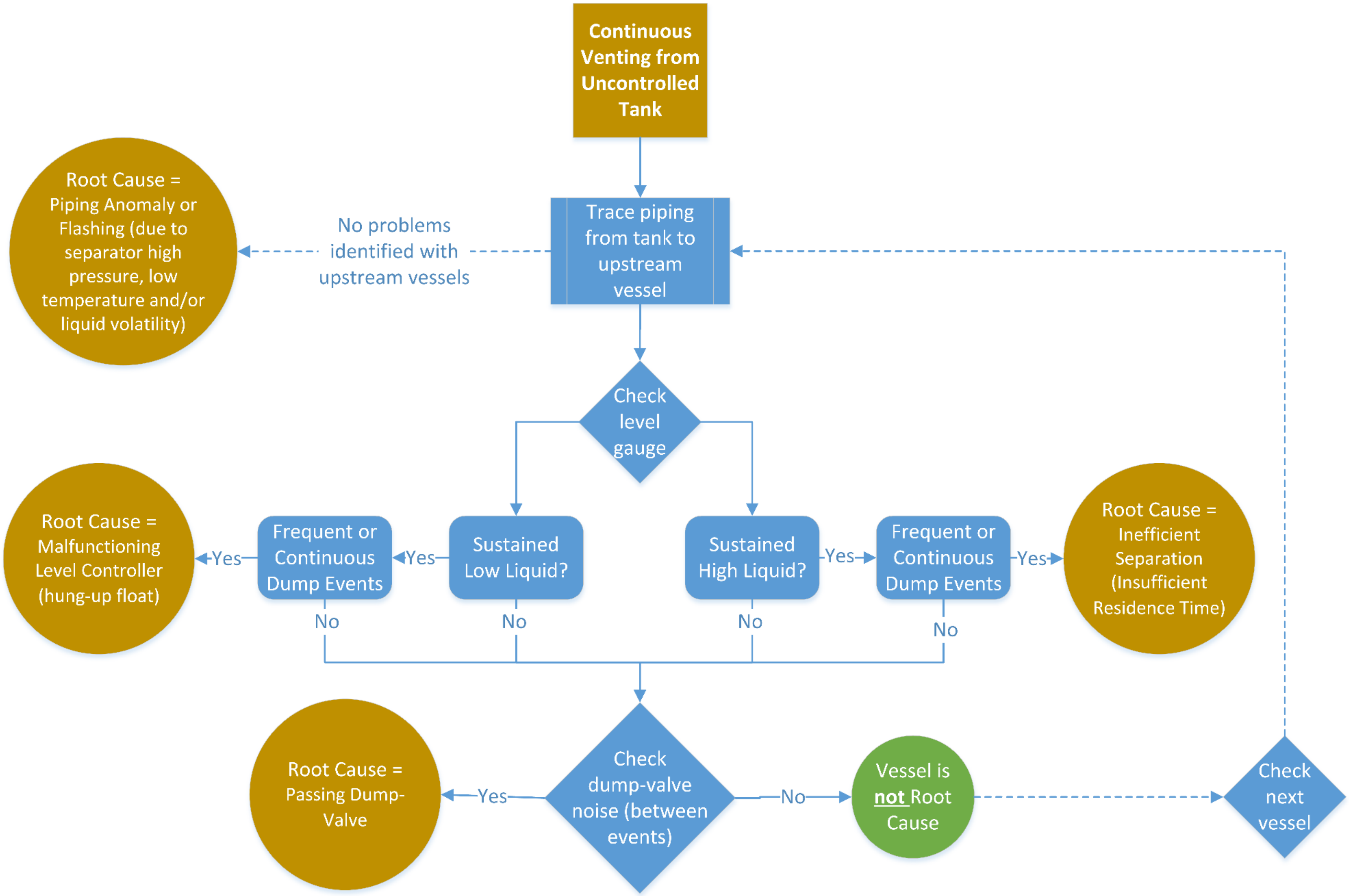


Figure 4: Decision tree for troubleshooting the root-cause of continuous venting from uncontrolled storage tanks.

3.2 COMPARISON OF GOR DETERMINED BY SIMULATION, CORRELATION AND DIRECT MEASUREMENT.

GOR is calculated according to the four methods presented in Section 2.3 over the range of separator pressure and temperature observed in the field dataset. To illustrate the relevant range and impact of process conditions, GOR is plotted as a function of pressure (with constant temperature) in Figure 6 to Figure 8 with the distribution of observed separator pressures (for 41 venting tanks) also presented. Alternatively, GOR is plotted as a function of temperature (with constant pressure) in Figure 9 to Figure 11 with the distribution of observed separator temperatures (for 35 venting tanks) also presented. Separator pressure and temperature distributions are derived from the sample of atmospheric storage tanks described in Section 2.1 and do not include controlled or low emitting tanks. Thus, distributions are biased toward tanks with greater venting rates. The relevance of separator operating conditions to emission inventories and environmental reporting is discussed further in Section 3.2.1.

To illustrate the volatility of different production types, GOR is plotted separately for condensate, light crude oil and medium crude oil product types corresponding to the properties of pressurized liquid samples presented in Table 2. Presenting results for specific samples enables comparison with process simulation results and, for two sites, direct measurement results. Table 2 contains a small number of data points and is not used for deriving correlations. Instead, subject measurement and simulation results are used to spot check correlation results.

Table 2: Pressurized sample and stock tank conditions for VapourSIM calculations.					
Parameter	**Units**	**Condensate[2]**		**Light Oil**	**Medium Oil**
GOR Measured in the Field	-	Yes	No	No	Yes
Upstream Separator Temperature	^{o}C	12	18	10	18
Upstream Separator Pressure	kPag	700	1800	1780	800
Stock Tank Liquid Temperature	^{o}C	10	10	10	10
Stock Tank Liquid API Gravity	^{o}	66.4	66.4	43.4	30.1
Stock Tank Liquid RVP[1]	kPa	70.2	70.2	41.8	25.4
Ambient Temperature	^{o}C	11	1	27	15
Ambient Pressure	kPa	91.1	91.1	96.7	90

[1] Stock tank oil RVP was not measured at selected sites. Therefore, RVP is estimated based on the measured API gravity and the empirical correlation in the Colorado Air Pollution Control Division PS Memo 05-01 (CAPCD, 2005).

[2] Subject condensate stock tanks are tied into an LP flare header that imposes about 1.3 kPa backpressure on the tank. Ambient pressure is increased accordingly to represent flashing pressure end point.

Data collection described in Section 2.1 identified two sites with sufficient tank-top gas and sales oil flow measurements to spot check GOR determined by correlations. The first is a gas battery with condensate storage tanks tied into a low pressure (LP) flare that is equipped with an optical flow meter. LP flare flows exceed 500 m^3 per day so combined metering uncertainty is required to be less than 5 percent of the monthly volume (BC OGC, 2018b). Condensate liquids are transported by truck and measured by weigh scale. Liquid deliveries are less than 100 m^3 per day so combined measurement uncertainty is required to be less than 1 percent of the monthly volume (BC OGC, 2018b). Total daily gas and liquid volumes are obtained from a data historian corresponding to dates when pressurized liquid samples were collected. Pressurized sample integrity is confirmed by comparing bubble point pressure (determined by VapourSIM) to sampling pressure (at sample temperature). This quality assurance step indicated only 1 of 3 samples are within percent difference tolerance listed in Table 16. Thus, only one simulated GOR is plotted for condensate in Figure 6.

The second site is a light oil battery where tank-top gas flow measurements and sampling was motivated by offsite odour questions and to characterize atmospheric emissions of GHGs and criteria air contaminants (CACs). The battery featured a single oil well flowing to a 2-phase vertical separator (operating at about 1780 kPag and 10 ^{o}C) with gas flowing to an incinerator and oil flowing to two 750 BBL atmospheric storage tanks. No emission control was installed on the tanks. Tank-top gas flow measurements were completed by Clearstone using an ultrasonic meter. The tank vent gas was sampled using evacuated SiloCan™ canisters while pressurized hydrocarbon liquids were sampled off the separator using evacuated stainless steel cylinders. Sampling and determination of GOR was completed according to the measurement protocols presented in Appendix Section 6.3[8]. Integrity of the pressurized oil sample was confirmed by the bubble point quality assurance check (described in Section 6.3.1).

GOR representative of the **peak instantaneous venting** was determined using VapourSIM, based on the pressurized oil sample analysis results and reported oil production rate, and flash calculation endpoint equal to stock tank temperature and local barometric pressure. GOR representative of **total venting** was determined using VapourSIM, pressurized sample analyte fractions, and flash calculation endpoint equal to RVP (which is less than local barometric pressure).

Tank-top venting was metered over a 4 hour period (between 12:30 and 16:30) and was characterized by the cyclical behaviour depicted in Figure 5 due to the use of on/off level control

[8] This procedure for collecting pressurized liquid samples is adapted from the American Petroleum Institute E&P TANK Version 2.0 User's Manual (API, 2000). Refinements to sampling procedures (completed after the subject test) are adopted in some jurisdictions and should be referenced by laboratories collecting pressurized samples and determining the volume and composition of gas flashed. Refined test procedures are stated in appendix B of the California Air Resource Board's (CARB) Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (CARB, 2019).

on the separator. Peak flow rates occur during dumping events which occurred approximately every 100 seconds and comprise flashing and working (physical displacement) contributions. Venting decreases substantially between dumping events, but does not decrease to zero even though there is no oil flow to the tank during these periods. The minimum flow rates observed in Figure 5 are attributed to residual weathering of the oil between dumping events. Ultimately, the oil will weather to its sales product RVP which typically varies by season due to impacts on the tank operating temperature. Further, although less dramatic weathering may occur during subsequent handling and transport to the receiving refinery. It is reasonable to predict peak instantaneous emissions by flashing the oil to local barometric pressure and the stock tank temperature and also accounting for working contributions. To account for total venting it is more appropriate to flash the product to its sales oil RVP, which effectively performs a mass balance based on the composition of the oil leaving the separator and the composition of the oil leaving the stock tank (the difference is the total vent gas contribution).

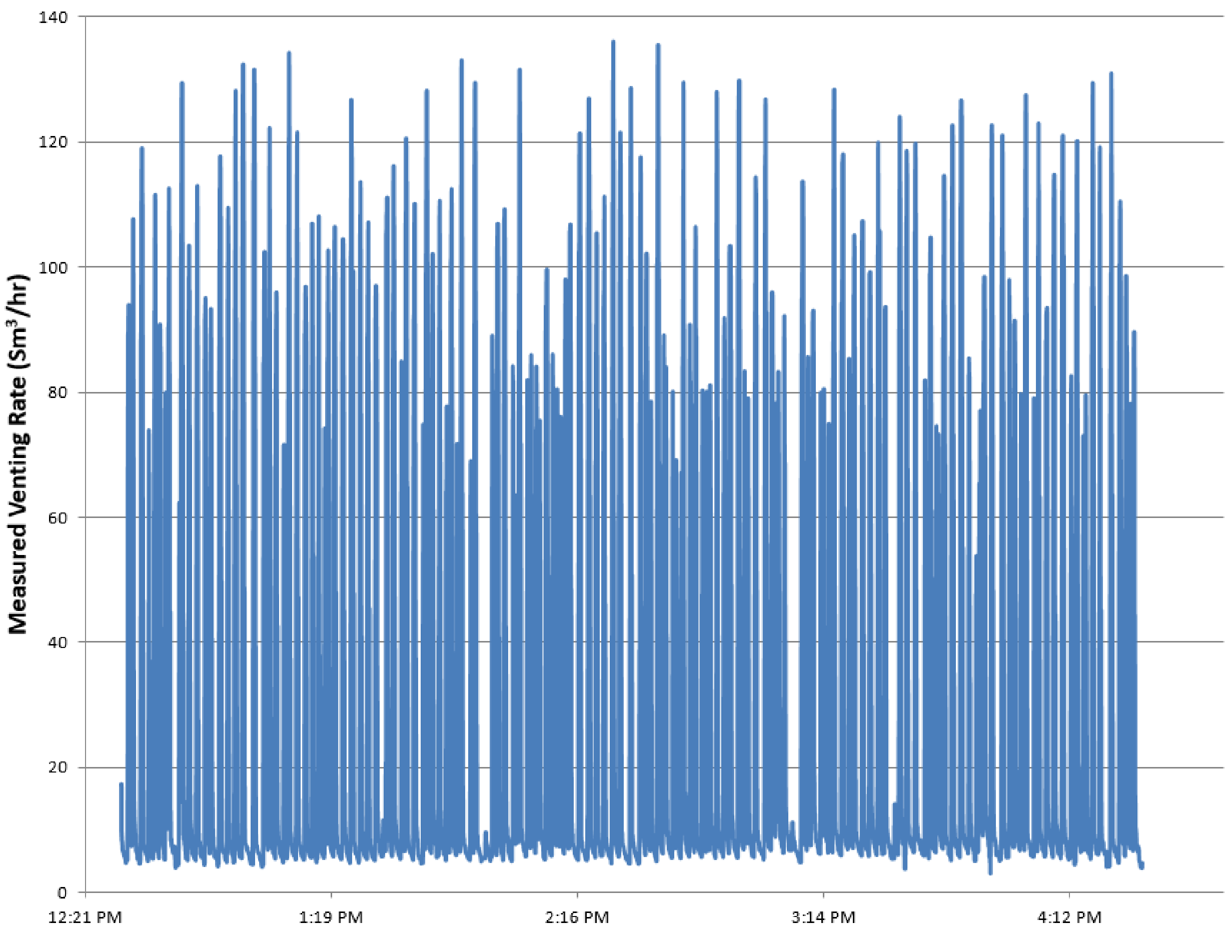


Figure 5: Storage tank venting measured by ultrasonic flow meter over a four hour period at a light oil battery.

Storage tanks can display temporally-dynamic emission behavior. Tanks tied into new, high producing wells may display almost continuous venting plumes while tanks tied into mature or end-of-life wells may display sporadic venting plumes. The example measurements presented in Figure 5 were completed six months after the subject well started producing and are representative of its peak production period. When observed by IR Cameras, the venting plume should 'pulse' at the dump event frequency (e.g. every 100 seconds). If no additional wells are tied into the tank and oil production declines, the magnitude and frequency of gas flashing, and plume 'pulse' rate, will decrease. Lyon et al. (2016) observed a positive correlation between oil production and emission detection and speculated it was related to more frequent tank flashing events due to greater production rates.

3.2.1 SEPARATOR OPERATING CONDITIONS

National emission inventories (NIR) for the UOG industry and time series 1990 to 2011 (CAPP, 2005 and ECCC, 2014) feature flashing correlations that apply separator operating conditions representative of mature conventional oil production and consistent with minimum suction pressure for reciprocating compressors receiving gas from production batteries (e.g., separator pressure = 441 kPaa and temperature = 30^{o} C). However, an increase in solution gas production is observed between 2011 and 2017 in AER ST98 raw gas production statistics (see Figure S5.3 in AER, 2019) and is an indicator of greater oil production pressures. Therefore, it is reasonable for separator pressure used in NIR to increase accordingly.

The mean separator pressure for the distribution embedded in Figure 6 to Figure 8 is 870 kPaa (but is likely biased upward because study data only includes tanks with large emission plumes). Determining a more representative separator pressure and temperature for emission inventories should be based on random sampling and not field data available to this study (described in Section 2.1 with inherent upward bias). Notwithstanding and in the absence of a random dataset, information available at this time indicates a representative separator pressure is likely between 441 and 870 kPaa while temperature is between 14 and 30 ^{o}C.

Moreover, economic conditions are motivating greater development of gas wells containing natural gas liquids in Petroleum Services Association of Canada (PSAC) area AB2 (Foothills Front - west central Alberta) and BC2 (Northern BC). BC2 accounts for all gas production in BC while AB2 accounts for more than 50 percent of Alberta gas production and both feature deep (greater than 1,500 meter), high pressure and liquids-rich reservoirs (e.g., shales like the Montney and Duvernay). As production of natural gas liquids increases, the population (and/or throughput) of separators with operating pressures greater than 441 kPaa will increase. However, volatile liquids are typically re-combined with sales gas after metering; stored in pressurized vessels (bullets); or stored in controlled tanks so the increase in liquids-rich gas production is not a conclusive indicator of increasing flashing emissions across the UOG industry. Section 3.3 describes field evidence that most liquids-rich gas batteries feature 'wet-metering' or tank controls and are not a source of excessive flashing. Conversely, instances of uncontrolled condensate tanks at liquids-rich gas batteries likely exceed regulated methane limits.

3.2.2 GOR AS A FUNCTION OF SEPARATOR PRESSURE

GOR is calculated with correlations and plotted as a function of separator pressure for condensate with API gravity of 66.4 in Figure 6; light oil with API gravity of 43.4 in Figure 7; and medium oil API gravity of 30.1 in Figure 8. GOR determined by VapourSIM are plotted as cross markers and used to spot check correlation results. Red font markers indicate a flash end point equal to atmospheric pressure and stock tank temperature (representative of instantaneous venting when pressurized liquid enters the tank). Green font markers indicate a flash end point equal to sales oil RVP and representative of total venting due to instantaneous flashing plus weathering over a longer period of time. The difference between red and green simulated GOR is the contribution from working and breathing losses (i.e., weathering) that occurs over the entire period oil is stored in the tank (e.g., days, weeks or months). The simulated flash end-point (e.g., atmospheric pressure or RVP) is selected depending on GOR end use. For example, the maximum instantaneous flashing rate, determined by choosing atmospheric pressure end-point, is necessary for designing VRUs. Alternatively, total venting determined with RVP end-point is appropriate for environmental reporting concerned with total atmospheric emissions.

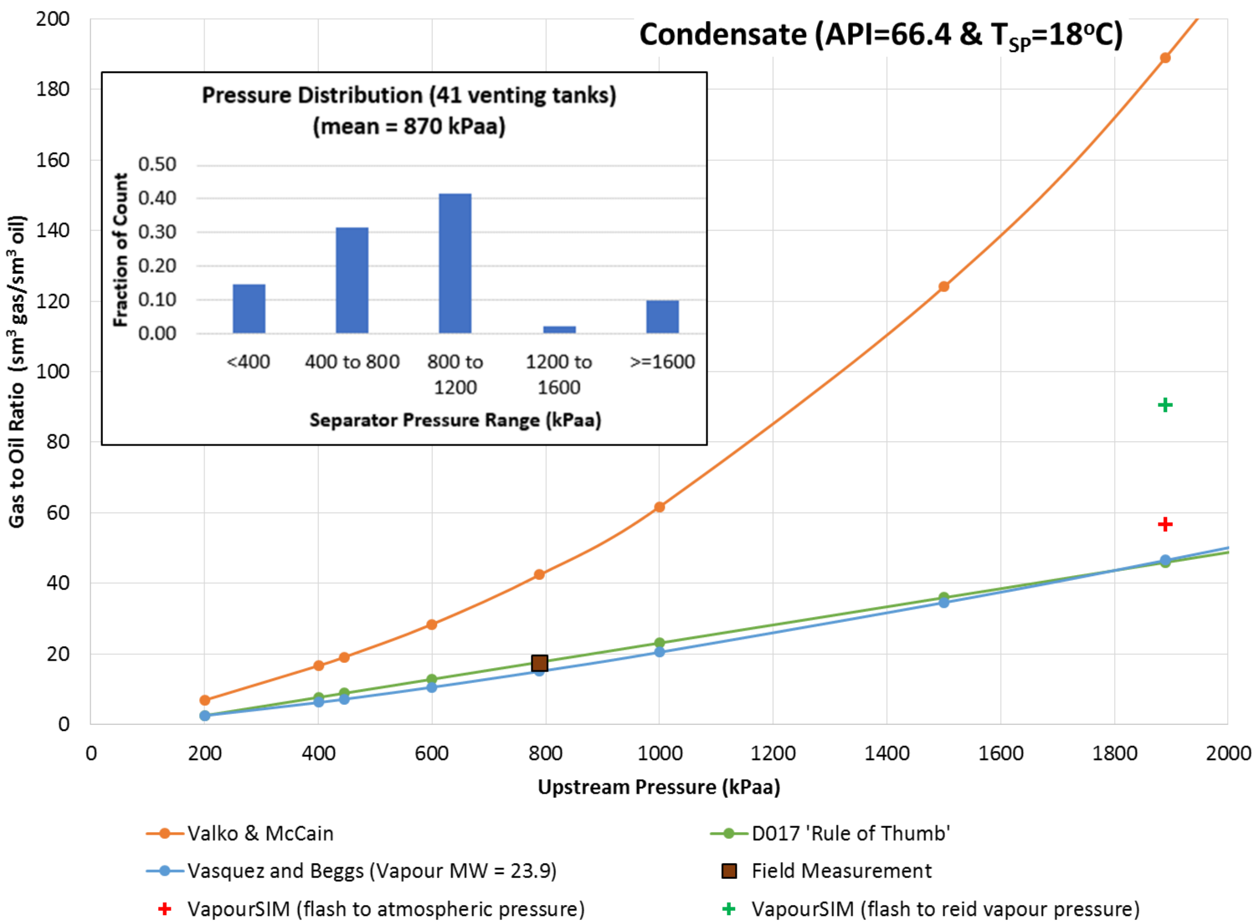
GOR determined by field measurements are plotted as brown box markers and also used to spot check correlation results.

The VapourSIM (flashed to atmospheric pressure) and measured GOR results are reasonably aligned with Valko and McCain results for light (see Figure 7) and medium crude oils (see Figure 8). This is expected because the pressure and temperature of subject oil streams and API gravity of the subject oil samples are within the range of conditions the correlation was derived from (stated in Table 20). However, GOR predicted by Valko and McCain for condensate is more than 2 times greater than VapourSIM (flashed to atmospheric pressure) and measured GOR results plotted in Figure 6. This is attributed to the condensate API gravity (66.4) being greater than the maximum API gravity (56.8^{o}) used to derive the Valko and McCain correlation. Moreover, their 2003 publication describes a small upward bias (0.4 percent) for separator pressures greater than 690 kPag. It’s speculated this upward bias is exacerbated when API is greater than the correlation upper bound (56.8^{o}) and responsible for 2^{nd} degree polynomial behavior displayed in Figure 6.

