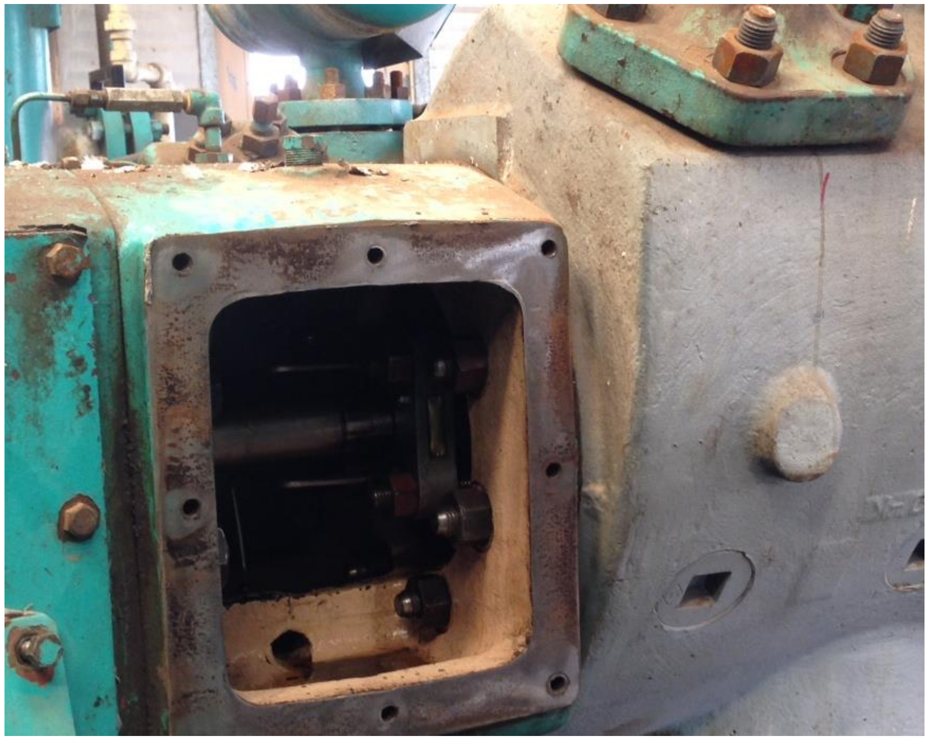
TECHNICAL REPORT



March 2, 2020

Methane Emissions from BC Compressor Seals and Storage Tanks.

Prepared For: BC Oil & Gas Methane Emissions Research Collaborative (MERC)
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EXECUTIVE SUMMARY

This study investigates methodology and data sources for estimating methane emissions from uncontrolled storage tanks, reciprocating compressor rod-packing vents and centrifugal compressor seal vents relevant to the British Columbia (BC) upstream oil and natural gas (UOG) sector. Data source opportunities, challenges and gaps are described. Data flow diagrams are developed to depict how information from numerous sources is combined to generate emission inventories. The resulting assessment of methane emissions and their uncertainty is developed using best available information and pragmatic methods for bridging data gaps. More rigorous approaches for resolving knowledge gaps are proposed and intended to inform future research and field campaign planning.

This report is prepared for the BC Oil and Gas Methane Emissions Research Collaborative (MERC) and funded by the BC Oil and Gas Research and Innovation Society (BC OGRIS).

Emission Source Descriptions

Uncontrolled storage tanks

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. 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). Uncontrolled flashing losses are estimated by this study because this is the dominant contributor of methane from UOG storage tanks. Breathing and working losses are not assessed because these mechanisms contribute little methane relative to flashing. Fugitive emissions from controlled tanks are not included in the scope of this study.

Reciprocating compressor rod-packings

Reciprocating compressors are commonly used at gas production and processing facilities and less so for gas transmission applications. Reciprocating compressors are fitted with pressure packing, a series of precision-machined mechanical rings that form a tight seal around the piston rod to prevent compressed gas from escaping but still allow the piston to move freely. Leaks in the packing system are common, with the size of the leak depending on fitting, cylinder pressure, and alignment of packings parts. Piston rods wear more slowly than packing rings, so as systems age, leak rates increase due to the uneven wear. Leakage from the packing case discharges into the distance piece which may be left open, with the vent piping connected directly to the packing case, or the distance piece may be closed, with the vents connected to both the packing case and the distance piece. Gas can also migrate and vent from the crankcase. Common practice is to route the packing and distance piece vents outside the building to the atmosphere if the process gas is sweet, or to a flare if the gas is sour.

Centrifugal compressor seals

Centrifugal compressors are commonly used by gas transmission pipelines and less so for gas production or processing applications. Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used.

A typical wet seal design for a centrifugal compressor comprises two face contact seal rings held in close contact by a spring mechanism balanced with fluid pressures from the process gas and seal oil, plus an inner and outer labyrinth seal. The seal oil is supplied at a pressure greater than the process gas pressure, and, in combination with tight seal clearance tolerances, provides a positive seal from gas leakage along the shaft to the atmosphere. A small quantity of oil passes through the inner seal ring to the inner drain (i.e., located on the inboard side of the seal), where it is exposed to the gas pressure and will dissolve/entrain some of the buffer (e.g., nitrogen (N_2) or other inert gas) or process gas. Thus, this oil is directed to a seal pot (or separator system) where the separated gas is vented, flared or recycled to the suction side of the compressor; or used as fuel gas. Some gas, particularly heavier fractions, remain in solution or are suspended as fine bubbles in the oil leaving the seal pots and is usually routed to a degassing drum.

Dry gas seals operate without oil. Instead, the dry seals feature two precision-machined sealing plates with one stationary and the other rotates with the shaft. At high rotation speed, seal gas separates the plates via a pressure dam effect. Due to very close running clearances, leakage rates are very low (but increases for worn plates). Tandem gas seal arrangements are becoming the minimum standard for high pressure applications with flammable gases. A primary seal absorbs the total pressure drop to a vent system, and the secondary seal acts as a backup should the primary seal fail. The inner-seal (primary) vent can usually be routed to flare with back-pressure control. Emissions are still typical at the outer seal (secondary) vent.

Screw Compressors

Screw compressors utilize a rotary positive displacement mechanism that compresses gas between intermeshing helical lobes and chambers in the compressor housing (or casing). As the mechanism rotates, the meshing and rotation of the two helical rotors produces a series of volume-reducing cavities. Gas is drawn in through an inlet port in the casing, captured in a cavity, compressed as the cavity reduces in volume, and then discharged through another port in the casing. Lubricating oil is required to provide sealing between the intermeshing lobes and casing as well as lubrication for bearings and shaft seals. Bearing and seal oil is drained into the rotors where it combines with process gas. A separator (located downstream of the compressor discharge) removes this oil from the process gas. It is then cooled, filtered and recycled back to the lubricating oil injection points (NEXT, 2018). This is a closed system that precludes seal gas venting so screw compressors are not investigated further.

Emission Inventory Methodology

This study assesses emissions from uncontrolled storage tanks, reciprocating compressor rod-packings and centrifugal compressor seals that occurred between November 2018 and October 2019. Other emission sources such as combustion, flaring and fugitives as well as dehydrator, pneumatic, truck loading, blowdown and other venting sources are outside the scope of the study.

The inventory boundary includes the following segments of the BC UOG industry. These segments are targeted because they feature the majority of storage tanks and compressors of interest.

- Natural gas production,
- Light and medium oil production,
- Natural gas processing, and
- Natural gas transmission.

Oil and gas production from both conventional and unconventional sites are included with the number of each facility subtype presented in Table ES1. Facility and production types are further classified according to 'site classification' stratums defined by the BC methane field study methodology (Cap-Op, 2018) to facilitate use of factors from this study.

The following industry segments are specifically excluded from the inventory because they are not relevant to BC UOG industry or have negligible storage tank and compressor venting emissions.

- Cold heavy oil production
- Thermal heavy oil production
- Disposal and waste treatment, and
- Incidents and equipment failures
- Refineries,
- Petrochemical plants,
- Liquid fuel distribution and sales,
- LNG plants,
- Offshore facilities,

- Facility construction, decommission and reclamation activities, and
- Electric power generation.

Table ES1: BC facility subtypes included in the emission inventory boundary for production and processing industry segments.

Subtype Code	Subtype Description	Field Study Code	Active Codes in 2018/19
GAS FLOW	Well (Tight Gas)	WT	4916
GAS FLOW	Well (Conventional Gas)	WC	4220
CR-OIL PUMP	Well (Oil)	WO	940
311	Crude Oil Single Well Battery	SWB	76
351	Gas Single Well Battery	SWB	52
321	Crude Oil Multiwell Group Battery	MGB	6
361	Gas Multiwell Group Battery	MGB	113
393	Mixed Oil and Gas Battery	MGB	25
322	Crude Oil Multiwell Proration Battery	MPB	41
362	Gas Multiwell Effluent Measurement Battery	MEM	177
401	Gas Plant Sweet	GP1	24
402	Gas Plant Acid Gas Flaring (<1 t/d Sulphur)	GP2	26
403	Gas Plant Acid Gas Flaring (>1 t/d Sulphur)	GP7	4
404	Gas Plant Acid Gas Injection	GP3	3
405	Gas Plant Sulphur Recovery	GP4	4
407	Gas Plant Fractionation	GP6	1
611	Custom Treating Facility	CT1	5

Relevant publications and raw data sources were reviewed to identify best available information. Data source reliability and use is prioritized according to regulatory backstop, verification assurance and relevance to 2019 operating year. A step-by-step illustration of how information from numerous data sources is combined to bridge data gaps and generate emission estimates is presented in Figure ES2 for compressors and Figure ES3 for tanks.

A quantitative assessment of uncertainties in estimated methane emissions is developed according to IPCC Tier 1 methodology. This approach employs simple error propagation equations based on the assumption of uncorrelated normally distributed uncertainties under addition and multiplication.

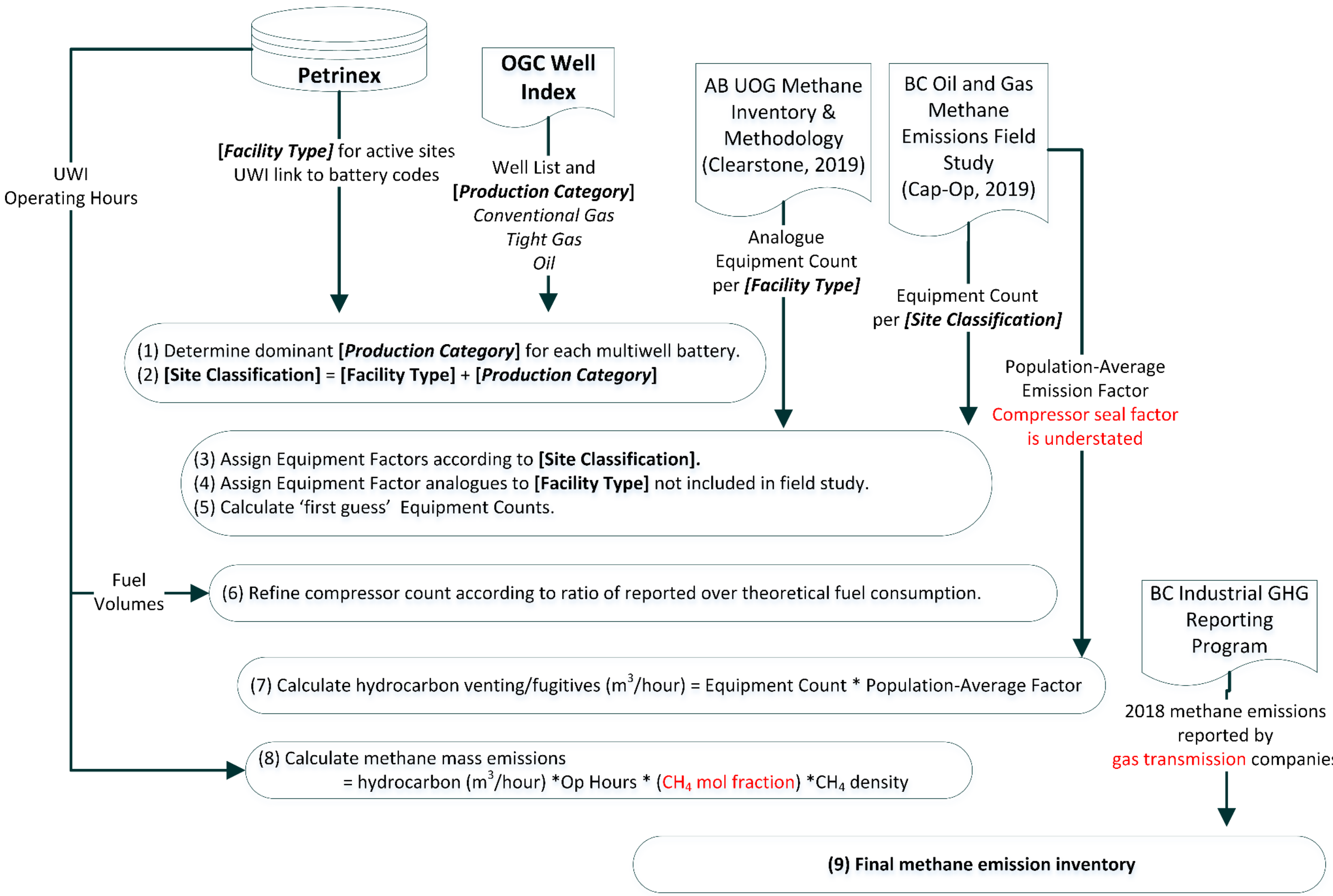
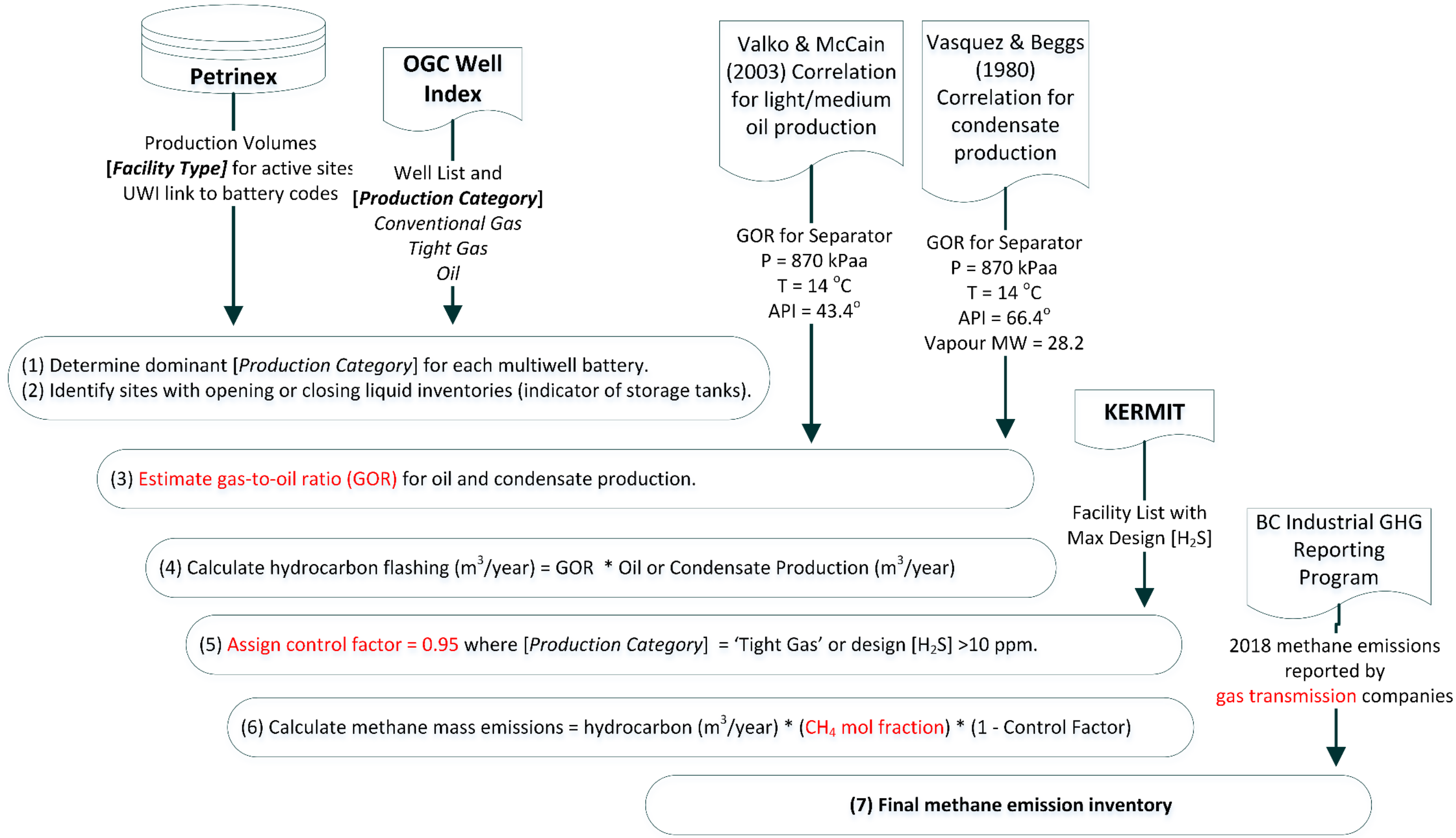


Figure ES2: Compressor seal and water tank emission inventory using Petrinex activity data and population average factors.



Assumptions:

(1) Tank emission control factor (0.95) applied to sites with design [H_2S] >10 ppm or that produce unconventional (tight or shale) natural gas.

(2) Storage tank emissions only calculated for sites reporting liquid invoices (i.e., indicator of site storage).

Figure ES3: Hydrocarbon tank emission inventory using Petrinex activity data and empirical correlations

Data Gaps and Methodology Challenges

The following knowledge gaps could have material impacts on emission estimates for storage tanks and compressors.

Unintentional gas carry-through to storage tanks

Unintentional gas carry-through to storage tanks are a less recognized, potentially significant and often unaccounted contribution to atmospheric emissions of CH_4 (Clearstone, 2020). However, the frequency and magnitude of this emission type is not defined and therefore not included in the current CH_4 emission inventory. The following mechanisms can be responsible for unintentional gas carry-through.

- 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 from fully sealing with its seat. The seat or disk can also be scoured or damaged to the point where a full seal is not possible. Passing dump-valves can be detected and leak rate estimated using an acoustic leak instrument that measures ‘noise’ across the valve body.
- It is 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.
- Inefficient separation of gas and liquid phases in upstream separators can allow some gas carry-through, by entrainment or in solution, to the tanks. A ‘tell-tale’ indicator of inefficient separation is sustained high liquid levels in the upstream separator. This may initiate frequent signals for the dump-valve to open resulting in almost continuous flow of pressurized hydrocarbon liquids to the storage tanks and reduces residence time for separation of gas from the liquid phase.
- Although much less frequent, 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.

Use of correlations to estimate tank flashing

According to BC OGC Measurement Guidelines (BC OGC, 2018b), 0.0257 m^3 of gas/m^3 of oil/kPa of pressure drop estimate may be used as the GOR factor for determining the quantity of flash gas released from conventional light-medium oil production, if well oil production rates do not exceed 2 m^3 per day **or** if all gas production is vented or flared. WCI.363(h) quantification methodology for storage tank flashing also permits the use of correlations (WCI, 2013). The flexibility to use simple correlations for **all** instances of gas flared or vented introduces reporting inaccuracies because correlations are unable to account for sample specific analyte fractions (a measure of liquid volatility), 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). To improve the accuracy of reported vent and flare volumes (from tank flashing), use of correlations should be limited to sites that do not exceed 2 m^3 per day (regardless of whether production is vented or flared).

<u>Data for transmission stations</u>

Gas transmission stations are generally not included in data sources available to this study. Moreover, gas transmission stations were not included in recent BC or AB field studies so relevant equipment factors are not available. These data gaps preclude the development of a bottom-up emission inventory by this study. Instead, this inventory relies on CH_4 emissions reported to the BC GHG Reporting program that were quantified according to WCI.353 methodologies and subject to 3rd party verification.

<u>Results</u>

Estimated compressor counts (with 95 percent confidence level) are presented in Table ES2 for production and processing segments. These are compared to values reported to BC CIIP and KERMIT. The compressor counts estimated for production and processing (724) appears reasonable as they are within the range of values reported by CIIP (612) and KERMIT (1138).

Table ES2: Comparison of estimated compressor counts (with 95% confidence limits) with unit counts derived from BC CIIP and KERMIT data sources.

Segment	Estimated Unit Count	95% Confidence Limits				CIIP (2018 report)	KERMIT
		Lower Limit	Upper Limit	Lower (%)	Upper (%)	Unit Count	Unit Count
Production	392	374	426	4.5%	8.6%		876
Processing	332	325	358	2.3%	7.8%		262
Total	724	705	767	2.7%	5.9%	612[a]	1,138[b]

[a] *Includes centrifugal, reciprocating and screw compressors from all segments that operated in 2018 (of these, there are 70 electric driven and 542 natural gas fired compressors)*

[b] *Includes centrifugal, reciprocating and screw compressors that have permit to operate (of these, there are 149 electric driven and 989 natural gas fired compressors).*

Estimated storage tank counts (with 95 percent confidence level) are presented in Table ES3 for production and processing segments. These counts are compared to values reported to BC CIIP and KERMIT. Total predicted storage tank counts (1611) at production and processing segments are in close proximity to the upper bound estimate of 2,001 reported by KERMIT.

