TECHNICAL REPORT

April 22, 2019

2018 Alberta Upstream Oil & Gas Methane Emissions Inventory and Methodology

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EXECUTIVE SUMMARY

This report presents a detailed inventory of 2018 methane emissions from the upstream oil and natural gas (UOG) sector in Alberta, and delineates the boundaries, methodologies and data sources used. The type and quality of emissions, activity and infrastructure data available for use in this emissions inventory has improved and enables a progressively more refined assessment compared to previous inventories for the UOG sector (ECCC, 2014). The updated inventory is intended for use by the Alberta Energy Regulator (AER) and its evaluation of methane emissions from the UOG sector. As such, inventory refinements and boundaries considered in this report focus on subsectors and activities contributing the most to UOG methane emissions. This effort may also inform Canada's National Inventory Report submission to the UNFCCC Secretariat. Moreover, software tools developed by this project may be leveraged to establish a methane baseline (for 2012 and/or 2014 inventory years) and demonstrate achievement of provincially and federally stated methane reduction targets.

This report is an extension of previous GHG inventories for the period of 1990 through 2011, which were published by the Canadian Association of Petroleum Producers (CAPP, 2005) and Environment and Climate Change Canada (ECCC, 2014). The key features of this inventory include the following:

- Application of a rigorous bottom-up (IPCC Tier 3) approach in which emissions have been identified at the individual facility and well level by type of primary source (e.g. fuel combustion, flaring, venting fugitive equipment leaks and accidental releases).
- Compliance with IPCC (2006) methodology and good practice guidance for assessing GHG emissions.
- Quantitative assessment of the uncertainties in all presented emission estimates using an IPCC Tier 1 methodology.

Key refinement from the previous inventory model include:

- Semi-automated parsing of key AER input data streams that enable **monthly** calculation of the provincial inventory.
- Refined equipment, component and pneumatic counts and updated leak factors based on 2017 field observations (Clearstone, 2018).
- Delineation of batteries into individual upstream well sites that enables more comprehensive accounting emission sources.
- Delineation of emission subcategories that provides granularity relevant to AER Directive 060 methane mitigation requirements. Fugitive and venting subcategories now include:
    - Compressor Seals
    - Compressor Starts
    - Fugitive Equipment Leaks (contribution from detected leaks).
    - Fugitive Equipment Leaks (no-leak contribution)
    - Fugitives due to Ruptures
    - Fugitives due to Spills
    - Fugitives due to Well Gas Migration

- Fugitives due to Well Surface Casing Vents
- Glycol Dehydrator Off-Gas
- Pneumatic Instruments
- Pneumatic Pumps
- Storage Tanks (Breathing Losses)
- Storage Tanks (Flashing Losses)
- Storage Tanks (Working Losses)
- Truck Loading of High Vapour Pressure Products (NGLs)
- Truck Loading of Low Vapour Pressure Products (Crude Oils)

Scope

Alberta UOG sector assets and operations are extensive. The inventory of 2018 emissions includes approximately 120,000 gas wellheads and 58,000 oil wellheads. There are 9,200 batteries producing gas into more than 3,500 gathering systems delivering to almost 550 gas plants. Oil is produced from more than 11,500 batteries that delivered to tank terminals. UOG facilities are inter-connected by tens of thousands of kilometers of pipeline which flow hydrocarbons from wells to batteries, plants and ultimately markets. The resulting 2018 inventory database contains more than 800,000 point sources.

Industry Segments:

The organization boundary identifies the facilities included and explicitly excluded from the inventory. Notionally, the Alberta UOG industry includes all surface facilities from the well through to the end consumer for the natural gas system (Figure ES1) and to the refinery gate for the crude oil system (Figure ES2). However, given the tremendous scope of the UOG industry and timeline expectations, software development has prioritized industry segments and emission categories contributing the most to overall UOG methane emission uncertainty. Thus inventory boundaries considered in this report include the following segments which are prioritized according their methane emission contribution:

1. natural gas production
2. light and medium oil production
3. cold heavy oil production
4. accidents and equipment failures
5. natural gas processing
6. thermal heavy oil production
7. disposal and waste treatment

The following industry segments are excluded from the emission inventory because they are minor methane contributes or are accounted in other rigorous reporting programs. Facilities emitting greater than 100 kt CO_2E per year are subject to the Carbon Competitiveness Incentive Regulation (CCIR formerly the Specified Gas Emitters Regulation) and report annually to Alberta Environment and Parks (AEP). Because CCIR emission report quality is assured by third party verification, there is limited value investing software development effort in these facilities. Instead, annual CCIR emission results should supersede preliminary NirCalc estimates[1]. Moreover, emissions from the natural gas transmission, storage and distribution sector are compiled annually and available from the Canadian Energy Partnership for Environmental Innovation (CEPEI) based on detailed inventories prepared by individual natural gas companies in this sector.

1. well drilling, testing and servicing
2. oil sands mining, extraction and upgrading
3. natural gas transmission, storage and distribution
4. petroleum liquids transportation

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

5. Refineries,
6. Petrochemical plants,
7. Liquid fuel distribution and sales,
8. LNG plants,
9. Offshore facilities, and
10. Facility construction, decommission and reclamation activities.
11. Electric power generation.[2]

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[1] NirCalc determines air emissions for all facilities and wells that report volumetric data to Petrinex (including those excluded from the inventory). However, emissions from excluded sectors are not validated.

[2] Natural gas fuel combusted at UOG facilities for the purpose of generating electricity for delivery to the power pool or for cogeneration at an in situ oil sands injection facilities is excluded. Subject emission contributions belong to the electric power sector and accounted under separate inventories. Fuel combusted for power generated and consumed at subject UOG facilities is included in the UOG inventory boundary.

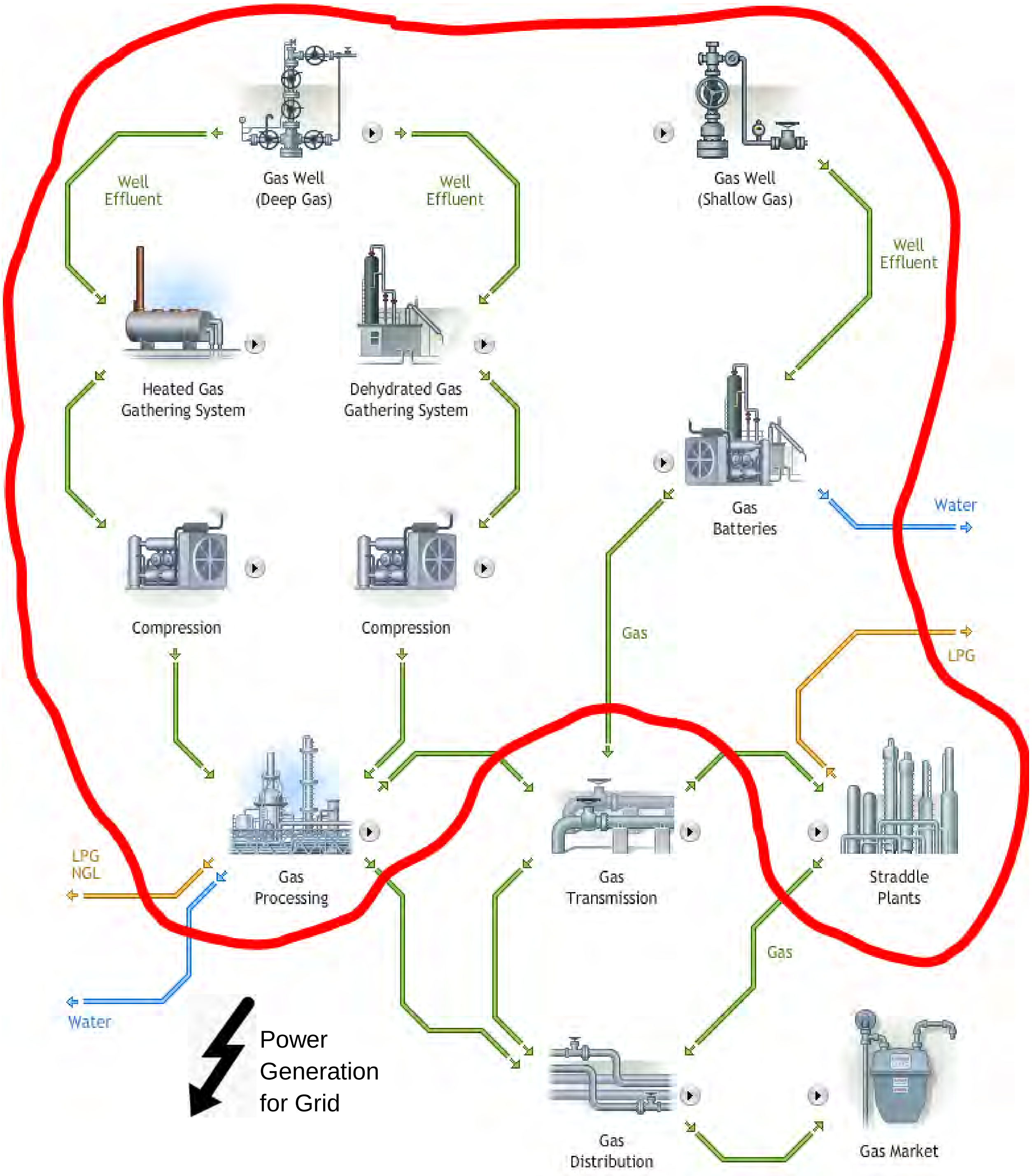

Figure ES1: Upstream Natural Gas System and Inventory Boundary

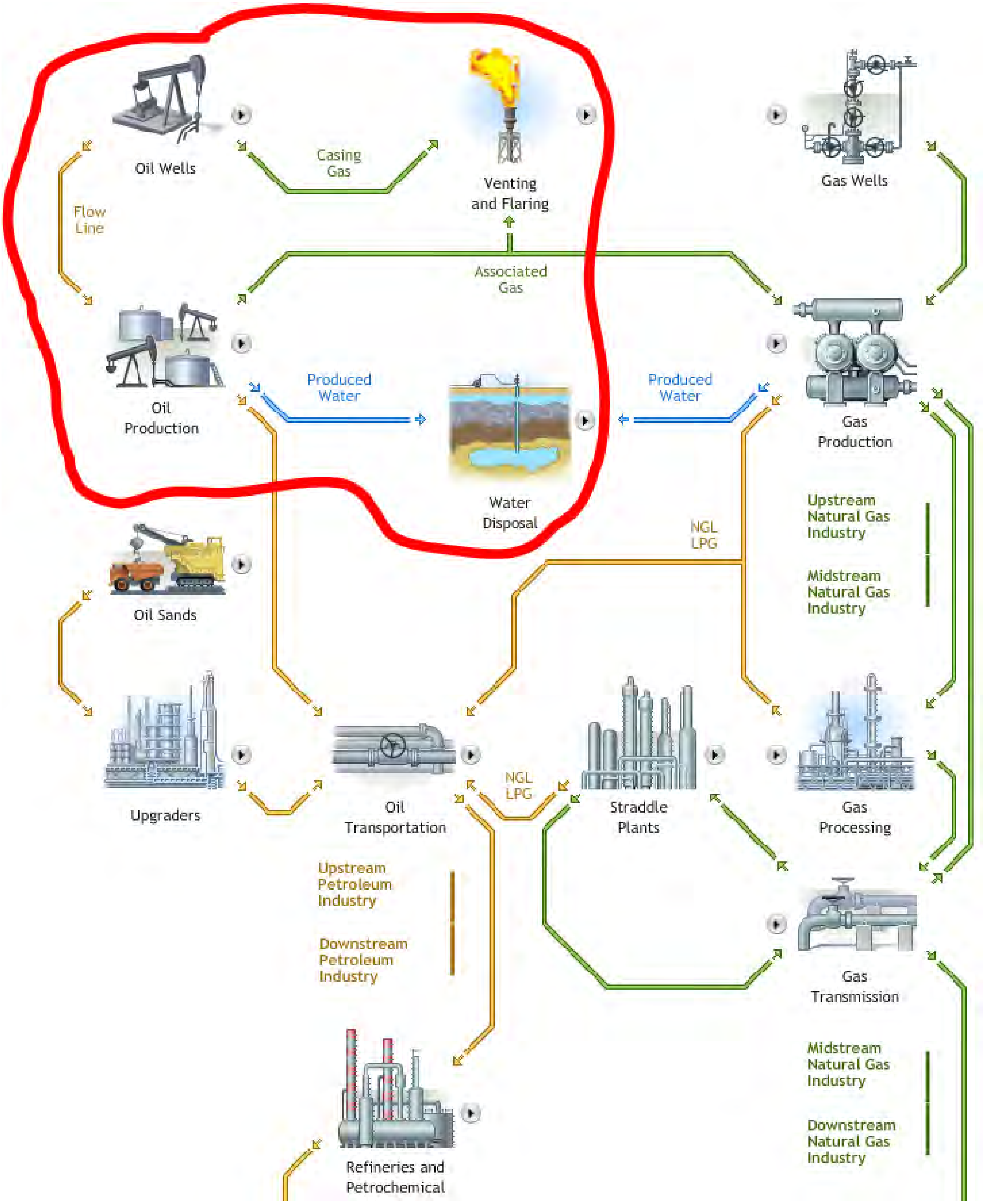

Figure ES2: Upstream Crude Oil System and Inventory Boundary

Substances:

Emissions of methane (CH_4) are reported in this inventory.