VapourSIM GOR results, determined by flashing pressurized sample to their sales oil RVP, are greater than light and medium crude oil GORs determined by all correlations. This is because flashing to RVP represents total venting and accounts for all evaporative losses (i.e., flashing, working and breathing) that occur over a long period of time. GORs determined by this method are sensitive to the sales point and RVP selected[9]. Because stock tank oil RVP is not always monitored by producers, some jurisdictions have approved estimation correlations (CAPCD, 2005), that may result in conservative (positive bias) flashing results. The difference between subject VapourSIM results (plotted as green cross markers) and other methods highlights the importance of RVP selection point and laboratory determination.

AER rule-of-thumb is simple to implement and not vulnerable to sampling challenges. It provides reliable flashing values for light oil but tends to overstate medium oil flashing and understate condensate flashing.

GOR calculated with the Vazquez and Beggs correlation are less than VapourSIM (flashed to atmospheric pressure) and measured spot checks for each product type plotted. Other studies have observed the Vazquez and Beggs correlation to underestimate flashing emissions (Gidney and Pena, 2009).



9 Crude oil weathering continues along the entire supply chain with the greatest RVP occurring at the stock tank and lowest RVP at refinery receipt tanks.

Figure 6: GOR correlation estimates over separator pressure range of 200 to 2,000 kPaa for condensate with API = 66.4º and separator temperature = 18 ºC.

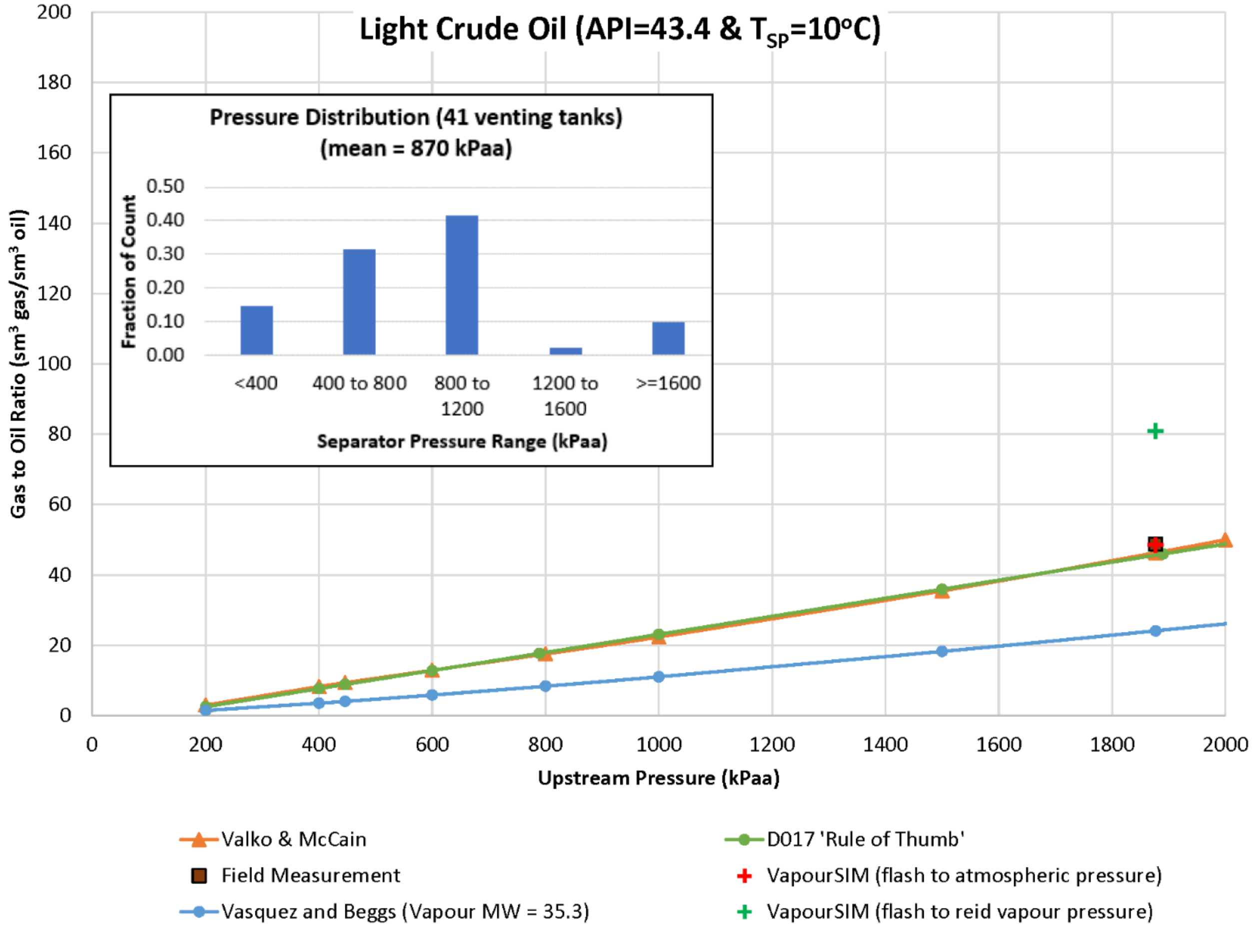


Figure 7: GOR correlation estimates over separator pressure range of 200 to 2,000 kPaa for light crude oil with API = 43.4º and separator temperature = 10 ºC.

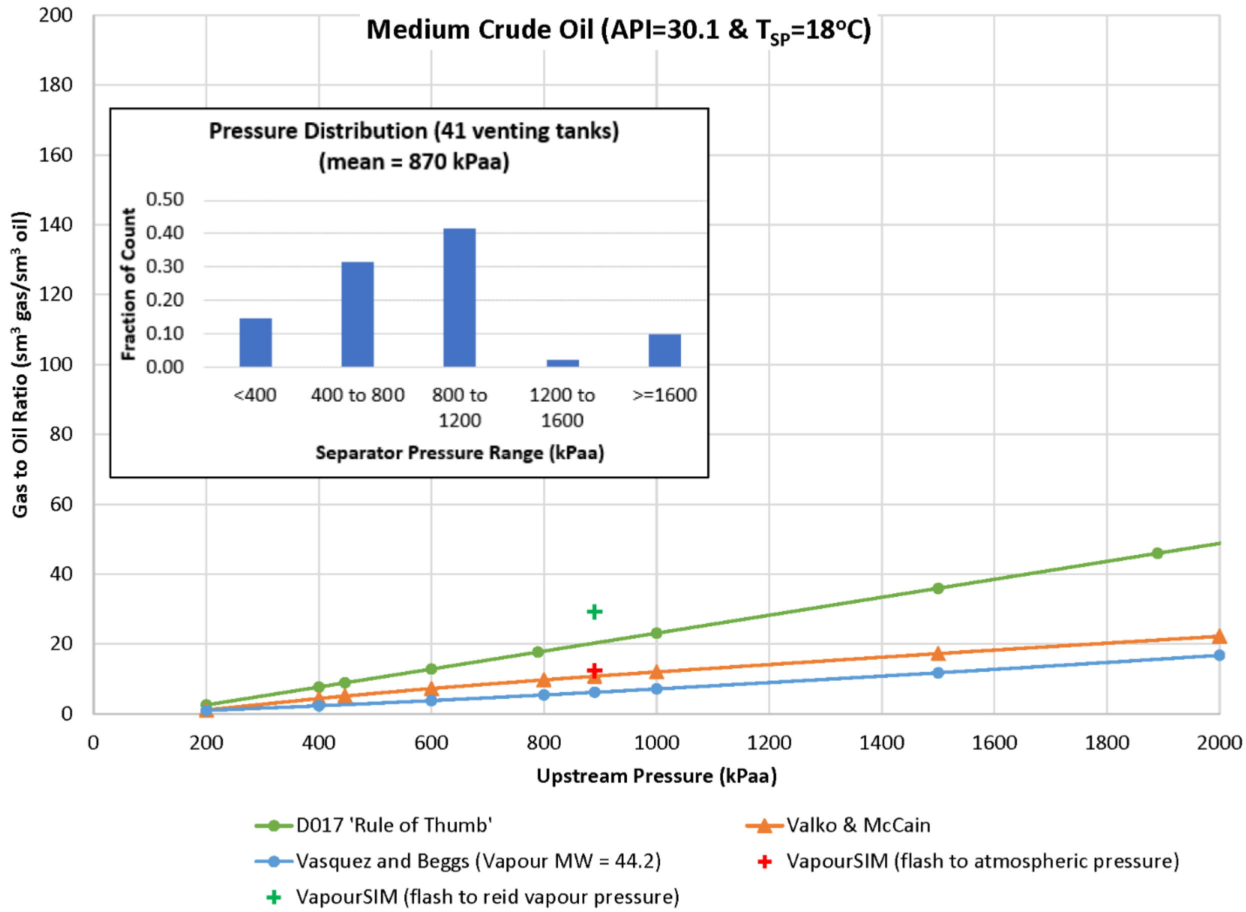


Figure 8: GOR correlation estimates over separator pressure range of 200 to 2,000 kPaa for a medium crude oil with API = 30.1° and separator temperature = 18 °C.

3.2.3 GOR AS A FUNCTION OF SEPARATOR TEMPERATURE

GOR is calculated with correlations and plotted as a function of separator temperature for condensate with API gravity of 66.4 in Figure 9; light oil with API gravity of 43.4 in Figure 10; and medium oil API gravity of 30.1 in Figure 11. GOR determined by VapourSIM are plotted as cross markers and used to spot check correlation results. Red font markers indicate a flash end point equal to atmospheric pressure and stock tank temperature (representative of instantaneous venting when pressurized liquid enters the tank). Green font markers indicate a flash end point equal to sales oil RVP and representative of total venting due to instantaneous flashing plus weathering over a longer period of time. GOR determined by field measurements are plotted as brown box markers and also used to spot check correlation results.

These trends indicate GOR is dependent on separator temperature when using the Valko and McCain but not the Vazquez and Beggs or rule-of-thumb correlations. Because the temperature distribution range is small (e.g., 5°C to 30°C), deviations from GOR predicted using the mean temperature of 14°C are less important.

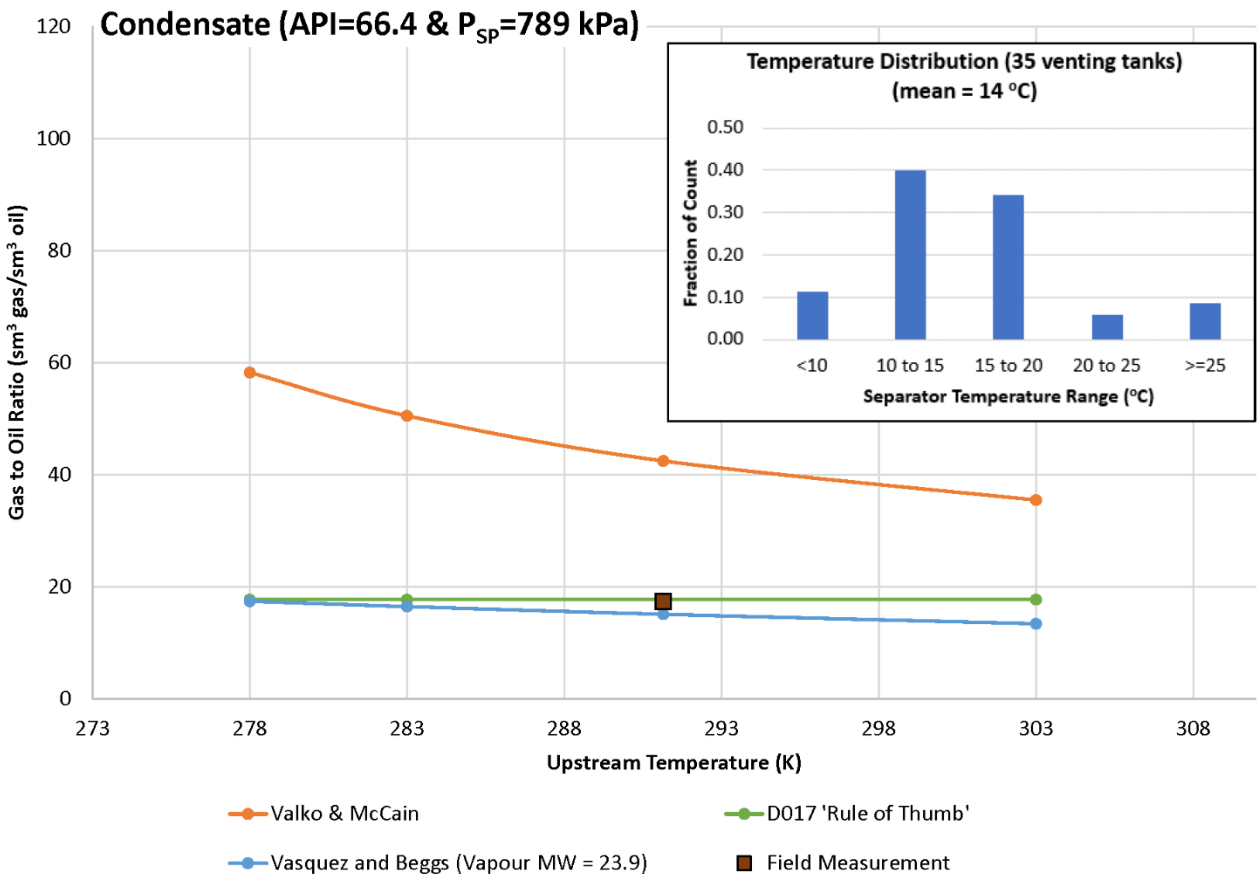


Figure 9: GOR correlation estimates over separator temperature range of 278 to 303 K for condensate with API = 66.4° and separator pressure = 789 kPaa.

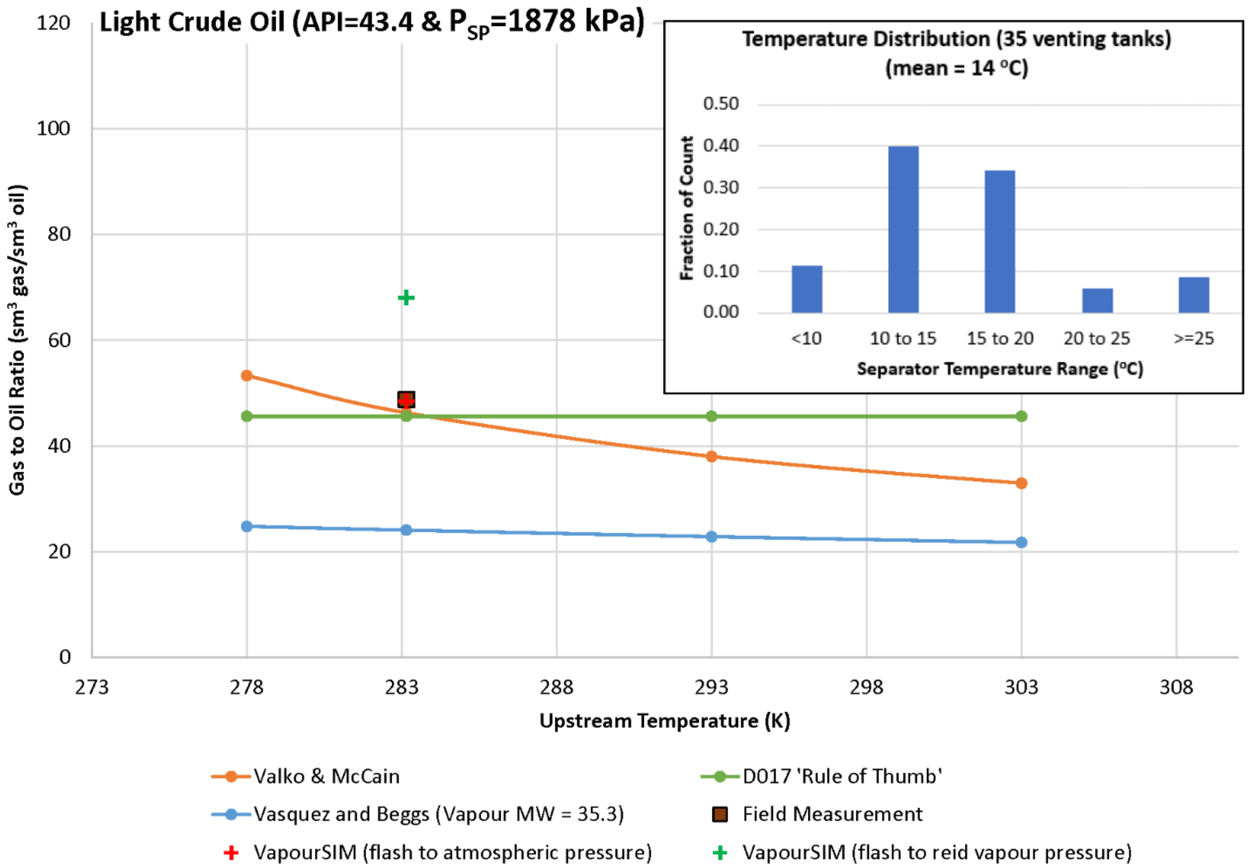


Figure 10: GOR correlation estimates over separator temperature range of 278 to 303 K for light oil with API =43.4º and separator pressure = 1,878 kPaa.

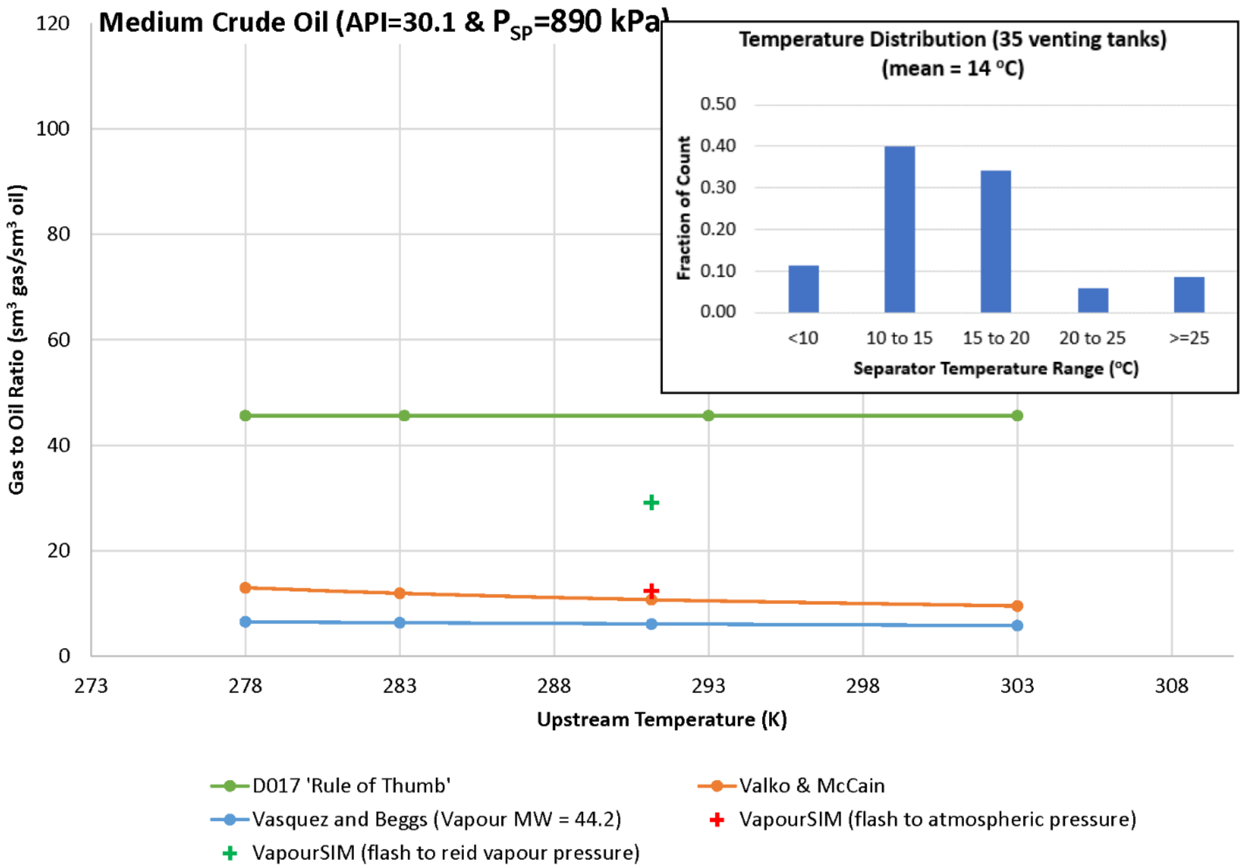


Figure 11: GOR correlation estimates over separator temperature range of 278 to 303 K for medium oil with API =30.1 and separator pressure = 890 kPaa.

The simulation and correlation method results presented above (except for rule-of-thumb) rely on the properties and analyte fractions determined by laboratories from pressurized oil samples. If collection and handling compromises sample integrity, subsequent outcomes may not be representative of actual site characteristics. Of the seven pressurized oil samples available and investigated by this study, only three laboratory analysis passed the bubble point pressure quality assurance test. The importance of reliable GOR for designing vapour recovery systems and environmental reporting is highlighted by recent EPA enforcement order research on hydrocarbon liquid sampling and analysis (EPA, 2015 and Southern Petroleum, 2018). To improve analysis data reliability the steps recommended by Colorado regulators, when performing and verifying flash gas liberation analysis on pressurized liquid hydrocarbon samples, should be considered (CAPCD, 2017).

3.2.4 TANK VENTING RISK MATRIX

To support first attempts at estimating tank venting during LDAR surveys, the risk matrix in Figure 12 is proposed. It provides tank vent rates based on separator pressure, oil production volume and the AER rule-of-thumb. This matrix is a simple and consistent method that provides a basis for evaluating the vent plume observed in the field by an IR camera. A plume that appears much greater than the vent matrix rate is an indicator that equipment components may be malfunctioning and contributing to tank venting. If the vent matrix rate is consistent with the plume magnitude it improves confidence in tank vent rates stated in LDAR reports and helps identify sites at risk of exceeding regulated methane limits. Estimated vent rates are coloured according to whether they are less than the following limits.

- Green when estimate is less than Environment and Climate Change Canada (2020) and British Columbia (2022) Methane Regulation limit of 42 m^3 per day.
- Pale green when estimate is less than Alberta Directive 060 (2022) Defined Vent Gas limit of 100 m^3 per day.
- White when estimate is less than British Columbia (2020) Methane Regulation limit of 300 m^3 per day.
- Pale yellow when estimate is less than Alberta Directive 060 (2020) Overall Vent Gas limit of 500 m^3 per day.
- Yellow when estimate is **greater** than Alberta Directive 060 (2020) Overall Vent Gas limit of 500 m^3 per day.