Table ES3: Comparison of estimated storage tank counts (and 95% confidence limits) with unit counts derived from BC CIIP and KERMIT data sources.

Segment	Estimated Unit Count	95% Confidence Limits				CIIP (2018 report)	KERMIT
		Lower Limit	Upper Limit	Lower (%)	Upper (%)	Unit Count	Unit Count
Production	1,487	1313	1723	11.7%	15.8%		1,614
Processing	124	87	268	29.6%	116.2%		387
Total	1611	1433	1887	11.1%	17.1%	NA	2,001

*NA: Not available

The number of compressors and storage tanks at natural gas transmission stations is not estimated because of data gaps.

Estimated CH_4 emissions (with 95 percent confidence level) are summarized by industry segment and equipment type in Table ES4. Reciprocating compressors are responsible for the majority of compressor CH_4 emissions (853 tonnes) from production and processing segments while centrifugal compressors are responsible for the majority of compressor CH_4 emissions (2,264 tonnes) from the transmission segment. Storage tanks are estimated to emit 2,612 tonnes of CH_4 per year with the majority of emissions from the production segment (99 percent).

Table ES4: Estimated methane emissions (tonnes/year) with 95% confidence limits summarized by industry segment and equipment type.

Segment	Process Equipment	Type	Estimated Emissions (t CH_4/ year)	95% Confidence Limits			
				Lower Limit (t CH_4/ year)	Upper Limit (t CH_4/ year)	Lower (%)	Upper (%)
Production	Reciprocating Compressor	Electric	35	31	44	12.9%	23.8%
		Natural Gas	432	409	473	5.2%	9.6%
	Storage Tanks	Hydrocarbon	2,141	86	8618	96.0	302.5%
		Water	455	446	469	2.0%	3.0%
Processing	Reciprocating Compressor	Natural Gas	386	375	418	2.9%	8.2%
	Centrifugal Compressor		10	7	18	30.8%	87.5%
Transmission	Centrifugal Compressor	Electric and Natural Gas	2,264	1811	2717	20.0%	20.0%
	Storage Tanks	Hydrocarbon	16	13	18	15.2%	16.8%

The relative difference between estimated emissions and values reported to the BC industrial GHG reporting program are presented in Table ES5 (for production and processing segments). Estimated compressor emissions are two to eight times **less** than measured and reported by companies according to WCI.353(e) and 353(m). Estimated tank emissions are almost five times **greater** than reported by companies according to WCI.353(m) and 363(h).

This study observed quantification bias that suggests storage tank emissions reported to the BC GHG program may be understated. The study also observed compressor rod-packing emission factors derived from the 2018 BC methane field study may understate actual emissions.

Table ES5: Estimated compressor rod-packing and storage tank methane emissions (95% confidence level) compared with 2018 values submitted to the BC Industrial GHG Reporting Program for production and processing segments.

Equipment Type	Estimated Methane Emissions (t CH_4/yr)			2018 Reported Emissions (t CH_4/yr)	Relative Difference between estimated and reported methane	
	Estimated	Lower Limit (2.5% interval)	Upper Limit (97.5% interval)			
Reciprocating Compressor Rod-Packing	863	837	917	4,141	-3,278 t/yr	-380%
Storage Tank	2,596	541	9,073	537	2,059 t/yr	79%

Conclusions and Recommendations

Because the BC GHG Reporting Program requires annual direct measurement and verification of reciprocating compressor rod-packings (per WCI.363(m)) and centrifugal compressor seals (per WCI.353(e)); this reporting program provides a more reliable estimate of compressor CH_4 emissions than can be achieved using emission factors. Compressor seal CH_4 emissions, estimated by this study using emission factors, have a narrow confidence interval (e.g., minus 3 percent and plus 6 percent of the estimated mean). Results from the BC GHG Reporting Program are 4.5 times **greater** than estimated using emission factors. This suggests emission factors, CF and confidence intervals applied by this study are not representative and understate compressor rod-packing emissions.

Because the BC GHG Reporting Program permits a wide range of quantification methods for reporting storage tank emissions, the accuracy and completeness of reported values are uncertain. The independent assessment of storage tank CH_4 emissions (this study) features a wide confidence interval (e.g., minus 79 percent and plus 250 percent of the estimated mean) due to uncertainty in GOR, tank vapour composition and emission control parameters. Lower bound results (565 tonnes CH_4/year) are greater than submitted to the BC GHG Reporting Program (537 tonnes CH_4/year) which suggests BC UOG storage tank emissions may be understated. Similar conclusions are made by related field studies (Brandt et al, 2016; Lyon et al, 2016; and

Zavala-Araiza et al, 2018). Therefore, BC GHG reporting program parameters and methods should be refined to mitigate systematic downward bias. These refinements may include:

- BC GHG Reporting Program accuracy could be improved by refining WCI.363(h) methodology to follow BC OGC measurement guidelines and only permit use of correlations for sites producing less than 2 m^3 per day (regardless of whether production is vented or flared). This is particularly relevant to GORs determined using the Vasquez and Beggs correlation for liquids with API gravity less than 56.8º.
- When GOR is determined by process simulation, the integrity of pressurized liquid samples should be confirmed by comparing the calculated bubble point to the field sample pressure as described in PS Memo 17-01 (CAPCD, 2017).
- When GOR is determined by direct measurement, flash gas sampling and laboratory analysis should be completed to determine CH_4 concentrations.
- Unintentional gas carry-though can be detected and measured using acoustic leak detection on dump-valves according to WCI.363(h.1) methodology. However, inefficient separation, malfunctioning level controllers and piping anomalies may also cause unintentional gas carry-though. A more thorough root-cause analysis (proposed in Clearstone, 2020) will improve quantification (and mitigation) of these emissions.

Storage tank emissions from unintentional gas carry-through are not accounted in the current CH_4 emission inventory because plausible estimation methods are not available. This knowledge gap could be resolved by a field campaign designed to identify subject tanks and complete discrete measurements of gas flashing and unintentional gas carry-through.

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AB	Alberta
AER	Alberta Energy Regulator
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BC	British Columbia
BC OGC	British Columbia Oil and Gas Commission
BC OGRIS	British Columbia Oil and Gas Research and Innovation Society
BHGE	Baker Hughes GE
BTEX	Benzene, Toluene, Ethyl Benzene, Xylenes
CAPCD	Colorado Air Pollution Control Division
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Environmental Protection Act
CEPEI	Canadian Energy Partnership for Environmental Innovation
CF	Control Factor
CH_4	Methane
CIIP	CleanBC Industrial Incentive Program
CO_2	Carbon Dioxide
CO_2E	Carbon Dioxide Equivalent
CT	Custom Treating Facility
C_1	One Carbon
C_9	Nine Carbons
DPR	Drilling and Production Regulation
EPA	Environmental Protection Agency
ECCC	Environment and Climate Change Canada
EF	Emission Factor
FEMP	Fugitive Emissions Management Program
GHG	Greenhouse Gas
GIS	Gas in Solution Ratio
GOR	Gas to Oil Ratio
GP	Gas Plant
HAP	Hazardous Air Pollutants
He	Helium
H_2	Hydrogen
H_2S	Hydrogen Sulphide
hr	hour
ID	Identifier
IPCC	Intergovernmental Panel on Climate Change
IR	Infrared
ISO	International Organization for Standardization

KERMIT	Knowledge, Enterprise, Resource, Management, Information and Technology
kW	Kilowatt
LDAR	Leak Detection and Repair
MEMPR	Ministry of Energy and Mines and Petroleum
MERC	BC Oil & Gas Methane Emissions Research Collaborative
MEM	Gas Multi Well Effluent Measurement Battery
MGB	Multi Well Group Battery
MOF	Ministry of Finance
MPB	Multi Well Proration Battery
MSAPR	Multi-Sector Air Pollutants Regulations
NAICS	North American Industry Classification System
NPRI	National Pollutant Release Inventory
N_2	Nitrogen
OGI	Optical Gas Imaging
O_2	Oxygen
Petrinex	Petroleum Information Excellence
PRV	Pressure Relief Valve
PS	Permit Section
PTAC	Petroleum Technology Alliance of Canada
PVRV	Pressure/Vacuum Relief Valve
QA	Quality Assurance
QC	Quality Control
QOGI	Quantitative Optical Gas Imaging
RSC	Reduced Sulphur Compound
RVP	Reid Vapour Pressure
SABA	Supplied Air Breathing Apparatus
SG	Specific Gravity
SWB	Single Well Battery
THC	Total Hydrocarbon
TVP	True Vapour Pressure
UOG	Upstream Oil and Gas
UWI	Unique Well Identifiers
VOC	Volatile Organic Compound
VRT	Vapour Recovery Tower
VRU	Vapour Recovery Unit
WA	Well Authorization
WC	Conventional Gas Well
WCI	Western Climate Initiative
WO	Conventional Oil Well
WT	Conventional Tight Gas Well

GLOSSARY

Analyte A chemical component of interest in a sample that is the subject of a chemical analysis. The remainder of the sample is called the matrix.

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 (O_2) does not enter the vapour space of the tank when it is connected to a flare system or vapour recovery unit (VRU). 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.

Centrifugal Compressor

Centrifugal compressors are typically driven by natural gas fired turbines and used for large volume, high pressure and high reliability applications such as natural gas transmission or gas plant sales. Centrifugal compressors are dynamic compressors, meaning energy is transferred from a moving set of blades to the gas. This energy takes the form of velocity and pressure. Centrifugal compressors use an impeller consisting of radial or backward bending blades. As the impeller rotates, gas between the rotating blades is moved from the area near the shaft radially outward into a diffuser. Energy is transferred to the gas while it is travelling through the impeller. Some of the energy results in an increase in pressure, some contributes to the velocity of the gas. This velocity decreases in the diffuser, resulting in a higher pressure and compression of the gas.

Centrifugal Compressor Seal

Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used. A centrifugal compressor has two seals, one on each side of the housing where the shaft penetration occurs. Controlled seal vent lines that are tied into a flare header, VRU or other gas capture system have a very low probability of leaking to the atmosphere.

Compressor Station

A facility where gas pressure is increased to overcome friction losses through a pipeline or pipe system or for underground natural gas storage. Both centrifugal and reciprocating compressor units may be used in these applications. A compressor station typically comprises several units in series or parallel, as well as the necessary suction and discharge piping.

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 (15^{o}C and 101.325 kPa). Condensate density is less than 800 kg/m^3**.**

Conventional Gas Gas consisting of a mixture of hydrocarbon compounds, primarily methane, and small quantities of various non-hydrocarbons (BC OGC, 2019c). Conventional gas production does not include gas produced unconventional (Tight or Shale) reservoir zones listed in schedule 2 of the BC OGC Drilling and Production Regulation (BC OGC, 2018a).

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 light and medium crude oil types are defined by the AER (AER, 2019b). The heavy crude oil density is obtained from BC OGC (BC OGC, 2019c)

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 is 920 kg/m^3 and greater.

Crude Oil Single-Well Battery A production facility for a single oil well (Petrinex, 2018).

Crude Oil MultiWell Group Battery A production facility consisting of two or more flow-lined oil wells having individual separation and measuring equipment but with all equipment sharing a common surface location (Petrinex, 2018).

Crude Oil Multiwell Proration Battery A production facility consisting of two or more flow-lined oil wells having common separation and measuring equipment. Total production is prorated to each well based on individual well tests. Individual well production tests can occur at the central site or at remote satellite facilities (Petrinex, 2018).

Distance Piece An enclosure that houses the rod, packing drain and vents for the rod lube oil and separates the cylinder from the crankcase in reciprocating compressors.

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 and BC OGC Measurement Guideline, 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.

Gas Processing A natural gas processing plant is a facility for extracting condensable hydrocarbons from natural gas, and for upgrading the quality of the natural gas to market specifications (i.e., removing contaminants such as H_2O, H_2S and CO_2). The processing facilities include sweet plants, sour plants that flare acid gas, sour plants that re-inject acid gas, sour plants that extract the elemental sulphur from acid gas, and straddle plants.

Gas Single Well Battery A production facility for a single gas well where production is measured at the wellhead. Production is delivered directly and is not combined with production from other wells prior to delivery to a gas gathering system or other disposition (Petrinex, 2018).

Gas Multiwell Effluent

Measurement Battery	A production reporting entity consisting of two or more gas wells where estimated production from gas wells in the battery is determined by the continuous measurement of multiphase fluid from each well (effluent measurement). Commingled production is separated and measured then prorated back to wells based on the estimated production (Petrinex, 2018).
Gas Multiwell Group Battery	A production reporting entity consisting of two or more gas wells where production components are separated and measured at each wellhead. Production from all wells in the group is combined after measurement and then delivered to a gas gathering system or other disposition (Petrinex, 2018).
Gas Transmission	The gas transmission system transports sales-quality natural gas from the producers (i.e., from gas batteries, gas processing plants and imports at the border) to market (i.e., gas distribution systems, the border for export, and direct sales to end customers).
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.
Hydrocarbons	All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.
Infrared (IR) Camera	An optical gas imaging camera tuned to observe hydrocarbon gases in the 3.2 to 3.4 micrometer spectral range and capable of detecting a methane leak rate of approximately 1 g/hr at a distance of 3 metres.
Knock-out Drum	A vapor-liquid separator for removal of entrained liquids from gas flows.

Leak A leak is the unintentional loss 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 standards. An equipment component in hydrocarbon service is commonly deemed to be leaking when the emitted gas can be visualized with an infrared (IR) leak imaging camera, detected by an organic vapour analyzer in accordance with U.S. EPA Method 21 (i.e., hydrocarbon concentration screening value of 500 ppmv or more), or detected by any other techniques with similar or better detection capabilities.

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.

Methane Content of Natural Gas Volume of methane contained in a unit volume of natural gas at 15°C and 101.325 kPa.

Oil and Gas Production Oil and gas production facilities include conventional and unconventional sites. The production of light- and medium-density crude oils are mainly from single well batteries, satellite batteries and group batteries. Natural gas production comes from natural gas wells, as well as light/medium crude oil production units.

Oxidation State The degree of oxidation of an atom in terms of counting electrons (IUPAC, 2014)

Petrinex Petrinex is a joint strategic organization supporting Canada's upstream, midstream and downstream petroleum industry. It delivers efficient, standardized, safe and accurate management of "data of record" information essential to the operation of the petroleum sector.

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.

Power Output For engines it is the net shaft power available after all losses and power take-offs (e.g., ignition-system power generators, cooling fans, turbo chargers and pumps for fuel, lubricating oil and liquid coolant) have been subtracted. For heaters and boilers it is the net heat transferred to a target process fluid or system.

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 range of 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.

Production Tank (fixed roof) Fixed roof, hydrocarbon production tanks consist of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone or dome shaped to flat. Losses from fixed roof tanks are caused by changes in temperature, pressure and liquid level or during flashing.

Reciprocating Compressor Reciprocating compressors are positive displacement compressors that use pistons driven by a crankshaft to deliver high pressure gas. The intake gas enters the suction manifold, then flows into the compression cylinder where it gets compressed by a piston driven in a reciprocating motion via a crankshaft, and is then discharged. Compressors are typically skid mounted, driven by a natural gas fired engine or electric motor, include air cooled heat exchangers and are enclosed by a shed.

Reciprocating Compressor Rod Packing Packing systems (seals) are used on reciprocating compressors to control leakage around the piston rod on each cylinder. A reciprocating compressor is deemed to have one seal associated with each compressor cylinder (throw) regardless of whether it is really a single or tandem seal. Controlled rod packing vent lines that are tired into a flare header, VRU or other gas capture system have a very low probability of leaking to the atmosphere.

Reduced Sulphur Compound (RSC) - 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.

Screw Compressor Screw compressors utilize a rotary positive displacement mechanism that compresses gas between intermeshing helical lobes and chambers in the compressor housing. As the mechanism rotates, the meshing and rotation of the two helical rotors produces a series of volume-reducing cavities. Gas is drawn in through an inlet port in the casing, captured in a cavity, compressed as the cavity reduces in volume, and then discharged through another port in the casing. They are usually used for boosting the gas from wells to reciprocating compressors in the field or gas plants. Screw compressors are typically skid mounted, driven by a natural gas fired engine or electric motor and enclosed by a shed. Screw compressors are not equipped with rod-packings or vent seal gas.

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.

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".

Shale Gas Natural gas contained in gas bearing shales (BC OGC, 2019c).

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.

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.

Thermal Efficiency The percentage or portion of input energy converted to useful work or heat output. For combustion equipment, typical convention is to express the input energy in terms of the net (lower) heating value of the fuel. This results in the following relation for thermal efficiency:

$$\eta = Thermal\ Efficiency = \frac{Useful\ Work/Heat\ Output}{Net\ Heat/Energy\ Input}\ x\ 100\%$$

Alternatively, thermal efficiency may be expressed in terms of energy losses as follows:

$$\eta = \left(1 - \frac{\Sigma Energy\ \ Losses}{Net\ \ Heat/Energy\ Input}\right) x\ 100\%$$

Losses in thermal efficiency occur due to the following potential factors:

- exit combustion heat losses (i.e, residual heat value in the exhaust gases),
- air infiltration,
- incomplete combustion, and
- mechanical losses (e.g., friction losses and energy needed to run cooling fans and lubricating-oil pumps).

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.

Throw Parts of reciprocating compressor from the connecting rod to the cylinder. The number of throws on a compressor equals the number of connecting rods off the compressor crankshaft.

Tight Gas Natural gas contained in low permeability sandstones and carbonates (BC OGC, 2019c). Unconventional (Tight or Shale) formations are defined by reservoir zones in schedule 2 of the BC OGC Drilling and Production Regulation and represented by formation codes 2800, 2850, 4997, 5000, 7730, 8295 and 8550.

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 to atmosphere that would occur in the absence of a control device or during periods when a control device is not operational.
Unconventional Gas	Natural gas contained in difficult to produce formations requiring special completion, stimulation and other techniques to produce economically (coalbed gas, tight gas, shale and hydrates) (BC OGC, 2019c). Unconventional gas is produced from reservoir zones listed in schedule 2 of the BC OGC Drilling and Production Regulation (BC OGC, 2018a).
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.

Vented Emissions

Vented emissions are releases to the atmosphere by design or operational practice (i.e., intentional), and may occur on either a continuous or intermittent basis. The most common causes or sources of these emissions are gas operated devices that use natural gas as the supply medium (e.g., compressor start motors, chemical injection and odourization pumps, instrument control loops, valve actuators, and some types of glycol circulation pumps), equipment blowdowns and purging activities, and venting of still-column off-gas by glycol dehydrators.

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).

ACKNOWLEDGEMENTS

The development of this report has been sponsored by the BC Oil and Gas Research and Innovation Society (BC OGRIS) managed by BC Oil & Gas Methane Emissions Research Collaborative (MERC). The support and direction provided by each member of the Technical Advisory Committee (and their organizations) are gratefully acknowledged.

Special thanks are given to the individuals and organizations who responded to our data requests and provided review comments.

1 INTRODUCTION

British Columbia (BC) intends to become a low-carbon economy. In 2016, BC's Climate Leadership Plan introduced strategies aimed at reducing methane (CH_4) emissions from the upstream oil and natural gas (UOG) sector which included a CH_4 emission reduction target of 45 per cent by 2025 and developing infrastructure to power natural gas facilities with renewable electricity (GoBC, 2016). Recently, it introduced new regulations to reduce CH_4 emissions from storage tanks and compressor seals (BC OGC, 2020). This study reviews data sources and develops a preliminary inventory of CH_4 emissions from uncontrolled storage tanks, reciprocating compressor rod-packing vents and centrifugal compressor seal vents relevant to the BC UOG sector. The assessment is performed based on best available information from the BC government databases, industry stakeholders and other published and unpublished sources.

This report is prepared by Clearstone Engineering Ltd. for the BC Oil and Gas Methane Emissions Research Collaborative (MERC) and funded by the BC Oil and Gas Research and Innovation Society (BC OGRIS).

The key findings from relevant literature and field studies are presented in Section 2. Methodology used for developing CH_4emission inventory; including a description of data sources, boundaries, quantification methods and uncertainty methods are described in Section 3. Inventory results are presented in Section 4 conclusions in Section 5 and recommendations in Section 6. All references cited herein are listed in Appendix Section 7 along with key supplementary information.

1.1 BACKGROUND

This section provides details and working principles of storage tanks and compressor seals used in the UOG industry.

1.1.1 STORAGE TANKS

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. 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 combustion. Fugitive emissions may occur from pressurized components associated with vapour capture systems (i.e., equipment leaks) or unintentional gas carry-through from upstream vessels.

In BC, storage tanks at facilities commissioned **before** January 1, 2022 are limited to 9,000 m^3 natural gas per month per facility while facilities commissioned **on or after** January 1, 2022 are limited to 1,250 m^3 natural gas per month per facility (BC OGC, 2018a). Federal CH_4 regulations (that apply without an Order Declaring that the Provisions of the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) Do Not Apply in British Columbia in place) 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 (GoC, 2018). Because the effectiveness of regulatory limits depends on reliable quantification of tank losses, a preliminary inventory of CH_4 emissions from storage tanks is undertaken in this study.