Carbon dioxide (CO_2), nitrous oxide (N_2O), Criteria Air Contaminants (CAC) and other priority substances are also quantified, however, development effort focused on CH_4 sources and validation of other substances was not sufficient for publication.

Activities:

Emissions from all facets of the target segments of the oil and natural gas industry are included in this report except for construction operation, ancillary structures and operations (buildings, offices, etc.) and mobile (licensed for road) sources.

Timeframe:

This report provides the results of a detailed 'bottom-up' inventory of emissions from the UOG sector for 2018.

Emission Sources:

The primary types of emission sources included in this report are:

- fuel combustion,
- flaring,
- formation CO_2 releases,
- reported venting (vented volumes stated by production accounting),
- unreported venting (sum of all miscellaneous venting not normally reported by production accounting),
- fugitive equipment leaks,
- product storage and handling losses, and
- accidental releases.

Methodology

The aim has been to develop a complete and accurate assessment of the target emissions in a practicable and defensible manner that takes advantage of currently available information, provides sensible methods for bridging data gaps and quantifies uncertainties. Preplanning of the inventory, involvement of government and industry experts throughout the emissions inventory development and documentation of the applied methodology have provided a practical mechanism for ensuring transparency to stakeholders and interest groups, while promoting a constructive review process to help ensure a high-quality cost-effective product.

The emissions inventory was developed using an IPCC Tier 3 bottom-up assessment methodology beginning at the individual facility, well and process unit level and aggregating the results to ultimately provide emission estimates by facility and geographic area. Emission contributions due to both fuel-use and non-fuel-use sources (i.e., fugitive sources) have been evaluated. Input data was compiled and converted to a consistent format for processing using a sophisticated relational database application. A qualitative discussion of the uncertainties and specific assumptions used in the inventory, as well as a detailed description of the applied methodologies are provided.

Information Sources, Data Management and Processing

The emissions inventory has drawn on the most detailed information available from the AER, industry and other published and unpublished sources. A relational database application (NirCALC) was developed using Microsoft SQL to process and manage the emissions inventory information.

The relationship between internal NirCALC components and external data sources is illustrated in Figure ES3. Data collected from a number of sources is maintained in the NirCALC database and operated upon by a suite of related import, calculation, and reporting applications. NirCALC employs a bottom-up inventory approach where emission sources (described in Sections 3 to 10 below) are defined for equipment operating at individual facilities and wells. When available, equipment details (e.g., manufacturer, model, capacity, operating hours, etc) are provided by responsible companies via proposed AER D060 methane reports or the ECCC Multi-Sector Air Pollutant Regulation (MSAPR). However, these data sources are not yet deployed and company equipment inventories are typically not available in a consistent format and require maintenance as operations evolve. Therefore, NirCALC predicts ‘synthetic equipment’ based on facility specific production volumes (from Petrinex) and facility subtype averages derived from field observations (Clearstone, 2018).

For large emitters and companies complying with 2020 AER D060 requirements, inventory estimates can be compared with CCIR or AER methane reports and superseded if decision criteria are satisfied (however, this functionality has not yet been implemented).

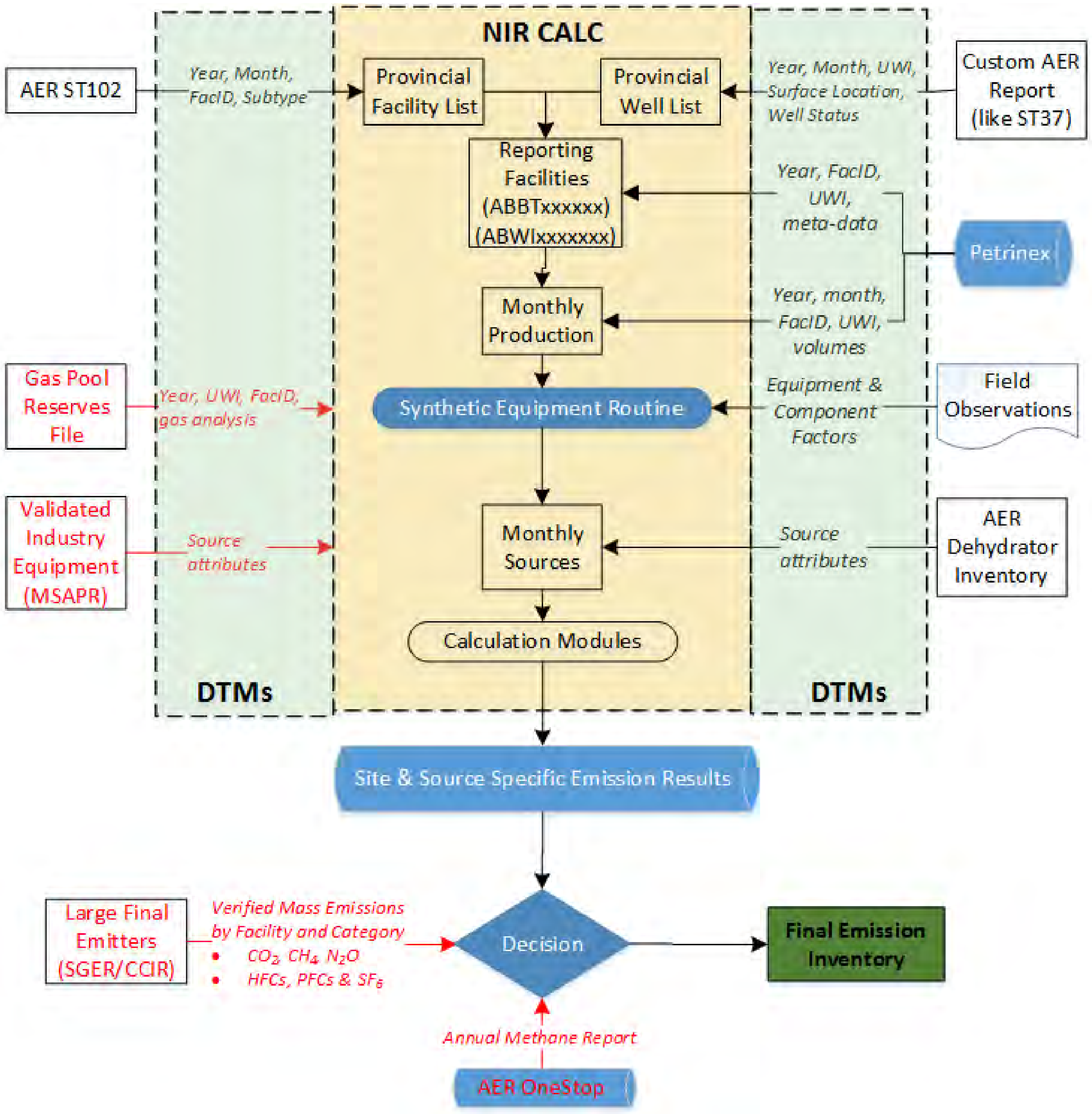

Figure ES3: NirCalc database outline and Alberta data sources.[3]

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[3] Data sources in red font have not yet been implemented.

Methane Results

2018 methane emissions for the UOG inventory boundary conditions described above are estimated at 715,170 tonnes. 2018 results are delineated by emission category and compared to 2011 results (960,299 tonnes from ECCC, 2014) in Figure ES4. The distribution of 2018 methane is presented in Figure ES5 according to emission subcategories. 2018 methane emissions decreased for all categories (except flaring) and are approximately 25 percent less than reported in the 2011 inventory.

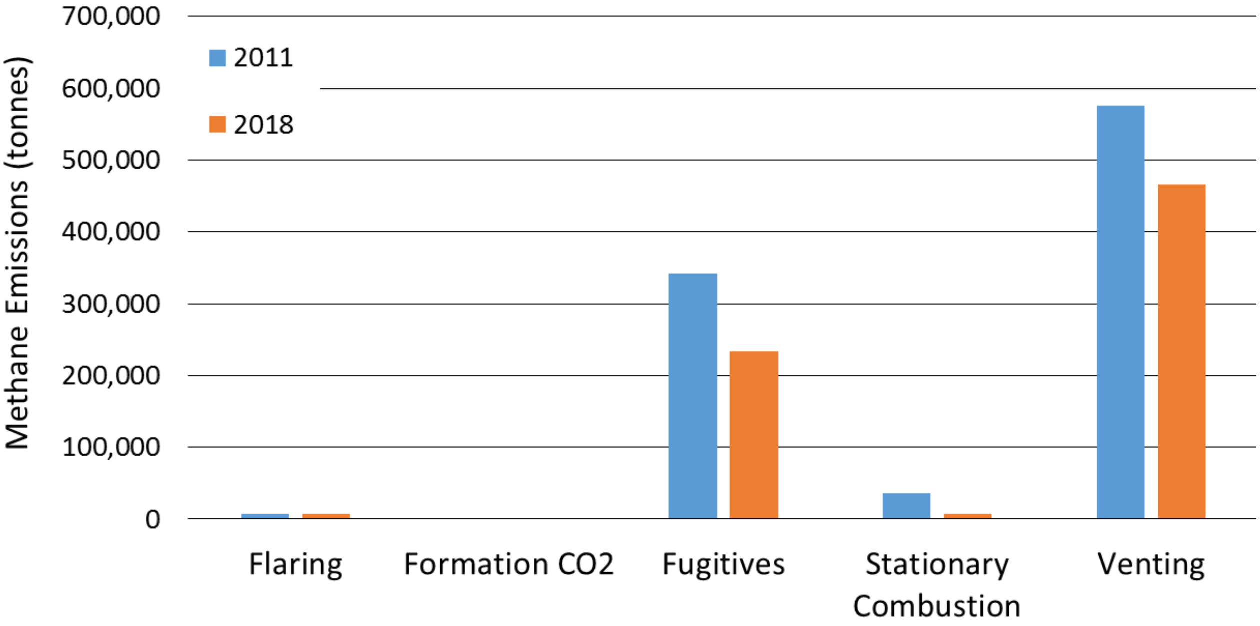

Figure ES4: Alberta Upstream oil & gas methane emissions by primary category for 2011 and 2018[4].