The vent matrix is a stop-gap method for LDAR service providers while more accurate vent measurement technologies are developed. Users should be aware that the rule-of-thumb overstates medium oil flashing and understates condensate flashing.

Hydrocarbon Tank Venting (m^3 per hour averaged over 1 day)

Estimated with AER Rule-of-Thumb

Select Separator Pressure (kPag)	Select Hydrocarbon Production Volume (m^3/day)																			
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
100	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1
200	0.2	0.4	0.6	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.9	4.1	4.3
400	0.4	0.9	1.3	1.7	2.1	2.6	3.0	3.4	3.9	4.3	4.7	5.1	5.6	6.0	6.4	6.9	7.3	7.7	8.1	8.6
600	0.6	1.3	1.9	2.6	3.2	3.9	4.5	5.1	5.8	6.4	7.1	7.7	8.4	9.0	9.6	10.3	10.9	11.6	12.2	12.9
800	0.9	1.7	2.6	3.4	4.3	5.1	6.0	6.9	7.7	8.6	9.4	10.3	11.1	12.0	12.9	13.7	14.6	15.4	16.3	17.1
1000	1.1	2.1	3.2	4.3	5.4	6.4	7.5	8.6	9.6	10.7	11.8	12.9	13.9	15.0	16.1	17.1	18.2	19.3	20.3	21.4
1200	1.3	2.6	3.9	5.1	6.4	7.7	9.0	10.3	11.6	12.9	14.1	15.4	16.7	18.0	19.3	20.6	21.8	23.1	24.4	25.7
1400	1.5	3.0	4.5	6.0	7.5	9.0	10.5	12.0	13.5	15.0	16.5	18.0	19.5	21.0	22.5	24.0	25.5	27.0	28.5	30.0
1600	1.7	3.4	5.1	6.9	8.6	10.3	12.0	13.7	15.4	17.1	18.8	20.6	22.3	24.0	25.7	27.4	29.1	30.8	32.6	34.3
1800	1.9	3.9	5.8	7.7	9.6	11.6	13.5	15.4	17.3	19.3	21.2	23.1	25.1	27.0	28.9	30.8	32.8	34.7	36.6	38.6
2000	2.1	4.3	6.4	8.6	10.7	12.9	15.0	17.1	19.3	21.4	23.6	25.7	27.8	30.0	32.1	34.3	36.4	38.6	40.7	42.8
2200	2.4	4.7	7.1	9.4	11.8	14.1	16.5	18.8	21.2	23.6	25.9	28.3	30.6	33.0	35.3	37.7	40.0	42.4	44.8	47.1
2400	2.6	5.1	7.7	10.3	12.9	15.4	18.0	20.6	23.1	25.7	28.3	30.8	33.4	36.0	38.6	41.1	43.7	46.3	48.8	51.4
2600	2.8	5.6	8.4	11.1	13.9	16.7	19.5	22.3	25.1	27.8	30.6	33.4	36.2	39.0	41.8	44.5	47.3	50.1	52.9	55.7
2800	3.0	6.0	9.0	12.0	15.0	18.0	21.0	24.0	27.0	30.0	33.0	36.0	39.0	42.0	45.0	48.0	51.0	54.0	57.0	60.0
3000	3.2	6.4	9.6	12.9	16.1	19.3	22.5	25.7	28.9	32.1	35.3	38.6	41.8	45.0	48.2	51.4	54.6	57.8	61.0	64.3

*Venting less than Environment and Climate Change Canada (2020) and British Columbia (2022) Methane Regulation limit of **42 m^3 per day***

*Venting less than Alberta Directive 060 (2022) Defined Vent Gas limit of **100 m^3 per day***

*Venting less than British Columbia (2020) Methane Regulation limit of **300 m^3 per day***

*Venting less than Alberta Directive 060 (2020) Overall Vent Gas limit of **500 m^3 per day***

*Venting **greater** than Alberta Directive 060 (2020) Overall Vent Gas limit of **500 m^3 per day***

Figure 12: Hydrocarbon tank venting risk matrix.

3.3 OBSERVED CONTROL OF FLASHING LOSSES AT GAS BATTERIES

The GOR ratios for pressurized condensates (see Figure 6) are greater than crude oils (see Figure 7 and Figure 8) and would result in greater flashing losses if stored in atmospheric tanks. However, condensate separated from primary gas production at wells and batteries is often recombined with the sales gas stream after metering[10] as illustrated in Figure 2 and referred to as 'wet-metering.' This type of metering configuration and 3-phase separation eliminates condensate flashing (except in cases where hydrocarbons unintentionally flow to the water tank and result in fugitive emissions) and is sometimes referred to as 'tank-less production.[11]'

A desire for continuous measurement of wellhead GOR, water liquids ratio, slug characteristics and other parameters to optimize reservoir performance is motivating technology innovation. An example is the "M-Flow Multiphase Meter" that employs microwave technology that can eliminate the need for wellsite separation, liquids storage and corresponding pneumatic instruments.

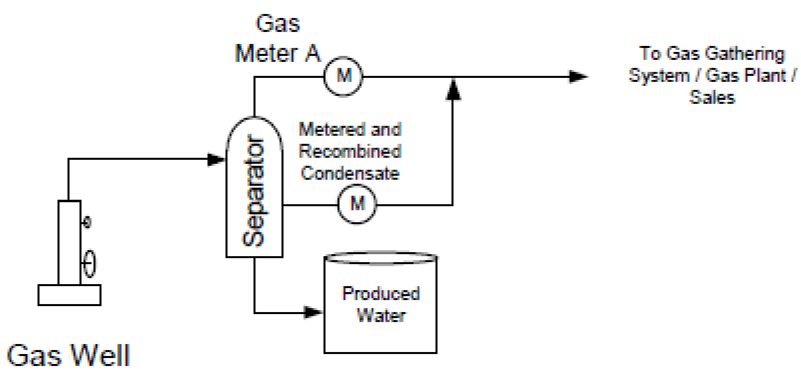


Figure 13: Gas well separation and metering schematic (source: AER Directive 017).

A review of Directive 017 and evidence collected during a 2017 field study (Clearstone, 2018) was completed to determine whether Petrinex facility subtypes consistently identify gas batteries where condensate is recombined **or** produced into storage tanks and flashed. The results of this review are as follows:

- Gas Multiwell Effluent Measurement batteries (subtype 362) feature continuous effluent (wet) measurement with no phase separation (or condensate is recombined into the sales

10 To achieve gas and oil/condensate measurement standards of accuracy defined in Directive 017, primary production from the well is typically separated into gas and liquid phase flows that are metered independently.

11 Alternatively, desire for continuous measurement of wellhead GOR, water liquids ratio, slug characteristics and other parameters to optimize reservoir performance is motivating measurement technology innovations with environmental co-benefits. An example is the "M-Flow Multiphase Meter" that employs microwave technology that can eliminate the need for gas wellsite separation, liquids storage and corresponding pneumatic instruments (M-Flow Technologies Ltd, 2019).

pipeline per Section 4.2.2.3 of Directive 017). This type of metering configuration was observed at all 12 batteries (with subtype 362) surveyed in 2017. Moreover, zero tank venting was detected at the 12 batteries.

- Gas Multiwell Proration SE AB batteries (subtype 363) feature shallow wells that produce low pressure gas from coal bed methane formations. Produced gas typically contains very little or no hydrocarbon liquids which explains why zero hydrocarbon storage tanks where observed at 11 batteries (with subtype 363) surveyed in 2017. If liquid hydrocarbons are present they are separated (2-phase) with water and stored in water tanks (e.g., there are only 2 instances of condensate production at subtype 363 batteries in the entire 2018 Petrinex dataset).
- Gas Multiwell Proration Outside SE AB batteries (subtype 364 or 367) are generally used for low productivity gas wells with low condensate or water production. Directive 017 does not require continuous measurement so condensate can be separated and stored in tanks. 4 of the 20 batteries (with subtype 364 or 367) surveyed in 2017 featured hydrocarbon storage tanks with tank venting detected at only 3 of the 20 batteries. 'Non-venting' sites featured tank-top capture and control **or** recombination of condensate into the sales pipeline.
- Gas Multiwell Group batteries (subtype 361 or 365) feature separation of gas and condensate so that each stream can be measured continuously as a single phase (per Section 4.2.2.2 of Directive 017). The 2017 field surveys observed hydrocarbon storage tanks at 18 of 28 batteries (with subtype 361 or 365) with tank venting detected at only 2 of the 28 batteries.
- Gas Single-well batteries (subtype 351) have the same measurement requirements as Multiwell Group batteries. 2017 field surveys observed hydrocarbon storage tanks at 9 of 20 single-well batteries with tank venting detected at only 2 of the 20 batteries.

Overall, tank venting was detected at 7 of 68 gas batteries with subtypes 351, 361 364, 365 and 367 while no tank venting was detected at subtypes 362 (that feature 'wet-metering') or 363 (that feature dry gas). Facility subtype 362 consistently identified 'wet-metering' operations that preclude hydrocarbon storage tanks. However, other subtypes include examples of facilities with and without hydrocarbon storage tanks. The key point is that emission inventories should only report tank emissions for batteries featuring liquid storage (instead of all that produce natural gas liquids) and ideally account for tank emission controls.

Hydrocarbon storage tanks were observed at all crude oil and crude bitumen battery types surveyed during 2017 so flashing losses are expected at these facility types.

4 TECHNO-ECONOMIC ASSESSMENT OF MITIGATING ACTIONS

This study investigates mitigating actions for primary oil and gas production facilities that feature one or more active wells and one or more fixed-roof storage tanks. As depicted in Figure 2, flashing emissions result from the delivery of pressurized hydrocarbon liquids to atmospheric storage tanks. These tank losses can be a significant source of GHG and volatile organic compound emissions as observed by emission detection studies (Clearstone, 2018; Zavala-Araiza et al, 2018; and Lavoie et al., 2017). Vapour control systems that preclude tank emissions are typically already installed at facilities featuring large throughput, sour service, odours, or highly volatile hydrocarbon liquids. However, recent methane regulations implemented in British Columbia (OGC, 2018a), Alberta (AER, 2018a) and across Canada (ECCC, 2018) will require mitigation of sweet tank venting that is typically uneconomic to conserve.

The range of tank venting rates considered by the economic assessment is based on the following provincial and federal methane regulatory limits.

- 42 m^3 per day tank vent limit specified by ECCC for 2020 and BC OGC for 2022.
- 100 m^3 per day Defined Vent Gas (DVG) limit specified by AER for 2022.
- 300 m^3 per day tank vent limit specified by BC OGC for 2020
- 500 m^3 per day Overall Vent Gas (OVG) limit specified by AER for 2020.
- 300 kg methane per day Overall Vent Gas (OVG) limit specified by AER for 2020 (equivalent to **1,000 m^3 per day** for tank vapour containing 44 percent methane by volume).
- 300 kg methane per day Overall Vent Gas (OVG) limit specified by AER for 2020 (equivalent to **3,000 m^3 per day** for tank vapour containing 15 percent methane by volume).

Key metrics and assumptions used to determine Net Present Values (NPV) are described in Appendix Section 6.5. Input values used for NPV calculations are presented in Appendix Section 6.6.

Net GHG emission reductions are assessed for each case as the difference between baseline and project emissions over the project life. Baseline emissions are equal to tank venting rates multiplied by the base-case venting emission factor presented in Table 3. Emissions for the project condition are determined using Table 3 emission factors and tank vapour end use described for each mitigating action investigated. Tank vapour methane fraction is a function of the produced hydrocarbon composition and separator operating conditions. The wide range of tank vapour compositions and corresponding properties are presented as upper and lower bounds in Table 3.

GHG emissions are expressed as CO_2E by applying the methane global warming potential (GWP) of 25 stated in the IPCC Fourth Assessment Report (AR4). Abatement cost curves presented below also feature results determined using methane GWP of 34 to acknowledge more recent science on the radiative forcing contribution of methane (Gasser et al., 2017).

Table 3: Typical tank vapour compositions and properties (Environment Canada, 2014).

Analyte Name	**Mol Fraction**		
	Base Case	**Upper Bound**	**Lower Bound**
Nitrogen	0.0297	0.06348	0.13999
Hydrogen Sulphide	0.0000	0.0000	0.0000
Carbon Dioxide	0.0134	0.00689	0.00330
Methane	0.5642	0.87234	0.10010
Ethane	0.1522	0.02262	0.15727
Propane	0.1163	0.00191	0.24160
n-Butane	0.0558	0.00114	0.16602
i-Butane	0.0265	0.00132	0.06640
n-Pentane	0.0158	0.00123	0.04545
i-Pentane	0.0126	0.00140	0.04211
Hexane	0.0093	0.00349	0.02966
Heptane plus	0.0042	0.02419	0.00800
Gas Mixture Properties			
MW (kg/kmol)	28.2334	19.90	44.24
HHV (MJ/m^3)	59.02	40.83	85.14
Combustion emission factor[1]	3.42	2.19	5.25
Flaring emission factor [1]	3.48	2.40	5.07
Venting emission factor [1]	9.60	14.82	1.70

[1] units of tonnes CO_2E per 1000 m^3 tank vapour and determined using AR4 GWP.

The mitigation approaches investigated are broadly grouped into two categories: tank top versus flash vessel vapour capture. Storage tanks certified with a minimum and maximum allowable working pressure rating can be fitted with overhead piping. Options to mitigate 100 percent of captured tank-top vapours are investigated in Section 4.1. Whereas non-certified tanks are not rated for pressure or vacuum service and at higher risk of failure if tank-top vapour capture piping is installed. Therefore, options to install a flash vessel between separators and non-certified tanks are investigated in Section 4.2. The applicability of each case depends on whether the subject site is connected to a natural gas gathering system; power distribution system; and or features sufficient lease area; certified tanks or a suitable well/reservoir for gas lift. Most UOG facilities operating in western Canada will satisfy one or more of the site requirements summarized in Table 4.

Table 4: Site features required for deployment of mitigating technologies.					
Case # and Description	**Connection to electric grid**	**Connection to gas gathering system**	**Certified tanks**	**Sufficient lease area**	**Well and reservoir suitable for gas lift**
#1 Tank Top to Existing High Pressure Flare	**X**		**X**		
#2 Tank Top to Low Pressure Flare			**X**	**X**	
#3 Tank Top to Booster Compressor for Gas Lift	**X**		**X**	**X**	**X**
#4 Tank Top to Vapour Combustor	**X**		**X**		
#5 Flash Vessel to Electrical Generators	**X**			**X**	
#6 Tank Top to Electrical Generators	**X**		**X**	**X**	
#7 Flash Vessel to Existing High Pressure Flare					
#8 Flash Vessel to Vapour Combustor					
#9 Tank Top to VRU for Gas Sales	**X**	**X**	**X**	**X**	
#10 Flash Vessel to VRU for Gas Sales	**X**	**X**		**X**	

The following sections provide a description of installed equipment and their process function; process flow diagrams (PFD), total installed capital cost (TICC) details; and annual GHG emission reductions for each mitigation case investigated. The resulting NPV, sensitivity analysis (identifying parameters most important to achieving a positive NPV), and average abatement cost curves (indicating influence of carbon valuation on NPV) are discussed below and summarized in Section 4.3.

4.1 TANK TOP VAPOUR CAPTURE

The following use cases, that involve tank-top vapour capture, are discussed in this section.

- Case #1 Tank Top to Existing High Pressure Flare Stack: Install blower for vapour tie-into high pressure flare.
- Case #2 Tank Top to Low Pressure Flare Stack: Install a low pressure flare.
- Case #3 Tank Top to Booster Compressor for Gas Lift: Install rotary vane compressor for vapour recovery and rotary screw compressor for gas injection.

- Case #4 Tank Top to Vapour Combustor: Install blower and vapour combustor.
- Case #6 Tank Top to Electrical Generators: Install blower, power generator(s), and connections for electricity delivery into distribution system.
- Case #9 Tank Top to Vapour Recovery Unit (VRU) for Gas Sales: Install rotary vane compressor for delivery of tank vapours into sales pipeline.

4.1.1 CASE 1: TANK TOP TO EXISTING HIGH PRESSURE FLARE STACK

Connecting tank-top vapours to an existing high pressure knock-out drum (V-800) and flare stack (FL-800) requires the following equipment:

- Low pressure suction header and blanket control valves. This overhead piping operates at about 3.4 kPag and provides a pathway for tank vapour with positive pressure to flow to the blower. It also supplies blanket gas from the separator to the tank ullage during unloading events (e.g., emptying oil into a truck).
- Tank pressure vacuum relief valve to protect the tank from over/under pressure events.
- Suction scrubber (V-200) to protect the blower from fine particulates and liquid droplets.
- 3 hp blower (K-200) to boost vapours from 3.4 kPag to the high pressure flare header operating pressure of about 34 kPag. The blower and suction scrubber are mounted on a skid for fast mobilization and easy set up.

The case #1 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.1.1.1 GHG EMISSION REDUCTIONS

Directing tank vapours to an existing high pressure flare stack reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 98 percent of hydrocarbons are oxidized results in an annual reduction of 1,118 t CO_2E. This is a 64 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year.

4.1.1.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigating action does not generate revenue and will always have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $311,220 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 5. Input parameters relevant to this technology are presented in appendix Figure 36.

As evident from the Figure 14 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $320,495. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs; operating life and annual operating costs. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is \$27.8 per t CO_2E avoided. That is, for every tonne of CO_2E not released to the atmosphere as a result of the project the operator incurs an average cost of \$27.8 (to purchase and install the technology). As shown in Figure 15, the average abatement cost varies with tank venting rates. If a policy was implemented whereby the federal carbon price (levelized value of \$46 per t CO_2E) was charged on venting emissions, this project would be economic at sites venting about 300 m^3 per day or greater. Moreover, if federal carbon pricing is increased to \$100 per t CO_2E by 2027, the levelized price increases to \$80 per t CO_2E and the project becomes economical for venting around 200 m^3 per day or greater. If CO_2E was determined using methane GWP of 34, abatement costs would be approximately36 percent lower than that obtained for GWP of 25 as depicted by the dashed plot in Figure 15.

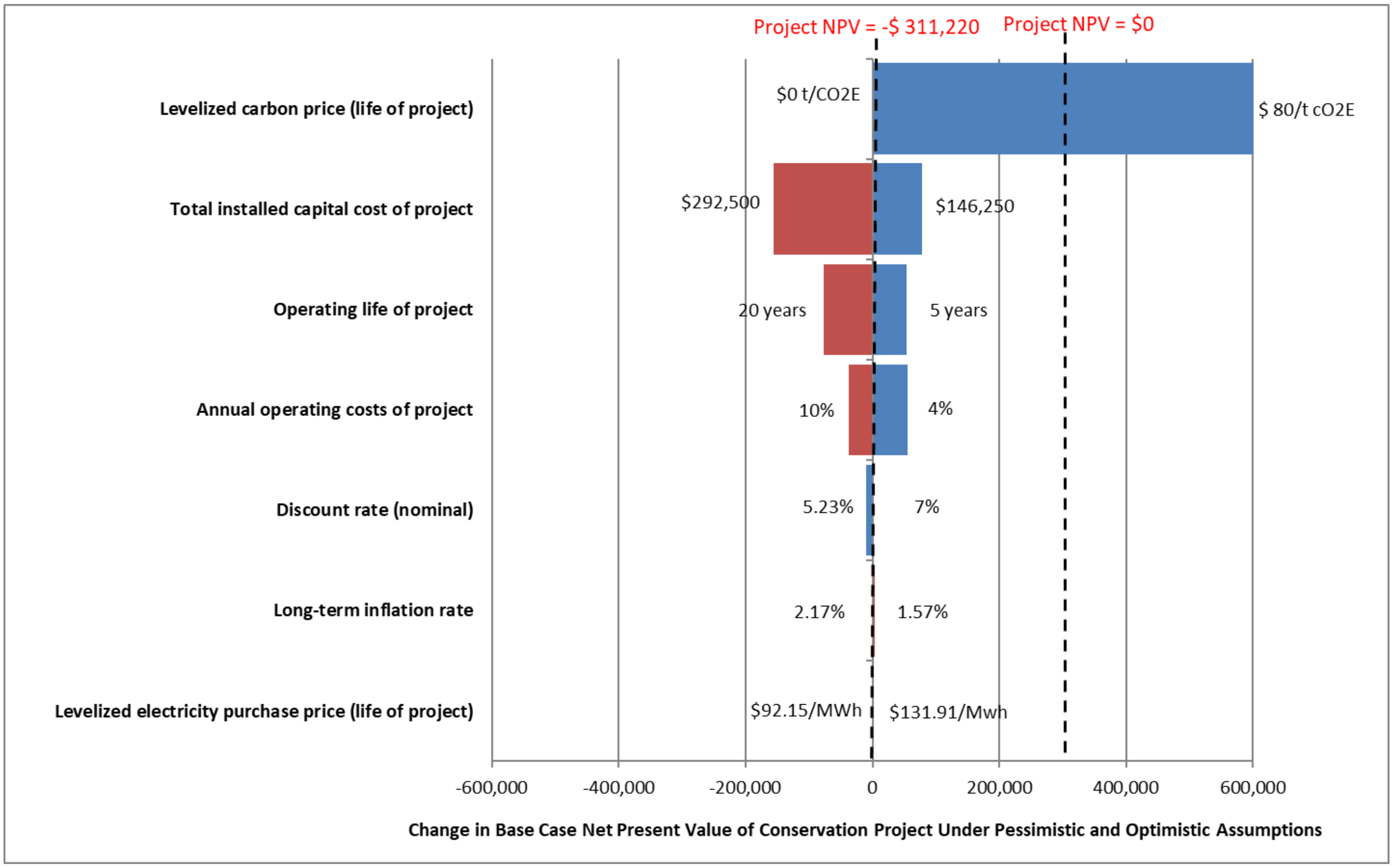


Figure 14: Tornado chart showing impact of upper and lower bound input values on NPV for connecting to an existing high pressure flare.