1.1.2 RECIPROCATING COMPRESSOR ROD PACKINGS

Reciprocating compressors are commonly used at gas production and processing facilities and less so for gas transmission applications. Reciprocating compressors are fitted with pressure packing, a series of precision-machined mechanical rings that form a tight seal around the piston rod to prevent compressed gas from escaping but still allow the piston to move freely. Leaks in the packing system are common, with the size of the leak depending on fitting, cylinder pressure, and alignment of packings parts. Piston rods wear more slowly than packing rings, so as systems age, leak rates increase due to the uneven wear. As shown in Figure 1, leakage from the packing case discharges into the distance piece which may be left open, with the vent piping connected directly to the packing case, or the distance piece may be closed, with the vents connected to both the packing case and the distance piece. Gas can also migrate and vent from the crankcase. Common practice is to route the packing and distance piece vents outside the building to the atmosphere if the process gas is sweet, or to a flare if the gas is sour. Uncontrolled packing emissions are classified as vents.

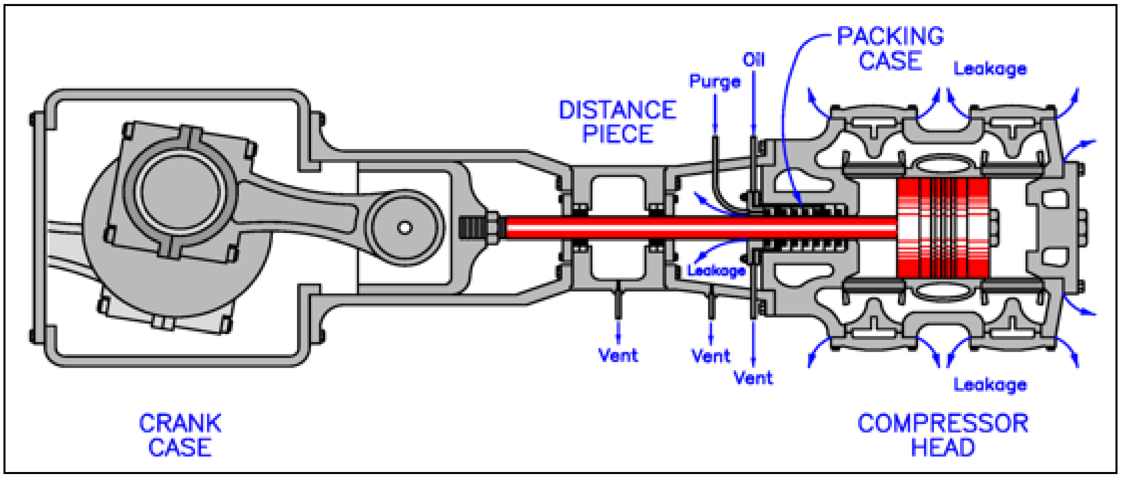

Figure 1: Schematic of a typical piston rod packing-case assembly for a reciprocating compressor.

BC CH_4 regulations limits rod packing venting to a fleet-average of 0.83 m^3 per hour per cylinder (and individual units to be limited to 5 m^3 per hour per cylinder) for compressors installed before January 1, 2021 (BC OGC, 2018a). Rod packing venting is prohibited from units installed on or after January 1, 2021 (BC OGC, 2018a). In view of this, a preliminary investigation of CH_4 emissions from existing reciprocating compressor rod-packing vents is performed in this study.

1.1.3 CENTRIFUGAL COMPRESSOR SEALS

Centrifugal compressors are commonly used by gas transmission pipelines and less so for gas production or processing applications. Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used.

A typical wet seal design for a centrifugal compressor comprises two face contact seal rings held in close contact by a spring mechanism balanced with fluid pressures from the process gas and seal oil, plus an inner and outer labyrinth seal as shown in Figure 2.

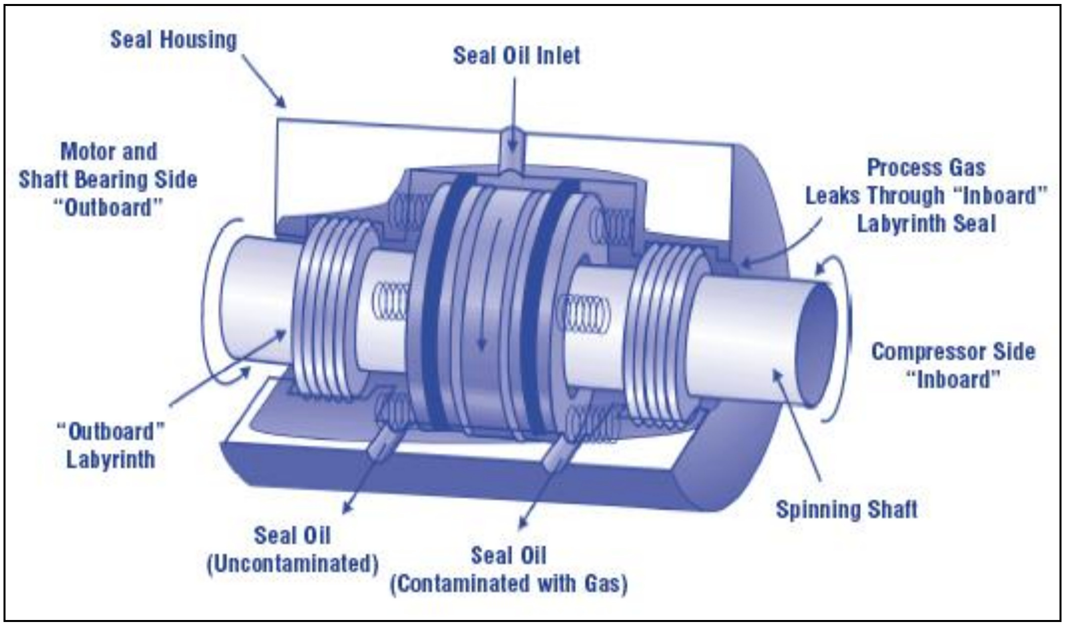

Figure 2: Schematic diagram of a typical tandem wet seal design for a centrifugal compressor.

The seal oil is supplied at a pressure greater than the process gas pressure, and, in combination with tight seal clearance tolerances, provides a positive seal from gas leakage along the shaft to the atmosphere. A small quantity of oil passes through the inner seal ring to the inner drain (i.e., located on the inboard side of the seal), where it is exposed to the gas pressure and will dissolve/entrain some of the buffer (e.g., nitrogen (N_2) or other inert gas) or process gas. Thus, this oil is directed to a seal pot (or separator system) where the separated gas is vented, flared or recycled to the suction side of the compressor; or used as fuel gas. Some gas, particularly heavier fractions, remain in solution or are suspended as fine bubbles in the oil leaving the seal pots and is usually routed to a degassing drum. Average wet seal emissions are approximately 46 sm^3 per hour per compressor (Subramanian et al, 2015) which exceeds provincial CH_4 limits of 10.2 sm^3 per hour per compressor unit in BC.

Dry gas seals operate without oil. Instead, the dry seal example presented in Figure 3 features two precision-machined sealing plates with one stationary and the other rotates with the shaft. At high rotation speed, seal gas separates the plates via a pressure dam effect. Due to very close running clearances, leakage rates are very low (but increases for worn plates). Average dry gas seal emissions are approximately 4 sm^3 per hour per compressor (CEPEI, 2018) which may exceed the provincial CH_4 limit of 3.42 sm^3 per hour per compressor for units installed on or after January 1, 2021.

For the tandem gas seal arrangement presented in Figure 4, the primary seal absorbs the total pressure drop to a vent system, and the secondary seal acts as a backup should the primary seal fail. This arrangement is becoming the minimum standard for high pressure applications with flammable gases. The inner-seal (primary) vent can usually be routed to flare with back-pressure control. Emissions are still typical at the outer seal (secondary) vent. A special tandem arrangement is available with an internal labyrinth to allow internal buffering with N_2 or air to result in leakage of N_2 or air from the secondary seal vent. This arrangement normally prevents any leakage of process gas to the atmosphere but may result in high N_2 consumption.

If operating pressures are low (3500 kPa) and a small amount of N_2 or another available inert seal gas is available and can be tolerated in the process; a double opposed gas seal arrangement can be used. No leakage of hydrocarbons to the atmosphere or flare normally occurs with this arrangement.

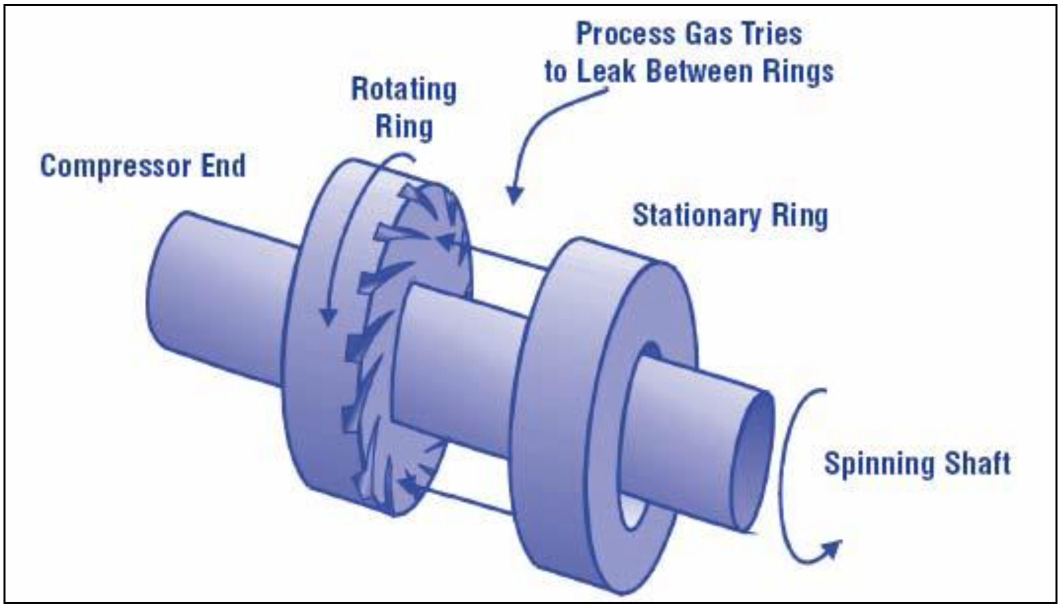

Figure 3: Schematic diagram of a dry-gas seal at one end of the shaft on a centrifugal compressor.

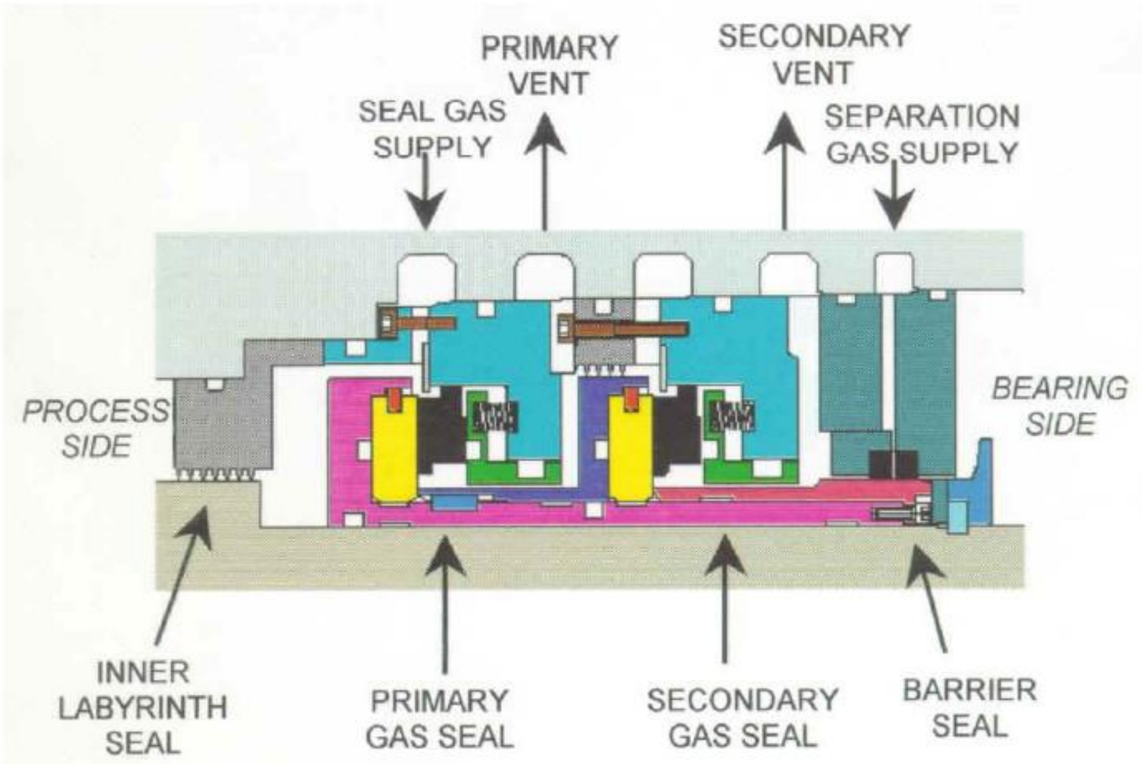

Figure 4: Schematic diagram of a tandem dry-gas seal/barrier arrangement on a centrifugal compressor.

1.1.4 SCREW COMPRESSORS

Screw compressors utilize a rotary positive displacement mechanism that compresses gas between intermeshing helical lobes and chambers in the compressor housing (or casing). As the mechanism rotates, the meshing and rotation of the two helical rotors produces a series of volume-reducing cavities. Gas is drawn in through an inlet port in the casing, captured in a cavity, compressed as the cavity reduces in volume, and then discharged through another port in the casing. They are usually used for boosting the gas from wells to reciprocating compressors in the field or gas plants. Screw compressors are typically skid mounted, driven by a natural gas fired engine or electric motor and enclosed by a shed.

Lubricating oil is required to provide sealing between the intermeshing lobes and casing as well as lubrication for bearings and shaft seals. Bearing and seal oil is drained into the rotors where it combines with process gas. A separator (located downstream of the compressor discharge) removes this oil from the process gas. It is then cooled, filtered and recycled back to the lubricating oil injection points (NEXT, 2018). This is a closed system that precludes seal gas venting to the atmosphere. Therefore, screw compressors are not investigated further.

2 LITERATURE REVIEW

This section summarizes the findings of existing literature and field studies on compressor seals and storage tanks operating in the UOG industry. Its purpose is to identify representative emission release rates and controls, and to identify any gaps that occur in the data to facilitate CH_4 inventory efforts.

2.1 UPDATE OF EQUIPMENT, COMPONENT AND FUGITIVE EMISSION FACTORS FOR ALBERTA UPSTREAM OIL AND GAS – CLEARSTONE (2018)

This study delineates the methodology used to determine average factors and confidence intervals for estimating fugitive and venting emissions from the Alberta (AB) UOG. A field campaign targeted UOG wells, multi-well batteries, and compressor stations contributing the most to UOG CH_4 emission uncertainty. Field data was correlated to Petrinex Facility IDs and Unique Well Identifiers (UWI) so that the following factors would be representative and applicable to AER regulated UOG production data.

- Process equipment count per facility subtype[1] or well status code[2].
- Component count per process equipment unit.
- Emission control type per process equipment unit.
- Pneumatic device count per facility subtype or well status code by device and driver types.
- Leak rate per component and service type considering the entire population of components with the potential to leak (i.e., 'population average' factor).
- Leak rate per component and service type considering leaking components only (i.e., 'leaker' factor).

Confidence intervals for each of these factors were determined using the bootstrapping method; a 95% confidence level; and consider the systematic (bias) and random (precision) uncertainties encountered during measurements and data processing.

AB production tank and compressor equipment counts per AER facility subtype and well status code determined from 2017 field observations are presented in Table 1. These factors provide the AB inventory model a 'first guess' regarding the number of units installed. The quantity of fired units at a specific site is adjusted by the model to align the volume of natural gas fuel reported for the site with theoretical fuel determined from adjusted fired equipment counts, reported production hours and typical power ratings. The following equipment is not included in Table 1.

[1] Facility subtypes are defined in Table 2 of AER Manual 011 (AER, 2016b).
[2] Well status codes are defined by the four category types: fluid, mode, type and structure.

- Centrifugal compressors were not observed at sites surveyed during the 2017 field study.
- Screw compressors are not included because they do not feature seal vents.
- Water production tanks were not included in the 2017 AB sampling plan.

Table 1: Average (mean) process equipment counts per AER facility subtype and well status code.

Facility Type Description	AER SubType Code	Hydrocarbon Production Tank	Reciprocating Compressor	
			Natural Gas Driver	Electric Driver
Crude oil multiwell group battery	321	1.29		
Crude oil multiwell proration battery	322	2.57	0.21	0.09
Crude bitumen multiwell group battery	341	1.07		
Crude bitumen multiwell proration battery	342	1.54		
Gas multiwell group battery	361	0.28	0.07	
Gas multiwell effluent battery	362	0.41	0.08	
Gas multiwell proration battery (outside SE AB)	364	0.30	0.25	
Compressor station	601	0.19	0.82	0.06
Custom treating facility	611	3.51		
Gas gathering system	621	0.32	0.70	0.18
Well: Crude oil flowing	CR-OIL FLOW	0.05		
Well: Crude oil pumping	CR-OIL PUMP	0.19		
Well: Gas flowing	GAS FLOW	0.21	0.02	
Well: Gas pumping	GAS PUMP	0.32		

The two types of emission factors that are used to estimate emissions are population average emission factors and leaker emission factors. Leaker emission factors are applied to the results of leak detection or screening programs, whereas population average emission factors do not require any screening information and are simply applied to an inventory of the potential leak sources. The population average and leaker emission factors (volume and mass basis) for reciprocating rod compressor packings and tank thief hatches are provided in Table 2. The reciprocating compressor rod-packing population-average emission factor is calculated on a per rod-packing basis and excludes compressors that are tied into a flare or VRU. The compressor rod-packing 'leaker' factor is calculated on a per vent line basis (not per rod-packing basis) because gas is typically routed to common vent line and the actual number of leaking packings is not known.

Tank thief hatch leak factors are only applicable to controlled tanks (because gas is intentionally emitted from uncontrolled tanks).

Table 2: Population average and leaker emission factors for reciprocating compressor rod packing from Alberta UOG facilities on a volume (standard conditions) or mass basis (Table 9 (Page 53) and Table 10 (Page 55)).

Component Type	Factor Type	Leaker count	Component count	Emission factor (kg/h/source)	Emission factor (m^3/h/source)
Reciprocating Compressor Rod-Packing	Population-average		139	0.20622	0.28745
	Leaker	27		1.08150	0.77563
Tank Thief Hatch	Population-average	6	52	0.12870	0.12860
	Leaker	6		0.81672	0.82401

Typical leakage rates for reciprocating gas compressors for packing rings in good condition range from 0.17 m^3 to 0.29 m^3 per hour per rod-packing, however, leakage rates from 2.9 m^3 to 5.8 m^3 per hour per rod packing warrants maintenance (Ariel, 2018). The population-average factors in Table 2 are within manufacturer tolerances for packing rings in good condition. Also, the 2019 field study by Advisian and AER reports a population-average factor of 0.318 m^3/hr/throw which is about 10 percent greater than the 2018 Clearstone factor of 0.287 m^3/h/throw but well within Clearstone's upper confidence limit of 0.540 m^3/h/throw (AER, 2019a)[3]. The average emission control factor (CF) for storage tanks and reciprocating compressor rod-packings are presented in Table 3. Storage tanks are connected to a flare header or vapour recovery unit (VRU) to prevent the release of natural gas to the atmosphere. Similarly, reciprocating compressor rod-packing vents are tied into the flare header or conserved to avoid CH_4 releases. Although these CFs provide insight on the number of tanks controlled, they are naive to the magnitude of emissions from each tank and therefore not representative of overall emission control. Thus, they have limited value.

[3] The population-average factor presented in AER, 2019a for Clearstone, 2018 is not correct. The incorrect value of 0.242 m^3/h/throw appears to be recalculated from primary data but does not incorporate component counting and leak detection bias. These uncertainties were incorporated into the bootstrapping method and had an upward influence on population mean leak factors extracted from resultant Monte Carlo distributions.

Table 3: Average (mean) emission control and confidence interval per process equipment unit (Table 6; Page 37).					
Type of controls	**Process units count**	**Control device count**	**Average control factor**	**95% confidence interval (% of mean)**	
Storage tank tied into flare or conserved	213	46	0.21	28%	31%
Rod packing compressors vent tied into flare or conserved	54	7	0.12	65%	72%
Pop tank tied into flare or conserved	20	2	0.10	100%	123%

2.2 COMPRESSOR SEAL VENT AND MAINTENANCE STUDY – AER (2019)

The study investigates reciprocating compressor rod packing and centrifugal compressor (dry and wet) seal vent emissions and maintenance practices as they are subject to regulations intended to reduce CH_4 emissions (AER, 2019a). The approach involved developing a field measurement plan and industry survey; executing the survey and field campaign; analyzing data for correlations; determining emission factors; and preparing a summary report.