The 2018 methane emission estimate lower and upper bounds are -0.4 and +1.0 percent of the total and are determined according to tier 1 IPCC (2000) good practice with 95 percent confidence level (i.e., the interval that has a 95% probability of containing the unknown true value). This narrow confidence interval is due to the very large number of discrete emission source records (greater than 800,000) and tendency for uncertainty in the aggregate emission estimate to decrease by a factor of $1/N^{0.5}$ (where N is the number of sources). A narrow confidence interval is reasonable if the measurements and emission factors, relied on for the inventory, are truly representative of Alberta UOG methane releases. However, disconnects between reported and true releases imply wider confidence levels, but are challenging to quantitatively represent. Thus, IPCC tier 2 Monte Carlo uncertainty methods that develop repeated, random outcomes may produce more representative confidence intervals and will be considered for future inventories

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[4] Well drilling & completion; natural gas transmission, storage & distribution; and oil sands mining contributions are not included.

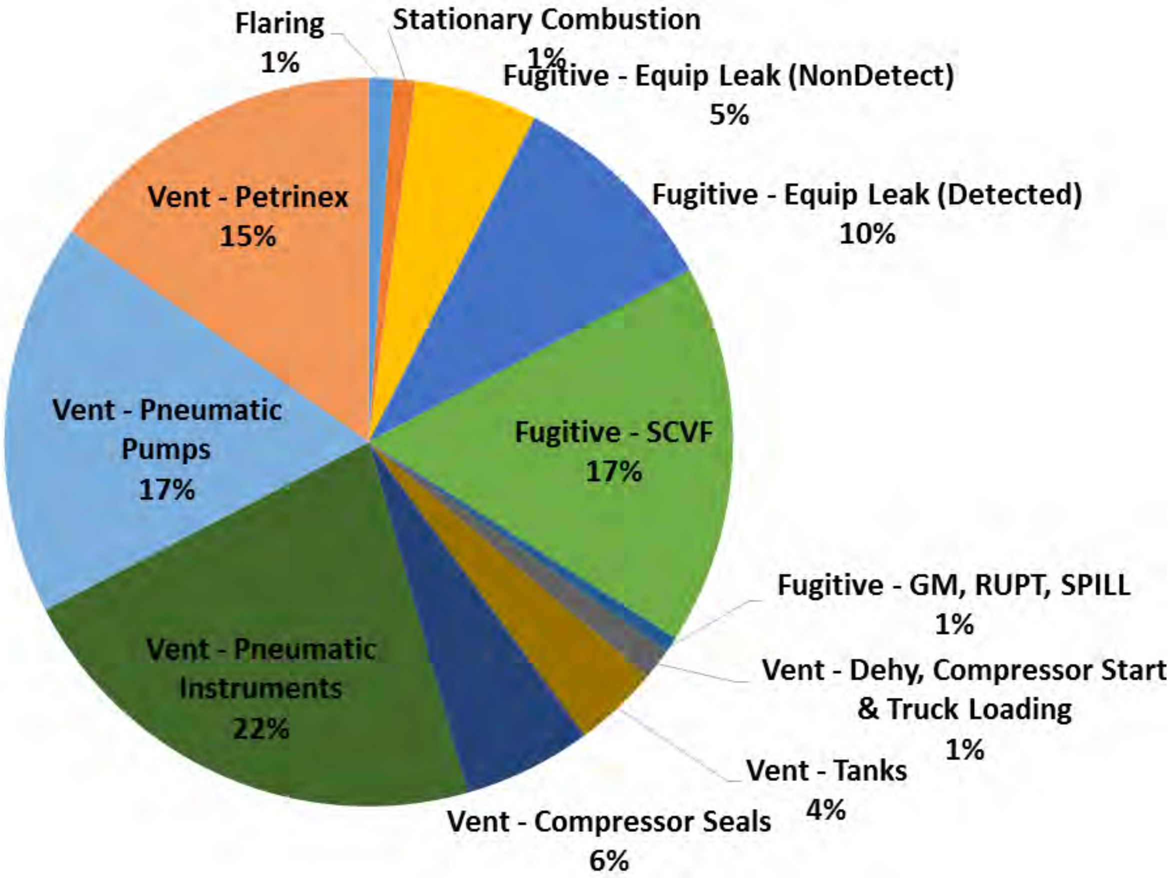

Figure ES5: Distribution of 2018 Alberta Upstream oil & gas methane emissions by subcategory[5].

The reduction in methane emissions are driven by the following industry changes and methodology refinements. Possible improvements to inventory accuracy are also discussed.

Fugitive – Equipment Leaks

Fugitive methane emissions from equipment leaks decreased from 145,000 tonnes (2011) to 108,000 (2018) for a difference 37,000 tonnes (~25 percent). A comparison of leak factors used in the 2011 (CAPP, 2014) versus 2018 (Clearstone, 2018) emission inventories observed very little difference in total fugitive equipment leaks when factors are applied to the same component population (see Section 4.4.3 of Clearstone, 2018). Instead, the primary driver for the decrease is a general reduction in the number of operating oil and gas sites in Alberta. The 2015 decline in commodity prices forced marginally economic wells and facilities to suspend operation and persistently low prices have not justified returning these sites to production. Thus, the number of sites, and equipment components at risk of leaking, has decreased by 20 to 30 percent since 2011 as summarized in Table ES1.

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[5] Well drilling & completion; natural gas transmission, storage & distribution; and oil sands mining contributions are not included.

Table ES1: Number of Alberta oil and gas sites operating in 2011 versus 2018.			
Site Grouping	**Site Counts**		**Difference**
	2011	**2018**	
Gas Well	147,995	116,412	-21%
Gas Battery	12,682	9,249	-27%
Gas Gathering or Compressor Station	3,677	3,582	-3%
Gas Plant	639	507	-21%
Oil/Bitumen Well	76,075	53,900	-29%
Oil/Bitumen Battery	15,001	10,599	-29%

Moreover, the 2018 inventory calculates fugitive emissions according to operating hours reported to Petrinex for wells and batteries[6] during the subject calculation month. This data granularity was not available for the 2011 inventory and enables a more precise assessment of sites that started-up or shut-in during 2018. In 2011, equipment leaks were calculated for the entire year regardless of whether the sites started or stopped production part way through the inventory year[7].

The 2018 methane fugitive equipment leaks in Figure ES4 are less than recent regulatory impact analysis inventories (e.g., ECCC, 2017) because factors derived from 2017 field data (Clearstone, 2018) are much less than used in ECCC, 2017. There is a tendency to apply pre-2007 leak factors (CAPP, 2004c) to an estimated sub-set of facilities that have not implemented fugitive emission management plans (FEMP) and post-2007 leak factors to facilities with FEMP. The 2017 field campaign was designed to include randomly selected facilities/wells so featured a mix of sites with and without FEMP (operated by 63 different companies). Thus, 2017 leak factors can be applied universally and suggest application of pre-2007 leak factors introduces a large upward bias on fugitive emissions.

Finally, 2018 results are presented for equipment leaks occurring above (detected) and below (non-detect) the IR Camera method detection limit. This provides some perspective on the magnitude of equipment leaks that can be mitigated by implementing aggressive FEMPs.

Surface Casing Vent Flow (SCVF)

Methodology refinements decreased well SCVF methane emissions by 72,000 tonnes. Historic inventories for reporting years 2000, 2005 and 2011 used an average SCVF factor of 1,731 m^3 per capable well per year (developed from AER SCVF records available for 2000). For 2018, SCVF is determined directly from flow rates reported by operators to the AER according to the requirements of ID 2003-1. For instances of wells with documented SCVF but no repair record or

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[6] Battery operating hours are estimated as the maximum from wells upstream of subject batteries. This level of detail is not available for compressor stations, gathering systems, gas plants and other facilities so operating hours are estimated as the maximum total for the subject month.

[7] This methodology refinement also introduces a small downward bias for wells/batteries that are not depressurized during downtime periods.

reported flow rates; the SCVF leaker emission factor (3.74 m^3 THC per hour per well from Clearstone, 2018) is applied to estimate emissions. Considering that SCVF is responsible for 17 percent of 2018 methane emissions (and 20 percent of 2011 methane), validation of AER SCVF records should be prioritized to improve accuracy. This may be accomplished by leveraging fugitive survey measurements (AER 060 Section 8.10.2.3(d)) to update SCVF flow rates reported to the AER Digital Data Submission (DDS) service. Moreover, mitigating actions for wells with non-serious SCVF or that belong to insolvent licensees (i.e., orphaned wells) should be eligible for offset credits because these actions are in addition to regulatory requirements.

Pneumatic Instrument and Pump Venting

Pneumatic methane emissions decreased approximately 4,000 tonnes (~1 percent) relative to 2011 despite the decrease in site counts (Table ES1). This indicates that 2017 field observations (Clearstone, 2018) result in greater pneumatic device inventories than predicted for the 2011 emission inventory.

The accuracy of pneumatic pump emissions would benefit from better knowledge of seasonal variation in pump usage[8]. Operating data collected for GHG offset projects could be used to improve pump run-time estimates.

Reported Venting

The volume of gas venting reported by operators to Petrinex has decreased 53 percent (123,000 tonnes methane) relative to 2011. The majority (110,000 tonnes methane) is due to less production casing venting reported by cold heavy oil production with sand (CHOPS) wells and likely driven by declining reservoirs, suspension of marginal wells and increased regulatory monitoring (to ensure compliance with AER Directive 060). However, it’s also acknowledged that 2016 airborne measurements of a 60 × 60 km region near Lloydminster, Alberta observed methane emissions four times greater than estimated using bottom-up inventory methods (Johnson et al, 2017). Johnson et al speculate unexplained emissions in the Lloydminster region are most likely attributable to underreported venting of casing gas from CHOPS sites. Such observations have motivated efforts (e.g. CHOPS Methane Challenge) to improve measurement accuracy, reporting and mitigation of CHOPS production casing venting (Alberta Innovates, 2018).

Reported venting from other sources (e.g., equipment depressurization events and storage tanks) has decreased by approximately 12,000 tonnes of methane and is likely due to improved production accounting fidelity and fewer instances of misreported venting (e.g., flaring activity reported as VENT instead of FLARE). However, storage tank gas carry-through (e.g., leakage past separator/scrubber drain valves, inefficient gas-liquid separation in upstream vessels, malfunctioning level controllers or leakage past the seat of level control valves, or unintentional

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[8] The 2018 inventory estimated pneumatic pumps at gas sites are only used for methanol injection during cold months (November through March) while pumps at oil sites are used all year for de-waxing and corrosion inhibitor.

storage of high vapour pressure liquids) may be underappreciated and therefore under reported.

A number of applied research projects focused on methane detection and quantification are underway in Alberta. These include Petroleum Technology Alliance of Canada (PTAC) sponsored studies: (1) FEMP effectiveness assessment and (2) investigation of storage tank venting and fugitive emissions that are scheduled for completion in the fall of 2019. Such field studies should provide further insight into temporally transient methane sources and help reconcile bottom-up inventories with top-down measurements. Future refinements to UOG inventory methodologies will consider these and other evidenced based studies.