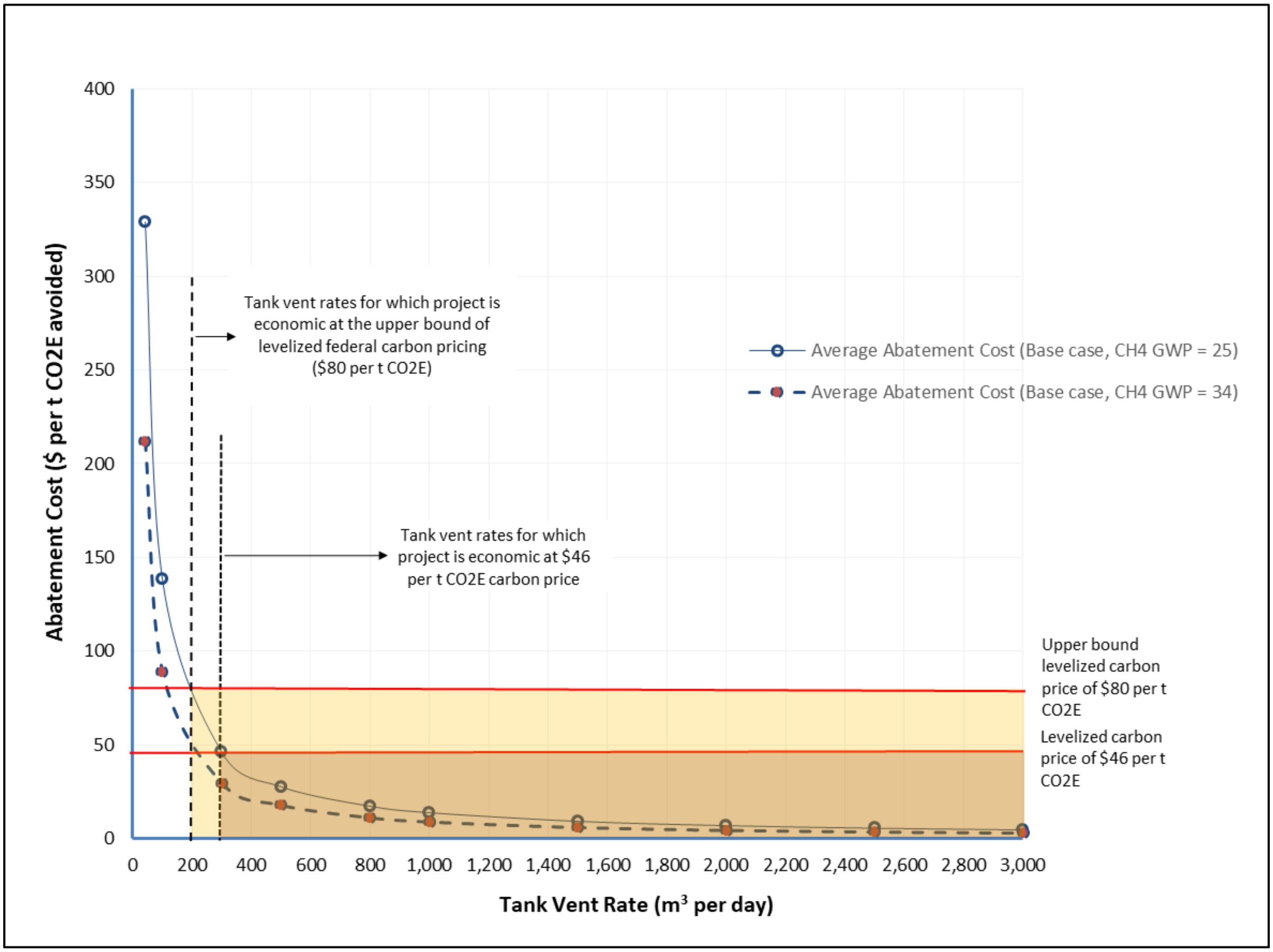


Figure 15: Average abatement cost as a function of tank venting rates for connecting to an existing high pressure flare.

Table 5: Evaluation of base-case Net Present Value (NPV) for connecting to an existing high pressure flare.											
Year	**Tank Venting Volume**	**Salvage Value**	**Total Net Project Benefits**		**Electricity cost**	**Net Capital Costs**	**Net Operating Costs**	**Total Net Project Costs**		**Total Project Net Benefits**	
			Undiscounted	**Discounted**				**Undiscounted**	**Discounted**	**Undiscounted**	**Discounted**
	(10^3 m^3/ year)	**($/ year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**
2019						195,000		195,000	195,000	(195,000)	(195,000)
2020	183	-	-	-	343		15,142	15,484	14,478	(15,484)	(14,478)
2021	183	-	-	-	343		15,470	15,813	13,825	(15,813)	(13,825)
2022	183	-	-	-	343		15,806	16,149	13,201	(16,149)	(13,201)
2023	183	-	-	-	343		16,149	16,492	12,605	(16,492)	(12,605)
2024	183	-	-	-	343		16,499	16,842	12,036	(16,842)	(12,036)
2025	183	-	-	-	343		16,857	17,200	11,493	(17,200)	(11,493)
2026	183	-	-	-	343		17,223	17,566	10,975	(17,566)	(10,975)
2027	183	-	-	-	343		17,597	17,940	10,480	(17,940)	(10,480)
2028	183	-	-	-	343		17,979	18,322	10,008	(18,322)	(10,008)
2029	183	4,772	4,772	2,437	343		18,369	18,712	9,557	(13,940)	(7,119)
	1,825	4,772	4,772	2,437	3,428	195,000	167,091	365,519	313,657	(360,747)	(311,220)

4.1.2 CASE 2: TANK TOP TO LOW PRESSURE FLARE STACK

Connecting tank-top vapours to a low pressure knock-out drum (V-801) and flare stack (FL-801) requires the following equipment:

- Low pressure suction header and blanket control valves. This overhead piping operates at about 3.4 kPag and provides a pathway for tank vapour with positive pressure to flow to the flare tip. It also supplies blanket gas from the separator to the tank ullage during unloading events (e.g., emptying oil into a truck).
- Tank pressure vacuum relief valve to protect the tank from over/under pressure events.

The case #2 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.1.2.1 GHG EMISSION REDUCTIONS

Directing tank vapours to a low pressure flare reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 98 percent of hydrocarbons are oxidized results in an annual reduction of 1,118 t CO_2E. This is a 64 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year.

4.1.2.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigating action does not generate revenue and will have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $245,424 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 6. Input parameters relevant to this technology are presented in appendix Figure 37.

As evident from the Figure 16 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $386,300. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs; operating life and annual operating costs. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $22 per t CO_2E avoided. The variation of average abatement cost with tank venting rates is presented in Figure 17.

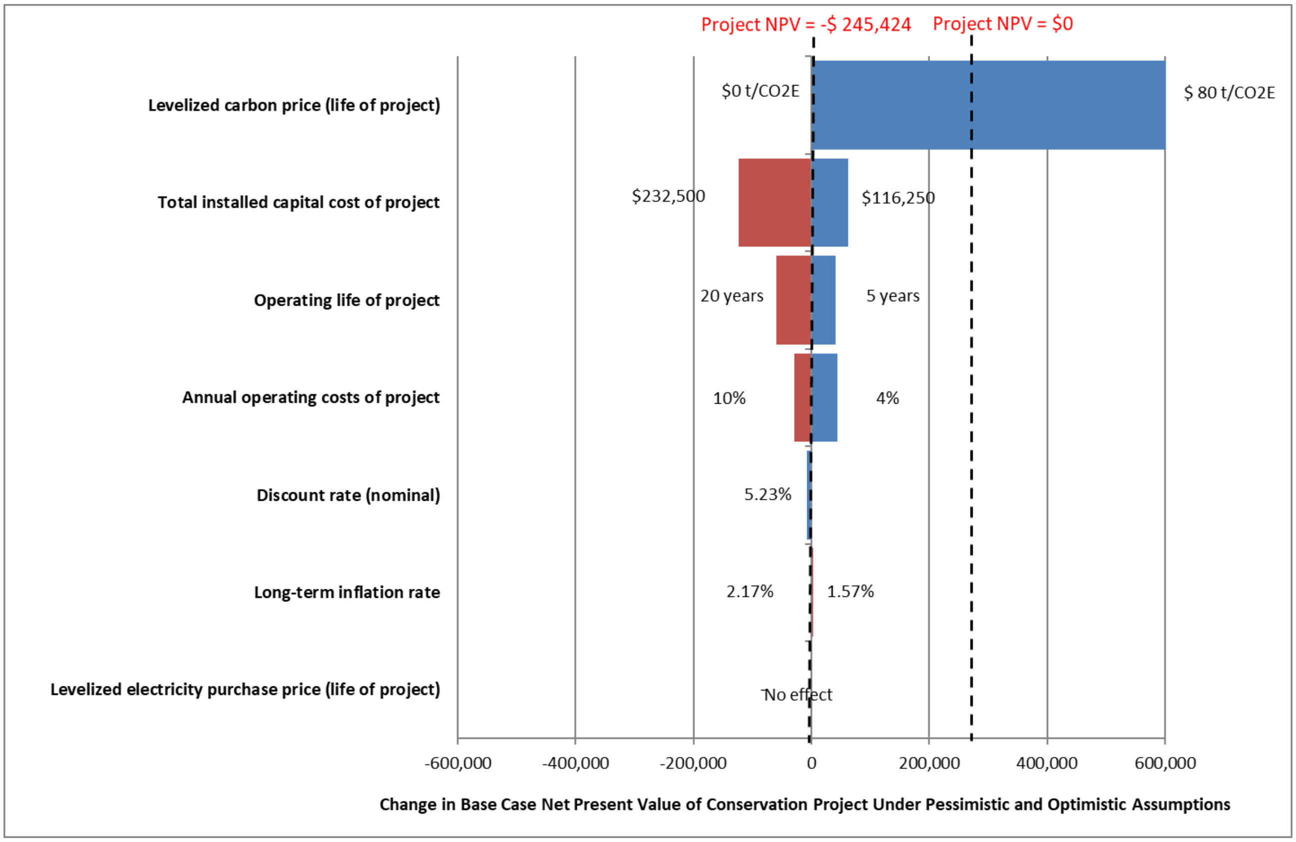


Figure 16: Tornado chart showing impact of upper and lower bound input values on NPV for installing a new low pressure flare.

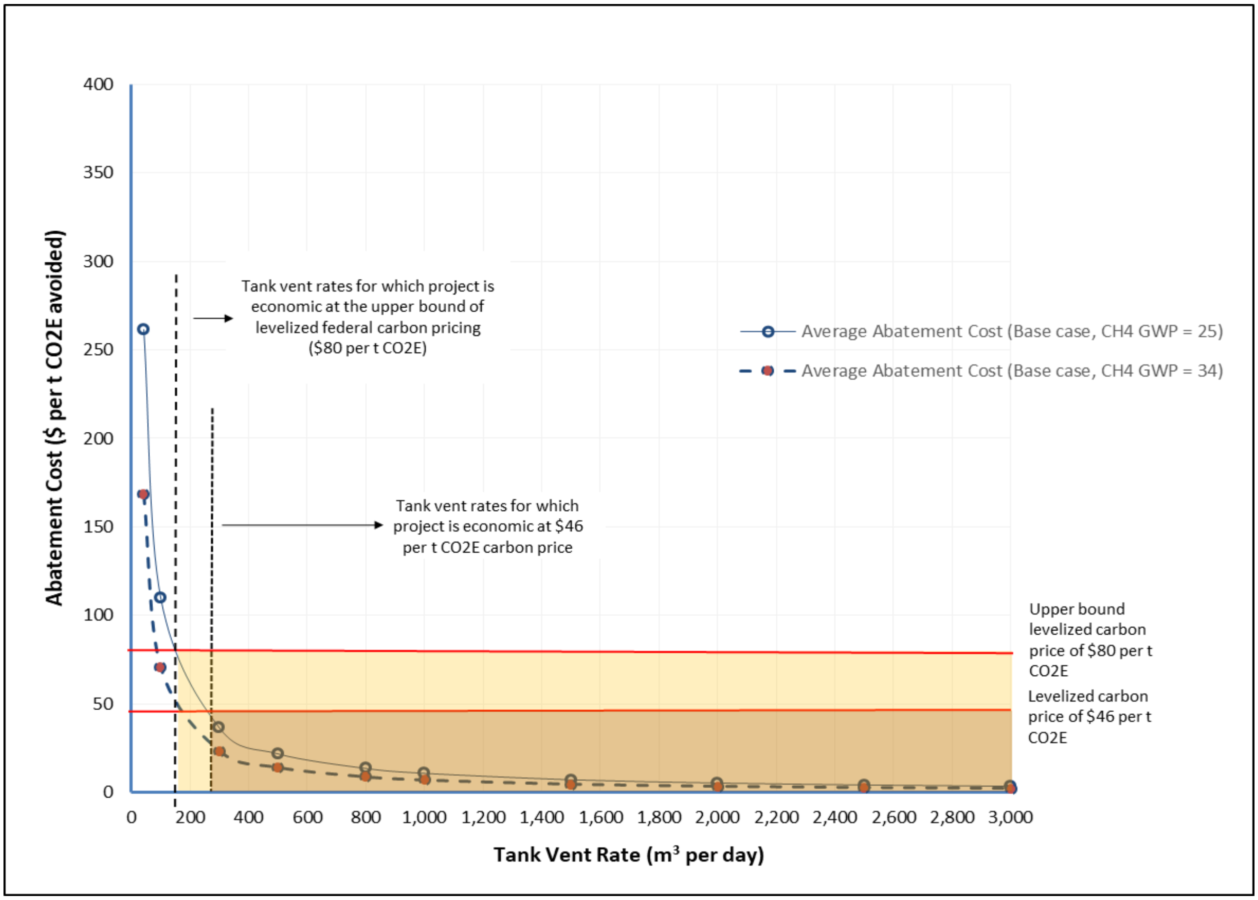


Figure 17: Average abatement cost as a function of tank venting rates for installing a new low pressure flare.

Table 6: Evaluation of base-case Net Present Value (NPV) for installing and operating a new low pressure flare.										
Year	**Tank Venting Volume**	**Salvage Value**	**Total Net Project Benefits**		**Net Capital Costs**	**Net Operating Costs**	**Total Net Project Costs**		**Total Project Net Benefits**	
			Undiscounted	**Discounted**			**Undiscounted**	**Discounted**	**Undiscounted**	**Discounted**
	(10^3 m^3/ year)	**($/ year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**
2019					155,000		155,000	155,000	(155,000)	(155,000)
2020	183	-	-	-		12,036	12,036	11,254	(12,036)	(11,254)
2021	183	-	-	-		12,297	12,297	10,751	(12,297)	(10,751)
2022	183	-	-	-		12,564	12,564	10,270	(12,564)	(10,270)
2023	183	-	-	-		12,836	12,836	9,811	(12,836)	(9,811)
2024	183	-	-	-		13,115	13,115	9,373	(13,115)	(9,373)
2025	183	-	-	-		13,399	13,399	8,954	(13,399)	(8,954)
2026	183	-	-	-		13,690	13,690	8,553	(13,690)	(8,553)
2027	183	-	-	-		13,987	13,987	8,171	(13,987)	(8,171)
2028	183	-	-	-		14,291	14,291	7,806	(14,291)	(7,806)
2029	183	3,867	3,867	1,975		14,601	14,601	7,457	(10,734)	(5,482)
	1,825	3,867	3,867	1,975	155,000	132,816	287,816	247,399	(283,949)	(245,424)

4.1.3 CASE 3: TANK TOP TO BOOSTER COMPRESSOR FOR GAS LIFT

Directing tank-top vapours into the wellhead requires the following equipment:

- Low pressure suction header and blanket control valves. This overhead piping operates at about 3.4 kPag and provides a pathway for tank vapour with positive pressure to flow to the VRU compressor (K-200). It also supplies blanket gas from the separator to the tank ullage during unloading events (e.g., emptying oil into a truck).
- Tank pressure vacuum relief valve to protect the tank from over/under pressure events.
- Suction scrubber (V-200) to protect the compressor from fine particulates and liquid droplets.
- Rotary vane VRU compressor (K-200) and rotary screw injection compressor (K-201) to achieve gas compression and injection into the wellhead.
- Pressure relief valves to protect the scrubber and compressors from overpressure events.
- High pressure piping tied into the wellhead casing and equipped with emergency shut down valve and instrumentation.

The case #3 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

In order to understand the effect of gas injection on oil well productivity, a correlation was developed between injected gas and incremental oil production based on a six-well problem investigated by Ghassemzadeh and Pourafshary (2015). Using this, the volume of incremental oil was determined at various tank venting flow rates. The ratio of gas injected to incremental oil produced was obtained to be 223 m^3/m^3 under the base case. For sensitivity analysis, a lower and upper estimate of 36 m^3/m^3 and 361 m^3/m^3 was adopted based on venting limits.

4.1.3.1 GHG EMISSION REDUCTIONS

Directing tank-top vapours into the wellhead eliminates venting to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 100 percent of hydrocarbons are tied into the wellhead results in an annual reduction of 1,752 t CO_2E. This is a 100 percent reduction relative to baseline GHG emissions.

4.1.3.2 ECONOMIC ASSSESSMENT AND SENSITIVITY

This mitigating action generates revenue which is sufficient for a NPV of positive $283,250 (on a royalties-in basis) for a ten year operating life with annual cash flows delineated in Table 7. Input parameters relevant to this technology are presented in appendix Figure 38.

As evident from the Figure 18 tornado chart, project NPV is highly sensitive to ratio of gas injection to incremental oil production as well as the monetization of GHG emission reductions.

The lower bound ratio decreases NPV to negative \$645,081. At a ratio of 361 m^3/m^3, NPV increases to \$3,968,300. Similarly, valuing GHG emission reductions at a levelized federal carbon price of \$80 per t CO_2E increases NPV to \$1,273,300. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs; operating life and annual operating costs.

There are no abatement costs for this project. Indeed, directing tank vapours to the wellhead earns the owner \$16.2 per t CO_2E avoided. As shown in Figure 19, the average abatement cost varies with tank venting rates.

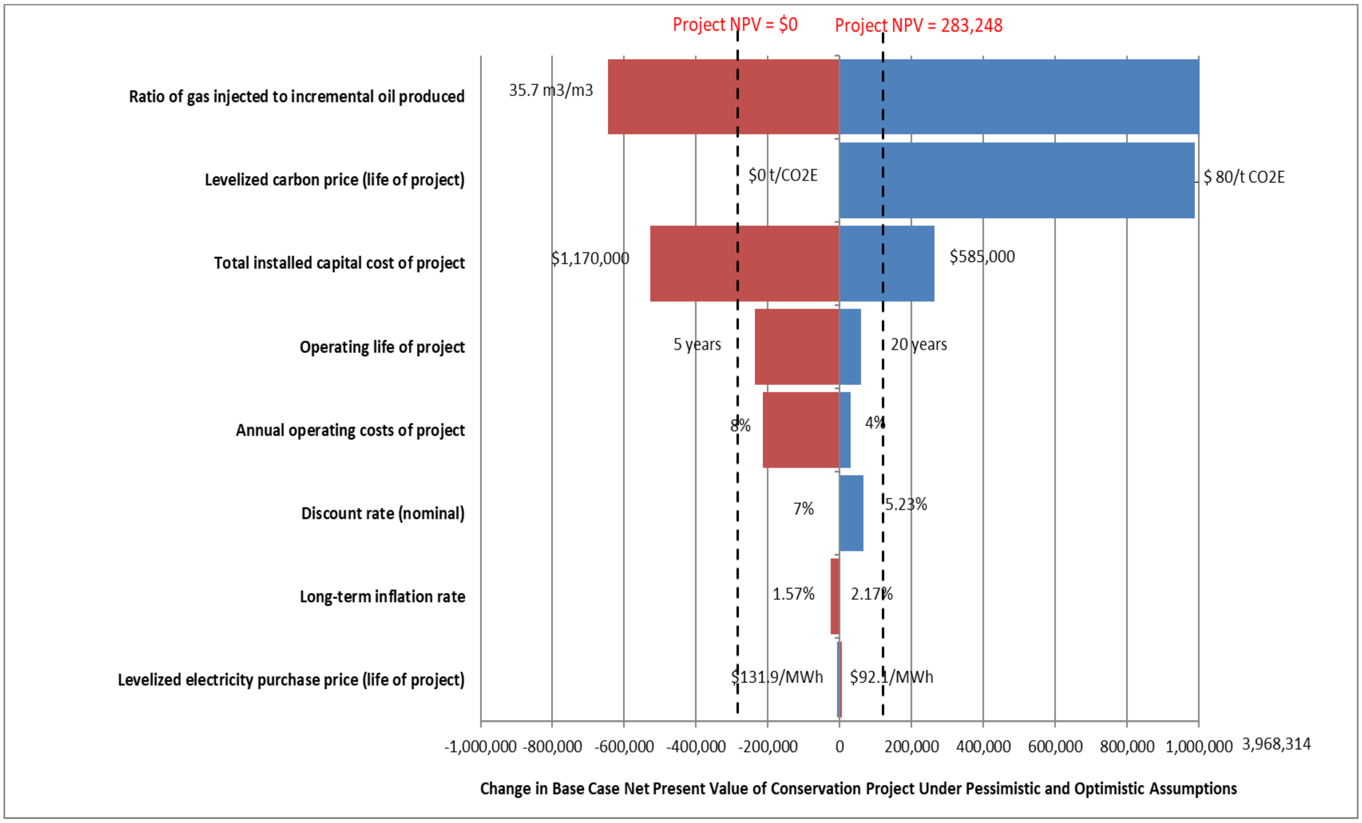


Figure 18: Tornado chart showing impact of upper and lower bound input values on NPV for installing a booster compressor and gas lift system.