Field measurements were completed for 98 reciprocating compressors and 10 centrifugal compressors operating across AB. The selection was based on random selection from a population of candidate sites with sufficient fuel consumption (indicative of a compressor) and excluded sour gas facilities. However, considering centrifugal compressors are not common for the UOG industry, the report does not describe how random selection identified 10 centrifugal compressor locations. A total of four types of measurement technologies (Hi-Flow Sampler, Bellows Meter, Laminar Mass Flow Meter and Quantitative Optical Gas Imaging (QOGI) were employed with QOGI being the most common measurement method due to accessibility issues. All vent rate data for compressors were corrected to standard reference conditions (15° C and 101.325 kPa). However, the report does not state whether total hydrocarbon or natural gas (inclusive of inerts) vent rates are presented.

Measurement technologies were evaluated by using more than one method to measure the same vent and then plotting ‘variation’ (relative difference between technology measurement and mean of measurements) versus each measured rate. This evaluation observed large variation relative to the mean for low vent rates (less than 0.2 m^3/hr) and convergence of measured rates when greater than 0.2 m^3/hr. Considering the Directive 060 limit of 0.83 m^3/hr/throw for reciprocating compressor, this evaluation indicates all four measurement technologies are reliable for vent rates greater than 0.2 m^3/hr and therefore suitable for confirming compliance with Directive 060. However, a consistent positive bias is expected for Hi-Flow measurements because this device draws a continuous vacuum on the source. A consistent negative bias is expected for Bellows measurements because this device imposes a backpressure on the source. Neither of these bias are observed in the results presented.

Overall, most reciprocating compressors measured during this study emit less than the regulatory limit (i.e., over 90 percent of the compressors vent less than 0.83 m^3/hr/throw). The population-average vent rate for a reciprocating compressor is 0.318 m^3/hr/throw, which is within the range (0.242 to 0.492 m^3/hr/throw) determined by other recent measurement studies (Accurata, 2018).

Centrifugal dry seal vent rates ranged from 0.016 to 5.97 m^3/hr/unit and are generally greater than the wet seal vent rates (0.038 to 0.632 m^3/hr/unit) measured in this study. The report authors identify a number of measurement challenges (e.g., small sample size, stack height, complicated piping configurations, inaccessible vents (precluding measurement of all release points, etc) that may explain why dry seal rates were generally greater than wet seals. The measured dry seal vent rates were usually greater than the Directive 060 limit of 3.40 m^3/hr/compressor for newly installed units, while measured wet seal vent rates were typically less than the regulatory limit. A population average vent rate was not calculated because the sample size was too small to be statistically valid.

The results presented in this study are useful for providing a range of emission rates observed for the AB UOG industry. However, additional uncertainty analysis is required to determine emission factor confidence intervals before factors could be adopted for provincial or national inventory purposes.

2.3 BRITISH COLUMBIA OIL AND GAS METHANE EMISSIONS FIELD STUDY (CAP-OP, 2018)

This study gathered and analyzed BC oil and gas operational details to develop modeling parameters for CH_4 emission inventories. To align with current and future production forecasts, the field campaign prioritized tight wells and batteries producing in the Montney . Sample well and battery sites were randomly selected from a filtered population of candidate sites. The candidate population included: a) active operations only, b) reasonably accessible sites (extremely remote locations like Horn River basin were excluded), c) sites with only one battery code (because measurement schematics were not available to delineate equipment between multiple codes) and d) wells in close proximity to batteries (3 km). Compressor stations and gas plants (large facilities) were excluded, however some compressors were observed at smaller facilities. Ultimately, the field sample plan included the following Petrinex facility subtypes:

- Wells (W)
- Single-Well Batteries (SWB)
- Multiwell Group Batteries (MGB)

- Multiwell Proration Batteries (MPB)
- Multiwell Effluent Measurement Batteries (MEM)

Field sample stratums were further delineated to consider production categories. Based on BC OGC records, sites producing "Shale Gas" and "Tight Gas" were defined as "Tight Gas (T)" and distinguished from older legacy wells that were defined "Conventional Gas (C)". A single "Oil (O)" category was applied to both "Tight Oil" and "Conventional Oil" production sites. Data analysis and factors were developed on the basis of Site Classifications = [Facility Type] + [Production Category].

Sample plan methodology utilized OGI cameras to detect leaks and vents. Emission rates were measured using the Hi-Flow Sampler or estimated based on plume size visualized through the OGI camera. Pneumatic venting rates were not measured because this emission source was the focus of other field studies. Combustion emission sources such as flares were not considered.

BC production tank and compressor equipment counts per site classification code determined from 2018 field observations are presented in Table 4. The number of components belonging to each equipment type were not determined in the BC study. Instead, the study relies on component counts completed in AB (Clearstone, 2018). Moreover, centrifugal compressors were not observed during BC surveys so factors could not be developed.

Table 4: Average (mean) process equipment counts per site classification code (from Cap-Op, 2018 (Table 7).

Classification Description	Class Code	Hydrocarbon Production Tank	Water Production Tank	Reciprocating Compressor	
				Natural Gas Driver	Electric Driver
Multiwell Effluent Measurement Battery – Conventional Gas	MEMC	0.71	0.57	1.29	0.14
Multiwell Effluent Measurement Battery – Tight Gas	MEMT	1.67	2.75	1.83	0
Multiwell Group Battery – Conventional Gas	MGBC	0	0	0	0
Multiwell Group Battery – Oil	MGBO	1.5	0.75	0	0
Multiwell Group Battery – Tight Gas	MGBT	0.73	2.20	0.67	0.27
Multiwell Proration Battery – Oil	MPBO	3.57	1.14	0.86	0.14
Single-Well Battery – Conventional Gas	SWBC	0.25	0.25	0	0
Single-Well Battery – Oil	SWBO	0.86	0.43	0.14	0
Single-Well Battery – Tight Gas	SWBT	0.67	0	0	0
Well – Conventional Gas	WC	0.02	0	0	0
Well – Oil	WO	0.13	0	0	0
Well – Tight Gas	WT	0.03	0.04	0.03	0

Storage tanks contributed 12 percent of total CH_4 emissions (i.e., 9 percent from light liquids tanks and 3 percent from produced water tanks). When summarized by major equipment (excluding pneumatics), tanks were responsible for 65 percent of total non-pneumatic venting emissions. This also included hydrocarbon venting from produced water tanks (25 percent of total tank venting). Venting factors, average of detected vents and population-average, are presented in Table 5 for **uncontrolled** hydrocarbon and water storage tanks. Leak factors, average of detected leaks and population-average, are presented in Table 6 for **controlled** hydrocarbon and water storage tanks. Tank thief hatch components were observed to be the dominant contributor of tank-top fugitive emissions. Confidence intervals were not calculated for storage tank emission factors.

Table 5: Average vent rates from uncontrolled storage tanks (from Cap-Op, 2018 - Table 25).

Type of Storage Tanks	Total Equipment Count*	Number of Vents	Total Vent Rate (m^3/hr)	Average Rate per Vent Source (m^3/hr)	Average Vent Rate for Total Equipment Population (m^3/hr)
Production Tank Fixed Roof - Hydrocarbon	85	6	31.04	5.17	0.38
Production Tank – Water	90	6	11.37	1.90	0.13

** Understood to include controlled and uncontrolled storage tanks.*

Table 6: Average leak rates from controlled storage tanks (from Cap-Op, 2018 - Table 26).

Type of Storage Tanks	Total Equipment Count	Number of Leaks	Total Leak Rate (m^3/hr)	Average Rate per Leak Source (m^3/hr)	Average Leak Rate for Total Equipment Population (m^3/hr)
Production Tank Fixed Roof – Hydrocarbon	85	12	11.51	0.96	0.14

** Understood to include controlled and uncontrolled storage tanks.*

BC population-average and ‘leaker’ emissions factors for reciprocating compressor rod-packings are provided on a mass basis in Table 7 and compared to the corresponding AB factor. Adoption of the BC compressor seal factor for emission inventory purposes should consider:

- Screw compressors are not equipped with rod-packings or vent seal gas. Therefore, 11 screw compressors counted in BC should not be included in the denominator when calculating population-average leak factors. Recalculating the BC factor with a denominator of 58 reciprocating compressors results in a population-average leak factor of approximately 0.17 kg/hr which is close to the AB factor of 0.206 kg/hr.

- 16 reciprocating compressors were observed to have emission controls on rod-packing vents (e.g., tied into flare). Inclusion of these compressors in the denominator of the population-average leak factor accounts for emission controls within the sample population. Therefore, emission inventory calculations do not require identification of controlled compressors or application of CF.
- Uncertainty assessments are difficult to complete because confidence intervals were not calculated for BC rod-packing emission factors or compressor counts.

Table 7: Average vent rates (kg/hr) from BC and AB reciprocating compressor rod-packings.

Region (ref year)	Unit counts	Leak counts	Emissions Factor (kg/hr per leaking source)	Emissions Factor (kg/hr per population)	References
BC (2018)*	69	18	0.40	0.14	(Cap-Op, 2018)
AB (2018)	139	27	1.082	0.206	(Clearstone, 2018)

* Includes reciprocating and rotary screw compressors.

The Site Classification stratums described above were intended to provide granularity and enable more accurate delineation of CH_4 profiles. However, this stratum design resulted in very small sample sizes that may impact the representativeness of factors. For example, four or less site surveys were completed for SWBT, SWBC, MGBO and MGBC Site Classifications that represent approximately 20 percent of the subject facility population. Moreover, before factors can be utilized in emission inventories, Site Classifications must be determined for each Petrinex facility identifier based on knowledge of linked (upstream) UWI and their production categories (e.g., tight or conventional production). This process is further complicated because tight and conventional production categories are not defined in Petrinex or other known data source and multiwell batteries often feature more than one production category.

2.4 STUDY TO INVESTIGATE FUGITIVE AND VENTING EMISSIONS FROM ABOVEGROUND, FIXED-ROOF STORAGE TANKS (CLEARSTONE, 2020).

This study investigates the root-causes of fugitive and venting emissions from aboveground, fixed-roof, storage tanks at UOG facilities located in BC and AB. It proposes a field troubleshooting decision tree for investigating whether tank venting emissions are due to malfunctioning equipment or process conditions (e.g., gas flashing). Moreover, it reviews gas flashing quantification methods and completes a techno-economic assessment for emission mitigation options.

A significant portion of CH_4 emissions are from a small number of large emitters or abnormal process vents (Brandt et al, 2016; Zavala-Araiza et al, 2018; and Lyon et al, 2016). This could be due to storage losses in excess of what can be predicted using simulators or correlations. To distinguish between gas flashing and unintentional gas carry-through, leak detection and repair (LDAR) surveys could incorporate the troubleshooting decision tree. This involves identifying tanks that continuously vent, tracing pipe to upstream vessels and observing vessel liquid level and dump frequency. Sustained high-liquid level and frequent/continuous dump events denote inefficient gas separation from liquids prior to delivery to the tank, while low-liquid level and frequent/continuous dump events signal malfunctioning level controller. The responsible component may be a passing dump-valve that can be checked with an acoustic leak detector. If there are no problems identified, the subject vessel is unlikely to be the source of continuous venting and the same steps are repeated for other vessels connected to the tank. If no malfunctioning components or abnormal piping are identified, tank emissions may be due to volatile liquid flashing exclusively and can be quantified according to methods described in BC OGC measurement guidelines (BC OGC, 2018).

The proposed decision method is not applicable for controlled tanks or tanks with intermittent venting.

Tank-top equipment leaks are only relevant to controlled storage tanks, where the leak occurs due to malfunctioning equipment components or sudden increase in pressures above relief set-points. Unintentional gas carry-through to tanks are 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.

BC OGC measurement guidelines specify methods for quantifying gas flashing for tanks not experiencing unintentional gas carry-through (BC OGC, 2018b). The PTAC study recommends direct measurement of gas venting and oil production (i.e., the 24-hour test) or collecting a pressurized liquid sample and subsequent process simulations to determine gas-to-oil ratio (GOR). To confirm the reliability of process simulation results, the steps outlined by Colorado regulators (PS Memo 17-01) should be followed for performing flash gas liberation analysis (CAPCD, 2017). When site-specific measurements and process conditions are not available, gas flashing can be estimated using empirical correlations[4]. The PTAC study recommends the Valko

[4] 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).

and McCain correlation for determining flash gas factors for light/medium crude oils. For lighter condensates with API gravity greater 56.8°, the Vasquez and Beggs or 0.0257 m^3 of gas/m^3 of oil/kPa of pressure drop correlations are suggested.

Techno-economic assessments show that current commodity prices are not sufficient for most gas conservation or emission mitigation projects to achieve a positive net present value. Alternative revenue opportunities are required for these projects to proceed solely based on economic drivers.

2.5 MEASUREMENT-BASED EMISSION FACTORS USING BHGE ADVANCED METHANE SENSING TECHNOLOGIES AND ANALYTICS – ECCC (2019)

This study summarized the deployment and observations of a continuous emission measurement system at oil and gas sites using Baker Hughes GE (BHGE) methane sensing and analytics technology (LUMEN™). It characterizes CH_4 emissions from subject components for seven Bonavista Energy Corporation sites located in AB.

Table 8 presents emission rates (scfm) and date of most recent maintenance for rod packing vents monitored at three different reciprocating compressors. Due to limited sample sizes and because components were selected based on the presence of a leak, the BHGE emission factors developed in this study are not representative of the entire component population and not suitable for population-average leak factors. BHGE average emission rates are analogous to 'Leaker' emission factors because only leaking sources are included in the average. Comparisons between BHGE factors and population-average factors presented in Clearstone, 2014 are not appropriate.

The BHGE leaker factor for rod-packing vents presented in Table 8 is approximately 2.6 times less than the leaker factor presented in Clearstone, 2018 and 2.3 times less than the leaker factor presented in Cap-Op, 2018. Although the report asserts long periods between rod packing maintenance result in higher emissions, continuous monitoring data does not necessarily support this conclusion. For example, node 31 rod-packing was serviced 12 months while node 46 was serviced 6 months before their respective measurement campaigns. As depicted in Figure 5, continuous monitoring data indicates node 31 vent rate is an order of magnitude greater than node 46 but there is no indication that emissions from either increase over time (6 months for node 31 and 3 months for node 46). Thus, it is also plausible that rod-packing vent rate depends on the packing design, material or maintenance performed and could be confirmed by completing measurements after maintenance. Using a Hi-Flow Sampler will provide a single measurement point whereas a positive displacement meter (over an extended period) should provide vent magnitude and frequency that illustrates transient behaviour and supports calculation of a representative average emission rate.

Table 8: Reciprocating compressor rod packing emission rates (scfm) determined by BHGE (Table 1-2 (Page 7) and Figure 1-3 (Page 9), Figure 9.4-1 (Page 48)), Clearstone and Cap-Op.			
	ECCC, 2019		
Site #	3	4	6
Sensor node #	31	46	69
Measurement Period	Aug 2018 to Feb 2019	Nov 2019 to Feb 2019	
Date of last packing maintenance	Aug 2017	May 2018	Nov 2018
Average Emission rates (scfm/vent)	0.4685	0.0384	0.00640
Leaker emission factor (BHGE, 2019)	0.171 scfm (0.29 m^3/hr/vent)		
Leaker emission factor (Clearstone, 2018)	0.7756 m^3/hr/vent		
Leaker emission factor (Cap-Op, 2018)	0.68 m^3/hr/vent		

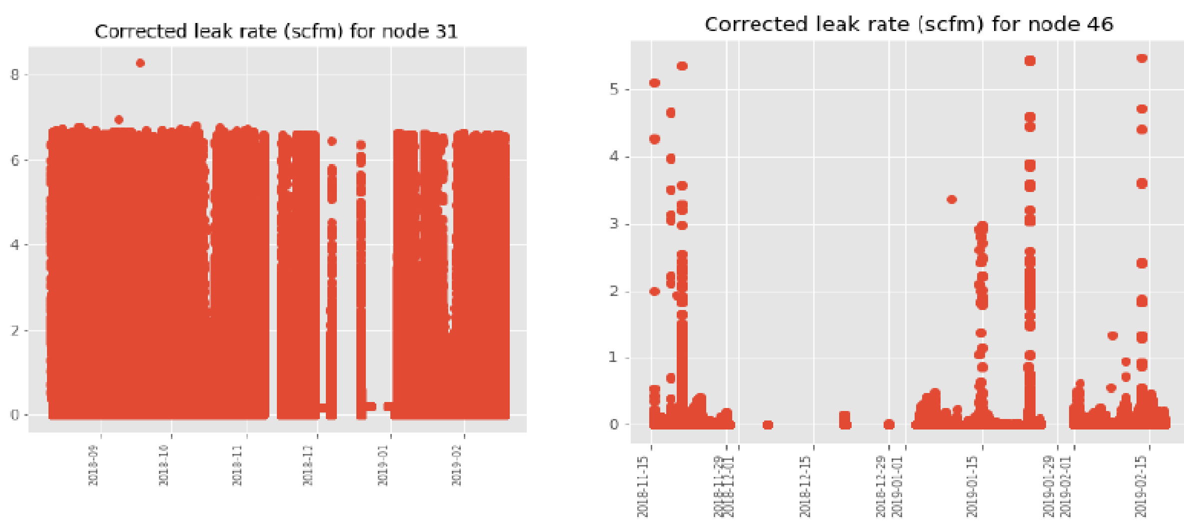

Figure 5: Rod-packing emission rate (scfm) monitored by node 31 over 6 months and node 46 over 3 months (source: Figure 9.5-8 from ECCC, 2019).

The emissions from storage tank thief hatches were monitored for three tanks and attributed to faulty gaskets and seals within the hatch. Table 9 presents average emission rates (scfm) for each thief hatch monitored. The BHGE leaker factor for thief hatches presented in Table 9 is approximately 15 times less than the leaker factor presented in Clearstone, 2018 and 17 times less than the leaker factor presented in Cap-Op, 2018. These leaker factors are not appropriate for developing emission inventories unless all subject components are screened and the number of leaking components known.

Table 9: Tank thief hatch emission rates (scfm) determined by BHGE (Table 1-2 (Page 7); Section 9.2, Figure 9.4-1 (Page 48)), Clearstone and Cap-Op.			
BHGE Site #	1	2	5
Average Emission rates (scfm/thief hatch)	0.087	0.004	0.012
Leaker emission factor (BHGE, 2019)	0.033 scfm (0.056 m^3/hr/vent)		
Leaker emission factor (Clearstone, 2018)	0.8240 m^3/hr/vent		
Leaker emission factor (Cap-Op, 2018)	0.96 m^3/hr/vent		

The LUMEN™ system offers the advantage of identifying abnormal behavior or less-than-optimal operations, which is the first step to minimize emissions.

2.6 MODELING INPUTS FOR UPSTREAM OIL AND GAS METHANE EMISSION SOURCES (GREENPATH, 2016)

This study provided CH_4 emission model input records for pneumatic vent and equipment leak sources for UOG facilities located in AB and BC[5]. GreenPath compiled observations (data) from its client databases (spanning 8 years of field surveys) and public reference documents to generate equipment profiles that could be used by ECCC for CH_4 emission modelling purposes. Pneumatic instrument and pump counts were determined for 7 facility types relevant to BC and 14 facility types relevant to AB. Equipment component counts were determined for the same 'model' facility types based on default component counts presented in the 2014 CAPP Report - *Update of Fugitive Equipment Leak Emission Factors* completed by Clearstone. This approach required GreenPath to estimate the number of process equipment units per 'model' facility type to calculate component counts. The equipment counts varied from site to site and 'model' facilities were not always representative of the sites.

[5] Insufficient data was available to determine equipment profiles for Saskatchewan and Manitoba.

Other observations stated in the report include:

- Pneumatics driven by instrument air are more common in BC than in AB due to greater number of sour sites and generally newer asset vintage.
- Instrument air is more likely to be found at larger facilities that are either connected to the grid or generate their own power.
- Very small fraction of pneumatics are observed to be driven by propane (less than 2 percent).
- Anecdotal evidence suggests 20 to 30 percent of leaking components (that do not constitute a health, safety, or environmental issue) are repaired within 90 days of detection. The remaining leaks are repaired at the next shutdown/turnaround.

Table 10 provides compressor rod-packing counts per facility type. Storage tank losses are not included in the report scope.

Table 10: Compressor and rod-packing counts by facility type.

Facility Type	Reciprocating Compressors (seals to atmosphere)	Rod-packing counts
Compressor Station	1	0
Gas Plant - Small Sweet	2	0
Gas Plant - Large Sweet	4	4
Gas Plant – Sulphur Recovery	0	2
Gas Plant – Acid Gas Injection	0	2

3 METHODOLOGY

This study is based on literature review and characterization of data sources relevant to UOG storage tanks and compressors located in BC. A description of data sources and methods for developing a preliminary inventory of CH_4 emissions are presented in the following subsections.