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LIST OF ACRYNOMS

AAAQO	-	Ambient Air Quality Objectives and Guidelines
API	-	American Petroleum Institute
BC MOE	-	British Columbia Ministry of Environment
BC OGC	-	British Columbia Oil and Gas Commission
BC RR	-	British Columbia Reporting Regulation under the GGRTA
BOE	-	Barrels of oil equivalent
CCIR	-	Carbon Competitiveness Incentive Regulation
CEPEI	-	Canadian Energy Partnership for Environmental Innovation
CSA	-	Canadian Standards Association
CDM	-	Clean Development Mechanism
DI&M	-	Directed Inspection and Maintenance
E	-	Equivalent
GHG	-	Greenhouse Gas
GOR	-	Gas to Oil Ratio
IPCC	-	Intergovernmental Panel on Climate Change
ISO	-	International Organization for Standardization
LPG	-	Liquefied Petroleum Gas
NAICS	-	North American Industry Classification System
NPRI	-	National Pollution Release Inventory
OE	-	Oil Equivalent
PFD	-	Process Flow Diagram
P&ID	-	Piping & Instrumentation Diagram
PTAC	-	Petroleum Technology Alliance of Canada
QA	-	Quality Assurance
QC	-	Quality Control
SCFV	-	Surface Casing Vent Flows
UNFCCC	-	United Nations Framework Convention on Climate Change
UOG	-	Upstream Oil and Gas
VRU	-	Vapour recovery Unit

CONVERSIONS

USEFUL CONVERSION FACTORS		
Physical Quantity	**SI to English Conversion**	**English to SI Conversion**
Length	1 m =3.2808 ft 1 km = 0.6213712 mi	1 ft = 0.3048 m 1 mi = 1.609344 km
Area	1 m^2 = 10.7639 ft^2	1 ft^2 = 0.092903 m^2
Volume	1 m^3 = 35.3134 ft^3 1 L = 0.2641720 U.S. gal	1 ft^3 = 0.02837 m^3 1 U.S. gal = 3.785412 L
Velocity	1 m/s = 3.2808 ft/s 1 km/h = 0.6213712 mph	1 ft/s = 0.3048 m/s **1 MPH = 1.609344 KM/H**
Density	1 kg/m^3 = 0.06243 lbm/ft^3	1 lbm/ft^3 = 16.018 kg/m^3
Force	1 N = 0.2248 lb_f	1 lb_f = 4.4482 N
Mass	1 kg = 2.20462 lb_m	1 lb_m = 0.45359737 kg
Pressure	1 kPa = 0.145038 psi 1 kPa = 4.01474" WC	1 psi = 6.89476 kPa 1" WC = 0.249082 kPa
Energy	1 kJ = 0.94783 Btu	1 Btu = 1.05504 kJ
Power	1 W = 3.4121 Btu/h 1 kW = 1.3405 hp	1 Btu/h = 0.29307 W 1 hp = 0.746 kW
Heat Flux/Unit Area	1 W/m^2 = 0.317 Btu/h·ft^2	1 Btu/h·ft^2 = 3.154 W/m^2
Heat Flux/Unit Length	1 W/m = 1.0403 Btu/h·ft	1 Btu/h·ft = 0.9613 W/m
Heat Generation/Unit Volume	1 W/m^3 = 0.096623 Btu/h·ft^3	1 Btu/h·ft^3 = 10.35 W/m^3
Energy/Unit Mass	1 kJ/kg = 0.4299 Btu/lb_m	1 Btu/lb_m = 2.326 kJ/kg
Specific Heat	1 kJ/kgºC = 0.23884 Btu/lb_mºF	1 Btu/lb_m·ºF = 4.1869 kJ/kg·ºC
Thermal Conductivity	1 W/mºC = 0.5778 Btu/h·ftºF	1 Btu/h·ft·ºF = 1.7307 W/m·ºC
Convective Heat Transfer Coefficient	1 W/m^2C = 0.1761 Btu/h·ft^{2}·ºF	1 Btu/h·ft^{2}·ºF = 5.6782 W/m^2·ºC

ACKNOWLEDGEMENTS

The development of this report has been sponsored by Natural Resources Canada. The support and direction provided by each of the participating industry representatives and government agencies involved is gratefully acknowledged.

1 INTRODUCTION

The following subsections describe the general calculation approach used to estimate atmospheric emissions of methane and other substances from the Alberta upstream oil and natural gas industry (UOG).

General information concerning planning and designing of an emissions inventory and important emission-related determinations common to many of the target sources are presented in Section 2 along with the reference emission-source classification scheme. Sections 3 to 10 provide supplemental source-specific information. The source types considered include: natural gas-fuelled compressor engines (i.e., both turbines and reciprocating engines), process heaters and boilers, thermal oxidizers, industrial space heaters and torches, thermoelectric generators; flaring; fugitive equipment leaks; venting and accidental releases. Section 11 provides an overview of the UOG industry by sub-sector and activities. The list of the references cited is presented in Section 12 while a glossary of key terms and definitions are presented in Sections 13 and 14.

2 GENERAL INFORMATION

2.1 ORGANIZATIONAL AND REPORTING BOUNDARIES

The following organization and operational boundaries are based on a decision framework was prepared for the AER (Clearstone, 2017). ISO 14064-1 recommends reliance on financial or product accounting systems already in place when defining an organizational boundary. UOG operators in Alberta are subject to AER rules and directives governing the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources. This includes the accurate and transparent measurement and reporting of hydrocarbon flows to support royalty, commodity and equity transactions which have evolved into a production accounting system known as Petrinex. Thus, Petrinex will be relied upon to define wells, facilities and hydrocarbon flows included in the emission inventory.

2.1.1 ORGANIZATION BOUNDARY

The organization boundary identifies the facilities included and explicitly excluded from the inventory. Notionally, the Alberta UOG industry includes all surface facilities from the well through to the end consumer for the natural gas system (Figure 1) and to the refinery gate for the crude oil system (Figure 2). However, given the tremendous scope of the UOG industry and timeline expectations, software development has prioritized industry segments and emission categories contributing the most to overall UOG methane emission uncertainty. Thus inventory boundaries considered in this report include the following segments which are prioritized according their methane emission contribution:

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[10] Natural gas fuel combusted at UOG facilities for the purpose of generating electricity for delivery to the power pool or for cogeneration at an in situ oil sands injection facilities is excluded. Subject emission contributions belong to the electric power sector and accounted under separate inventories. Fuel combusted for power generated and consumed at subject UOG facilities is included in the UOG inventory boundary.