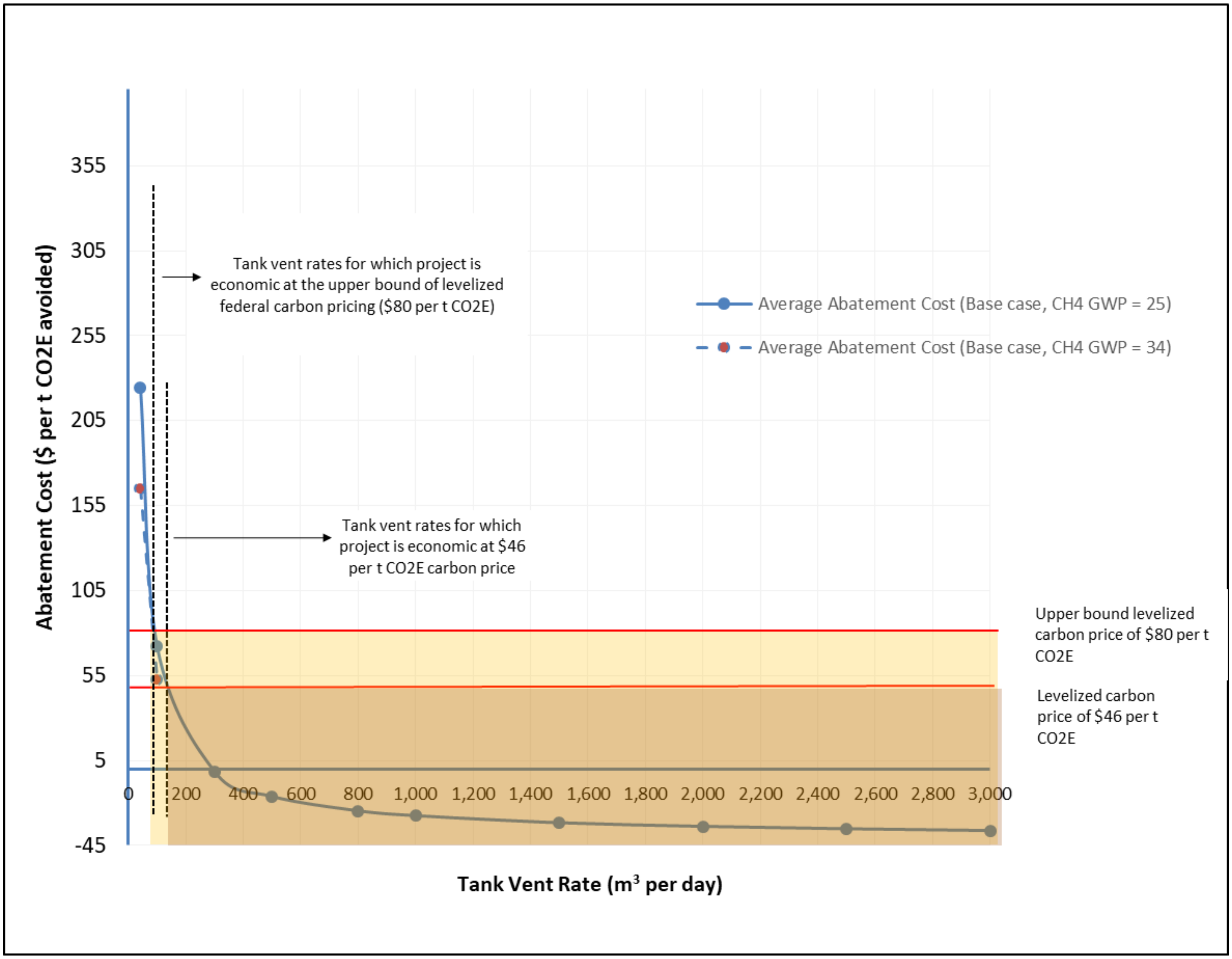


Figure 19: Average abatement cost as a function of tank venting rates for installing a booster compressor and gas lift system.

Table 7: Evaluation of base-case Net Present Value (NPV) for installing and operating a booster compressor and gas lift system.

Year	Tank Venting Volume	Levelized Carbon Price	Value of Carbon Savings	Oil production	Oil sales	Salvage Value	Total Net Project Benefits		Electricity cost	Royalty Payments	Net Capital Costs	Fixed Operating Costs	Total Net Project Costs		Total Project Net Benefits	
							Undiscounted	Discounted					Undiscounted	Discounted	Undiscounted	Discounted
	(10^3 m^3/ year)	($ / t CO_2E)	($ / year)	(m^3/ year)	($ / year)	($)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019											779,933		779,933	779,933	(779,933)	(779,933)
2020	183	-	-	816.88	346,640	-	346,640	324,114	4,931	17,332		35,862	58,124	54,347	288,516	269,767
2021	183	-	-	696.10	295,387	-	295,387	258,244	4,931	14,769		36,640	56,340	49,255	239,047	208,988
2022	183	-	-	593.18	251,712	-	251,712	205,761	4,931	12,586		37,435	54,951	44,919	196,761	160,841
2023	183	-	-	505.47	214,495	-	214,495	163,943	4,931	10,725		38,247	53,903	41,199	160,592	122,745
2024	183	-	-	430.73	182,781	-	182,781	130,625	4,931	9,139		39,077	53,147	37,982	129,634	92,643
2025	183	-	-	367.05	155,755	-	155,755	104,078	4,931	7,788		39,925	52,644	35,177	103,112	68,901
2026	183	-	-	312.78	132,726	-	132,726	82,926	4,931	6,636		40,792	52,358	32,713	80,368	50,213
2027	183	-	-	266.53	113,102	-	113,102	66,073	4,931	5,655		41,677	52,262	30,531	60,839	35,542
2028	183	-	-	227.12	96,379	-	96,379	52,645	4,931	4,819		42,581	52,331	28,584	44,048	24,060
2029	183	-	-	193.54	82,129	28,136	110,264	56,315	4,931	4,106		43,505	52,542	26,835	57,722	29,481
	1,825		-			28,136	1,899,241	1,444,724			779,933	395,741	1,318,534	1,161,475	580,707	283,248

4.1.4 CASE 4: TANK TOP TO VAPOUR COMBUSTOR

Connecting tank-top vapours to vapour combustor (FL-800) requires the following equipment:

- Low pressure suction header and blanket control valves. This overhead piping operates at about 3.4 kPag and provides a pathway for tank vapour with positive pressure to flow to the blower. It also supplies blanket gas from the separator to the tank ullage during unloading events (e.g., emptying oil into a truck).
- Tank pressure vacuum relief valve to protect the tank from over/under pressure events.
- Suction scrubber (V-200) to protect the blower from fine particulates and liquid droplets.
- 3 hp blower (K-200) to boost vapours from 3.4 kPag to the vapour combustor inlet pressure of about 34 kPag. The blower and suction scrubber are mounted on a skid for fast mobilization and easy set up.
- Vapour combustor (FL-800)

The case #4 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.1.4.1 GHG EMISSION REDUCTIONS

Discharging tank vapours to vapour combustor reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 100 percent of hydrocarbons are oxidized results in an annual reduction of 1,128 t CO_2E. This is a 64 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year.

4.1.4.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigation action does not generate revenue and will have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $245,424 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 8. Input parameters relevant to this technology are presented in appendix Figure 39.

As evident from the Figure 20 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $386,300. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs; operating life and annual operating costs. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $22 per t CO_2E avoided. Figure 21 depicts the variation of average abatement cost with tank venting rates.

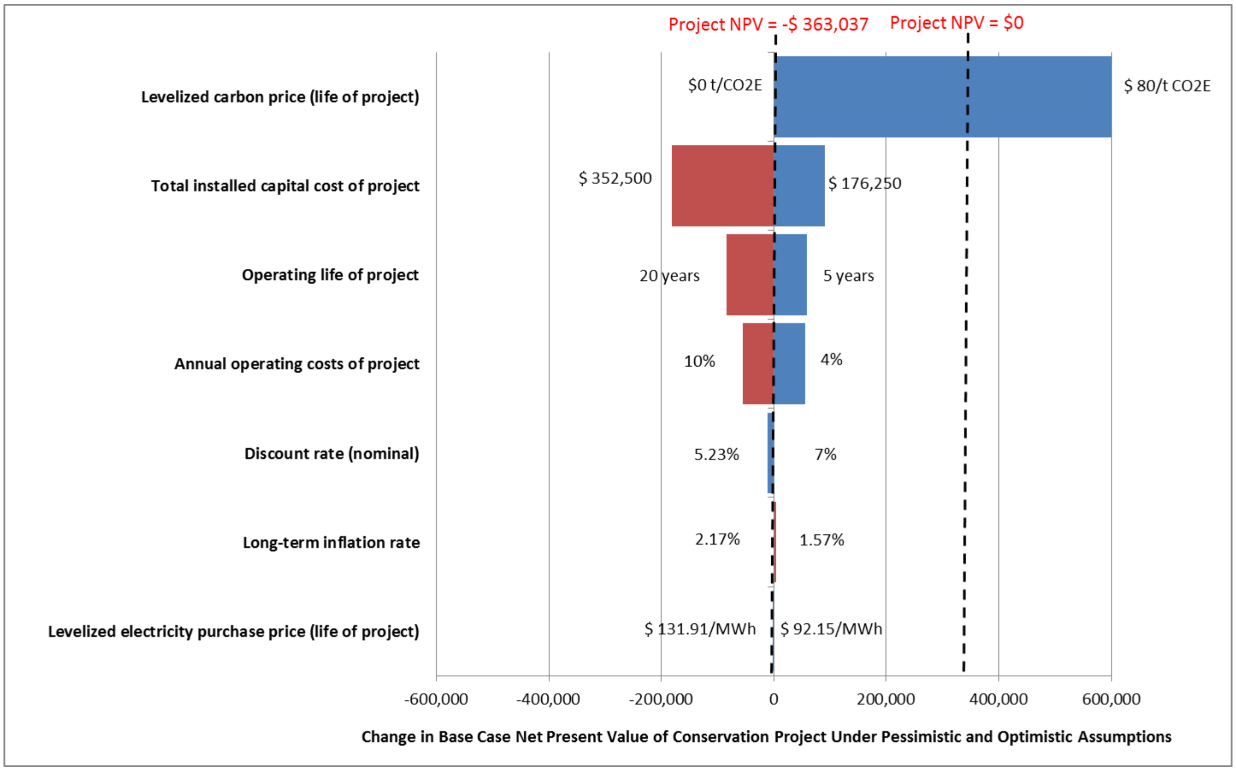


Figure 20: Tornado chart showing impact of upper and lower bound input values on NPV for installing a new vapour combustor.

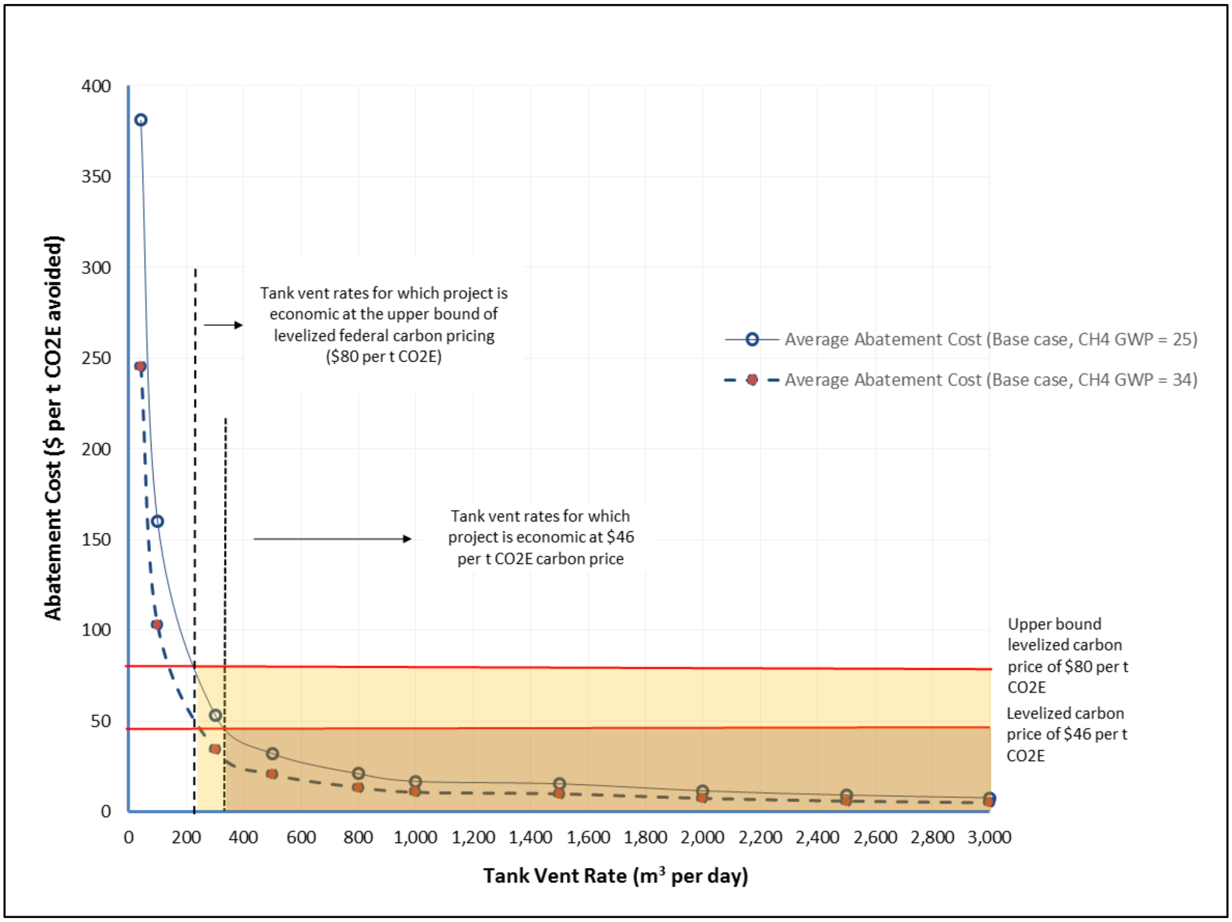


Figure 21: Average abatement cost as a function of tank venting rates for installing a new vapor combustor.

Table 8: Evaluation of base-case Net Present Value (NPV) for installing and operating a vapour combustor.											
Year	Tank Venting Volume	Salvage Value	Total Net Project Benefits		Electricity cost	Net Capital Costs	Net Operating Costs	Total Net Project Costs		Total Project Net Benefits	
			Undiscounted	Discounted				Undiscounted	Discounted	Undiscounted	Discounted
	(10^3 m^3/ year)	($/ year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019						235,000		235,000	235,000	(235,000)	(235,000)
2020	183	-	-	-	317		16,807	17,124	16,011	(17,124)	(16,011)
2021	183	-	-	-	317		17,172	17,489	15,290	(17,489)	(15,290)
2022	183	-	-	-	317		17,544	17,861	14,601	(17,861)	(14,601)
2023	183	-	-	-	317		17,925	18,242	13,943	(18,242)	(13,943)
2024	183	-	-	-	317		18,314	18,631	13,315	(18,631)	(13,315)
2025	183	-	-	-	317		18,711	19,029	12,715	(19,029)	(12,715)
2026	183	-	-	-	317		19,117	19,435	12,143	(19,435)	(12,143)
2027	183	-	-	-	317		19,532	19,849	11,596	(19,849)	(11,596)
2028	183	-	-	-	317		19,956	20,273	11,074	(20,273)	(11,074)
2029	183	6,315	6,315	3,225	317		20,389	20,706	10,575	(14,391)	(7,350)
	1,825	6,315	6,315	3,225	3,172	235,000	185,468	423,640	366,262	(417,325)	(363,037)

4.1.5 CASE 6: TANK TOP TO ELECTRIC GENERATOR(S)

Directing tank-top vapours to electric generators requires the following equipment:

- Low pressure suction header and blanket control valves. This overhead piping operates at about 3.4 kPag and provides a pathway for tank vapour with positive pressure to flow to the blower. It also supplies blanket gas from the separator to the tank ullage during unloading events (e.g., emptying oil into a truck).
- Tank pressure vacuum relief valve to protect the tank from over/under pressure events.
- Suction scrubber (V-200) to protect the blower from fine particulates and liquid droplets.
- 3 hp blower (K-200) to boost vapours from 3.4 kPag to the generator inlet fuel pressure of about 34 kPag. The blower and suction scrubber are mounted on a skid for fast mobilization and easy set up.
- Thermo-electric generator (G200) and Electrical generator (G210) to produce power. For gas rates up to 50 m^3 per day, the thermoelectric generator is employed. For flow rates above 50 m^3 per day, the electrical generator is used.
- Connection to on-site power demands and electricity distribution system.

The case #6 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.1.5.1 GHG EMISSION REDUCTIONS

Directing tank-top vapours to electric generators reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 100 percent of hydrocarbons are oxidized results in an annual reduction of 1,128 t CO_2E. This is a 64 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year.

4.1.5.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigation action earns revenue by selling power, however, power sales are small relative to the incremental lifecycle costs of the project. The base-case NPV equals negative $113,275 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 9. Input parameters relevant to this technology are presented in appendix Figure 41.

As evident from the Figure 22 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $ 523,900. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs; operating life and annual operating costs. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is \$10 per t CO_2E avoided. As shown in Figure 23, the average abatement cost varies with tank venting rates.

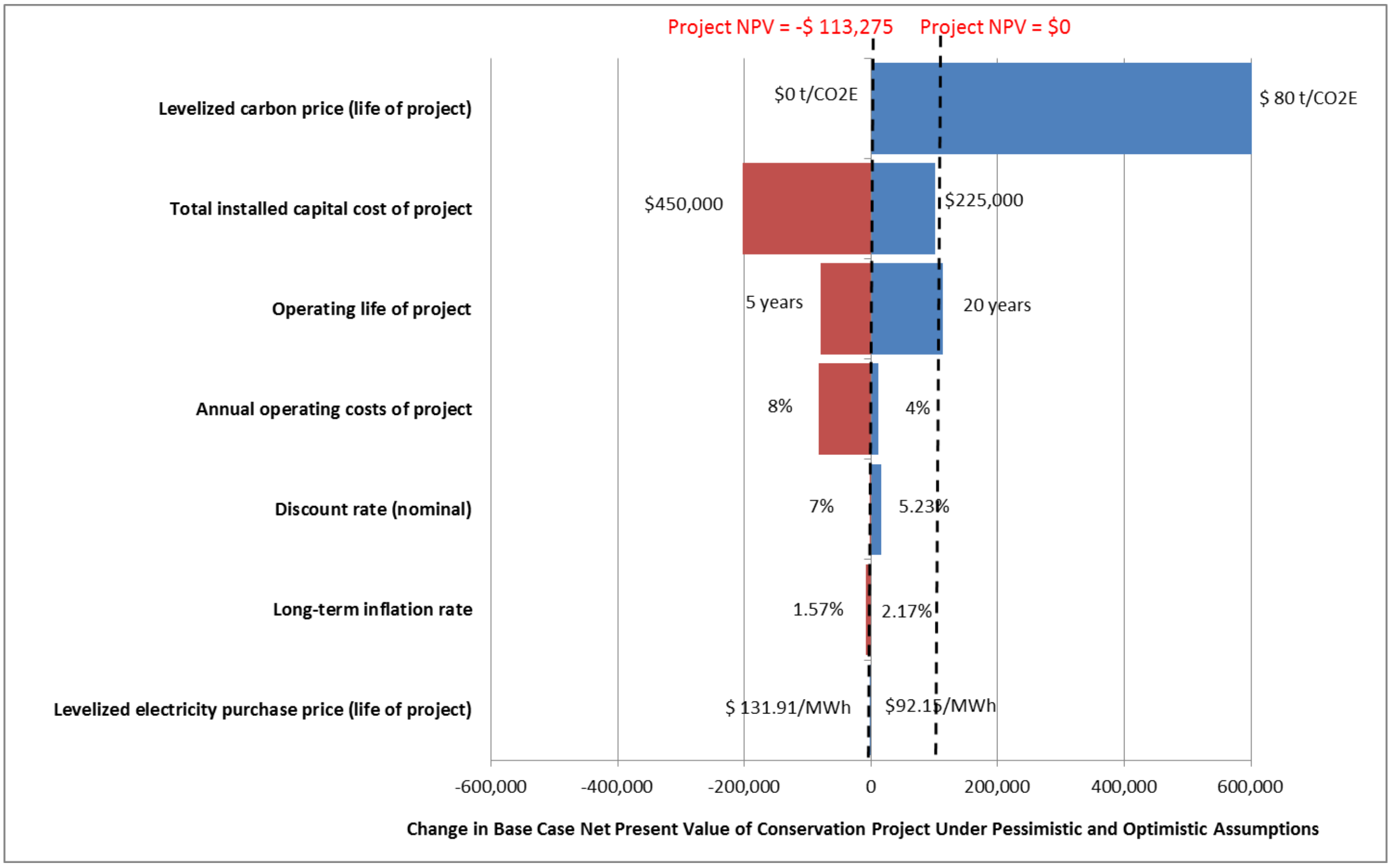


Figure 22: Tornado chart showing impact of upper and lower bound input values on NPV for installing power generation and grid connection equipment.