3.1 DATA SOURCES

This study reviewed raw data sources listed below to identify the best available information relevant to the subject emission inventory. Data use opportunities, challenges and gaps are discussed in this section. Data source reliability and use is prioritized according to regulatory backstop, verification assurance and relevance to 2019 operating year. For example, a voluntary reporting program is a less reliable data source than a regulated program with verification requirements.

3.1.1 PETRINEX

Oil and gas companies are required to report monthly production records to the BC government through the Petrinex data management system. This information supports royalty, commodity and equity transactions across the industry and with the BC Ministry of Finance (MOF), BC OGC; and Ministry of Energy and Mines and Petroleum Resources (MEMPR). Reporting to Petrinex by BC companies began in October 2018 with requirements delineated in an Industry Readiness Handbook (Petrinex, 2018) and quality standards consistent with existing BC OGC measurement guidelines (BC OGC, 2018b). Reported data includes well and facility hydrocarbon production, receipt and disposition (including fuel, flare and vent) volumes as well as subject locations, operators, facility types and other metadata.

To support inventory efforts, the BC OGC provided monthly volumetric data from November 2018 to October 2019 for all BC facilities reporting to Petrinex (BC OGC, 2019b). With this information, activity volumes and facility type codes for active production and processing sites were derived. Other ‘companion files’ from BC OGC included UWI with corresponding fluid types, formation codes, production hours and linked battery codes. Although the BC Petrinex dataset is similar to AB data (used for the AB CH_4 emission inventory Clearstone, 2019), some reporting conventions are different. Of particular note is the absence of gas gathering system and compressor station facility types from BC Petrinex data. Considering the large number of process equipment units assigned to these facility types in AB, their omission from BC Petrinex data precludes the use of AB process equipment count factors (Clearstone, 2018) for developing BC emission inventories. Thus, factors developed by the BC methane field study (Cap-Op, 2018) are more appropriate.

The Petrinex dataset is relied upon to define wells, facilities and hydrocarbon flows included in the subject BC emission inventory.

3.1.2 BC INDUSTRIAL GHG REPORTING PROGRAM

This program requires oil and gas companies to report annual GHG emissions and a verification statement[6] to the provincial government as specified by the Greenhouse Gas (GHG) Emission Reporting Regulation (GoBC, 2019a). It applies to companies that emit greater than 10,000 t CO_2E per year and is a reasonably complete account of BC oil and gas GHG emissions. Companies are required to follow Western Climate Initiative (WCI) quantification methods (WCI, 2013) and delineate emissions according to substance, emission category (e.g,, combustion, venting or fugitive) and source equipment type. Thus, verified CH_4 emissions from storage tanks, reciprocating compressor rod-packing vents and centrifugal compressor seal vents are available from the BC industrial GHG reporting program.

WCI quantification methods[7] require companies to complete annual measurements of gas vented from rod-packings and seals. Measurements are typically completed by LDAR service providers using a Hi Flow Sampler which is the same method used by the AB (Clearstone, 2018) and BC (Cap-Op, 2018) field studies. Because all reciprocating compressors (greater than 186 kW) and centrifugal compressors are subject to WCI annual measurement requirements, the BC GHG reports include many more data samples and should provide a more representative CH_4 estimate than field studies (with limited sample sizes).

WCI permits a range of measurement and estimation methods for quantifying storage tank emissions. WCI methods generally align with BC OGC Measurement Guidelines (OGC, 2018) as discussed below in Section 3.2.2. However, there is a tendency for companies to adopt the Vasquez-Beggs correlation because of its simplicity and small number of input parameters. This correlation may produce reasonable flashing estimates for condensates but tends to understate flashing for light and medium crude oils (Clearstone, 2020).

Compressor and storage tank CH_4 emissions reported for 2018 were aggregated by NAICS classification and provided to this study (BC CAS, 2019). These records are delineated by the equipment types and industry segments (e.g., production, processing and transmission) of interest but do not contain location or operator identifiers. A summary of reported CH_4 emissions by industry segment and equipment type is presented in Table 11. These sources contribute approximately 9 percent of total CH_4 emissions reported by production, processing and transmission facilities to the BC industrial GHG reporting program (GoBC, 2019a).

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[6] Verification statements are prepared by an independent third-party and provide the government a reasonable level of assurance that GHG assertions are true, accurate and complete.
[7] WCI.363(m) method applies to reciprocating compressors located at production and processing facilities. WCI.353(e) method applies to centrifugal compressors located at transmission stations.

Table 11: 2018 methane emissions submitted to the BC industrial GHG reporting program and their relative contribution to UOG emissions.						
Industry Segment	**Methane emissions (tonnes/year)**				**Total**	**Relative Contribution**
	Compressor Venting		**Storage Tank Venting**			
	Centrifugal Seal	**Reciprocating Rod-Packing**	**Scrubber Dump-Valve**	**Production Tank**		
Production	7	1,047	1	459	1,514	2.0%
Gas Processing	17	3,071		77	3,165	4.1%
Transmission	2,264		16		2,280	3.0%
Total	2,288	4,117	17	536	6,958	9.1%
Relative Contribution	3.0%	5.4%	0.0%	0.7%	9.1%	

BC GHG records do not contain equipment counts or emission control details because they are not subject to regulated reporting.

3.1.3 MULTI-SECTOR AIR POLLUTANTS REGULATIONS

The Multi-Sector Air Pollutants Regulations (MSAPR) were implemented by Environment and Climate Change Canada in 2016 and limit the amount of nitrogen oxides (NOx) permitted to be emitted from natural gas fired, stationary, spark-ignition engines (GoC, 2019). It requires operators to register natural gas fired engines[8] and disclose equipment details relevant to ownership and NOx emissions. The number of engines registered in BC and delineated by manufacturer, model and rated power was provided by ECCC for this study. Although location and end-use (e.g., reciprocating compressor, screw compressor, power generator, etc) details are not available, the MSAPR dataset provides an order-of-magnitude estimate for the number of natural gas compressor engines operating in BC.

The MSAPR dataset does not provide records for electric driven compressors, turbine driven centrifugal compressors or storage tanks.

3.1.4 CLEAN BC INDUSTRIAL INCENTIVE PROGRAM

The CleanBC Industrial Incentive Program (CIIP) is a voluntary carbon tax rebate initiative for large industrial operations that report their emissions under the GHG Industrial Reporting and Control Act (GoBC, 2019b). Oil and natural gas production, processing and transmission companies that emit greater than 10 kt CO_2E per year are eligible to participate in CIIP. To obtain the carbon tax rebate, companies submitted applications containing 2018 fuel and

[8] MSAPR registration is required for engines with rated power >250 kW if manufactured **before** 15 September 2016 and engines with rated power >75 kW if manufactured **after** 15 September 2016.

electricity consumption details. This included compressor driver fuel type, rated power, loading and annual operating hours. Although not specifically requested, compressor type (i.e., reciprocating, screw or centrifugal) could be determined from equipment identifiers available within the dataset.

2018 CIIP records represent an inventory of active natural gas fired and electric driven compressors which is not available from other data sources. However, because 2018 submissions were voluntary and not verified by a third party, it is unlikely this data source represents a complete compressor inventory. For example, the data set only includes 2 centrifugal compressors which suggests gas transmission compressors are missing. Moreover, CIIP does not include information on compressor seal emission controls or information on storage tanks.

Although the CIIP data is likely incomplete, it still provides details for a large sample of compressors operating in BC. This data is used to calculate average rated power for reciprocating (540 units), screw (16 units) and centrifugal (2 units) compressor drivers and then estimate theoretical fuel consumption (discussed in Section 3.3.3). Moreover, CIIP data represents a lower bound for compressor counts because the actual number of compressors will not be less than voluntarily stated by companies.

3.1.5 KERMIT

The BC OGC utilizes a database application named KERMIT (Knowledge, Enterprise, Resource, Management, Information, and Technology) to manage and enable electronic submission of information relevant to licensed pipelines and facilities (BC OGC, 2019a). KERMIT data provided by the BC OGC for this study includes the number and combined power of natural gas and electric driven compressors and storage tanks per facility as well as maximum H_2S concentration used for facility design. However, the KERMIT data set does not contain records for gas transmission stations because they are not regulated by the OGC.

This provides a cumulative count of compressor drivers and tanks licensed in BC. Units that are licensed but not installed or decommissioned remain in the KERMIT inventory. Instead of an accurate equipment inventory, KERMIT provides an upper bound for the maximum number of compressors and tanks operating at BC production and processing facilities.

3.2 DATA GAPS AND METHODOLOGY CHALLENGES

This section outlines knowledge gaps identified during the literature and data source review that could have material impacts on emission estimates for storage tanks and compressors. Possible methods for resolving knowledge gaps are discussed and intended to inform future research and field campaign planning.

3.2.1 UNINTENTIONAL GAS CARRY-THROUGH TO STORAGE TANKS

A recent PTAC study characterized unintentional gas carry-through to storage tanks as a less recognized, potentially significant and often unaccounted contribution to atmospheric emissions of CH_4 (Clearstone, 2020). Mechanisms responsible for unintentional gas carry-through were investigated and are summarized in the following subsections. However, the frequency and magnitude of this emission type is not defined and therefore not included in the current CH_4 emission inventory.

This knowledge gap could be resolved by a field campaign designed to identify subject tanks and complete discrete measurements of gas flashing and unintentional gas carry-through. Subject tanks and malfunctioning components could be identified during regulated LDAR surveys by using the proposed field troubleshooting decision tree (see Figure 4 in Clearstone, 2020). Sampling and flow rate measurement of pressurized liquids delivered to the tank would enable calculation of gas flashing using a process simulator. The difference between total venting measured at the tank-top and gas flashing would be the emission contribution from unintentional gas carry-through. To determine a population-average emission factor for use in inventories, the number of upstream valves controlling liquid flow should be counted for each tank screened during the LDAR surveys.

3.2.1.1 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 from fully sealing with its seat. 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.

Passing dump-valves can be detected and leak rate estimated using an acoustic leak instrument[9] that measures ‘noise’ across the valve body.

It is 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.

3.2.1.2 INEFFICIENT SEPARATION

Inefficient separation of gas and liquid phases in upstream separators can allow some gas carry-through, by entrainment or in solution, to the tanks. A ‘tell-tale’ indicator of inefficient separation is sustained high liquid levels in the upstream separator. This may initiate frequent signals for the dump-valve to open resulting in almost continuous flow of pressurized hydrocarbon liquids to the storage tanks and reduces residence time for separation of gas from the liquid phase. It 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). 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.

3.2.1.3 PIPING ANOMALIES

Although very few instances were observed by the PTAC investigation, piping anomalies can occur. Unintentional emission due to piping (or changes to piping) can include:

- Unintentional placement of high vapour pressure product in tanks not equipped with appropriate vapour controls. For example, liquids accumulating in 2nd, 3rd and greater compression stage scrubbers are normally recycled back to the 1st stage scrubber inlet. Instances where these highly volatile liquids, are piped directly to atmospheric tanks cause unnecessary storage tank emissions.
- 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.

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9 Portable acoustic leak detectors 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 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.

- Purge gas supplied to a separator liquid line and connected to a storage tank.
- Oil well production casing connected to a storage tank.

3.2.2 APPROVED QUANTIFICATION METHODOLOGY FOR TANK FLASHING

According to BC OGC Measurement Guidelines (BC OGC, 2018b), 0.0257 m^3 of gas/m^3 of oil/kPa of pressure drop estimate may be used as the GOR factor for determining the quantity of flash gas released from conventional light-medium oil production, if well oil production rates do not exceed 2 m^3 per day **or** if all gas production is vented or flared. WCI.363(h) quantification methodology for storage tank flashing also permits the use of correlations (WCI, 2013). The flexibility to use simple correlations for **all** instances of gas flared or vented introduces reporting inaccuracies because correlations are unable to account for sample specific analyte fractions (a measure of liquid volatility), 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). To improve the accuracy of reported vent and flare volumes (from tank flashing), use of correlations should be limited to sites that do not exceed 2 m^3 per day (regardless of whether production is vented or flared).

The volume of oil and condensate produced in BC between November 2018 and October 2019 to controlled and uncontrolled tanks are provided in Table 12 (BC OGC, 2019b). For uncontrolled tanks, the volume from sites producing less than and greater than 2 m^3 per day are determined. The total volume of oil and condensates from sites producing less than 2 m^3 per day represent about 1 percent of total oil and condensate production in BC. Thus, the use of correlations (with large uncertainties) by facilities producing less than 2 m^3 per day has little impact on the accuracy of provincial flash volumes because the volume of subject oil and condensate is less than 1 percent.

Table 12: Volumes of oil and condensates produced to storage tanks from November 2018 to October 2019.

Product	Production Volume (m^3 per year)		
	Controlled Tanks	Uncontrolled Tanks	
		Sites >2 m^3/day	Sites <2 m^3/day
Condensate	2,663,071	16,500	3,829
Oil	217,927	720,041	3,638

Direct measurement and process simulations described by the BC OGC measurement guidelines should be applied to account for site specific conditions for facilities producing greater than 2 m^3 per day. To improve the reliability of process simulation results, the integrity of subject pressurized samples should be confirmed by comparing the calculated bubble point to the field sample pressure. Colorado PS Memo 17-01 provides guidance on maximum percent difference between bubble point and sampling pressure to confirm samples are collected correctly and not compromised prior to laboratory analysis (CAPCD, 2017). GOR factors determined from liquid samples that exceed PS Memo 17-01 guidelines may not be representative of actual flashing emissions.

Also, BC OGC measurement guidelines and WCI quantification methodologies do not specify how tank vapour composition should be determined. This represents a material data gap considering CH_4 concentration of tank vapour can range from zero to more than 90 percent. Tank vapour composition can be determined by process simulation if this method is used to determine GOR. However, gas sampling and laboratory analysis is required to determine CH_4 concentration if tank flashing is determined based on the 24-hour test method.

3.2.3 TRANSMISSION STATIONS

Gas transmission stations are generally not included in the Petrinex, MSAPR, BC CIIP and KERMIT data sources described in Section 3.1. Moreover, gas transmission stations were not included in the BC or AB field studies described in Section 2 so relevant equipment factors are not available. These data gaps preclude the development of a bottom-up emission inventory by this study. Instead, this inventory relies on CH_4 emissions reported to the BC GHG Reporting program that were quantified according to WCI.353 methodologies and subject to 3rd party verification.

Confidence limits determined in the 2018 CEPEI GHG Inventory Uncertainty Analysis (CEPEI, 2020) are adopted for transmission stations. The CEPEI study derived the uncertainty values from a combination of published information sources and expert judgement by several industry experts. CEPEI uncertainties are determined for a 95 percent confidence level using the same IPCC (2000) Tier-1 approach described in Section 3.4.

3.2.4 UNCERTAINTIES FOR CAP-OP EQUIPMENT COUNTS AND VENTING FACTORS

Estimates of equipment counts and venting factors are important to drive CH_4 inventory efforts, but it is crucial to acknowledge that these values have a certain level of uncertainty that should be disclosed. Quantification of these uncertainties facilitates the prioritization of efforts to improve the accuracy of inventories developed using these data.

Confidence intervals were not determined for the equipment counts and venting factors presented in the BC oil and gas methane field study (Cap-Op, 2018) which challenges subsequent uncertainty analysis. To resolve this data gap, the current study adopts confidence intervals from the AB field study (Clearstone, 2018) for the rod-packing and water tank emission factors presented in Table 13. The AB analogues are adopted because of similarities between AB and

BC production infrastructure as well as methods applied by the two studies for collecting field data; measuring vent gas and deriving factors. However, the estimated CH_4 emission uncertainties presented in Section 4 may not be representative. To arrive at a more reliable outcome, BC field data could be revisited and confidence intervals derived using the bootstrapping method (described in Clearstone, 2018) and considering relevant systematic and random errors.

Table 13: Population-average emission factors (Cap-Op, 2018) and analogue confidence intervals (Clearstone, 2018) adopted for this study.

Component Type	Emission Factor	95% Confidence Interval (% of mean)	
		Lower	Upper
Compressor Rod-Packing	0.2186	0.53	0.88
Production Tank - Water	0.1300	0.70	1.15

Also, AB and BC field studies did not include gas processing facilities. Equipment count factors from national emission inventories (Clearstone, 2019 and ECCC, 2014) are adopted for these facility types. Average factors are assigned confidence intervals of 50 percent (lower bound) and 200 percent (upper bound) as best estimates. Conducting similar field studies at gas processing facilities would improve confidence in subject CH_4 emission estimates.

3.3 INVENTORY ASSESSMENT

The following sections provide a detailed description of how data sources are combined with published factors to estimate the number of storage tanks and compressors are operating in BC and corresponding CH_4 emissions. The data flow diagram presented in Figure 6 depicts how information from numerous data sources is combined to bridge data gaps and generate emission inventories for compressor seals and water tanks. A similar data flow diagram for hydrocarbon storage tanks is presented in Figure 7. Data gaps discussed in Section 3.2 are identified by red font in Figure 6 and Figure 7.

3.3.1 INVENTORY BOUNDARY

This study targets venting emissions from storage tanks and compressors (described in Section 1.1) that occurred between November 2018 and October 2019. Other emission sources such as combustion, flaring and fugitives as well as dehydrator, pneumatic, truck loading, blowdown and other venting sources are outside the scope of the study.

The inventory boundary includes the following segments of the BC UOG industry. These segments are targeted because they feature the majority of storage tanks and compressors of interest.

- Natural gas production,
- Light and medium oil production,
- Natural gas processing, and
- Natural gas transmission.

Oil and gas production from both conventional and unconventional sites are included. The classification of facility and production types are described in Section 3.3.2 with the number of each facility subtype included in Table 14.

The following industry segments are specifically excluded from the inventory because they are not relevant to BC UOG industry or have negligible storage tank and compressor venting emissions.

- Cold heavy oil production
- Thermal heavy oil production
- Disposal and waste treatment, and
- Incidents and equipment failures

The inventory explicitly excludes the following mid and downstream segments and activities:

- Refineries,
- Petrochemical plants,
- Liquid fuel distribution and sales,
- LNG plants,
- Offshore facilities,
- Facility construction, decommission and reclamation activities, and
- Electric power generation.

3.3.2 DETERMINATION OF SITE CLASSIFICATION

Before equipment and emission factors from the BC methane field study (Cap-Op, 2018) can be applied, Petrinex facility records must be categorized according to 'site classification' stratums defined by the study. The following step-by-step description explains how this is achieved.

1. The coding pattern presented on page 11 of the BC Methane Field Study (Cap-Op, 2018) is adopted with 'Production Category' defined by the BC OGC Well Index file[10] for each

[10] Production category is determined from 'Well Fluid' (oil or gas) plus 'Formation Codes' applicable to each WA listed in BC OGC well index file. Unconventional (Tight or Shale) formations are defined by reservoir zone in schedule 2 of the BC OGC Drilling and Production Regulation (BC OGC, 2018a) and represented by formation

well authorization (WA)[11] appearing in Petrinex Facility Volumetric Activity Report. Sites producing "Shale Gas" and "Tight Gas" are defined as "Tight Gas (T)" and distinguished from older legacy wells that are defined as "Conventional Gas (C)". A single "Oil (O)" category is applied to both "Tight Oil" and "Conventional Oil" production sites. Gas facilities that have missing links to UWI are assumed to be conventional (C).

2. Facility 'Production Category' is determined by counting the number of wells belonging to each battery according to well 'Production Category' and selecting the category with the greatest count.

3. 'Facility Type' is determined according to Petrinex facility subtypes[12] presented in Table 14 with coding pattern adopted from the BC Methane Field Study (Cap-Op, 2018). The first ten facility types were included in the 2018 BC field study while others were excluded from the field study and are assigned analogue factors from the UOG national emission inventory (ECCC, 2014).

4. 'Site Classification' can then be defined as 'Facility SubType' plus 'Production Category' for each facility that reported to Petrinex between November 2018 and October 2019. 'Site Classification' counts presented in Table 14 will evolve over time as facilities are constructed and decommissioned or as reservoirs targeted by drilling programs evolve.

Table 14: BC facility subtypes included in the emission inventory boundary for production and processing industry segments.

Subtype Code	Subtype Description	Field Study Code	Active Codes in 2018/19
GAS FLOW	Well (Tight Gas)	WT	4916
GAS FLOW	Well (Conventional Gas)	WC	4220
CR-OIL PUMP	Well (Oil)	WO	940
311	Crude Oil Single Well Battery	SWB	76
351	Gas Single Well Battery	SWB	52
321	Crude Oil Multiwell Group Battery	MGB	6
361	Gas Multiwell Group Battery	MGB	113

codes 2800, 2850, 4997, 5000, 7730, 8295 and 8550 (https://www.bcogc.ca/formation-code-listings). Conventional formations include all other formation codes.

[11] WA represent discrete wellheads while UWI represent discrete production strings. Because some wellheads feature more than one production string, the total number of UWI (13,061) is greater than the total number of WA (9,728) reporting production over the same inventory period.

[12] The complete list of Petrinex facility type and subtype codes is available from https://www.petrinex.gov.ab.ca/bbreportsBC/PRAFacilityCodes.htm.