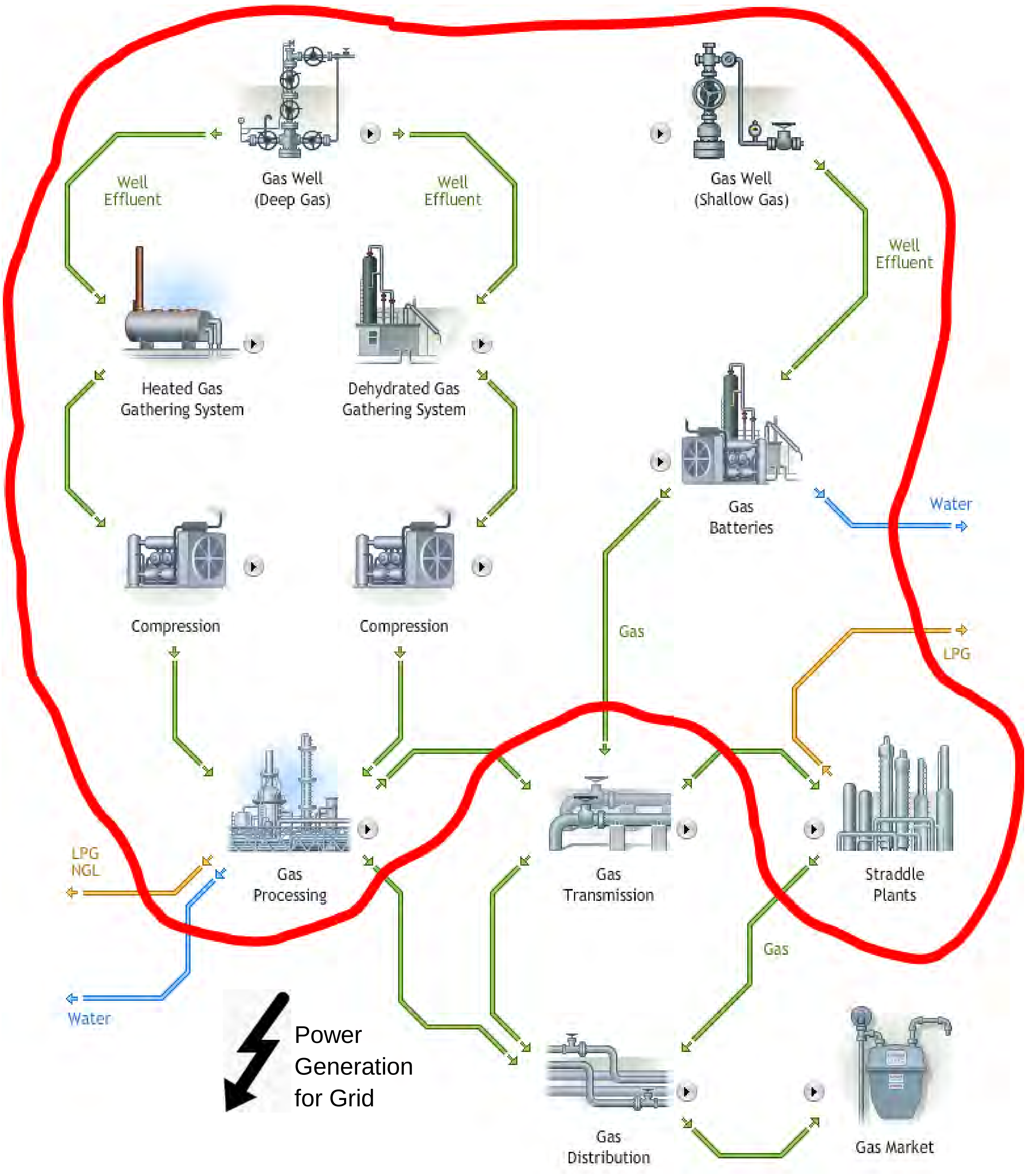

Figure 1: **Upstream Natural Gas System and Inventory Boundary**

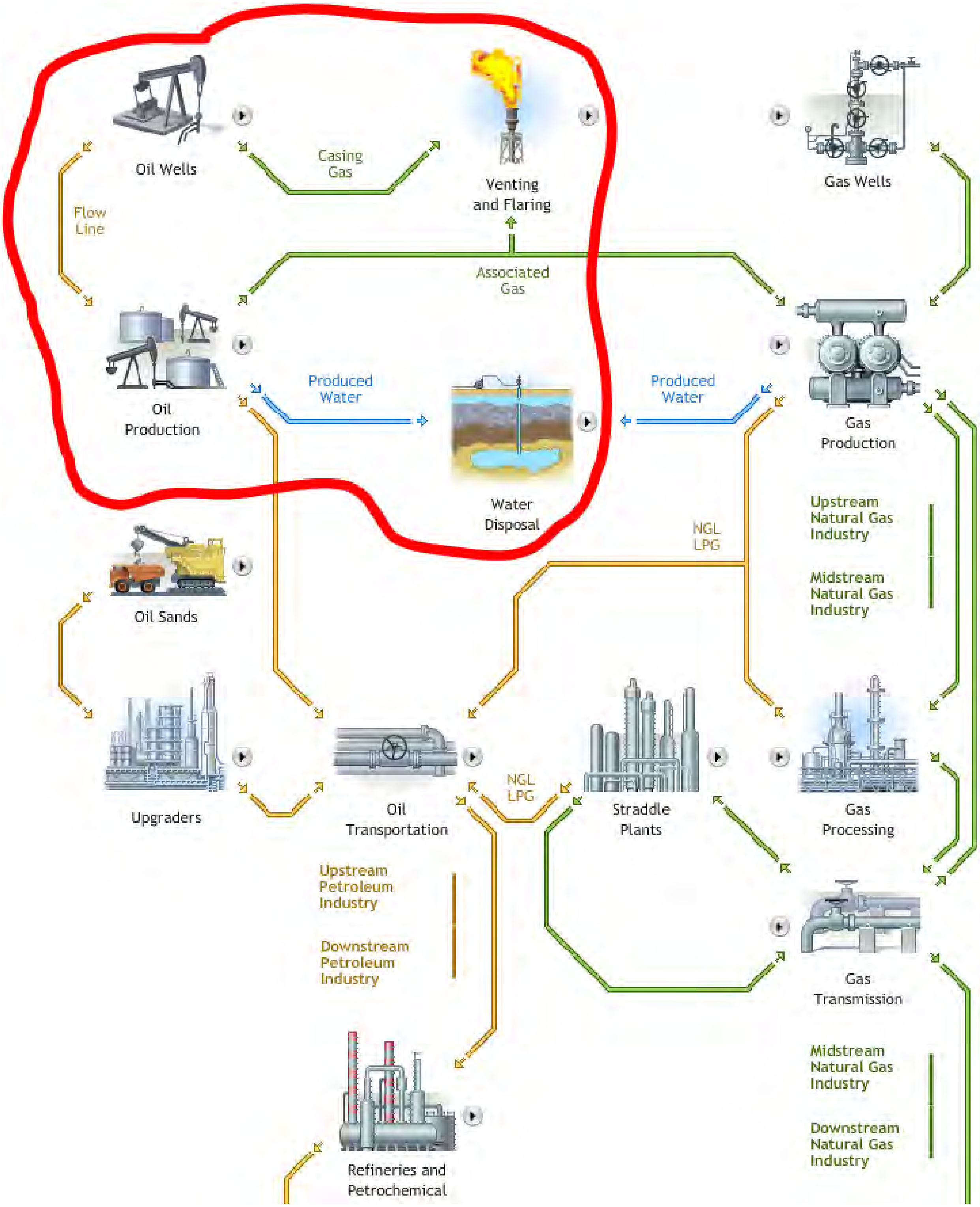

Figure 2: **Upstream Crude Oil System and Inventory Boundary**

2.1.2 OPERATIONAL BOUNDARIES

The operational boundary identifies emission sources and sinks that are directly and indirectly relevant to the organization. The following emission categories (i.e., sources) are relevant to the UOG industry and included within the inventory boundary.

- **Stationary Combustion – Natural Gas Fuel**: Direct emissions resulting from non-vehicular combustion of natural gas fuel for the purpose of energy production (e.g., for mechanical work or to generate electricity, heat or steam) and includes natural gas withdrawn from the process as well as natural gas purchased from third parties.

- **Flaring and Incineration**: Direct emissions from the controlled combustion of a gas or liquid stream produced on site, but not for the purpose of energy production. This may include naturally or artificially occurring CO_2 originally present in the produced oil and gas (often referred to as ”Formation CO2”). Artificially occurring CO_2 may result from enhanced recovery schemes such as CO_2 miscible floods or fire floods.

- **Fugitives:** Direct and unintentional release of hydrocarbon gas to the atmosphere. Subcategories include but are not limited to:

    - **Equipment Leaks** – are the loss of hydrocarbon gas and liquids to the atmosphere past mechanical connections, seals and valve seats due to normal wear and inefficiencies in these mechanisms. Results are presented separately for emissions occurring above and below the IR Camera method detection limit.

    - **Gas Migration (GM)** – is the undesirable result of wellbore leakage occurring outside the surface casing of a well (often referred to as external migration). This condition may exist when the wellbore penetrates a gas bearing formation and creates a pathway for gas migration to the surface.

    - **Spills & Pipeline Ruptures** – are unintentional releases of gases and unrecovered hydrocarbon liquids to the environment due to spills and equipment failures (e.g., pipeline ruptures).

    - **Well Surface Casing Vent Flow (SCVF)** – is the undesirable result of wellbore leakage and occurs at a wellhead vent port that permits the flow of gas and/or liquid out of the surface casing/casing annulus (often referred to as internal migration). This condition exists when gas enters the exterior casing annulus from a source formation below the surface casing shoe or through a compromised section the external surface casing wall or internal production casing wall (i.e., a casing failure).

- **Venting**: Direct and intentional release of hydrocarbon gas to the atmosphere. Venting does not include partial products of combustion that might occur during flaring or other combustion activities. Subcategories include but are not limited to:

    - **Compressor Seals** – Packings are used on reciprocating compressors to control leakage around the piston rod on each cylinder. Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Leakage from rod-packings and seals are typically routed outside of buildings via a vent header and released to the atmosphere if the process gas is sweet, or connected to a flare if the gas is sour.

    - **Glycol Dehydrator Off-Gas** – includes emissions from secondary absorption/desorption by the glycol, entrainment of some gas from the contactor in the rich glycol, and use of stripping gas in the reboiler.

    - **Pneumatic Instruments** – There are three potential sources of venting associated with natural gas driven pneumatic control loops:
        - venting actions of the pneumatic supply as it passes the restriction orifice and bleed port used in each pneumatic instrument (e.g., controllers, transmitters, positioners and transducers) in steady state;
        - additional pneumatic supply vented when the instrument is in a transient state, and;
        - gas pressure exhausted from the actuator during stroking of the control device (usually a valve or a set of louvres herein referred to as the final control device) towards its fail-safe state.

      Static, transient and dynamic contributions are released to the atmosphere via the instrument and are often piped away in a common vent line. The total amount of gas emitted by a single control loop depends on the number of venting instrument components, the size and movement of the actuator, the design of these components, their condition (i.e., are they fouled or damaged), and the degree of changes needed by the final control device in response to process changes.

    - **Pneumatic Pumps** – are gas driven motors that operate by expanding the supply gas against a diaphragm or piston and rod assembly which in turn drives a pump plunger. The expanded supply gas is vented to atmosphere (or into a collection system) and the cycle repeated. Gas consumption rates (i.e., emission rates) depend on the amount of work completed.

    - **Pneumatic Starters** – are widely used to start reciprocating engines or turbines which drive natural gas compressors or electric generators. Specific starting gas requirements will vary according to the pressure of the start gas, the condition of the engine/turbine, the size of the compressor/generator that is being driven, ambient air temperature, oil viscosity, fuel type, and design cranking speed.

  - **Reported Venting** – are venting volumes stated in production accounting reports to Petrinex. They can include contributions from process upsets, equipment depressurization events, well production casings, treaters, storage tanks and well flowbacks.

  - **Storage Losses** – comprise normal evaporation losses due to breathing and working effects, plus flashing losses where the received liquids have an initial vapour pressure close to or greater than local atmospheric pressure. Gas carry-through to storage tanks due to leakage past drain valves into tank inlet headers, inefficient gas-liquid separation in upstream vessels, malfunctioning level controllers or leakage past the seat of level control valves, or unintentional storage of high vapour pressure liquids in atmospheric tanks are all known to be noteworthy sources at some sites but could not be accounted for due to a lack of appropriate emission factors.

  - **Truck Loading/Unloading Losses** – are evaporation losses to the atmosphere resulting from the exposure and agitation of liquids during loading and/or unloading activities.

Because delineation between fuel consumption and venting is not required by regulators[11], duplicate accounting of some sources is likely and has a positive bias on emissions. Accounting practices for activities such as compressor starts, pneumatic venting, storage tank losses and purge gas flows are difficult to predict so NirCalc venting estimates are not discounted from reported fuel volumes. Thus, inventory results likely overstate and are a conservative estimate of fuel combustion emissions.

The following categories are relevant to the UOG industry but are **excluded** from the inventory boundary because they are not large contributors to overall methane uncertainty.

- **Stationary Combustion – Liquid Fuels**: Direct emissions resulting from non-vehicular combustion of propane, gasoline, diesel and other liquid fuels for the purpose of energy production (e.g., for mechanical work or to generate electricity, heat or steam).

- **Mobile Combustion**: Direct emissions resulting from non-licensed vehicle (i.e., off-road) combustion of fuel for the purpose of on-site transport of products or waste streams.

- **Biomass Combustion**: Direct emissions resulting from combustion of biomass (plant or plant materials) where the primary purpose is **not** energy production (e.g., combustion of non-

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[11] Reporting of discrete venting and fugitive emissions by source category will be required in Alberta by 2020 as indicated in AER Directives 017 and 060 (released December 2018).

merchantable wood cleared from site areas). Combustion of bio-fuels is **not** accounted as biomass combustion, rather its included in stationary or mobile fuel combustion categories.

- **Industrial Process**: Direct emissions from an industrial process involving chemical or physical reactions other than combustion where the primary purpose of the industrial process is not energy production.

- **Indirect emissions** result from activities related to business operations, but are outside the organization's operational control. Indirect emissions are caused by the purchase of electricity, heat or hydrogen used within the organization but without the release of onsite emissions. Other indirect emissions can include air travel, road vehicle travel, head office space, accommodation, construction and decommissioning activities.

2.2 BASIC EMISSIONS ASSESSMENT METHOD

The presented emissions inventory has been developed using a bottom-up approach, beginning with individual facilities and their equipment, and the following primary types of primary emissions sources:

- fuel combustion
- flaring,
- formation CO_2, releases,
- venting (reported and unreported), and
- fugitive and other unintentional releases.

For each target substance, the determined emissions have been aggregated to determine overall emissions by facility type, activity type and geographic area.

The particular emissions assessment methodology applied to each facility and its equipment was determined on a case-by-case basis, with the objective being to obtain the most reliable estimates possible from the information available. The basic methods considered in each case are listed below in the order of decreasing preference. In general, uncertainties associated with the emission estimate increase as one moves down the list of possible methods.

- **Emission Monitoring Results** – Some facilities, as a condition of their operating approval, are required to monitor and report their atmospheric emissions of certain substances. The use of actual emission monitoring results is the preferred approach wherever such data are available. Typically, continuous emission monitoring will yield emission estimates with uncertainties in the range of ±5 percent.

- **Large Final Emitters** – Facilities emitting greater than 100 kt CO_2E per year are subject to annual CCIR reporting; reasonable assurance third party verification; and compliance obligations. Facility operators must prepare a standardized quantification methodology document (QMD) to define facility operations, boundaries, and the methods and assumptions used to quantify GHG emissions. This level of documentation and assurance produces facility emission results that are more reliable than estimated by NirCALC routines.

- **Emission Source Simulation Results** – Computer models are available for estimating emissions from some types of sources; for example, GRI GlyCalc for predicting emissions from glycol dehydrators and US EPA TANKS to predict evaporation losses from storage tanks. These models apply empirical correlations and/or fundamental engineering principles to develop rigorous emission estimates based on the specific operating and design parameters of the source. When properly applied, simulators offer the ability to predict accurately emissions from individual sources (generally to within ±25 percent or better), but have the disadvantage of requiring more time, effort, user knowledge, and input data to apply. Moreover, the necessary design and operating input data may be difficult to obtain. Consequently, the use of emission source simulations herein is primarily limited to the development of emission factors based on typical process and operating conditions for different segments of the industry.

- **Emission Factors** – 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:

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

Equation 1

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 which indicates the fraction by which the emissions are reduced (kg/kg).
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.

Where published or default values for specific parameters are used, the references for these are stated.

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. The available sources of emission factors are, in the order of decreasing preference:

i) custom factors based on recent emission measurements on the target source,
ii) manufacturer's values
iii) Canadian-specific values (e.g., Clearstone, 2018), and
iv) published values from the open literature (e.g., EPA AP-42) compilation of air pollutant emission factors).

- **Destruction and Removal Efficiencies (DREs) –** The emissions of individual substances input to a combustion device may be estimated based on the extent to which they are expected to be destroyed (i.e., converted to intermediate, partially-oxidized and fully-oxidized products of combustion) and/or removed by that device. By-products of combustion are determined using a relation of the form:

$$\boldsymbol{ER_i = \left(1 - \frac{DRE_i}{100}\right) \cdot IR_i}$$

Equation 2

where,

ER_i = emission rate of substance i from the selected source.
DRE_i = destruction and removal efficiency of substance i for the selected source.
= *99.9% for heaters, boilers and incinerators.*
= *99.5% for steam or air assist flares.*
= *98% for unassisted flares.*
IR_i = input rate of substance i to the selected source.