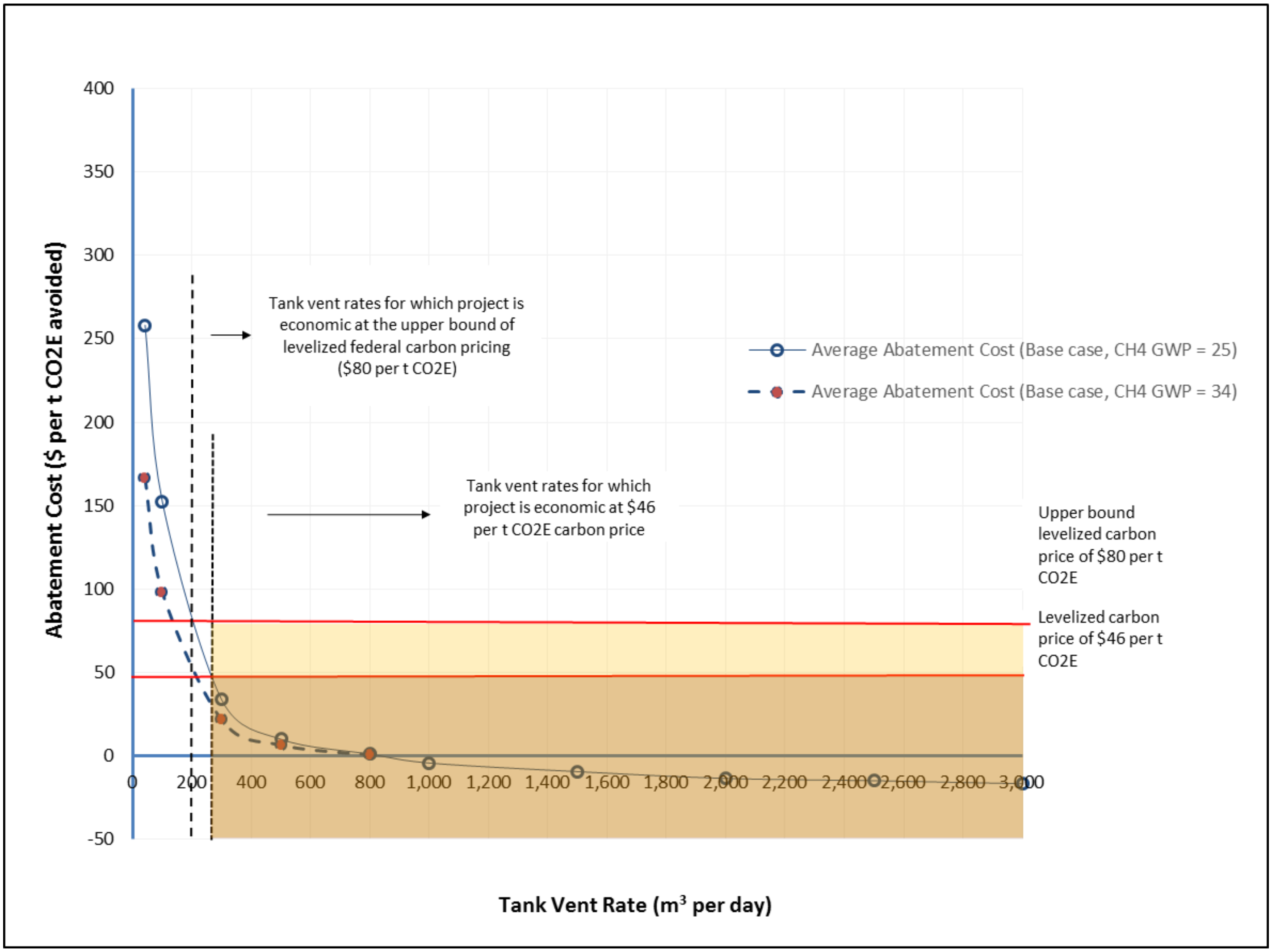


Figure 23: Average abatement cost as a function of storage tank venting rates installing power generation and grid connection equipment.

Table 9: Evaluation of base-case Net Present Value (NPV) for installing and operating power generation and grid connection equipment.

Year	Electricity Generated	Electricity Sales	Salvage Value	Total Net Project Benefits		Electricity cost	Net Capital Costs	Net Operating Costs	Total Net Project Costs		Total Project Net Benefits	
				Undiscounted	Discounted				Undiscounted	Discounted	Undiscounted	Discounted
	(MWh/year)	($ / year)	($/ year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019							300,000		300,000	300,000	(300,000)	(300,000)
2020	718	41,181	-	41,181	38,505	254		13,793	14,047	13,134	27,134	25,371
2021	718	41,181	-	41,181	36,003	254		14,092	14,346	12,542	26,835	23,461
2022	718	41,181	-	41,181	33,663	254		14,398	14,652	11,977	26,529	21,686
2023	718	41,181	-	41,181	31,476	254		14,710	14,965	11,438	26,217	20,038
2024	718	41,181	-	41,181	29,430	254		15,030	15,284	10,923	25,897	18,508
2025	718	41,181	-	41,181	27,518	254		15,356	15,610	10,431	25,571	17,087
2026	718	41,181	-	41,181	25,730	254		15,689	15,943	9,961	25,238	15,769
2027	718	41,181	-	41,181	24,058	254		16,030	16,284	9,513	24,898	14,545
2028	718	41,181	-	41,181	22,494	254		16,377	16,631	9,085	24,550	13,410
2029	718	41,181	8,800	49,981	25,527	254		16,733	16,987	8,676	32,995	16,851
	7,181	411,812	8,800	420,612	294,404	2,540	300,000	152,208	454,748	407,679	(34,136)	(113,275)

4.1.6 CASE 9: TANK TOP TO VRU PACKAGE INSTALLATION

Directing tank-top vapours to VRU for delivery into sales pipeline requires the following equipment:

- Low pressure suction header and blanket control valves. This overhead piping operates at about 3.4 kPag and provides a pathway for tank vapour with positive pressure to flow to the blower. It also supplies blanket gas from the separator to the tank ullage during unloading events (e.g., emptying oil into a truck).
- Tank pressure vacuum relief valve to protect the tank from over/under pressure events.
- Suction scrubber (V-200) to protect the compressor from fine particulates and liquid droplets.
- Rotary vane compressor (K200) for delivery of tank vapours into sales pipeline.
- Pressure relief valves to protect the scrubber and compressor from overpressure events.

The case #9 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.1.6.1 GHG EMISSION REDUCTIONS

Directing tank-top vapours into the sales pipeline eliminates venting to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 100 percent of tank hydrocarbons are delivered into the sales pipeline results in an annual reduction of 1,752 t CO_2E. This is a 100 percent reduction relative to baseline GHG emissions.

4.1.6.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigating action does not generate revenue and will have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $460,700 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 10. Input parameters relevant to this technology are presented in appendix Figure 44.

As evident from the Figure 24 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $ 529,400. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs, annual operating costs and operating life. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $26.3 per t CO_2E avoided. As shown in Figure 25, the average abatement cost varies with tank venting rates.

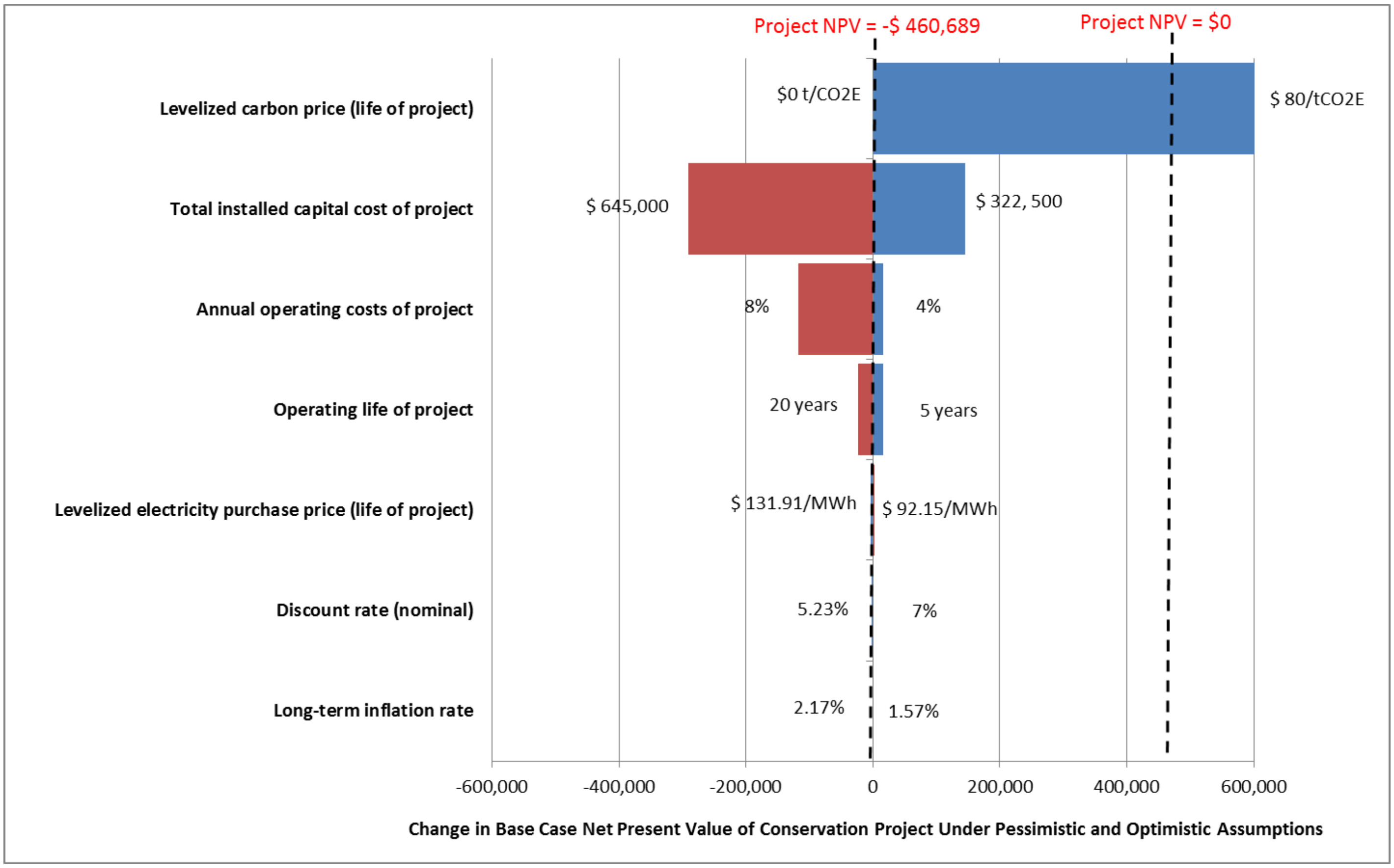


Figure 24: Tornado chart showing impact of upper and lower bound input values on NPV for installing a new vapour recovery unit.

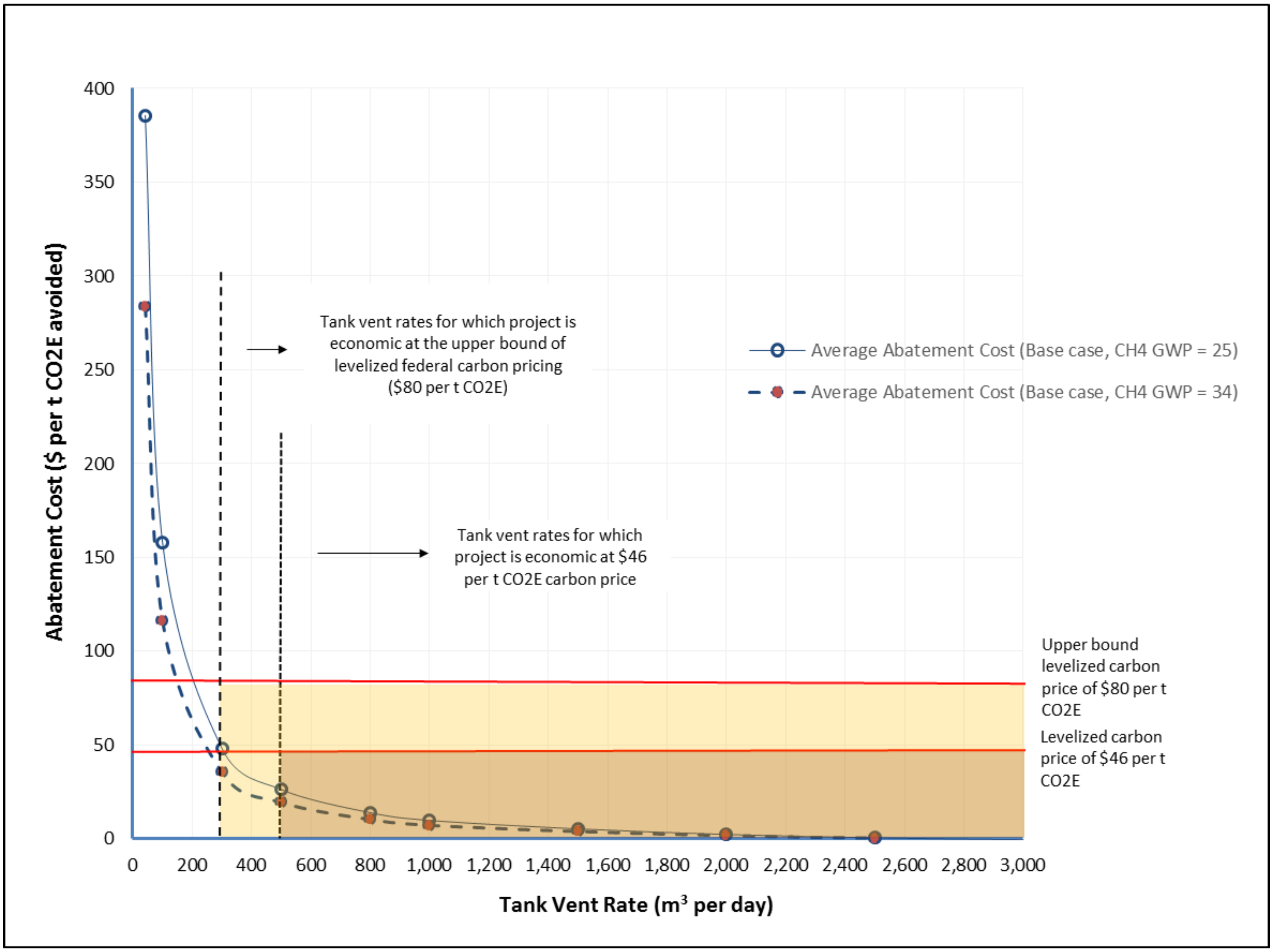


Figure 25: Average abatement cost as a function of storage tank venting rates for installing a new vapour recovery unit.

Table 10: Evaluation of base-case Net Present Value (NPV) for installing and operating a vapor recovery unit.																
Year	**Tank Venting Volume**	**Sales Gas Volume**	**Levelized Carbon Price**	**Value of Carbon Savings**	**Gas Sales**	**Salvage Value**	**Total Net Project Benefits**		**Electricity cost**	**Royalty Payments**	**Net Capital Costs**	**Net Operating Costs**	**Total Net Project Costs**		**Total Project Net Benefits**	
							Undiscounted	**Discounted**					**Undiscounted**	**Discounted**	**Undiscounted**	**Discounted**
	(10^3 m^3/ year)	**(10^3 m^3/ year)**	**($ / t CO_2E)**	**($ / year)**	**($ / year)**	**($/ year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**	**($ / year)**
2019											430,000		430,000	430,000	(430,000)	(430,000)
2020	183	183	-	-	19,260	-	19,260	18,008	2,686			19,770	22,456	20,997	(3,196)	(2,989)
2021	183	183	-	-	19,260	-	19,260	16,838	2,686			20,199	22,885	20,008	(3,625)	(3,169)
2022	183	183	-	-	19,260	-	19,260	15,744	2,686			20,637	23,324	19,066	(4,064)	(3,322)
2023	183	183	-	-	19,260	-	19,260	14,721	2,686			21,085	23,771	18,169	(4,511)	(3,448)
2024	183	183	-	-	19,260	-	19,260	13,764	2,686			21,543	24,229	17,315	(4,969)	(3,551)
2025	183	183	-	-	19,260	-	19,260	12,870	2,686			22,010	24,696	16,502	(5,436)	(3,633)
2026	183	183	-	-	19,260	-	19,260	12,033	2,686			22,488	25,174	15,728	(5,914)	(3,695)
2027	183	183	-	-	19,260	-	19,260	11,251	2,686			22,976	25,662	14,991	(6,402)	(3,740)
2028	183	183	-	-	19,260	-	19,260	10,520	2,686			23,474	26,161	14,290	(6,901)	(3,769)
2029	183	183	-	-	19,260	8,639	27,899	14,249	2,686			23,984	26,670	13,621	1,229	628
	1,825			-	192,599	8,639	201,238	139,999	26,863	-	430,000	218,165	675,028	600,688	(473,790)	(460,689)

4.2 FLASH VESSEL VAPOUR CAPTURE

The following use cases, that involve flash vessel vapour capture, are discussed in this section.

- Case #5 Flash Vessel to Electrical Generators: Install flash vessel, power generator and connections for electricity delivery into distribution system.
- Case #7 Flash Vessel to Existing High Pressure Flare Stack: Install flash vessel and tie-in to existing high pressure flare.
- Case #8 Flash Vessel to Vapour Combustor: Install flash vessel and vapour combustor.
- Case #10 Flash Vessel to Vapour Recovery Compressor for Gas Sales: Install flash vessel and rotary vane compressor for delivery of tank vapours into sales pipeline.

A flash vessel is installed downstream of the separator to enable pressure drop and gas flashing. The minimum pressure required to overcome the tank pressure head and enable gravity feed is about 273 kPag. Therefore the fraction of flash gas that is captured increases as the separator operating pressure increases. Capture efficiency is determined using the Valko and McCain correlation for the range of separator pressures investigated and plotted in Figure 26. Capture efficiency increases with increasing separator pressure and is incorporated into the overall control efficiency applied to mitigation cases discussed below.

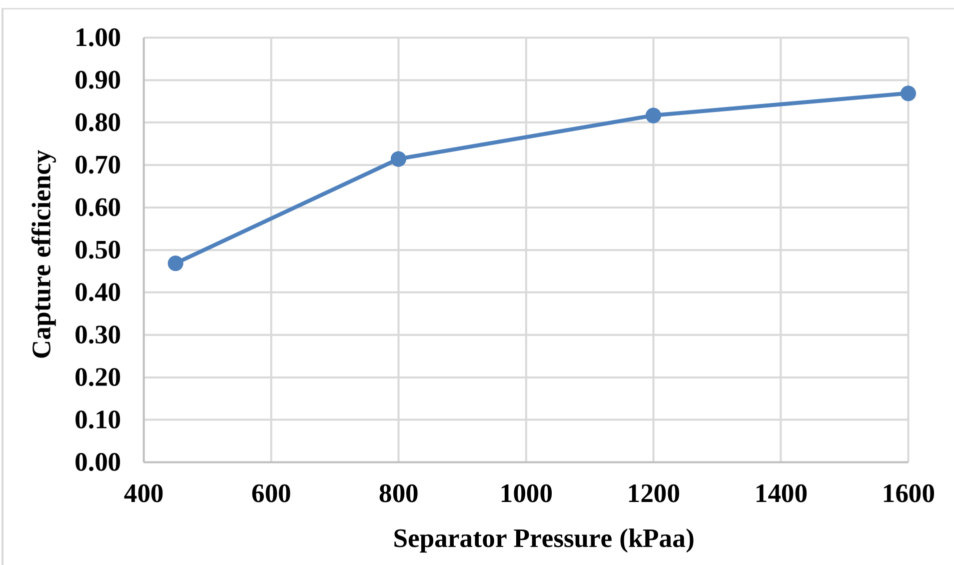


Figure 26: Variation of control efficiency with separator pressure for light oil production.

4.2.1 CASE 5: FLASH VESSEL TO ELECTRIC GENERATOR

Connecting flash vessel vapours to an electric generator requires the following equipment:

- Flash vessel (V-200) to decrease liquid pressure to about 273 kPag required for gravity flow into the storage tanks.
- Electrical generator (G200) to produce power.
- Connection to on-site power demands and electricity distribution system.

The case #5 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.2.1.1 GHG EMISSION REDUCTIONS

Directing vapours to electric generator reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 71 percent of hydrocarbons are oxidized results in an annual reduction of 805 t CO_2E. This is a 46 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year. The project emissions are due to fuel combustion in the generator plus venting of the fraction of gas not captured in the flash vessel (i.e., 29% percent).

4.2.1.2 ECONOMIC ASSESSMENT AND SENSITIVITY

The mitigating action earns revenue by selling power, however, power sales are small relative to the incremental lifecycle costs of the project. The base-case NPV equals negative $121,500 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 11. Input parameters relevant to this technology are presented in appendix Figure 40.

As evident from the Figure 27 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $333,600. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs; operating life and annual operating costs. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $15 per t CO_2E avoided. As shown in Figure 28, the average abatement cost varies with tank venting rates.

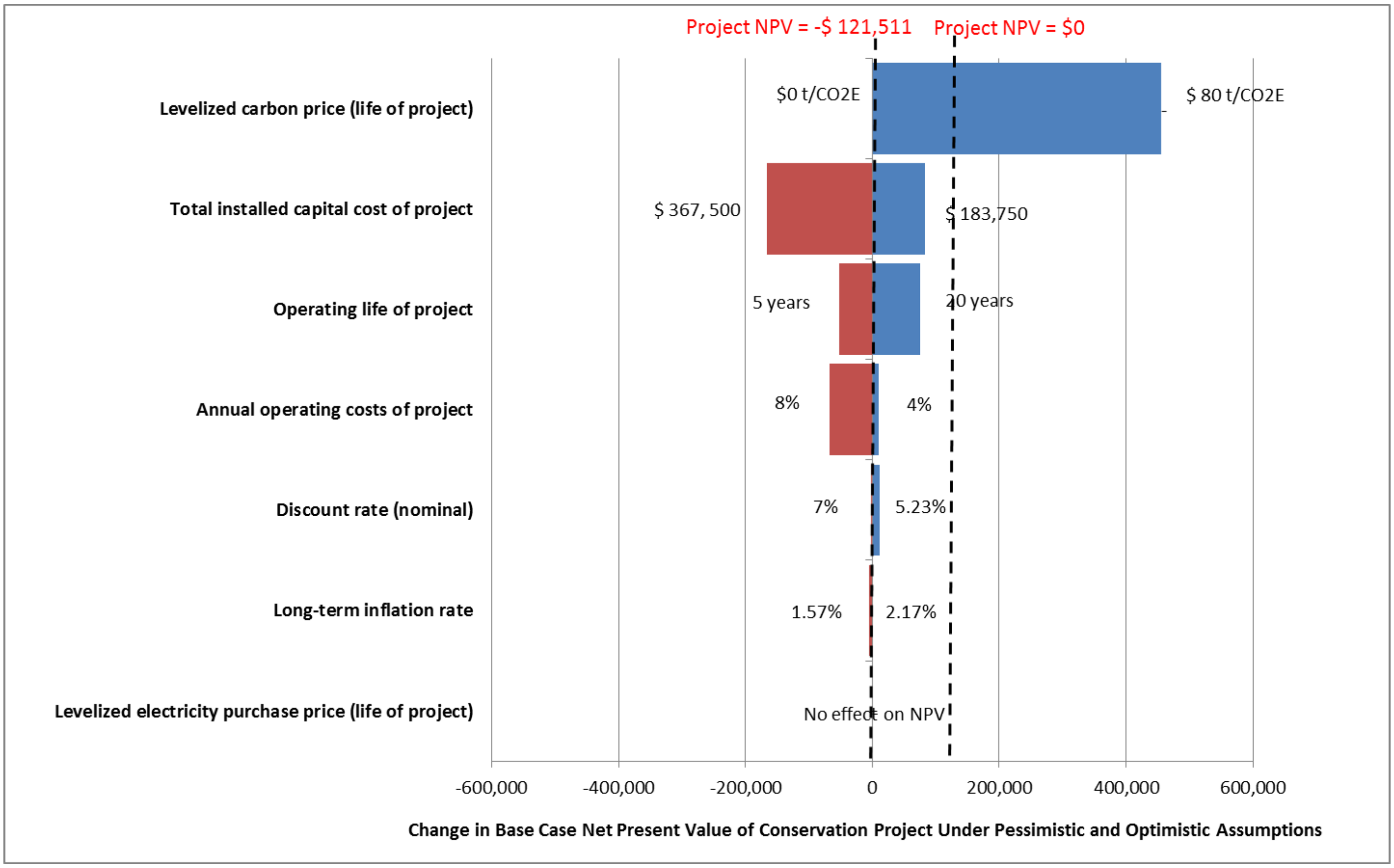


Figure 27: Tornado chart showing impact of upper and lower bound input values on NPV for installing power generation and grid connection equipment.