Table 14: BC facility subtypes included in the emission inventory boundary for production and processing industry segments.			
Subtype Code	**Subtype Description**	**Field Study Code**	**Active Codes in 2018/19**
393	Mixed Oil and Gas Battery	MGB	25
322	Crude Oil Multiwell Proration Battery	MPB	41
362	Gas Multiwell Effluent Measurement Battery	MEM	177
401	Gas Plant Sweet	GP1	24
402	Gas Plant Acid Gas Flaring (<1 t/d Sulphur)	GP2	26
403	Gas Plant Acid Gas Flaring (>1 t/d Sulphur)	GP7	4
404	Gas Plant Acid Gas Injection	GP3	3
405	Gas Plant Sulphur Recovery	GP4	4
407	Gas Plant Fractionation	GP6	1
611	Custom Treating Facility	CT1	5

3.3.3 COMPRESSORS AND WATER TANKS

The number of compressors and water tanks in operation between November 2018 and October 2019 is determined by multiplying equipment factors by Petrinex facility counts for each 'Site Classification' stratum.

- 'First guess' compressor and water tank counts are determined based on major equipment factors derived in the BC Methane Field Study (Cap-Op, 2018).

- The number of hours each facility operates is determined based on well production hours from Petrinex during the reporting period of November 2018 to October 2019. Facilities are assumed to operate if at least one well is producing so facility operating hours equal the maximum number of days upstream wells produced.

- The number of compressor units assigned to each facility are refined according to the ratio of natural gas fuel reported for the site versus theoretical fuel determined from reported production hours and typical power ratings. The theoretical fuel allocation method is used to determine the volume of fuel consumed by individual combustion units at a given facility. Theoretical fuel is estimated based on maximum rated power output, the heating value of the fuel and an appropriate thermal efficiency and loading factor for subject equipment using Equation 1. The compressor counts thus obtained are referred to as 'final' estimates.

$$Q_{theoretical\_i} = \frac{P_{rated\ i} * LD_i * OH_i * N_i * 0.0036}{EF_i * HHV_i}$$

Equation 1

Where:

$Q_{theoretical\_i}$ = Theoretical fuel for each source i (10^3 m^3)
$P_{rated\ i}$ = Rated power for source i (kW)
LD_i = Loading factor for source i (default 0.75)
OH_i = Annual operating hours for source i
EF_i = Equipment efficiency for source i
HHV_i = Higher heating value of the fuel used by source i (default 39.7 MJ per m^3 from Table 2 of Clearstone, 2019).
N_i = quantity of units per source (dimensionless)

Thermal efficiencies and power rating for subject equipment are presented in Table 15. Average power ratings are calculated for natural gas driven reciprocating, screw and centrifugal compressors from the 2018 CIIP dataset (GoBC, 2019b). Power ratings for other fired equipment and thermal efficiencies are adopted from the 2018 AB UOG methane inventory report (Clearstone, 2019).

Table 15: Power rating and thermal efficiencies for different types of combustion units.

Source Type	Power Output (kW)	Thermal Efficiency (%)
Reciprocating Compressor - Natural Gas	1,097	35
Centrifugal Compressor - Natural Gas	2,287	30
Catalytic Heater	3.2	80
Catalytic Incinerator	223	80
Incinerator	223	80
Line Heater	223	80
Process Boiler	462	80
Pump Jack	45.3	35
Screw Compressor - Natural Gas	406	35
Thermal Electric Generator	0.50	3.6
Treater	462	80
Unit Heater	223	80
Well Pump	45.3	35

- The hydrocarbon release rate (m^3 per hour) is determined by multiplying the refined compressor and water tank count by corresponding population-average emission factors (Cap-Op, 2018). For water storage tank, an average vent rate of 0.13 m^3 per hour per unit is applied. However, the BC compressor population-average factor is recalculated using a denominator of 58 reciprocating compressors because screw compressors (11) are not equipped with rod-packings or vent seal gas (i.e., the wrong number of compressors was used for BC emission factor calculations). The revised factor equals 0.2186 m^3 per hour per compressor.

- The annual CH_4 emissions (tonnes per year) are obtained by multiplying the hydrocarbon release rate (m^3/hour) by operating hours for each subject facility and CH_4 mole fraction of the subject process gas (and converted to mass emissions). The CH_4 mole fraction of process gas for each facility is not known. To bridge this data gap, the typical mole fraction for sweet gas production and processing facilities (0.9188 from Table 3 in ECCC, 2014) is applied to both compressor and water tank[13] emissions.

- The mitigating benefit of emission controls is already accounted in population-average leak factors because both controlled and uncontrolled units were included in the calculation of BC 'Major Equipment' and population-average leak factors (Cap-Op, 2018). Therefore, no emission CF is applied when calculating compressor seal and water tank emissions.

- Data sources available for this project do not provide discrete records for the number of gas transmission compressor stations or turbine drivers in operation. Therefore, a bottom-up inventory is not possible. To bridge this data gap, CH_4 emissions from centrifugal compressor seals are obtained from inventories prepared by gas transmission companies and reported to the BC Industrial GHG Reporting Program. This approach is consistent with the most recent bottom-up inventories prepared for the Canadian UOG industry (ECCC, 2014 and CAPP, 2005).

[13] The CH_4 mole fraction of hydrocarbon tank vapour is typically less than 0.9188 but its speculated water tank emissions are dominated by natural gas carry-through (Clearstone, 2019) and therefore contain mostly CH_4.

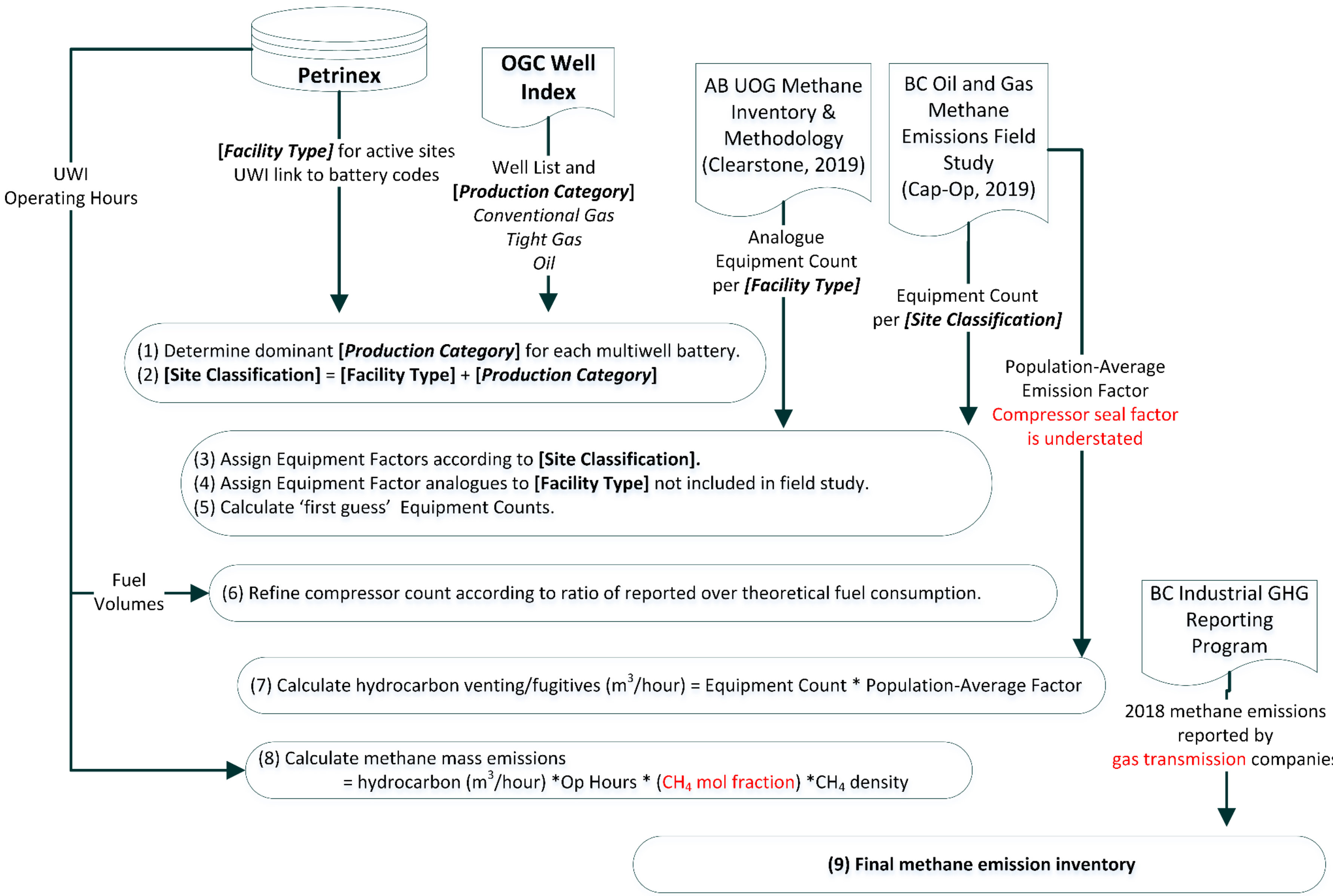


Figure 6: Compressor seal and water tank emission inventory using Petrinex activity data and population average factors.

3.3.4 HYDROCARBON STORAGE TANK EMISSIONS

Hydrocarbon storage tank emissions are determined from oil and condensate production volumes instead of tank counts and emission factors. A step-by-step description of this approach is provided below.

- The volume of oil produced from wells are obtained from Petrinex and deemed to be stored on-site only when liquid inventories are also reported (i.e., indicator of site storage). Sites that produce hydrocarbons but do not report liquid inventories likely feature ‘wet metering’ where hydrocarbon liquids are recombined with the sales gas stream after metering and not stored on site.

- GOR are determined based on methodology described in Section 7.2.3 and 7.2.4. Associated gas will flash out of solution when produced oil is delivered into atmospheric storage tanks. The magnitude of gas flashing depends on oil composition as well as separator and storage tank conditions (pressure and temperature). Ideally, these process conditions are known and simulations are completed to accurately predict gas flashing. However, site-specific conditions are not available for this study and empirical correlations are applied instead. The Valko and McCain (2003) correlation is applied to **oil** production with API Gravity = 43.4^o and upstream vessel (separator) pressure of 870 kPaa and is 14^o C (Clearstone, 2019). The Vasquez and Beggs (1980) correlation is applied to **condensate** production with API Gravity = 66.4^o and upstream vessel (separator) pressure of 870 kPaa and is 14^o C (Clearstone, 2019).

- The annual hydrocarbon flashing (m^3 per year) is obtained by multiplying annual oil or condensate production volumes (reported to Petrinex) by GOR.

- Sites with tank-top emission controls are identified and incorporated into CH_4 inventory calculations as follows. These assumptions result in emission control being applied to approximately 99 percent of condensate production and approximately 23 percent of oil production.

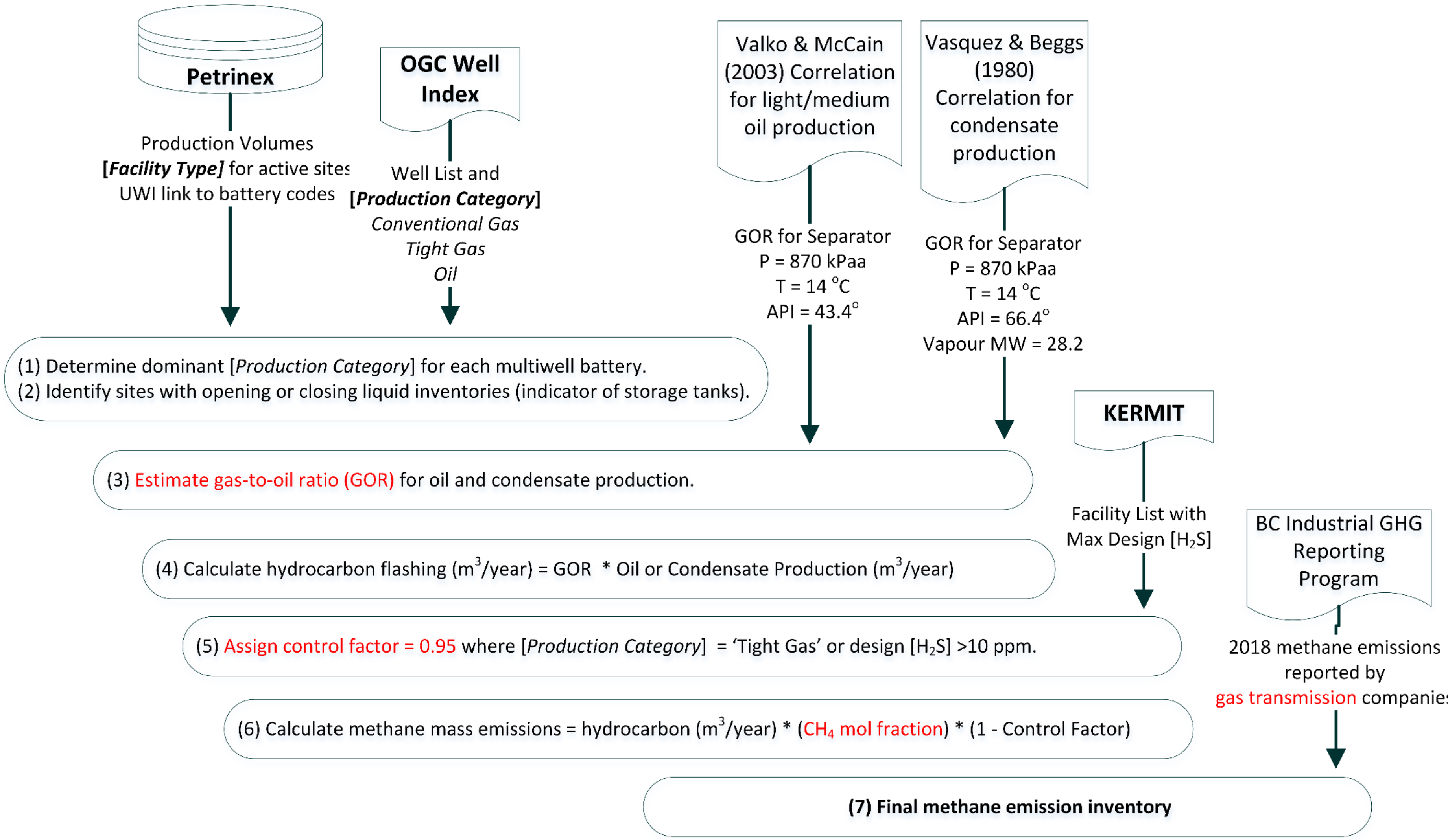
  - Sites designed for sour service will feature emission controls that preclude the release of process gas into the atmosphere. The BC OGC permits process gas venting if the gas contains no more than 20 ppm H_2S (OGC, 2018a Section 41(6)). Therefore, an emission CF (0.95) is applied to sites with design H_2S concentration greater than 20 ppm.

  - Liquid condensate produced from unconventional (tight or shale) natural gas wells typically has density less than 800 kg per m^3 (API gravity greater than 46^o)

with separation of gas and liquid streams (for metering) occurring at pressures greater than 2,000 kPa gauge. GOR for condensate at these process conditions is high (e.g., greater than 50 m^3 gas per m^3 oil) and would result in excessive product loss (and environmental impact) if produced into atmospheric storage tanks (Clearstone, 2019). Instead, the condensate is either recombined with the sales gas stream after metering (referred to as 'wet-metering') or storage tanks are equipped with vapour capture and control systems. Therefore, an emission CF (0.95) is applied to tank emissions at unconventional natural gas sites.

- The annual CH_4 emissions (tonnes per year) are determined by multiplying the hydrocarbon flashing by the CF and CH_4 mole fraction of the subject tank vapour (and converted to mass emissions). The CH_4 mole fraction of vapour for each tank is not known. To bridge this data gap, the typical mole fraction for condensate tanks (0.5642 from Table 3 in ECCC, 2014) and light/medium oil tanks (0.1001 from Table 5 in ECCC, 2014) are applied.

- Breathing and working losses are not calculated because they are a small contributor to total tank emissions (relative to flashing losses) at upstream production sites. Moreover, the evaporation of 'weathered' condensate or oil during breathing and working activities (that occurs after flashing) should contain zero or very little CH_4 (i.e., lighter hydrocarbons flash out of solution before heavier hydrocarbons). According to detailed hydrocarbon analysis available from crudemonitor.ca, weathered crude oils and condensates (sampled at BC and AB oil terminals) do not contain CH_4. It is possible some residual CH_4 is released during product handling between the production tank and storage terminal but this is expected to have negligible contribution to the subject CH_4 inventory.



Assumptions:

(1) Tank emission control factor (0.95) applied to sites with design [H_2S] >10 ppm or that produce unconventional (tight or shale) natural gas.

(2) Storage tank emissions only calculated for sites reporting liquid invoices (i.e., indicator of site storage).

Figure 7: Hydrocarbon tank emission inventory using Petrinex activity data and empirical correlations

3.4 UNCERTAINTY ASSESSMENT

Uncertainties in inventories may arise through at least three different processes (IPCC, 2000):

- Uncertainties from definitions (e.g., meaning incomplete, unclear, or faulty definition of an emission or uptake),
- Uncertainty from natural variability of the process that produces the emission,
- Uncertainties from the assessment of the process or quantity, including, depending on the method used: (i) uncertainties from measuring, (ii) uncertainties from sampling, (iii) uncertainties from reference data that may be incompletely described, and (iv) uncertainties from expert judgment.

For the purposes of this study, uncertainties from definitions were assumed to be adequately controlled through the applied QA/QC procedures, and therefore, negligible. Quantitative uncertainty estimates to account for the latter two contributions were developed using the Tier 1 approach published by IPCC (2000). This approach employs simple error propagation equations based on the assumption of uncorrelated normally distributed uncertainties under addition and multiplication.

3.4.1 ERROR PROPAGATION EQUATIONS

An emissions inventory may be viewed as the sum of emission estimates for multiple sources, where the estimate for each source is typically the product of an emission factor and a corresponding activity value. The overall uncertainty in the sum of the individual emission estimates is determined using the following relation (this expression is exact for uncorrelated or independent variables):

$$U_{total} = \frac{\sqrt{(U_1 \bullet x_1)^2 + (U_2 \bullet x_2)^2 + \ldots + (U_n \bullet x_n)^2}}{x_1 + x_2 + \ldots + x_n}$$

Equation 2

Where:

U_{total}	=	is the percentage uncertainty in the sum of the quantities.
x_i and U_i	=	are the uncertain quantities and the percentage uncertainties associated with them, respectively.

The uncertainty in each individual emission estimate in the summation is determined by combining the uncertainty in the corresponding emission factor and activity parameter using the following relation (this is approximate for all random variables):

$$U_{total} = \sqrt{U_1^2 + U_2^2 + \ldots + U_n^2}$$

Equation 3

Where the activity parameter for a source is continuous (e.g., gas throughput or fuel gas consumption), the uncertainty in the emission estimate for that source is calculated using Equation 3. Where the activity parameter for a source is a count or integer value (e.g., number of equipment components, number of stations, number of compressors, etc.), Equation 2 is used to evaluate the aggregate uncertainty for N sources of the same type and average strength, and Equation 3 is used to account for the fact the value N may have some uncertainty in it.

3.4.2 DETERMINATION OF PRIMARY DATA UNCERTAINTIES

The uncertainties assigned to each type of activity data, emission factor and speciation profile are listed throughout this report along with their reference. The approach used to evaluate these uncertainty values was to first, where applicable, divide each factor or parameter into its constituent elements, then determine the uncertainty in each element, and finally calculate the combined uncertainty using the rules described in Section 3.4.1.

The uncertainty in each primary data type was estimated using one of the following approaches, presented in the order of decreasing preference:

- Error analysis of the available measurement data.
- Applicable uncertainty estimates presented in the open literature.
- Default uncertainty values published by IPCC (2000).
- Expert judgment.

In each case, the uncertainty is the probable error in the measurement or accounting techniques used to determine the input quantity, and in any related extrapolations or interpolations of these values.

When deriving uncertainty values from measurement data, a Student-t distribution was assumed for sample sizes of less than 30 and a normal distribution was assumed for larger sample sizes.

The primary uncertainty values were obtained from ECCC, 2014 and Clearstone, 2018. For transmission, confidence limits for emissions are obtained from previous studies on GHG inventory uncertainty analysis (CEPEI, 2020).

Where suitable data or published values were unavailable, it was necessary to use professional judgment and solicit informal input from applicable experts to provide uncertainty values. The application of formal protocols for expert elicitation was beyond the scope of this work. Rather, values were estimated by the project team and through information discussions with industry experts. The formal review of this document by the Project Advisory Committee was deemed to provide a reasonable mechanism for the critique of the presented uncertainty values.

3.4.3 DETERMINATION OF ERROR BOUNDS

In practice, uncertainties in inventory source categories and individual source estimates may vary from a few percent to orders of magnitude, and may be correlated. Equation 2 and Equation 3, used for combining uncertainties, are applicable in cases where the variables are uncorrelated with a standard deviation of less than about 30 percent of the mean. However, as no other practical means of combining uncertainties is available, the presented relations may still be used to obtain an approximate result (IPCC, 2000).