In the absence of site-specific data on the type of flare, it is assumed that flares at production and processing facilities are unassisted flares.

All source-specific considerations and default emission factors are delineated in Sections 3 to 11, which follow.

2.3 DETERMINATION OF HHV AND LHV

The higher (or gross) heating value (HHV) and the lower (or net) heating value (LHV) of a multi-component gas are calculated using the following equations, respectively:

$$\boldsymbol{HHV = \sum_{i=1}^{i=n} HHV_i \cdot Y_i}$$

Equation 3

and,

$$\boldsymbol{LHV = \sum_{i=1}^{i=n} LHV_i \cdot Y_i}$$

Equation 4

where,

HHV_i = higher (gross) heating value of the component i (MJ/m^3),
LHV_i = lower (net) heating value of the component i (MJ/m^3),
n = number of components, and
Y_i = mole fraction of component i.

2.4 CONVERSION FROM MASS FRACTIONS TO MOLE FRACTIONS

The mass fraction of component i in a multi-component mixture may be converted to a mole fraction using the following equation:

$$\boldsymbol{Y_i = \frac{X_i \cdot MW}{MW_i}}$$

Equation 5

Where,

X_i = mass fraction of component I (kg/kg)
Y_i = mole fraction of component i (kmole/kmole)
MW_i = molecular weight of component i (kg/kmole)
MW = molecular weight of the multi-component mixture (kg/kmole) as given below:

$$\boldsymbol{MW = \frac{1.0}{\left\{\sum_{i=1}^{i=n}\left(\frac{X_i}{MW_i}\right)\right\}}}$$

Equation 6

2.5 DETERMINATION OF CO_2 EMISSION FACTORS FOR COMBUSTION PROCESSES

Normal practice is to estimate emissions due to incomplete combustion and also assume that all carbon present in a fuel or waste gas is converted to CO_2 when it is combusted. This double counting of that portion of the carbon that is not fully oxidized to CO_2 by the combustion process accounts for the fact any products of incomplete combustion are quickly oxidized to CO_2 in the atmosphere (i.e., within a few days to weeks for non-methane hydrocarbons and within 11.5 years for CH_4). Accordingly, the CO_2 emission factor for a given natural gas or waste gas mixture is calculated using the following equation:

$$\boldsymbol{EF_{CO_2} = \sum_i \frac{y_i \cdot n_{c_i} \cdot MW_{CO_2}}{V_{STP} \cdot HHV} \cdot g_c}$$

Equation 7

Where,

EF_{CO2} = emission factor for estimating CO_2 emissions from a specified fuel or waste gas (ng/J)
y_i = mole fraction of component i (kmole/kmole)
$n_{c,i}$ = number of carbon atoms per molecule of component I (dimensionless)
MW_{CO2} = molecular weight of CO2 (kg/kmole)
= 44.010 (kg/kmole)
V_{STP} = volume of one mole of gas at standard conditions of 101.325 kPa and 15°C (m^3/kmole)
= 23.6444813 (m^3/kmole)
HHV = higher heating value of the fuel or waste gas (MJ/m^3)
g_c = constant of proportionality
= 10^6 ($ng \cdot kg^{-1} \cdot MJ \cdot J^{-1}$)

2.6 DETERMINATION OF PRESSURES AND TEMPERATURES

Some of the calculation methodologies presented in this document require that the inlet and outlet temperatures and pressures be known to facilitate rigorous process simulations and to estimate and prorate energy use. Some pressure and temperature data were obtained through a survey of CAPP members; however, in many cases it was necessary to rely on design data available from the applicable regulatory authorities. The following are specific assumptions that have been made in this regard:

- Most gas pipelines are operated at or near their maximum design operating pressure as this facilitates more energy efficient transport of the gas.

- Most liquid pipelines are also operated near their maximum design operating pressure.
- The inlet pressure of a facility is equal to the maximum design operating pressure of the connected gathering systems.
- The discharge pressure of a particular product or waste stream is equal to the maximum design operating pressure of the associated pipeline. If there is no pipeline for handing a particular product then that product is assumed to be transported by truck, rail, or marine vessel.
- The pipeline maximum design operating pressures are available in the pipeline attribute files maintained by the applicable regulatory authority.
- The inject pressure for disposal wells and wells used in secondary recovery schemes is equal to the maximum design operating pressure of the connected pipelines.

2.7 DETERMINATION OF CO_2-EQUIVALENT GHG EMISSIONS

Total annual GHG emissions are calculated in terms of tonnes CO_2E for each emission source identified using Equation 8. Global warming potentials (GWP) specified in the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) are intended to represent total radiative forcing contributed by target GHG emissions (IPCC, 2012).

$$\boldsymbol{CO_2E = ER_{CH_4} \cdot GWP_{CH_4} + ER_{CO_2} \cdot GWP_{CO_2} + ER_{N_2O} \cdot GWP_{N_2O}}$$

Equation 8

Where:

CO_2E = carbon dioxide equivalent emissions (tonnes)
GWP_{CO2} = global warming potential of compound CO_2
= 1
GWP_{CH4} = global warming potential of compound CH_4
= 25
GWP_{N2O} = global warming potential of compound N_2O
= 298
ER_i = emission release of compound i (tonnes)

2.8 DETERMINATION OF BARRELS OF OIL EQUIVALENT PRODUCTION

Total production in barrels of oil equivalent (BOE) is calculated using Equation 9. OE conversion factors are provided in Table 1 (CAPP, 2003), which are determined by dividing the HHV of the subject product by the HHV of light/medium crude oil (i.e., 38.5 GJ/m^3).

$$Q_{Total} = \sum_{m=1}^{12} \sum_{i=1}^{N} (Q_{m,i} \cdot OE_i) \cdot 6.2898$$

Equation 9

Where:

Q_{Total} = Total annual production (BOE)
$Q_{m,i}$ = Monthly volume of product i obtained from production accounting
OE_i = Oil equivalent conversion factor for product I (see Table 1).
= $HHV_i/HHV_{Light\ Oil}$
M = month
N = number of products
6.2898 = Conversion factor (m^3OE to BOE)

Table 1: Oil Equivalent Conversion Factors on an energy equivalent basis.

Product	m^3OE Conversion Factor
Light/Medium Crude oil in m^3	1.0
Heavy Crude oil in m^3	1.075
Natural gas in 1000 m^3	0.971
Liquid ethane in m^3	0.48
Liquid propane in m^3	0.66
Liquid butane in m^3	0.75
Liquid condensate C5+ in m^3	0.85
NGL in m^3 (gas plant NGL sales)	0.72
Solid sulphur in tonnes	0.24

2.9 UNITS OF MEASURE AND REFERENCE CONDITIONS

In the general literature, emissions and source parameters may be expressed using a wide range of units, formats, classifications and terminology. Herein, every effort has been made to maintain a consistent convention to allow convenient comparisons and aggregation of results, and to be consistent with applicable national and international reporting requirements.

Consumption of gaseous fuels or combustibles is expressed in terms of the gross (or higher) heating value of the material in units of GJ; this is common practice for gas purchases and sales. Liquid fuels are expressed on a volume basis in units of litres. All emission factors are expressed on an energy basis in units of ng/J (gross) in general accordance with IPCC (2000) good practice guidance. All volumetric gas flows are expressed in cubic metres at standard reference conditions of 101.325 kPa and 15ºC. The conversion table presented at the front of this volume may be used to convert available data to these units as needed.

Throughout this document, the term "sour natural gas" is used to indicate a natural gas containing 0.01 moles or more of H_2S per kmole of total gas (i.e., 10 ppmv H_2S) as defined by AER Directive 56. Petroleum liquid production is classified as sour when it contains 0.5 percent sulphur on a mass basis (this sulphur content does not have to be in the form of H_2S). Substances that contain less than these limits are referred to as sweet.

2.10 SPECIATION OF EMISSIONS

The speciation of fugitive and process emissions to determine the amounts of specific substances emitted (e.g., CH_4, CO_2, VOC, benzene and H_2S), or of a particular component (or specie) of a substance, is done using site-specific composition data, where available, and the default profiles presented in Table 2 to Table 6. Table 7 and Table 8 provide typical compositions of processed natural gas compositions.

The use of the default profiles is described below.

- Dry gas profiles were applied to low-pressure gas gathering systems and to gas batteries.
- Sweet gas profiles were used for dehydrated gas gathering systems and sweet gas processing plants.
- Sour gas profiles were dedicated to heated gas gathering systems and to sour-gas processing plants; however, all fuel gas are assumed to be sweet.
- Conventional oil, heavy oil and crude bitumen profiles were applied to the corresponding production and battery facilities.

The profiles were implemented using the equation below.

$$\boldsymbol{ER_i = \frac{ER \cdot Y_i \cdot MW_i}{MW}}$$

Equation 10

Where,

ER_i = average emission rate (kg/h) of the chemical compound i,
ER = total mass emission rate (kg/h),
Y_i = mole fraction of component k in the effluent stream,
MW_i = molecular weight of component i, and
MW = average molecular weight of the bulk fluid.

Total emissions were determined for each of the chemical species in the applied speciation profiles. By including inorganic compounds in the profiles it is assumed that the estimated emission rates (except those from equipment leaks and from combustion activities) are total mass emissions on a moisture-free basis. **As**

the emissions from equipment leaks are expressed as total hydrocarbons (THC), they are speciated based on the normalized hydrocarbon portion of the profiles (inorganic emissions from equipment leaks are calculated in appropriate proportion to the THC emissions) using the following relations for mixtures expressed on a mol basis:

$$\boldsymbol{Y_{Inorganic} = \sum Y_i \qquad for\ i = 1\ to\ N\ and\ i\ \neq any\ organic\ components}$$

Equation 11

And

$$\boldsymbol{Y_i' = \frac{Y_i}{1 - Y_{Inorganic}} \qquad for\ i = 1\ to\ N\quad and\ i \neq any\ inorganic\ components}$$

Equation 12

Where,

Y_i = mol fraction of component i.
$Y_{Inorganic}$ = sum of the mol fractions of all inorganic components in the initial mixture.
N = total number of components in the mixture.
Y'_I = mol fraction of organic component i in the normalized mixture expressed on an inorganic component free basis.

For mixtures expressed on a mass basis the following relations are applied:

$$\boldsymbol{X_{Inorganic} = \sum X_i \qquad for\ i = 1\ to\ N\ and\ i\ \neq any\ organic\ components}$$

Equation 13

And

$$\boldsymbol{X_i' = \frac{X_i}{1 - X_{Inorganic}} \qquad for\ i = 1\ to\ N\quad and\ i \neq any\ inorganic\ components}$$

Equation 14

Where,

X_i = mass fraction of component i.
$X_{Inorganic}$ = sum of the mass fractions of all inorganic components in the initial mixture.
N = total number of components in the mixture.
X'_I = mass fraction of organic component i in the normalized mixture expressed on an inorganic component free basis.

Table 2: Speciation profiles (on a moisture-free basis) for dry and sweet gas production and processing facilities.