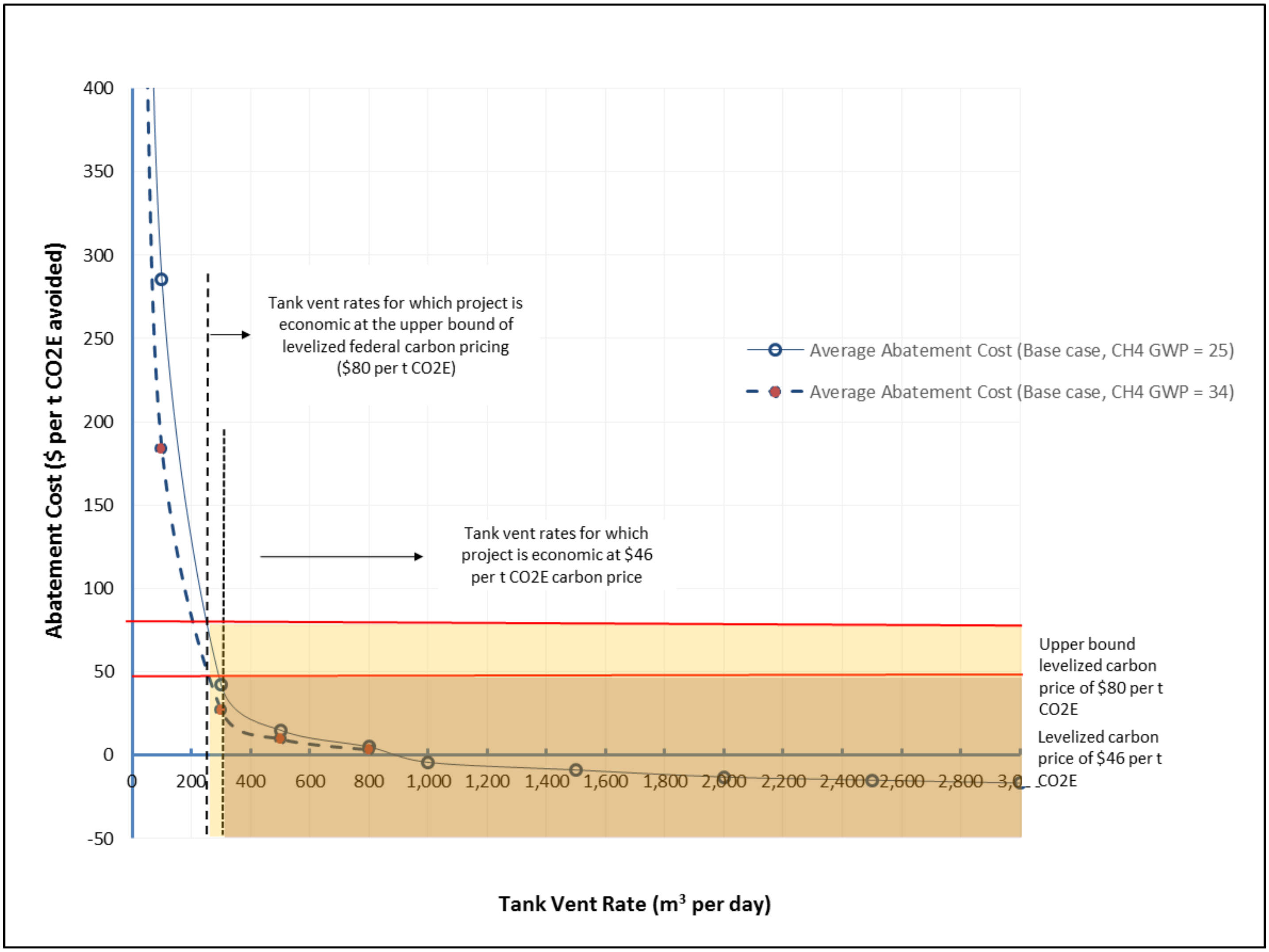


Figure 28: Average abatement cost as a function of storage tank venting rates for installing a flash vessel, power generation and grid connection equipment.

Table 11: Evaluation of base-case Net Present Value (NPV) for installing and operating a flash vessel, power generation and grid connection equipment.

Year	Tank Venting Volume	Electricity Generated	Levelized Carbon Price	Value of Carbon Savings	Electricity Sales	Salvage Value	Total Net Project Benefits		Electricity cost	Royalty Payments	Net Capital Costs	Net Operating Costs	Total Net Project Costs		Total Project Net Benefits	
							Undiscounted	Discounted					Undiscounted	Discounted	Undiscounted	Discounted
	(10^3 m^3/ year)	(MWh/year)	($ / t CO_2E)	($ / year)	($ / year)	($/ year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019											245,000		245,000	245,000	(245,000)	(245,000)
2020	183	513	-	-	29,418	-	29,418	27,507	-			11,264	11,264	10,532	18,154	16,975
2021	183	513	-	-	29,418	-	29,418	25,719	-			11,509	11,509	10,062	17,910	15,658
2022	183	513	-	-	29,418	-	29,418	24,048	-			11,758	11,758	9,612	17,660	14,436
2023	183	513	-	-	29,418	-	29,418	22,485	-			12,014	12,014	9,182	17,405	13,303
2024	183	513	-	-	29,418	-	29,418	21,024	-			12,274	12,274	8,772	17,144	12,252
2025	183	513	-	-	29,418	-	29,418	19,658	-			12,541	12,541	8,380	16,878	11,278
2026	183	513	-	-	29,418	-	29,418	18,380	-			12,813	12,813	8,005	16,606	10,375
2027	183	513	-	-	29,418	-	29,418	17,186	-			13,091	13,091	7,647	16,328	9,538
2028	183	513	-	-	29,418	-	29,418	16,069	-			13,375	13,375	7,306	16,044	8,763
2029	183	513	-	-	29,418	5,609	35,027	17,889	-			13,665	13,665	6,979	21,362	10,910
	1,825			-	294,185	5,609	299,794	209,966	-	-	245,000	124,303	369,303	331,477	(69,510)	(121,511)

4.2.2 CASE 7: FLASH VESSEL TO EXISTING HIGH PRESSURE FLARE STACK

Connecting flash vessel vapours to an existing high pressure knock-out drum (V-800) and flare stack (FL-800) is the simplest mitigation action. It only requires the flash vessel, pressure relief and control valves. The case #7 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.2.2.1 GHG EMISSION REDUCTIONS

Directing vapours to an existing high pressure flare stack reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 71 percent of hydrocarbons are flared results in an annual reduction of 799 t CO_2E. This is a 46 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year. The project emissions are due to flaring of flash vapours plus tank venting of the fraction of gas not captured in the flash vessel (i.e., 29 percent).

4.2.2.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigating action does not generate revenue and will have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $123,300 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 12. Input parameters relevant to this technology are presented in appendix Figure 42.

As evident from the Figure 29 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $328,000. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs and operating life. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $15.4 per t CO_2E avoided. As shown in Figure 30, the average abatement cost varies with tank venting rates.

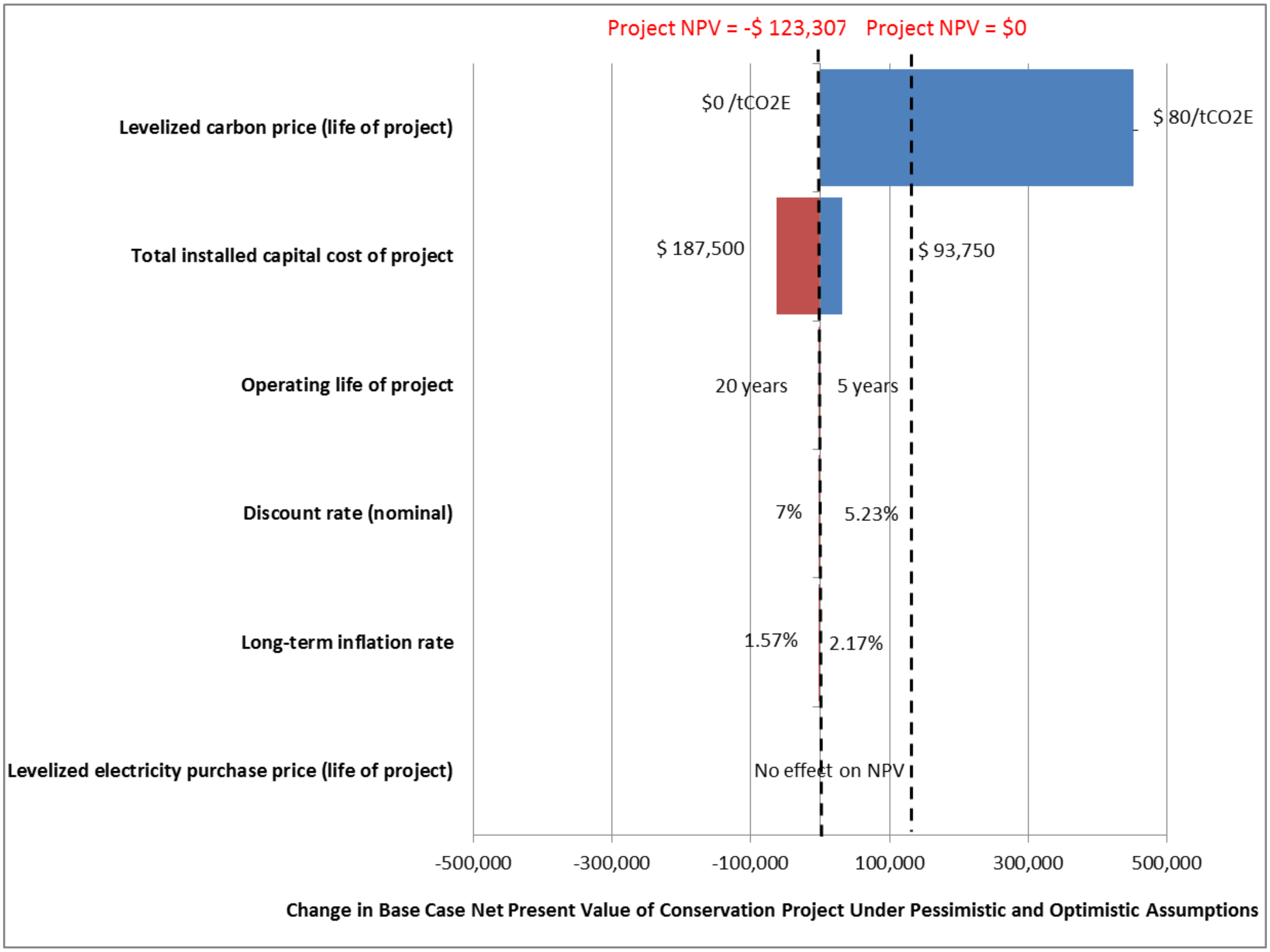


Figure 29: Tornado chart showing impact of upper and lower bound input values on NPV for installing a flash vessel and tie-in to existing high pressure flare.

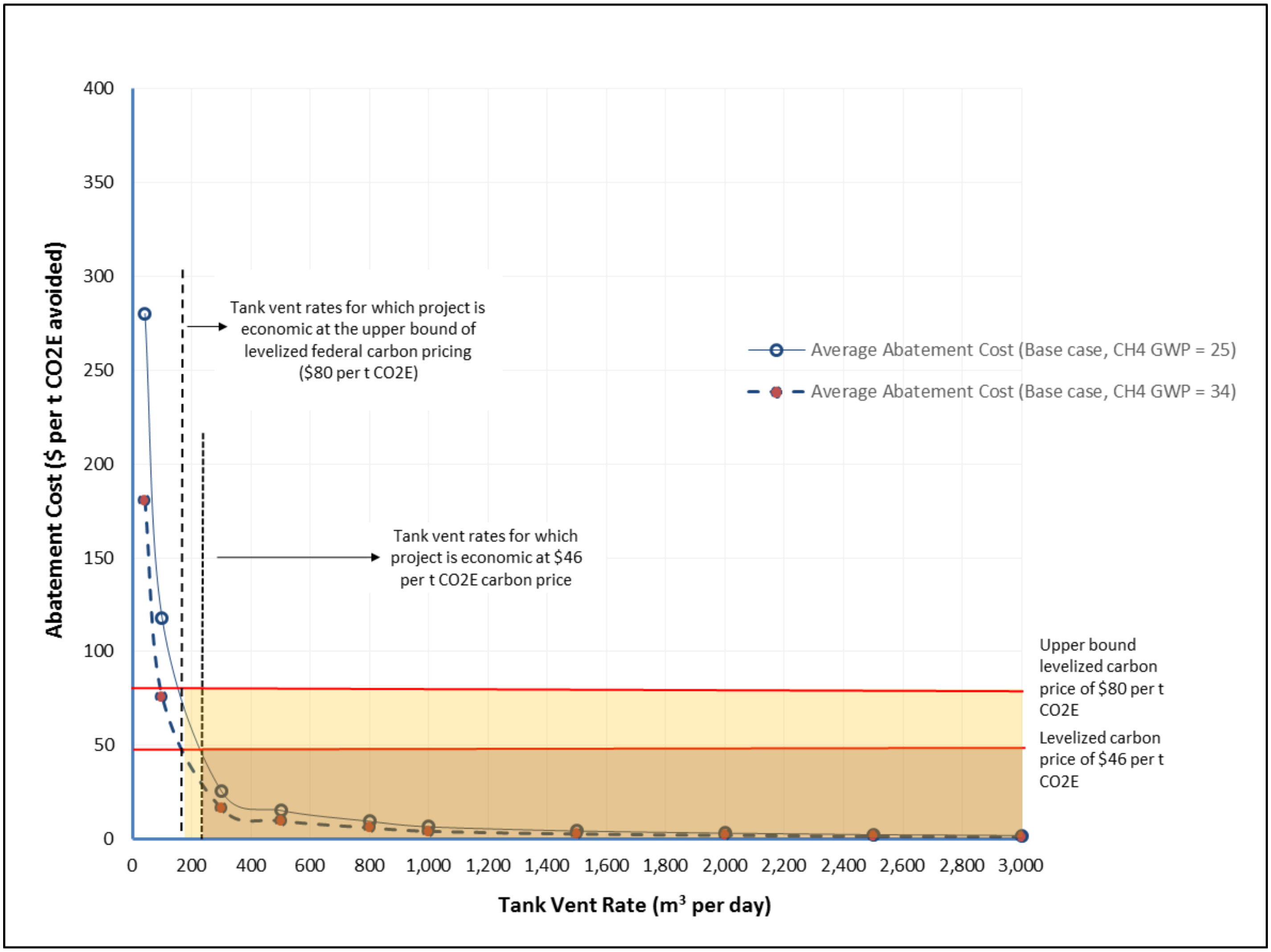


Figure 30: Average abatement cost as a function of tank venting rates for installing a flash vessel and tie-in to existing high pressure flare.

Table 12: Evaluation of base-case Net Present Value (NPV) for installing and operating a flash vessel and tie-in to existing high-pressure flare stack.

Year	Tank Venting Volume	Electricity Generated	Levelized Carbon Price	Value of Carbon Savings	Electricity Sales	Salvage Value	Total Net Project Benefits		Electricity cost	Royalty Payments	Net Capital Costs	Net Operating Costs	Total Net Project Costs		Total Project Net Benefits	
							Undiscounted	Discounted					Undiscounted	Discounted	Undiscounted	Discounted
	(10^3 m^3/ year)	(MWh/year)	($ / t CO_2E)	($ / year)	($ / year)	($/ year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019											125,000		125,000	125,000	(125,000)	(125,000)
2020	183		-	-	-	-	-	-	-			-	-	-	-	-
2021	183		-	-	-	-	-	-	-			-	-	-	-	-
2022	183		-	-	-	-	-	-	-			-	-	-	-	-
2023	183		-	-	-	-	-	-	-			-	-	-	-	-
2024	183		-	-	-	-	-	-	-			-	-	-	-	-
2025	183		-	-	-	-	-	-	-			-	-	-	-	-
2026	183		-	-	-	-	-	-	-			-	-	-	-	-
2027	183		-	-	-	-	-	-	-			-	-	-	-	-
2028	183		-	-	-	-	-	-	-			-	-	-	-	-
2029	183		-	-	-	3,316	3,316	1,693	-			-	-	-	3,316	1,693
	1,825			-	-	3,316	3,316	1,693	-	-	125,000	-	125,000	125,000	(121,684)	(123,307)

4.2.3 CASE 8: FLASH VESSEL TO VAPOUR COMBUSTOR

Connecting flash vessel vapours to vapour combustor (FL-800) requires the following equipment:

- Flash vessel (V-200) to decrease liquid pressure to about 273 kPag required for gravity flow into the storage tanks.
- Vapour combustor (FL-800)

The case #8 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.2.3.1 GHG EMISSION REDUCTIONS

Discharging vapours into vapour combustor reduces GHG emissions because methane is oxidized to CO_2 instead of vented directly to the atmosphere. The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 71 percent of hydrocarbons are oxidized results in an annual reduction of 1,128 t CO_2E. This is a 64 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year. The project emissions are due to fuel combustion in the vapour combustor plus venting of the fraction of gas not captured in the flash vessel (i.e., 29% percent).

4.2.3.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigating action does not generate revenue and will have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $307,200 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 13. Input parameters relevant to this technology are presented in appendix Figure 43.

As evident from the Figure 31 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $147,900. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs, operating life and annual operating costs. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $38.1 per t CO_2E avoided. As shown in Figure 32, the average abatement cost varies with tank venting rates.

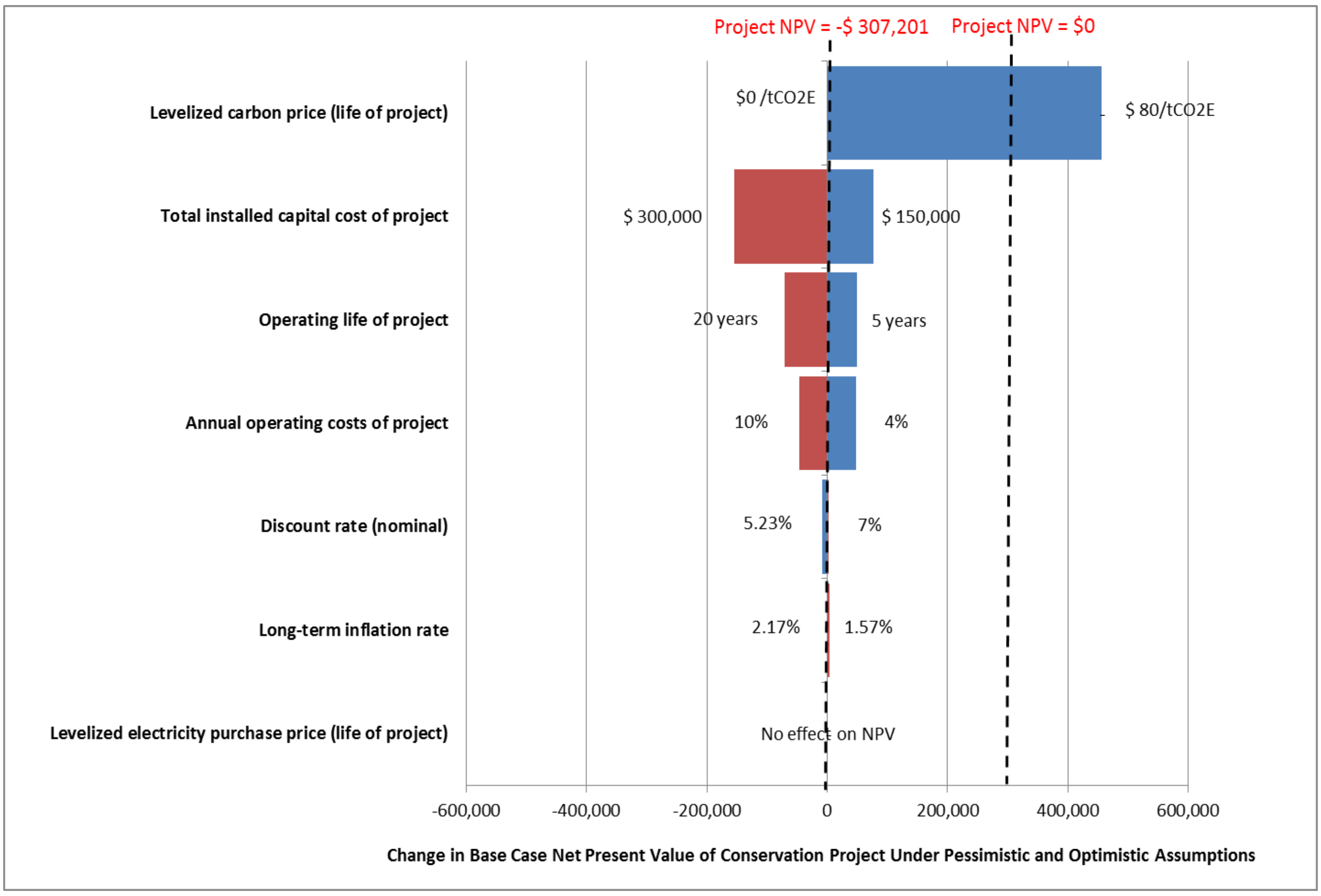


Figure 31: Tornado chart showing impact of upper and lower bound input values on NPV for installing a flash vessel and vapour combustor.