The inventory uncertainty is expressed by giving the range within which the unknown true emission total is expected to occur subject to a specified probability (or level of confidence). The higher the required level of confidence, the wider the range becomes. The IPCC suggests using a 95 percent confidence level which was adopted for use here.

To determine the upper and lower limit of the inventory confidence interval it is appropriate to consider the shape of the uncertainty probability function for each quantity being combined. IPCC (2000) good practice has been followed in this regard, which is to assume either a normal or lognormal distribution depending on which provides the most realistic results (i.e., results in positive non-zero confidence limits). Other distributions should only be used where there are compelling reasons, either from empirical observations or from expert judgment backed by theoretical argument.

Accordingly, wherever the percent uncertainty for a quantity is less than 100 percent, a normal probability function is assumed resulting in a symmetric distribution about the mean (i.e., a balanced uncertainty of $\pm U_i$). Wherever the percent uncertainty for a quantity is greater than 100 percent, the uncertainty value was taken to be $(100/U_i)*100$ when determining the lower limit and $+U_i$ when determining the upper limit resulting in an unbalanced uncertainty. This is equivalent to assuming a lognormal distribution and was done, where applicable, to avoid a negative or zero lower confidence limit for the target quantity. These rules concerning balanced and unbalanced uncertainties were applied appropriately to each quantity before combining uncertainties using Equation 2 and Equation 3. Thus, two sets of calculations were performed: one to determine the combined uncertainty applicable for evaluation of the upper confidence limit, and one to determine the value applicable for evaluation of the lower confidence limit.

For example, a quantity, x, that is determined to have an upper uncertainty bound of U_{Upper} = +50 percent would be assumed to have a lower uncertainty bound of U_{Lower} = -50 percent. In comparison, a quantity that is determined to have an upper uncertainty bound of U_{Upper} = +125 percent would be assumed to have a lower confidence limit of U_{Lower} = (100/125) * 100% = -80 percent. Similarly, an upper uncertainty bound of U_{Upper} = +200 percent would result in a lower uncertainty bound of U_{Lower} = (100/200) * 100% = -50 percent.

While use of the lognormal assumption results in a tighter confidence interval than might otherwise be expected, it is conservative with respect to the potential amount of emissions since it results in greater estimated emissions at the lower confidence limit. Use of a normal distribution in these cases would result in a negative emission rate, which is meaningless, or, if the negative values were arbitrarily set to zero, an understatement of the lower probable emissions.

3.4.4 UNCERTAINTY DATA

The emission factor uncertainties are included throughout this report wherever the emission factors are presented. Production volume uncertainties are based on maximum uncertainty of monthly volumes permitted by the BC OGC Measurement Guidelines (BC OGC, 2018) and provided in Table 16. Table 17 lists a number of other quantities used in emission calculations and their assumed uncertainty limits.

Table 16: Compilation of uncertainties associated with production volumes.

Facility Type	Quantity	Production Volume Range	Uncertainty (±%)
Oil Batteries	Oil Production	< 100 m^3/d	1
		> 100 m^3/d	0.5
Oil Proration	Oil Production	>30 m^3/d	5
		>6 and ≤30 m^3/d	10
		>2 and ≤6 m^3/d	20
		≤2 m^3/d	40
Gas Batteries	Condensate Production	All	2
All Facilities	Other[1]	All	25
	Fuel Volumes	> 500 m^3/d	5
		<= 500 m^3/d	20

[1] Based on engineering judgement and industry consultations.

Table 17: Compilation of uncertainties used in emission estimation calculations.		
Item	**Description**	**Uncertainty (±%)**
Speciation Profiles	Individual species mole fractions	25
Stream Molecular Weights	Calculated from speciation profiles	10
Stream High Heating Value	Calculated from speciation profiles	10
Combustion Units	Power Rating	25
	Efficiency	25
	Loading Factor	25
Storage Tanks	Vapour Pressures	25
	Storage Temperature	25
	Proportion of tanks that are controlled	37[1]

[1] The uncertainty in predicting whether or not storage tanks are equipped with emission control is estimated from 2018 BC methane field data (Cap-Op, 2018).

In comparing the total uncertainty estimate for different source categories it is important to consider the number of sources in each category as well as the uncertainties in the individual emission estimates for the sources in these categories. The percentage uncertainty in the aggregate emission estimate for a category will tend to decrease by a factor of $1/N^{0.5}$ where N is the number of sources in that category. Thus, it is possible that a category with many sources and relatively high uncertainties in individual emission estimates (e.g., fugitive equipment leaks) may have a lower total uncertainty in the aggregate emission estimate than a category with much fewer sources and better uncertainties per source (e.g., venting). In general the uncertainties associated with the emissions from a specific facility are relatively large but when the emissions from many hundreds or thousands of facilities are aggregated the overall uncertainty may be very low.

4 RESULTS

Results of the inventory and uncertainty assessments described in Sections 3.3 and 3.4 are presented below. Estimated process equipment counts and CH_4 emissions are compared with results from independent publications and differences are discussed.

4.1 PROCESS EQUIPMENT COUNTS

BC UOG process equipment counts are estimated for fixed-roof, atmospheric water and hydrocarbon storage tanks as well as reciprocating compressors and centrifugal compressors. Table 18 provides ‘first guess’ as well as ‘final’ equipment counts per site classification code (defined by Cap-Op, 2018) and industry segment. The ‘first guess’ counts are derived directly from average equipment factors (Cap-Op, 2018 or analogues from ECCC, 2014) multiplied by Petrinex facility counts and represent equipment operating between November 2018 and October 2019. Process equipment counts are not estimated for the transmission segment because of data gaps discussed in Section 3.2.3.

Because the Cap-Op and analogue factors are based on small sample sizes and appear to under-predict compressor counts (relative to other data sources), ‘first guess’ compressor counts were tested by comparing their theoretical fuel consumption with metered natural gas fuel consumption reported to Petrinex. Compressor counts were adjusted according to the ratio of reported over theoretical fuel for each site classification stratum. This inventory refinement increased the number of natural gas driven reciprocating compressors from 534 (first guess) to 686 and centrifugal compressors from 1 (first guess) to 8. The estimated number of electric driven compressors (30), water tanks (643) and hydrocarbon tanks (969) are not affected by this refinement.

Table 18: Estimated BC UOG equipment unit counts per site classification ('first guess' and final values).										
Segment	**Site Classification Description**	**Site Class Code**	**Final Counts**					**'First Guess' Counts**		
			Hydrocarbon Production Tank	**Water Production Tank**	**Reciprocating Compressor**		**Centrifugal Compressor**	**Reciprocating Compressor**		**Centrifugal Compressor**
					Natural Gas Driver	**Electric Driver**	**Natural Gas Driver**	**Natural Gas Driver**	**Electric Driver**	**Natural Gas Driver**
Production	Multiwell Effluent Measurement Battery – Conventional Gas	MEMC	71.7	57.6	114.8	14.1		130.3	14.1	
	Multiwell Effluent Measurement Battery – Tight Gas	MEMT	126.9	209.0	190.9			139.1		
	Multiwell Group Battery – Conventional Gas	MGBC								
	Multiwell Group Battery – Oil	MGBO	24.0	12.0						
	Multiwell Group Battery – Tight Gas	MGBT	26.3	79.2	45.9	9.7		24.1	9.7	
	Multiwell Proration Battery – Oil	MPBO	146.4	46.7	10.4	5.7		35.3	5.7	
	Single-Well Battery – Conventional Gas	SWBC	13.5	13.5						
	Single-Well Battery – Oil	SWBO	55.9	28.0	0.5			9.1		
	Single-Well Battery – Tight Gas	SWBT	6.0							
	Well – Conventional Gas	WC	84.4							
	Well – Oil	WO	122.2							
	Well – Tight Gas	WT	147.5	196.6				147.5		
	Custom Treating Facility	CT1	20.0							
Processing	Gas Plant Sweet	GP1	48.0		135.0			20.4		
	Gas Plant Acid Gas Flaring < 1 tonne/day	GP2	52.0		97.9			21.3		

Table 18: Estimated BC UOG equipment unit counts per site classification ('first guess' and final values).										
Segment	**Site Classification Description**	**Site Class Code**	**Final Counts**					**'First Guess' Counts**		
			Hydrocarbon Production Tank	**Water Production Tank**	**Reciprocating Compressor**		**Centrifugal Compressor**	**Reciprocating Compressor**		**Centrifugal Compressor**
					Natural Gas Driver	**Electric Driver**	**Natural Gas Driver**	**Natural Gas Driver**	**Electric Driver**	**Natural Gas Driver**
	Sulphur									
	Gas Plant Acid Gas Injection	GP3	6.0		55.6			2.9		
	Gas Plant Sulphur Recovery	GP4	8.0		12.6		8.0	0.6		0.4
	Gas Plant Fractionation	GP6	2.0							0.6
	Gas Plant Acid Gas Flaring > 1 tonne/day Sulphur	GP7	8.0		23.0			3.3		
Total			969	643	686	30	8	534	30	1

Final counts (and 95 percent confidence limits) are summarized by industry segment and equipment type in Table 19. There are a total of 724 compressors at production and processing segments, of which natural gas fired reciprocating compressor accounts for 95 percent of the total population. Electric driven reciprocating compressors and turbine driven centrifugal compressors are less common (representing 4 percent and 1 percent of the production and processing compressor population). Most (93 percent) of the 1611 estimated storage tanks are located at production sites.

Data gaps discussed in Section 3.2 preclude the estimation of electric driven compressors and water tanks for the processing segment.

Table 19: Equipment unit counts with 95% confidence limits summarized by industry segment and equipment type.

Segment	Process Equipment	Type	Estimated Unit Count	95% Confidence Limits			
				Lower Limit	Upper Limit	Lower (%)	Upper (%)
Production	Reciprocating Compressor	Electric	30	26	36	11.1%	21.5%
		Natural Gas	362	345	395	4.8%	9.2%
	Storage Tank	Hydrocarbon	845	671	1080	20.6%	27.8%
		Water	643	633	655	1.4%	2.0%
Processing	Reciprocating Compressor	Natural Gas	324	317	349	2.3%	7.7%
	Centrifugal Compressor	Natural Gas	8	6	15	23.1%	81.5%
	Storage Tank	Hydrocarbon	124	87	268	29.6%	116.2%

4.1.1 ESTIMATED VERSUS REPORTED COMPRESSOR COUNTS

Estimated compressor counts (with 95 percent confidence level) are presented in Table 20 for production and processing segments. These are compared to values reported to BC CIIP and KERMIT. The compressor counts estimated for production and processing (724) appears reasonable as they are within the range of values reported by CIIP (612) and KERMIT (1138). The number of compressor units at natural gas transmission stations is not estimated because of data gaps described in Section 3.2.3.

Table 20: Comparison of estimated compressor counts (with 95% confidence limits) with unit counts derived from BC CIIP and KERMIT data sources.

Segment	Estimated Unit Count	95% Confidence Limits				CIIP	KERMIT
		Lower Limit	Upper Limit	Lower (%)	Upper (%)	Unit Count	Unit Count
Production	392	374	426	4.5%	8.6%		876
Processing	332	325	358	2.3%	7.8%		262
Total	724	705	767	2.7%	5.9%	612[a]	1,138[b]

[a] *Includes centrifugal, reciprocating and screw compressors from all segments that operated in 2018 (of these, there are 70 electric driven and 542 natural gas fired compressors)*

[b] *Includes centrifugal, reciprocating and screw compressors that have permit to operate (of these, there are 149 electric driven and 989 natural gas fired compressors).*

4.1.2 ESTIMATED VERSUS REPORTED STORAGE TANK COUNTS

Estimated storage tank counts (with 95 percent confidence level) are presented in Table 21 for production and processing segments. These counts are compared to values reported to BC CIIP and KERMIT. Total predicted storage tank counts (1611) at production and processing segments are in close proximity to the upper bound estimate of 2,001 reported by KERMIT. This indicates Cap-Op factors multiplied by site counts (derived from Petrinex data) is a reasonable approach for estimating BC UOG storage tanks populations.

Table 21: Comparison of estimated storage tank counts (and 95% confidence limits) with unit counts derived from BC CIIP and KERMIT data sources.

Segment	Estimated Unit Count	95% Confidence Limits				CIIP (2018 report)	KERMIT
		Lower Limit	Upper Limit	Lower (%)	Upper (%)	Unit Count	Unit Count
Production	1,487	1313	1723	11.7%	15.8%		1,614
Processing	124	87	268	29.6%	116.2%		387
Total	1611	1433	1887	11.1%	17.1%	NA	2,001

*NA: Not available

The number of storage tanks at natural gas transmission stations is not estimated because of data gaps described in Section 3.2.3

4.2 METHANE EMISSIONS

Estimated CH_4 emissions (tonnes per year with 95 percent confidence level) are summarized by industry segment and equipment type in Table 22. Compressors are estimated to emit 3,127 tonnes of CH_4 per year with the majority emitted from the transmission segment (72 percent). The remaining 28 percent of emissions are from production (15 percent) and processing (13 percent) segments.

Reciprocating compressors are responsible for the majority of compressor CH_4 emissions from production and processing segments while centrifugal compressors are responsible for the majority of compressor CH_4 emissions from the transmission segment. Compressors contribute approximately 8 percent of total CH_4 reported by UOG to the BC GHG reporting program.

Storage tanks are estimated to emit 2,612 tonnes of CH_4 per year with the majority of emissions from the production segment (99 percent). Hydrocarbon storage tanks and water tanks are responsible for 82 percent and 18 percent, respectively, of production tank emissions. Transmission tank emissions are primarily due to unintentional gas carry-through. Storage tanks contribute less than 1 percent of total CH_4 reported by UOG to the BC GHG reporting program but would increase to about 3 percent if results from Table 22 were considered.

<table>
<tr><th colspan="8">Table 22: Estimated methane emissions (tonnes/year) with 95% confidence limits summarized by industry segment and equipment type.</th></tr>
<tr><th rowspan="2">Segment</th><th rowspan="2">Process Equipment</th><th rowspan="2">Type</th><th rowspan="2">Estimated Emissions (t CH_4/ year)</th><th colspan="4">95% Confidence Limits</th></tr>
<tr><th>Lower Limit (t CH_4/ year)</th><th>Upper Limit (t CH_4/ year)</th><th>Lower (%)</th><th>Upper (%)</th></tr>
<tr><td rowspan="4">Production</td><td rowspan="2">Reciprocating Compressor</td><td>Electric</td><td>35</td><td>31</td><td>44</td><td>12.9%</td><td>23.8%</td></tr>
<tr><td>Natural Gas</td><td>432</td><td>409</td><td>473</td><td>5.2%</td><td>9.6%</td></tr>
<tr><td rowspan="2">Storage Tanks</td><td>Hydrocarbon</td><td>2,141</td><td>86</td><td>8618</td><td>96.0</td><td>302.5%</td></tr>
<tr><td>Water</td><td>455</td><td>446</td><td>469</td><td>2.0%</td><td>3.0%</td></tr>
<tr><td rowspan="2">Processing</td><td>Reciprocating Compressor</td><td rowspan="2">Natural Gas</td><td>386</td><td>375</td><td>418</td><td>2.9%</td><td>8.2%</td></tr>
<tr><td>Centrifugal Compressor</td><td>10</td><td>7</td><td>18</td><td>30.8%</td><td>87.5%</td></tr>
<tr><td rowspan="2">Transmission</td><td>Centrifugal Compressor</td><td>Electric and Natural Gas</td><td>2,264</td><td>1811</td><td>2717</td><td>20.0%</td><td>20.0%</td></tr>
<tr><td>Storage Tanks</td><td>Hydrocarbon</td><td>16</td><td>13</td><td>18</td><td>15.2%</td><td>16.8%</td></tr>
</table>

4.2.1 ESTIMATED VERSUS REPORTED COMPRESSOR ROD-PACKING EMISSIONS

Estimated CH_4 emissions from reciprocating compressor rod-packings are aggregated and presented in Table 23 for production and processing segments of the industry. The relative difference between estimated emissions and values reported to the BC industrial GHG reporting program are presented. Estimated emissions are two to eight times **less** than measured and reported by production and processing companies (according to WCI.353(e) and 353(m)). Emissions from natural gas transmission are not included in Table 23 because independent assessment of emissions from this industry segment is impractical.

If the reported CH_4 emissions in Table 23 (BC CAS, 2019) are accurate and complete, they indicate emission factors, CF and confidence intervals applied by this study are not representative and **understate** compressor rod-packing emissions. Measurement and reporting bias that may influence factors applied by this study include:

- Examples of multiple production locations aggregated into a single Petrinex reporting entity. This practice omits facilities and has a downward bias on estimated compressor counts when using facility-based factors (e.g., Cap-Op, 2018). The current study mitigates the impact of this bias by adjusting compressor counts according to the ratio of reported over theoretical fuel consumption (resulting in an upward adjustment of 22 percent). The estimated compressor counts in Table 20 appear reasonable because they are between lower and upper bounds estimated from independent data sources.
- The Hi Flow Sampler measurement method can draw a vacuum on the rod-packing vent. If this occurs, measurement results will overstate actual emissions which would have an upward bias on the emission factor. This potential bias applies to the BC methane field study (Cap-Op, 2018) and reported methane emissions (BC CAS, 2019).
- It is possible some compressor rod-packing vents were not detected by the OGI method and omitted from the BC methane field study (Cap-Op, 2018) and reported methane emissions (BC CAS, 2019). This would have a downward bias on the emission factor and reported values.
- The Hi Flow Sampler displays measurement results in units of “liters per minute” **or** “cubic feet per minute” depending on user selection. A unit reading discrepancy between the Hi Flow display and those expected by the data management system would introduce an error factor of 28.3 times. This is a possible random error applicable to both emission factor and reported values.
- Instances where the Hi Flow Sampler fails to transition from a catalytic oxidation sensor (used to measure natural gas concentrations of 5 percent or less) to a thermal conductivity sensor (used to measure natural gas concentrations from 5 to 100 percent) were observed in historic measurements (Howard et al, 2015). Although this possible failure was mitigated by firmware updates by the manufacturer and understood by the 2018 BC methane field team, it would explain the difference in results presented in Table 23.

- Natural variation in rod-packing vent rates (up to one order of magnitude) were observed during continuous measurement of three units over a six month period by BHGE LUMEN™ technology (ECCC, 2019 Figures 9.4-2 and 9.5-8). Hi Flow Sampler measurements completed at the same time did not correlate well with the long-term average vent rates determined from continuous measurement. Although LUMEN™ measurements highlight the challenges associated with single Hi Flow measurements (i.e., a snap-shot in time) they were not designed to evaluate the efficacy of the Hi Flow method (or validated by continuous reference measurement). However, if rod-packing vent rates vary over time, a single measurement of each source would not fully characterize the emission distribution of the source and would introduce a random error to both emission factor and reported values.
- Finally, the 2018 field study sample sizes were not sufficient to adequately represent the full distribution of rod-packing venting occurring in BC. The discrepancy between estimated and reported emissions is greatest for gas processing facilities. Gas processing facilities were not included in the BC methane field study so the large discrepancy is not unexpected. Also, the analogue confidence intervals adopted from Clearstone, 2018 do not adequately represent the upper range of venting emissions.

Table 23: Compressor rod-packing estimated methane emissions (95% confidence level) compared with 2018 values submitted to the BC Industrial GHG Reporting Program.

Industry Segment	Estimated Methane Emissions (t CH_4/yr)			2018 Reported Emissions (t CH_4/yr)	Relative Difference between estimated and reported methane	
	Estimated	Lower Limit (2.5% interval)	Upper Limit (97.5% interval)			
Production	467	444	509	1,053	-587 t/yr	-126%
Processing	396	385	429	3,088	-2,692 t/yr	-680%
Total	863	837	917	4,141	-3,278 t/yr	-380%

To confirm the validity of reported methane emissions (BC CAS, 2019), the BC government could request or prioritize verification assurance of rod-packing measurement (and subsequent maintenance) records for compressors contributing the greatest emissions.

4.2.2 ESTIMATED VERSUS REPORTED STORAGE TANK EMISSIONS

Estimated CH_4 emissions from hydrocarbon and water storage tanks are aggregated and presented in Table 24 for production and processing segments of the industry. The relative difference between estimated emissions and values reported to the BC industrial GHG reporting program are presented. Estimated emissions are almost five times **greater** than reported by production and processing companies (according to WCI.353(m) and 363(h)). Storage tank emissions reported by natural gas transmission companies are very small (16 tonnes CH_4 per year), impractical to estimate with emission factors and therefore not included in Table 24.

Table 24: Storage tank estimated methane emissions (95% confidence level) compared with 2018 values submitted to the BC Industrial GHG Reporting Program.						
Industry Segment	**Estimated Methane Emissions (t CH_4/yr)**			**2018 Reported Emissions (t CH_4/yr)**	**Relative Difference between estimated and reported methane**	
	Estimated	**Lower Limit (2.5% Interval)**	**Upper Limit (97.5% Interval)**			
Production	2596	541	9,073	460	2,136 t/yr	82%
Processing	0	0	0	77		
Total	2,596	541	9,073	537	2,059 t/yr	79%

The reported CH_4 emissions in Table 24 (BC CAS, 2019) are at the lower bound of emissions estimated from production volumes, GOR factors and control predictions (described in Section 3.3.4). Uncertainty in GOR, tank vapour composition and control values are responsible for the wide confidence intervals associated with the estimate (i.e. minus 79 percent and plus 250 percent of the mean). Reported CH_4 emissions are likely subject to similar uncertainties and the following examples of emission assessment bias deserve greater attention.