Component	Dry Gas						Sweet Gas							
	Gas[1]		Light Liquid[2]		Dehy Off-Gas[3]		Gas[4]		Tank Vapours[5]		Light Liquid[2]		Dehy Off-Gas[3]	
	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	1.7099	2.9153	0.01	0.0050	6.0450	9.3101	0.6793	1.0865	2.9668	2.9436	0.01	0.0050	3.0220	3.5883
CO_2	0.2646	0.7088	0.05	0.0394	3.6656	8.8694	0.5814	1.4610	1.3436	2.0944	0.05	0.0394	6.3865	11.914
H_2S	0.0000	0.0000	0.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.00	0.0000	0.0000	0.0000
C_1	97.291	94.998	0.59	0.1695	87.460	77.143	91.880	84.163	56.421	32.060	0.59	0.1695	68.9410	46.881
C_2	0.7009	1.2828	31.52	16.975	2.8296	4.6780	5.4263	9.3166	15.222	16.212	31.52	16.975	11.4083	14.541
C_3	0.0295	0.0792	21.61	17.067	0.0000	0.0000	1.0490	2.6412	11.630	18.165	21.61	17.067	3.7118	6.9379
i-C_4	0.0012	0.0041	9.60	9.9936	0.0000	0.0000	0.1291	0.4284	2.6504	5.4564	9.60	9.9936	3.2751	8.0689
n-C_4	0.0020	0.0069	10.06	10.473	0.0000	0.0000	0.1949	0.6468	5.5796	11.487	10.06	10.473	3.2751	80.689
i-C_5	0.0006	0.0026	0.83	1.0725	0.0000	0.0000	0.0254	0.1046	1.2562	3.2103	0.83	1.0725	0.0000	0.0000
n-C_5	0.0005	0.0020	0.99	1.2793	0.0000	0.0000	0.0296	0.1219	1.5784	4.0336	0.99	1.2793	0.0000	0.0000
C_6	0.0001	0.0003	5.4826	8.4621	0.0000	0.0000	0.0056	0.0276	0.8697	2.6548	5.4826	8.4621	0.0000	0.0000
Benzene[6]	0.0000	0.0000	0.3874	0.5980	0.0000	0.0000	0.0004	0.0019	0.0615	0.1876	0.3874	0.5980	0.0000	0.0000
C_{7+}	0.0001	0.0003	18.87	33.866	0.0000	0.0000	0.0000	0.0000	0.4215	1.4960	18.87	33.866	0.0000	0.0000
Mole Wt	16.430	16.430	55.835	55.835	18.189	18.189	17.514	17.514	28.233	28.233	55.835	55.835	23.592	23.592

1 Based on a dry gas analysis taken downstream of a straddle plant (CAPP, 2004c).
2 Average composition for liquids from gas fields in Alberta (AER, 2003a).
3 Estimated by simulating dehydration of the gas (G) at water-saturated conditions, 28° C and 7 000 kPa (CAPP, 2004c).
4 Based on a gas analysis taken at an appropriate transmission point (Picard et al., 1987a).
5 Based on an analysis of the vapours from a condensate tank in northeastern B.C. (Picard and Colley, 1987a).
6 Benzene content estimated to be 6.6 percent of the C_6 fraction. Average benzene content (6.6%) determined from 93 extended gas analysis provided for this study.

Table 3: Speciation profiles (on a moisture-free basis) for sour gas production and processing facilities and for natural gas transmission facilities.

Component	Sour Gas						Natural Gas	
	Gas[1]		Tank Vapours[2]		Light Liquid[3]		Gas[4]	
	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	0.6552	1.0140	2.9668	2.9436	0.01	0.0050	0.7791	1.2500
CO_2	0.5608	1.3635	1.3436	2.0944	0.05	0.0394	0.6160	1.5527
H_2S	3.5460[5]	6.6755[5]	0.0000[5]	0.0000[5]	0.00	0.0000	0.0000	0.0000
C_1	88.6210	78.5447	56.4205	32.0598	0.59	0.1695	92.5394	85.0226
C_2	5.2339	8.6947	15.2219	16.2121	31.52	16.9753	4.5125	7.7709
C_3	1.0118	2.4649	11.6300	18.1646	21.61	17.0671	1.0904	2.7538
i-C_4	0.1245	0.3998	2.6504	5.4564	9.60	9.9936	0.1498	0.4985
n-C_4	0.1880	0.6037	5.5796	11.4867	10.06	10.4725	0.2103	0.7000
i-C_5	0.0245	0.0977	1.2562	3.2103	0.83	1.0725	0.0415	0.1716
n-C_5	0.0286	0.1140	1.5784	4.0336	0.99	1.2793	0.0358	0.1478
C_6	0.0056	0.0258	0.8697	2.6548	5.4826	8.4621	0.0159	0.0784
Benzene[6]	0.0004	0.0018	0.0615	0.1876	0.3874	0.5980	0.0011	0.0055
C_{7+}	0.0000	0.0000	0.4215	1.4960	18.87	33.8656	0.0084	0.0482
Mole Wt	18.1011	18.1011	28.2333	28.2333	55.8345	55.8345	17.4613	17.4613

1. The H_2S-free composition is based on an analysis taken at an appropriate transmission point (Picard et al., 1987b).
2. Based on an analysis of the vapours from a condensate tank in northeastern B.C. (Picard and Colley, 1987a).
3. Average composition for liquids from gas fields in Alberta (AER, 2003a)
4. Based on a dry gas analysis taken upstream of a straddle plant (CAPP, 2004c).
5. To be determined on a case-by-case basis and the rest of the composition then normalized .
6. Benzene content estimated to be 6.6 percent of the C_6 fraction. Average benzene content (6.6%) determined from 93 extended gas analysis provided for this study.

Table 4: Speciation profiles (on a moisture-free basis) for light/medium crude oil and primary heavy crude oil production facilities.

Component	Light/Medium Crude Oil						Heavy Crude Oil (Primary)					
	Gas[1]		Tank Vapours[2]		Light Liquid[3]		Gas[4]		Tank Vapours[4]		Light Liquid[4]	
	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	0.6190	0.7723	13.9989	8.8642	0.1316	0.0464	0.1817	0.3030	6.3477	8.9364	0.1046	0.0353
CO_2	5.2430	10.2765	0.3303	0.3286	0.3240	0.1794	0.0859	0.2250	0.6892	1.5243	0.7665	0.4069
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0002	0.0000	0.0000	0.0000	0.0000
C_1	73.2524	52.3386	10.0100	3.6300	9.7419	1.9668	98.0137	93.6026	87.2337	70.3327	7.6718	1.4844
C_2	11.9708	16.0314	15.7274	10.6900	3.6464	1.3798	0.9062	1.6221	2.2616	3.4177	2.7538	0.9987
C_3	5.3198	10.4477	24.1601	24.0821	4.9064	2.7227	0.0408	0.1071	0.1905	0.4222	3.8341	2.0392
i-C_4	0.8778	2.2723	6.6404	8.7244	1.9516	1.4275	0.0564	0.1951	0.1324	0.3868	1.8191	1.2752
n-C_4	1.7027	4.4077	16.6022	21.8126	4.0430	2.9572	0.0351	0.1214	0.1137	0.3321	3.5935	2.5191
i-C_5	0.3570	1.1472	4.2113	6.8682	3.0507	2.7699	0.0501	0.2152	0.1400	0.5076	2.4084	2.0958
n-C_5	0.3802	1.2217	4.5447	7.4120	3.6626	3.3255	0.0433	0.1860	0.1230	0.4460	2.7543	2.3968
C_6	0.2285	0.8768	2.7698	5.3954	16.9660	18.3993	0.0866	0.4441	0.3263	1.4133	16.7887	17.4499
Benzene[5]	0.0161	0.0620	0.1957	0.3813	1.1989	1.3002	0.0061	0.03138	0.0231	0.0999	1.1864	1.2331
C_{7+}	0.0327	0.1459	0.7997	1.8113	50.3769	63.5253	0.4940	2.9467	2.4188	12.1808	56.3190	68.0654
Mole Wt	22.4536	22.4536	44.2399	44.2399	79.4647	79.4647	16.7990	16.7990	19.8981	19.8981	82.9121	82.9121

1. Based on an analysis of the gas from a large solution-gas gathering system in central Alberta (Picard et al., 1987b).
2. Adapted from an analysis of the vapours from an oil storage tank in northeastern B.C (Site No. 2) (Picard and Colley, 1987a).
3. Average composition for liquids from conventional oil fields in Alberta (AER, 2003a).
4. Adapted from results presented by Ullman et al. (1987).
5. Benzene content estimated to be 6.6 percent of the C6 fraction. Average benzene content (6.6%) determined from 93 extended gas analysis provided for this study.

Table 5: Speciation profiles (on a moisture-free basis) light/medium crude oil and primary heavy crude oil production facilities.

Component	Sour Crude Oil			
	Sour Solution Natural Gas[1]		Sour Light Liquid[1]	
	Mole %	Mass %	Mole %	Mass %
N_2	3.2898	4.0741	0.1081	0.0385
CO_2	3.5298	6.8675	0.3733	0.2089
H_2S	3.2898	4.9558	0.8527	0.3695
C_1	71.7705	50.9011	7.4364	1.5172
C_2	9.0895	12.0828	3.8033	1.4544
C_3	5.3197	10.3703	6.0853	3.4126
i-C_4	0.8010	2.0581	1.9617	1.4500
n-C_4	1.6399	4.2138	5.8751	4.3427
i-C_5	0.3920	1.2503	3.5331	3.2418
n-C_5	0.4100	1.3077	4.6140	4.2336
C_6	0.2326	0.8859	18.6028	20.3852
Benzene[2]	0.01643	0.0626	1.3145	1.4405
C_{7+}	0.2190	0.9701	45.4395	57.9049
Mole Wt	22.6218	22.6218	78.5652	78.5652

1. Based on the average pool analysis for sour conventional oil operations (Alberta pool average gas and oil analyses, AER, 2003a).
2. Benzene content estimated to be 6.6 percent of the C6 fraction. Average benzene content (6.6%) determined from 93 extended gas analysis provided for this study.

Table 6: Speciation profiles (on a moisture-free basis) for thermal conventional heavy crude oil and cold bitumen production.

Component	Thermal Conventional Heavy Crude Oil						Cold Bitumen			
	Gas[1]		Tank Vapours[1]		Light Liquid[2]		Gas[3]		Tank Vapours/Light Liquid[3]	
	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	0.1932	0.1767	3.3516	3.0552	0.1044	0.0353	0.6130	0.6343	0.0000	0.0000
CO_2	2.6094	3.7485	16.1140	23.0772	0.7652	0.4066	28.5280	46.3771	22.0000	41.5226
H_2S	0.0150	0.0167	0.1439	0.1596	0.1744	0.0718	0.2490	0.3134	0.0000	0.0000
C_1	72.9361	38.1942	66.6600	34.8000	7.6584	1.4834	63.9410	37.8919	70.0000	48.1609
C_2	1.9370	1.9012	0.9490	0.9286	2.7490	0.9980	1.2070	1.3407	8.0000	10.3165
C_3	3.0956	4.4558	0.5394	0.7740	3.8274	2.0377	0.9160	1.4921	0.0000	0.0000
i-C_4	1.0807	2.0504	0.1922	0.3635	1.8159	1.2743	0.2640	0.5668	0.0000	0.0000
n-C_4	2.3889	4.5323	0.3678	0.6957	3.5872	2.5173	0.9520	2.0440	0.0000	0.0000
i-C_5	1.9994	4.7088	0.4541	1.0662	2.4042	2.0943	1.3020	3.4700	0.0000	0.0000
n-C_5	2.2733	5.3539	0.5829	1.3686	2.7495	2.3951	1.1310	3.0143	0.0000	0.0000
C_6	5.4252	15.2610	2.0468	5.7398	16.7593	18.6696	0.8378	2.6669	0.0000	0.0000
Benzene[4]	0.3834	1.0784	0.1446	0.4056	1.1843	17.4374	0.0592	0.1885	0.0000	0.0000
C_{7+}	5.6628	18.5221	8.4539	27.5661	56.2207	68.0166	0.0000	0.0000	0.0000	0.0000
Mole Wt	30.6359	30.6359	30.7306	30.7306	82.8268	82.8268	27.0719	27.0719	23.3179	23.3179

1. Adapted from results presented by Ullman et al. (1987).
2. Average composition for liquids from heavy oil fields in Alberta (AER, 2003a)
3. Provided by an operator of a major crude bitumen facility (CAPP, 2004c).
4. Benzene content estimated to be 6.6 percent of the C6 fraction. Average benzene content (6.6%) determined from 93 extended gas analysis provided for this study.