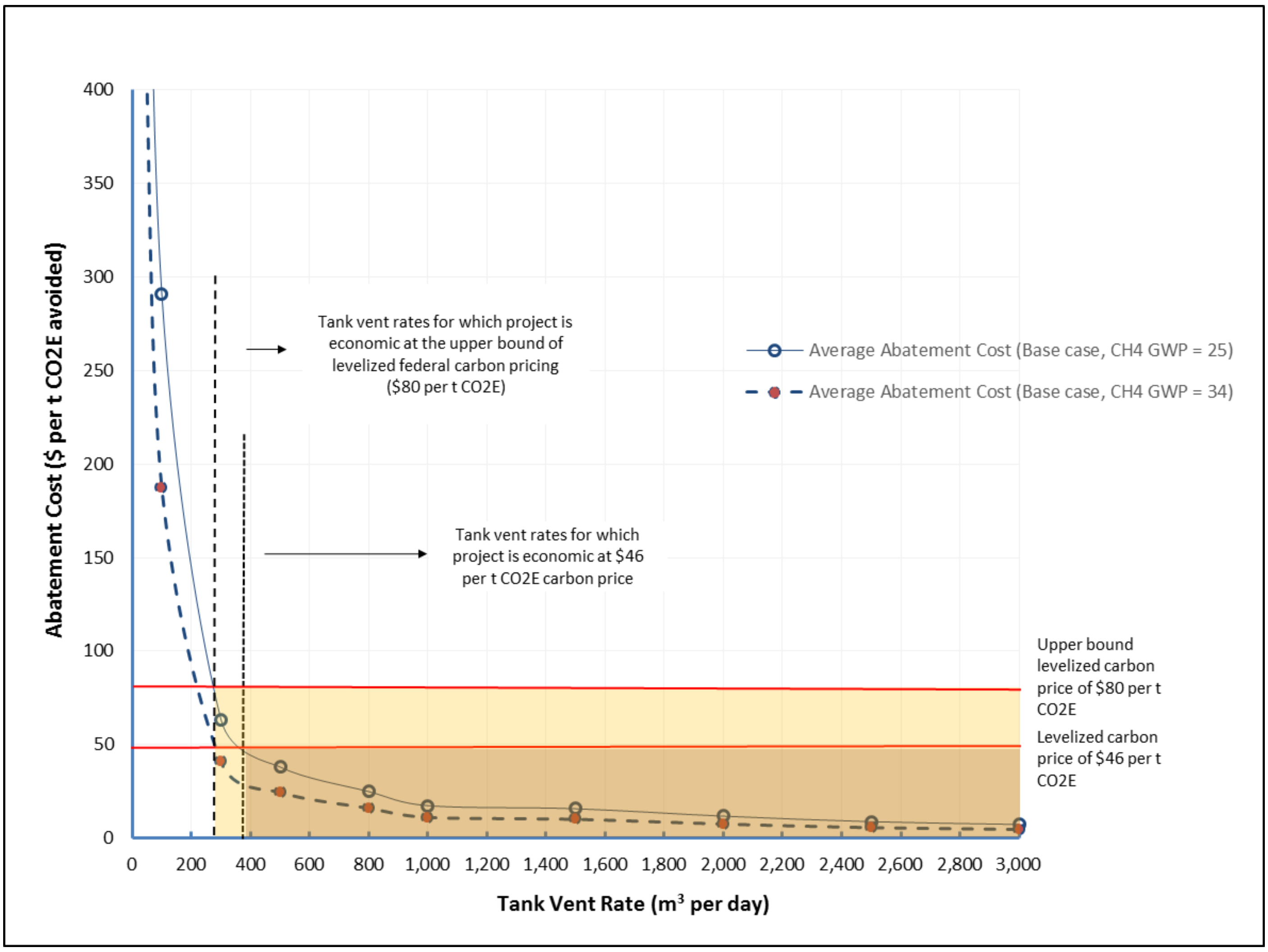


Figure 32: Average abatement cost as a function of tank venting rates for installing a flash vessel and vapour combustor.

Table 13: Evaluation of base-case Net Present Value (NPV) for installing and operating a flash vessel and vapour combustor.

Year	Tank Venting Volume	Electricity Generated	Levelized Carbon Price	Value of Carbon Savings	Electricity Sales	Salvage Value	Total Net Project Benefits		Electricity cost	Royalty Payments	Net Capital Costs	Net Operating Costs	Total Net Project Costs		Total Project Net Benefits	
							Undiscounted	Discounted					Undiscounted	Discounted	Undiscounted	Discounted
	(10^3 m^3/ year)	(MWh/year)	($ / t CO_2E)	($ / year)	($ / year)	($/ year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019											200,000		200,000	200,000	(200,000)	(200,000)
2020	183		-	-	-	-	-	-	-			14,304	14,304	13,374	(14,304)	(13,374)
2021	183		-	-	-	-	-	-	-			14,614	14,614	12,777	(14,614)	(12,777)
2022	183		-	-	-	-	-	-	-			14,931	14,931	12,206	(14,931)	(12,206)
2023	183		-	-	-	-	-	-	-			15,255	15,255	11,660	(15,255)	(11,660)
2024	183		-	-	-	-	-	-	-			15,586	15,586	11,139	(15,586)	(11,139)
2025	183		-	-	-	-	-	-	-			15,925	15,925	10,641	(15,925)	(10,641)
2026	183		-	-	-	-	-	-	-			16,270	16,270	10,165	(16,270)	(10,165)
2027	183		-	-	-	-	-	-	-			16,623	16,623	9,711	(16,623)	(9,711)
2028	183		-	-	-	-	-	-	-			16,984	16,984	9,277	(16,984)	(9,277)
2029	183		-	-	-	5,113	5,113	2,611	-			17,352	17,352	8,862	(12,240)	(6,251)
	1,825			-	-	5,113	5,113	2,611	-	-	200,000	157,845	357,845	309,812	(352,733)	(307,201)

4.2.4 CASE 10: FLASH VESSEL TO VRU PACKAGE INSTALLATION

Directing flash vessel vapours to VRU for delivery into sales pipeline requires the following equipment:

- Flash vessel (V-200) to decrease liquid pressure to about 273 kPag required for gravity flow into the storage tanks.
- Suction scrubber (V-200) to protect the compressor from fine particulates and liquid droplets.
- Rotary vane compressor (K200) for delivery of vapours into sales pipeline.
- Pressure relief valves to protect the scrubber and compressor from overpressure events.

The case #10 PFD is presented in Appendix Section 6.7 while installation and capital cost details are available in Section 6.8.

4.2.4.1 GHG EMISSION REDUCTIONS

The base case vent rate of 500 m^3 per day, Table 3 composition and assuming 71 percent of tank hydrocarbons are delivered into the sales pipeline results in an annual reduction of 1,252 t CO_2E. This is a 71 percent reduction relative to baseline GHG emissions of 1,752 t CO_2E per year. The project emissions are due to the venting of the fraction of gas not captured in the flash vessel (i.e., 29% percent).

4.2.4.2 ECONOMIC ASSESSMENT AND SENSITIVITY

This mitigating action does not generate revenue and will have a negative NPV unless the benefit of GHG reductions is monetized. The base-case NPV equals negative $620,000 (on a royalties-out basis) for a ten year operating life with annual cash flows delineated in Table 14. Input parameters relevant to this technology are presented in appendix Figure 45.

As evident from the Figure 33 tornado chart, project NPV is highly sensitive to the monetization of GHG emission reductions. Valuing GHG emission reductions at a levelized federal carbon price of $80 per t CO_2E increases NPV to positive $87,201. NPV is also sensitive to assumptions (in declining order of sensitivity) for: capital and installation costs, annual operating costs and operating life. However, the valuation of GHG emission reductions is the only input parameter that yields a positive project NPV when upper bound assumptions are adopted.

The average abatement cost for this project is $49.5 per t CO_2E avoided. As shown in Figure 34, the average abatement cost varies with tank venting rates.

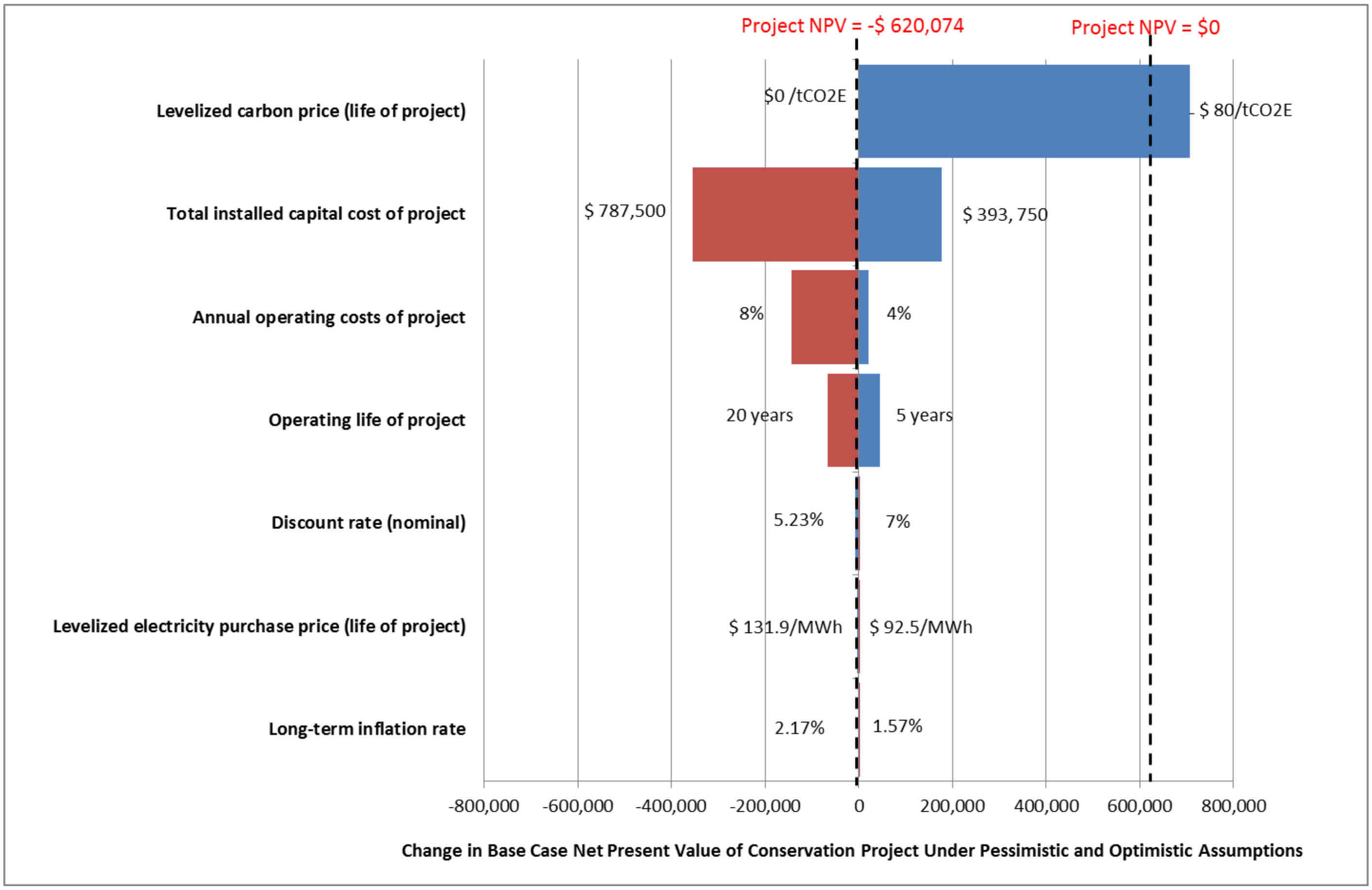


Figure 33: Tornado chart showing impact of upper and lower bound input values on NPV for installing a flash vessel and vapour recovery unit.

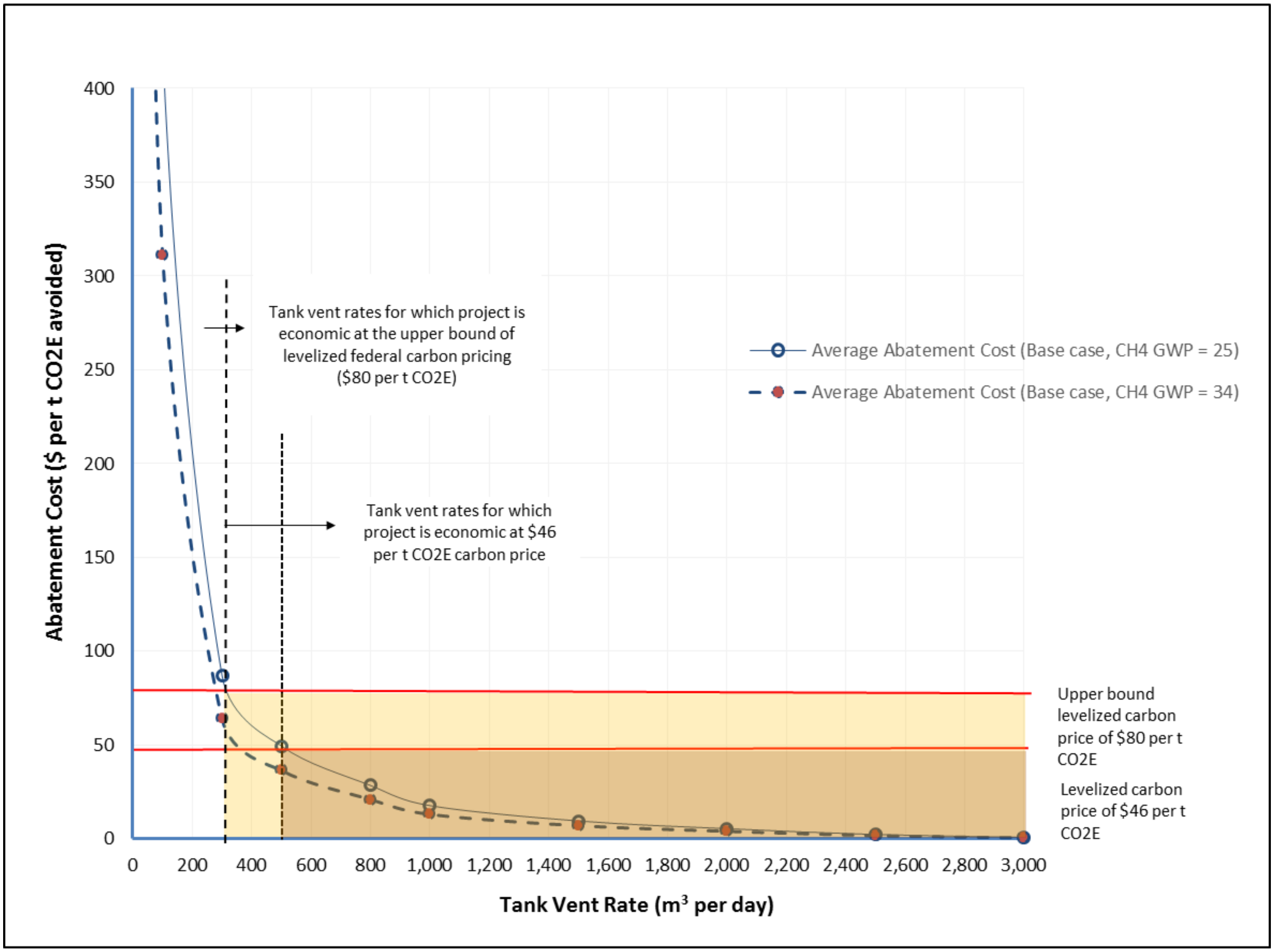


Figure 34: Average abatement cost as a function of storage tank venting rates for installing a flash vessel and vapour recovery unit.

Table 14: Evaluation of base-case Net Present Value (NPV) for installing and operating a flash vessel and vapour recovery unit.																
Year	Tank Venting Volume	Sales Gas Volume	Levelized Carbon Price	Value of Carbon Savings	Gas Sales	Salvage Value	Total Net Project Benefits		Electricity cost	Royalty Payments	Net Capital Costs	Net Operating Costs	Total Net Project Costs		Total Project Net Benefits	
							Undiscounted	Discounted					Undiscounted	Discounted	Undiscounted	Discounted
	(10^3 m^3/ year)	(10^3 m^3/ year)	($ / t CO_2E)	($ / year)	($ / year)	($/ year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)	($ / year)
2019											525,000		525,000	525,000	(525,000)	(525,000)
2020	183	130	-	-	13,759	-	13,759	12,865	1,792			24,138	25,930	24,245	(12,172)	(11,381)
2021	183	130	-	-	13,759	-	13,759	12,029	1,792			24,661	26,454	23,127	(12,695)	(11,099)
2022	183	130	-	-	13,759	-	13,759	11,247	1,792			25,197	26,989	22,062	(13,230)	(10,815)
2023	183	130	-	-	13,759	-	13,759	10,516	1,792			25,743	27,536	21,046	(13,777)	(10,530)
2024	183	130	-	-	13,759	-	13,759	9,833	1,792			26,302	28,094	20,078	(14,336)	(10,245)
2025	183	130	-	-	13,759	-	13,759	9,194	1,792			26,873	28,665	19,154	(14,907)	(9,961)
2026	183	130	-	-	13,759	-	13,759	8,596	1,792			27,456	29,248	18,274	(15,490)	(9,678)
2027	183	130	-	-	13,759	-	13,759	8,038	1,792			28,052	29,844	17,435	(16,086)	(9,397)
2028	183	130	-	-	13,759	-	13,759	7,515	1,792			28,660	30,453	16,634	(16,694)	(9,119)
2029	183	130	-	-	13,759	11,738	25,496	13,022	1,792			29,282	31,075	15,871	(5,578)	(2,849)
	1,825			-	137,586	11,738	149,324	102,853	17,925	-	525,000	266,364	809,289	722,927	(659,965)	(620,074)

4.3 SUMMARY OF ECONOMIC ASSESSMENT RESULTS

A business case exists for a mitigating action when NPV is greater than zero and an investor can expect to recover their invested capital and earn a nominal rate of return. As shown in Table 15, all options except case #3 lift gas opportunity, have a negative NPV under the base venting rate of 500 m^3 per day and would not normally be implemented because there is no economic benefit to facility owners. Other factors that motivate mitigating actions include regulatory requirements and corporate policies that improve environmental, health and safety performance above and beyond basic economic motivators. Average abatement costs (in present value terms) are also presented to show the total lifecycle cost incurred by an operator (net of any revenue) to avoid the release of one tonne of CO_2E. All actions are highly sensitive to the monetization of GHG emission reductions. When re-calculated using the current federal carbon price (levelized value of $46 per t CO_2E), NPV is positive for all cases but #8 and #10.

Table 15: Summary of TICC, NPV, GHG reduction and average abatement costs for options to mitigate of 500 m^3 per day tank venting.

Case # and Description	TICC	NPV	GHG reduction over 10 years	Average Abatement Cost ($/t CO_2E)
#1 Tank Top to Existing High Pressure Flare	$195,000	-$311,000	11,180	28
#2 Tank Top to Low Pressure Flare	$155,000	-$245,000	11,180	22
#3 Tank Top to Booster Compressor for Gas Lift	$780,000	$283,000	17,500	16
#4 Tank Top to Vapour Combustor	$235,000	-$363,000	11,275	32
#5 Flash Vessel to Electrical Generators	$245,000	-$122,000	8,055	15
#6 Tank Top to Electrical Generators	$300,000	-$113,000	11,275	10
#7 Flash Vessel to Existing High Pressure Flare	$125,000	-$123,000	9,535	15
#8 Flash Vessel to Vapour Combustor	$200,000	-$307,000	8,055	38
#9 Tank Top to VRU for Gas Sales	$430,000	-$461,000	17,522	26
#10 Flash Vessel to VRU for Gas Sales	$525,000	-$620,000	12,517	50

5 CONCLUSIONS AND RECOMMENDATIONS

Conclusions and recommendations include the following:

- Evidence collected by this study indicates separator and scrubber dump-valve leakage is contributing to fugitive emissions from storage tanks. However, this source is not accounted in provincial or national inventories. To resolve this data gap, a field measurement campaign should be implemented to develop component counts and population-average emission factors.

- A decision tree for identifying the root-cause of venting from uncontrolled storage tanks is proposed as a first troubleshooting attempt during LDAR surveys. Outcomes are intended to alert maintenance personal to equipment that may be malfunctioning and unknowingly contributing to tank venting.

- The key benefit of correlations is their simplicity and minimal input data requirements. However, they are unable to account for sample specific analyte fractions; stock tank liquid heating (that has an upward influence on GOR); or backpressure imposed by emission control overhead piping (that has a downward influence on GOR). When accurate determination of peak venting is required (e.g., for designing vapour recovery systems or compliance with Directive 017), more rigorous process simulation should be applied to account for site specific conditions.

- For emission inventory purposes, the Valko and McCain correlation is recommended when determining flash gas factors for crude oils within the range of parameters stated in Table 20. This is based on alignment with GORs determined with VapourSIM (flashed to atmospheric pressure) and measured spot checks plus its use in Colorado for determining flash gas factors (SLR, 2018). The Valko and McCain correlation is not recommended for lighter condensates with API gravity greater 56.8^{o}. Instead, the Vasquez & Beggs and D017 'Rule of Thumb' correlations provide more reasonable GOR estimates for condensates with API gravity greater 56.8^{o}.

- In general, the plotted GOR trends indicate the risk of uncontrolled tanks exceeding new venting limits increases with increasing separator pressure and liquid volatility. GOR is also dependent on separator temperature but a small range in temperature was observed in field data so this parameter is ultimately less important.

- GORs determined by process simulation (e.g., VapourSIM, Hysys, Aspen Plus, etc) and flashing pressurized samples to their sales oil RVP represent total venting (e.g., total evaporative flashing, working and breathing losses are accounted). This approach represents a mass balance between the composition and volume of oil leaving the separator and the composition and volume of oil leaving the stock tank. It's reasonable to use total venting GOR's for environmental reporting concerned with total atmospheric emissions.

- To improve laboratory analysis data reliability the steps recommended by Colorado regulators (described in Section 6.3.1), when performing and verifying flash gas liberation analysis on pressurized liquid hydrocarbon samples, should be considered (CAPCD, 2017).

- Techno-economic assessments are completed for ten storage tank emission mitigation options. Results indicate all but one option have a negative NPV when venting equals 500 m^3 per day. Unless alternative revenue opportunities (e.g., offset credits, royalty credits, energy efficiency incentives, etc) are available, current commodity prices and limited economic benefit to facility owners will challenge implementation of mitigation options. Of particular vulnerability are existing sites that require retrofits and may be forced to shut-in if incentives are not available. This outcome diminishes economic activity and Canada's capacity to implement climate solutions.