- This study applies emission controls to 41 percent of oil production sites and 66 percent of condensate production sites. Although the approach (described in Section 3.3.4) to determine which sites have emission control is reasonable, data from the 2018 BC methane field study suggest these control frequencies are overly optimistic. Of the 85 hydrocarbon tanks surveyed during the 2018 field study, 21 tanks (25 percent) appear to be equipped with emission controls[14].
- An emission control efficiency of 95 percent is applied for sites matching the 'control criteria' described in Section 3.3.4. However, well designed and maintained systems will provide greater emission control which suggests estimated emission results are overstated.
- There may be a tendency for companies to apply 100 percent control when reporting to the industrial GHG program. This is an overly optimistic assumption that understates reported emissions unless tank-top fugitive emissions are adequately monitored and reported (although subject emission would then be classified as fugitives not tank venting emissions).

  GORs determined using the Vasquez and Beggs correlation were observed to understate gas flashing from hydrocarbon liquids with API gravity less than 56.8^{o}.(Clearstone, 2020 and Gidney, 2009). Although it's not known how extensively Vasquez and Beggs correlation is applied, its use is permitted by WCI.363(h) and has a downward bias on storage tank emissions reported to the BC GHG program.
- Unintentional gas carry-through is partially accounted by WCI.353(m) and 363(h.1), however, WCI provides limited guidance on how to distinguish between flashing losses

14 Cap-Op Table 20 indicates there were 21 thief hatches with possible fugitive emissions. Because fugitive emissions only occur from controlled tanks, it is understood 21 of 85 tanks surveyed were controlled.

and gas carry-through. Thus, it is unclear how rigorously this possible emission source is monitored or how often it is mistakenly estimated as gas flashing. Regardless, unintentional gas carry-through is likely understated in reported emissions and is omitted from the estimate.

5 CONCLUSIONS

This study reviewed literature and field studies relevant to CH_4 emissions from BC UOG compressor seals and storage tanks. Emission factors, correlations and activity data sources for estimating emissions were prioritized and incorporated into data flow diagrams. Knowledge gaps were identified and possible methods for resolving these gaps proposed. A CH_4 emission inventory was developed and compared to independent assessments of corresponding equipment counts and emissions.

Specific observations and conclusions from this study include:

- The average compressor counts obtained from BC Field study (Cap-Op, 2018) provide a 'first guess' regarding the number of units installed. The quantity of fired units at a specific site is refined according to the volume of natural gas fuel reported for the site versus theoretical fuel determined from reported production hours and typical power ratings.

- Data on transmission equipment counts and corresponding emission factors are not available. This gap is bridged by adopting CH_4 emissions from inventories reported to BC Industrial GHG Reporting program.

- For hydrocarbon storage tanks, site-specific conditions (separator pressure, temperature and liquid sample) are unknown and thus, empirical correlations are applied. A light/medium oil GOR of 18 m^3 gas per m^3 oil is obtained with Valko and McCain (2003) correlation for API Gravity = 43.4^o and separator pressure and temperature of 870 kPaa and 14^o C. A condensate GOR of 21 m^3 gas per m^3 condensate is obtained with Vasquez and Beggs (1980) correlation for API Gravity = 66.4^o and separator pressure and temperature of 870 kPaa and 14^o C.

- For hydrocarbon storage tanks, emission CF is applied for sites designed for H_2S service or producing volatile liquids at unconventional natural gas sites. In addition, emissions are only calculated for sites reporting liquid invoices (i.e., indicator of site storage).

- Confidence intervals were not determined for the equipment counts and venting factors presented in the BC oil and gas methane field study (Cap-Op, 2018). To resolve this data gap, confidence intervals from the AB field study are adopted (Clearstone, 2018). This is done because of similarities between AB and BC production infrastructure as well as methods applied by the two studies for collecting field data, measuring vent gas and deriving factors. However, the estimated CH_4 emission uncertainties may not be representative of production facilities in BC.

- The use of average factors determined in this report is a statistical approach which is only valid when estimating total emissions from a large number of sources. Results for individual facilities or process units may easily be in error by several orders of magnitude or more. However, considering the IPCC Tier 1 rules for error propagation, the percentage uncertainty in the aggregate emission estimate for a category will tend to decrease by a factor of $1/N^{0.5}$ where N is the number of sources in that category. Thus, aggregate emission estimates become more representative as the number of sources and facilities increases.

Critical review of quantification, verification and reporting methods and comparison with field observations are important steps for improving the accuracy, precision and completeness of CH_4 emission inventories. Recent remote sensing field campaigns and academic publications (Brandt et al, 2016; Zavala-Araiza et al, 2018; and Lyon et al, 2016) highlight discrepancies between bottom-up and top-down methodologies. This study observed quantification bias that suggests storage tank emissions reported to the BC GHG program may be understated. The study also observed compressor rod-packing emission factors derived from the 2018 BC methane field study may understate actual emissions.

6 RECOMMENDATIONS

Key recommendations that may inform future inventories, research and field campaign planning include the following:

- Emission reporting programs and inventories should incorporate, where possible, direct measurement and mass balance methods.

- Because the BC GHG Reporting Program requires annual direct measurement and verification of reciprocating compressor rod-packings (WCI.363(m)) and centrifugal compressor seals (WCI.353(e)); this reporting program provides a more reliable estimate of compressor CH_4 emissions than can be achieved using emission factors. Compressor seal CH_4 emissions, estimated by this study using emission factors, have a narrow confidence interval (e.g., minus 3 percent and plus 6 percent of the estimated mean). Results from the BC GHG Reporting Program are 4.5 times **greater** than estimated using emission factors. This suggests emission factors, CF and confidence intervals applied by this study are not representative and understate compressor rod-packing emissions.

- Because the BC GHG Reporting Program permits a wide range of quantification methods for reporting storage tank emissions, the accuracy and completeness of reported values are uncertain. The independent assessment of storage tank CH_4 emissions (this study) features a wide confidence interval (e.g., minus 79 percent and plus 250 percent of the estimated mean) due to uncertainty in GOR, tank vapour composition and emission control parameters. Lower bound results (565 tonnes CH_4/year) are greater than submitted to the BC GHG Reporting Program (537 tonnes CH_4/year) which suggests BC UOG storage tank emissions may be understated. Similar conclusions are made by related field studies (Brandt et al, 2016; Lyon et al, 2016; and Zavala-Araiza et al, 2018). Therefore, BC GHG reporting program parameters and methods should be refined to mitigate systematic downward bias. These refinements may include:

  - BC GHG Reporting Program accuracy could be improved by refining WCI.363(h) methodology to follow BC OGC measurement guidelines and only permit use of correlations for sites producing less than 2 m^3 per day (regardless of whether production is vented or flared). This is particularly relevant to GORs determined using the Vasquez and Beggs correlation for liquids with API gravity less than 56.8^o.
  - When GOR is determined by process simulation, the integrity of pressurized liquid samples should be confirmed by comparing the calculated bubble point to the field sample pressure as described in PS Memo 17-01 (CAPCD, 2017).
  - When GOR is determined by direct measurement, flash gas sampling and laboratory analysis should be completed to determine CH_4 concentrations.
  - Unintentional gas carry-though can be detected and measured using acoustic leak detection on dump-valves according to WCI.363(h.1) methodology. However, inefficient separation, malfunctioning level controllers and piping anomalies may also cause unintentional gas carry-though. A more thorough root-cause analysis (proposed in Clearstone, 2020) will improve quantification (and mitigation) of these emissions.

- Storage tank emissions from unintentional gas carry-through are not accounted in the current CH_4 emission inventory because plausible estimation methods are not available. This knowledge gap could be resolved by a field campaign designed to identify subject tanks and complete discrete measurements of gas flashing and unintentional gas carry-through.

7 APPENDICIES

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7.2 METHODOLOGIES FOR QUANTIFYING 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 processing facilities. The schematic depicted in Figure 8 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).

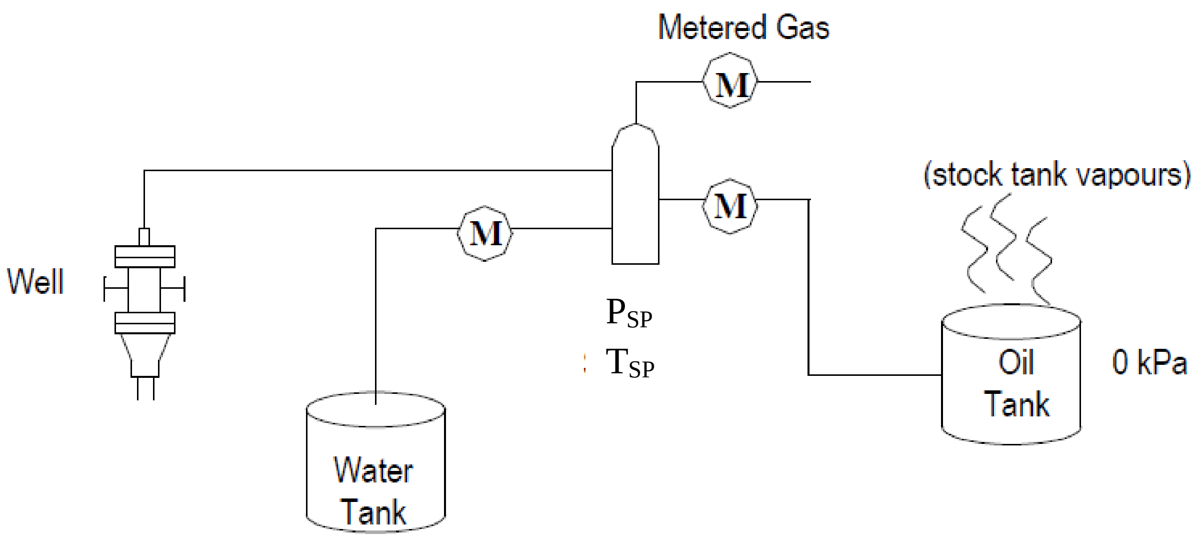

Figure 8: Oil well schematic with 3-phase separation and metering (source: AER Directive 017).

Gas-in-solution (GIS) and 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 ^{o}C 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.

Ideally flash gas factors are determined based on product specific field samples for representative operating conditions according to the following requirements stated in BC OGC Measurement Guideline (BC OGC, 2018b).

- 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.
- 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.
- 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. Further explanation of this simulation is presented in Section 7.2.1.

Some circumstances permit operators to use correlations described in Sections 7.2.2, 7.2.3 and 7.2.4. These correlations are often used to predict flashing losses for emission inventory purposes.

After the GOR or GIS factor is determined, storage tank flashing losses are calculated using Equation 4.

$$\boldsymbol{L_F = GOR \times Q_o \times Y_i \times \rho_i \times 0.001}$$

Equation 4

Where:

L_F	=	Flashing emissions of compound i (t/y)
Q_o	=	Oil production rate (m^3/y)
ρ_i	=	Density of compound i at standard conditions of 101.325 kPa and 15 ^oC
Y_i	=	Mole fraction of compound *i* in tank vapour
0.001	=	Conversion factor (tonnes/kg).
GOR	=	Gas Oil Ratio (m^3 gas/m^3 oil) of solution gas determined using the correlation. The Valko and McCain (2003) correlation is applied to oil production with API Gravity = 43.4^o and Vasquez and Beggs (1980) correlation is applied to condensate production with API Gravity = 66.4^o. The upstream vessel pressure of 870 kPaa and temperature of 14 ^oC is considered.

7.2.1 PROCESS SIMULATION

Process simulation packages can predict evaporative losses from the storage of stabilized or weathered and flashing products. A common simulation approach requires a pressurized oil sample collected at the desired separator operating conditions and analyzed by a laboratory to determine its composition[15]. A flash calculation is performed using an equation of state to determine the flash-gas factor and vapor speciation profile based on these results. The operating temperature and pressure of the separator are taken from the lab report. Two options are given for defining the flash calculation endpoint: (1) the flash endpoint is the temperature of the product in the storage tank and local barometric pressure, or (2) the flash endpoint is the Reid Vapor Pressure (RVP) of the stock tank sales oil and a temperature of 37.8°C (100°F). Option (1) provides peak instantaneous rates that occur upon delivery of liquids to the tank. Flashing peaks should occur at the same frequency as the separator delivery cycle. Knowing the peak magnitude and frequency is necessary for sizing VRUs. When tank operating conditions are used as the flash endpoint conditions, additional calculations should be performed to predict working and breathing losses in accordance with the applicable API evaporation loss correlations.

Option (2) provides the total amount of gas liberated from the product over a long period of time regardless of whether the weathering was due to flashing, working or breathing losses. Option (2) is equivalent to performing a mass balance between the flow and composition of pressurized liquid being dispensed to the stock tank and the flow and composition of the weathered sales product leaving the stock tank. The RVP of the sales oil will vary by month with the values in the winter being greater than those in the summer.

Regardless of the flash endpoint selected, pressurized sample analysis results should be checked to confirm sample integrity. This check demonstrates pressurized liquid hydrocarbon samples are collected correctly in the field and not compromised prior to testing. Colorado APCD specifies sampling pressure must be within Table 25 percent difference of the calculated bubble point pressure at field sample temperature (CAPCD, 2017). Simulators can calculate bubble point pressure using the Peng-Robinson equation of state and analyte fractions.

Table 25: Acceptable percent difference between bubble point and sampling pressure (at sample temperature) specified in Colorado PS Memo 17-01 (CAPCD, 2017).

Maximum Percent Difference	Field Sample Pressure Range (kPag)
± 5%	>= 3,447
± 7%	1,724 to 3,446
± 10%	689 to 1,723

[15] The pressurized liquid analysis should include at least C_1 through C_9 and C_{10+}, HAPs, He, H_2, N_2, and CO_2. H_2S concentrations and total sulphur content should be determined separately for each phase or sample. If O_2 is present in the analysis results, then this indicates some air ingress during the sampling and analysis activities, and the results should then be expressed on an air-free basis.

± 15%	345 to 688
± 20%	138 to 344
± 30%	< 138

7.2.2 BC OGC AND AER CORRELATION

A standard estimate may be used as the flash gas factor for conventional light-medium oil production until a more accurate, specific flash gas factor is determined (AER, 2018b). It may be used on a continuous basis, without the need for determining a more accurate flash gas factor, if well oil production rates do not exceed 2 m^3/d or if all battery gas production is vented or flared. The approved correlation presented in Equation 5.

$$V_s = 0.0257 \times V_O \times \Delta P$$

Equation 5

Where,

V_S = volume of solution gas released (m^3)

V_O = oil production volume (m^3)

ΔP = pressure drop between upstream vessel and storage tank (kPa)

0.0257 = 'rule-of-thumb' factor (m^3 of gas/m^3 of oil/kPa of pressure drop at unspecified reference conditions)

7.2.3 VAZQUEZ AND BEGGS CORRELATION

This correlation is based on a regression of experimentally determined bubble point pressures for a variety of crude oil systems. The range of parameters for which the correlation is derived is presented in Table 27 (Vazquez and Beggs, 1980).

$$GOR = C_1 \gamma_{gs} P_{SP}^{C_2} \exp\left(\frac{C_3}{\gamma_o T_{SP}} - \frac{C_4}{T_{SP}}\right)$$

Equation 6

Where,

GOR = gas-to-oil ratio (m^3/m^3) at standard conditions 101.325 kPa and 15.6 ^oC

γ_{gs} = γ_g corrected to correlated separator pressure of 100 psig

$$= \gamma_g \left[1 + \left(\frac{8.365}{\gamma_o} - 7.774\right)\frac{(1.8 \times T - 459.7)}{1000}\log_{10}\left(\frac{P}{790.83}\right)\right]$$

γ_g = Specific gravity of the solution gas with respect to air (dimensionless)

$= \frac{Molecular\ Weight\ of\ Solution\ Gas}{Molecular\ Weight\ of\ Air}$

P_{SP} = absolute pressure in the upstream vessel of interest (kPaa)

T_{SP} = temperature in the upstream vessel of interest (K)

γ_o = specific gravity of oil with respect to water (dimensionless)

$= \frac{141.5}{131.5+°API}$

C_1, C_2, C_3, C_4 = correlation parameters presented in Table 26

Table 26: Values of the Vasquez Beggs correlation parameters.		
Parameter	**$\Upsilon_o < 0.876$**	**$\Upsilon_o > 0.876$**
C_1	3.204×10^{-4}	7.803×10^{-4}
C_2	1.1870	1.0937
C_3	1881.24	2022.19
C_4	1748.29	1879.28

Table 27: Range of reservoir data used to develop Vasquez & Beggs flashing correlation.	
Parameter	**Value**
Size of dataset	5008
Bubble pressure, kPa	345 to 36,190
Reservoir temperature, °C	21 to 146
Solution gas-to-oil ratio at bubble point pressure, sm^3/sm^3	3.5 to 369
Oil specific gravity, °API	16 to 58
Vapour specific gravity	0.56 to 1.8

7.2.4 VALKO AND MCCAIN CORRELATION

The Valko and McCain (2003) correlation is perhaps the most widely used correlation for predicting flash-gas factors for pressurized crude oil dispensed to a production storage tank (or stock tank). For example, it was approved for modelling and design of vapour control systems under EPA consent decree orders (SLR, 2018). The range of separator conditions for which the correlation is derived is presented in Table 29. It may also be used with data outside the range of values for which they were derived but with reduced accuracy.

The correlation requires information on the operating conditions (i.e., temperature and pressure) of the first upstream pressure vessel (referred to here as a separator) from which the oil is dispensed and the API gravity of the weathered sales product from the stock tanks. Valko and McCain recognized field sampling and laboratory analysis of stock tank vapours is seldom completed. Thus, a key benefit of their correlation is it relies on parameters typically measured in the field (e.g., stock tank liquid density and upstream pressure/temperature) and does not require a pressurized liquid sample analysis. However, this is at the loss of some accuracy and the ability to predict the composition of the flash gases. Default flash-gas compositions are typically applied in these circumstances (e.g., to estimate CH_4, VOC and selected air toxic emissions such as benzene, toluene, ethyl benzene and xylenes [BTEX]).

GOR for the product entering the stock tank is determined using the following relations:

$$GOR = exp(ln\, GOR)$$

Equation 7

Where,

$$\ln GOR = 3.955 + 0.83z - 0.024z^2 + 0.075z^3$$

Equation 8

Where,

$$z = \sum_{n=1}^{3} z_n$$

Equation 9

Where,

$$z_n = C_{0,n} + C_{1,n}VAR_n + C_{2,n}VAR_n^2$$

Equation 10

And,

GOR = gas-to-oil ratio (scf of flash gas/bbl of stock tank oil) at standard conditions 101.325 kPa and 15.6 °C

z, z_n = calculation parameters (dimensionless)

C, *VAR* = correlation parameters (see Table 28).

Table 28: List of values for parameters C and VAR for Equation 47.				
n	**VAR**	**C0**	**C1**	**C2**
1	$\ln P_{SP}$	-8.005	2.7	-0.161
2	$\ln T_{SP}$	1.224	-0.5	0
3	API	-1.587	0.0441	-2.29×10^{-5}

P_{SP} = separator pressure (psia).

T_{SP} = separator temperature (°F).

API = API gravity of the stock tank oil (°API).

Table 29: Range of separator/stock tank data used to develop Valko & McCain flashing correlation.	
Parameter	**Value**
Size of dataset	881
Separator pressure, kPag	82.7 to 6550.0
Separator temperature, °C	1.7 to 90.0
Stock Tank Oil specific gravity, °API	6.0 to 56.8
Stock tank gas-to-oil ratio, sm^3/sm^3	0.36 to 93.9
Stock tank vapour specific gravity	0.581 to 1.598

7.3 EMISSION FACTOR QUANTIFICATION METHOD

The emission factor method is commonly used for inventory assessments. The emission factor relates to the quantity of a pollutant released with an activity associated with it. This is a statistical approach in which the average emission from a group of sources is related to an appropriate activity value using a simple relation of the form presented by Equation 11.

$$\boldsymbol{ER_{i,j} = EF_i \cdot A_i \cdot X_{i,j} \cdot (1 - CF_i) \cdot OF_i \cdot g_c}$$

Equation 11

Where,

$ER_{i,j}$ = emission rate of substance j from source i (t/y).
EF_i = emission factor for source i (kg/unit of activity).
A_i = activity value for source i (unit activity per unit of time).
$X_{i,j}$ = mass fraction of substance j in the emissions from source i (kg/kg).
CF_i = control factor for a specific control measure or device applied to source i.
OF_i = operating factor which indicates the fraction of the time the source is active (d/d).
g_c = a constant of proportionality used to convert the results to units of t/y.

The use of emission factors is often an over simplification which may be subject to very high uncertainties (e.g., orders of magnitude) when applied to a single source, but becomes a statistically valid approach when considering aggregate emissions from large numbers of sources. Such emission factors are typically based on manufacturer specifications or obtained from government reports.