Table 7: Typical compositions (mole percent) of processed natural gas by province.

Component	BC	AB			SK		MB	ON
	WA Border	Empress	SK Border	BC Border	AB Border	Regina	MN Border	Dawn
C_1	95.9490	92.8690	97.1294	95.6400	95.2128	95.0600	94.8890	94.7089
C_2	2.4160	4.0556	0.2579	2.5800	2.4306	0.4940	2.4740	2.4805
C_3	0.5440	1.1112	0.0201	0.0700	0.1374	0.0670	0.2130	0.2501
i-C_4	0.0710	0.1601	0.0005	0.0100	0.0043	0.0120	0.0130	0.0300
n-C_4	0.1130	0.2180	0.0005	0.0100	0.0043	0.0110	0.0200	0.0400
i-C_5	0.0190	0.0496	0.0008	0.0000	0.0013	0.0040	0.0050	0.0200
n-C_5	0.0110	0.0389	0.0004	0.0000	0.0010	0.0030	0.0080	0.0100
C_6	0.0260	0.0225	0.0001	0.0100	0.0012	0.0070	0.0030	0.0100
C_{7+}	0.0000	0.0126	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1250	0.6334	0.2618	0.5400	0.5552	0.1290	0.6560	0.6201
N_2	0.7260	0.8291	2.3284	1.1400	1.6519	4.2130	1.7190	1.8304
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Source: Unpublished data from the files of Clearstone Engineering Ltd originally published in (CAPP, 2004c).

Table 8: Typical compositions (mass percent) of processed natural gas by province.

Component	BC	AB			SK		MB	ON
	WA Border	Empress	SK Border	BC Border	AB Border	Regina	MN Border	Dawn
C_1	91.7957	85.4537	94.7955	91.7267	91.0242	91.3750	90.2786	89.8694
C_2	4.3324	6.9946	0.4718	4.6379	4.3553	0.8900	4.4118	4.4117
C_3	1.4306	2.8104	0.0539	0.1845	0.3611	0.1770	0.5570	0.6523
i-C_4	0.2461	0.5337	0.0018	0.0347	0.0149	0.0418	0.0448	0.1031
n-C_4	0.3917	0.7268	0.0018	0.0347	0.0149	0.0383	0.0689	0.1375
i-C_5	0.0818	0.2053	0.0035	0.0000	0.0056	0.0173	0.0214	0.0854
n-C_5	0.0473	0.1610	0.0018	0.0000	0.0043	0.0130	0.0342	0.0427
C_6	0.1336	0.1112	0.0005	0.0515	0.0062	0.0361	0.0153	0.0510
C_{7+}	0.0000	0.0724	0.0006	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.3281	1.5988	0.7009	1.4207	1.4561	0.3402	1.7121	1.6142
N_2	1.2128	1.3321	3.9680	1.9091	2.7575	7.0712	2.8557	3.0328
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Source: Unpublished data from the files of Clearstone Engineering Ltd originally published in (CAPP, 2004c).

2.11 DATA COLLECTION

Regardless of the techniques employed, a certain amount of source and activity data is needed to support the assessment effort. The key challenges in compiling these data included: ensuring completeness, accuracy (i.e., no double counting) and correct posting of the information.

The required activity data included the following:

- measured volumes of natural gas taken from the process,
- vented and flared waste-gas volumes,
- water disposal volumes,
- fuel purchases (e.g., propane, diesel fuel, etc.),
- fuel analyses,
- emissions monitoring results,
- process operating conditions that may be used to infer the work being done by combustion devices (e.g., gas compositions, temperatures, pressures and flows),
- spills and inspection reports.

Other required data includes the following:

- types of processes being used,
- equipment inventories,
- emission source control features,
- sulphur content of the fuels consumed and waste gas flared, and

- compositions of the inlet and outlet streams.

To fulfil these needs the study drew on official data managed by the AER.

Compilation of the required source data involved developing a detailed inventory of sources by facility or installation. This included larger point sources (e.g., compressor engines, process heaters or boilers, storage tanks, glycol dehydrators) through to the often many minor sources (e.g., portable fired equipment, pigging facilities, mainline block valves, metering equipment, etc). Equipment lists were inferred for each facility based on consideration of the type and amount of production accounting activity, the types of linked infrastructure (e.g., inlet and outlet pipeline systems), typical design and operating practices for the type of facility, and related trends determined from limited industry surveys. The specific details of these inferences are delineated by industry segment in Section 11.

While there is a natural tendency to trivialize smaller sources, these, due to their numbers and periods of activity, may often be significant on an aggregate basis. Therefore, the objective was to account for all sources unless their collective contribution to total emissions could be proven to be negligible and their inclusion impracticable.

2.12 DATA MANAGEMENT AND PROCESSING

A relational database application (NirCALC) was developed using Microsoft SQL to process and manage the emissions inventory information. The database was designed as a series of tables containing related data. Table 9 provides a summary of the primary tables within the database, a description of the type of data the table contains with further details presented in Section 2.12.3. In addition to these, there are a number of tables that contain emission factors, equipment schedules, control factors and lookup tables with definitions for codes used in the main tables.

Table 9: Emission database table details.

Table	**Description**
Monthly Production	production volumes for each facility (from provincial regulatory agencies)
Facilities	name, facility type, sector and location for each facility (contains facilities that were active at some point during the inventory year)
Sources	a list of all sources located at each facility
Stream Compositions	facility specific composition data
Monthly Emissions	emission results for each facility and source

The relationship between internal NirCALC components and external data sources is illustrated in Figure 3. Data collected from a number of sources is maintained in the NirCALC database and operated upon by a suite of related import, calculation, and reporting applications. NirCALC employs a bottom-up inventory approach where emission sources (described in Sections 3 to 10) are defined for equipment operating at individual facilities and wells. When available, equipment details (e.g., manufacturer, model, capacity, operating hours, etc) are provided by responsible companies via proposed AER D060 methane reports or the ECCC Multi-Sector Air Pollutant Regulation (MSAPR). However, these data sources are not yet deployed and company equipment inventories are typically not available in a consistent format and require maintenance as operations evolve. Therefore, NirCALC predicts ‘synthetic equipment’ based on facility specific production volumes (from Petrinex) and facility subtype averages derived from field observations (Clearstone, 2018).

NirCALC typically calculates emissions using emission factors as described in Section 2.2. For large emitters and companies complying with 2020 D060 requirements, inventory estimates can be compared with CCIR or AER methane reports and superseded if decision criteria are satisfied. This functionality has not yet been implemented.

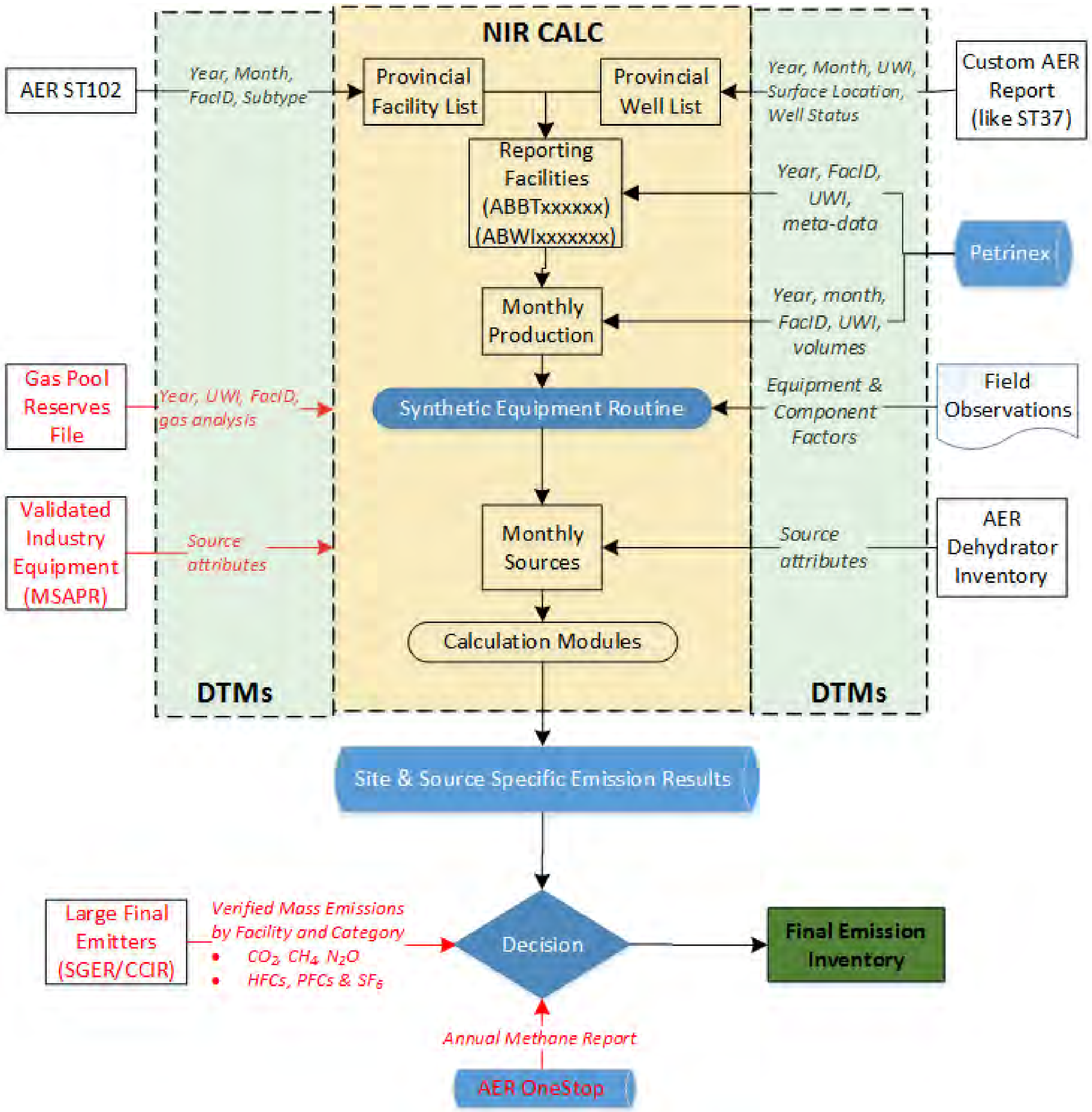

Figure 3: **NirCalc database outline and Alberta data sources.**[12]

Data collected from a number of sources; maintained in the NirCalc database; and operated upon by a suite of related import, calculation, and reporting applications. Data is collected, tested and parsed using Data Transfer Modules as described in Section 2.12.1. The addition of synthetic equipment that represent emission sources is described in Section 2.12.2. Key tables used to maintain records are described in Section 2.12.3. In addition to these, there are a number of tables that contain emission factors, equipment schedules, control factors and lookup tables with definitions for codes used in the main tables.

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[12] Data sources in red font have not yet been implemented.

Emission and uncertainty calculations are performed by Visual Basic modules at the individual source level. Results are determined for the emission categories presented in Table 10.

Table 10: Emission categories and subcategories included in the inventory.

Source Name	Emission Category	Emission Subcategory	Description
Fuel Combustion	COMB	ACID GAS	Combustion - Acid Gas
	COMB	DIESEL	Combustion - Diesel Fuel
	COMB	GASOLINE	Combustion - Gasoline Fuel
	COMB	NGAS	Combustion - Natural Gas Fuel
	COMB	PROPANE	Combustion - Propane Fuel
	COMB	SERV	Combustion - Well Service
	COMB	WDR	Combustion - Drilling Rigs
	COMB	WPU	Combustion - Well Completion (pumping)
Flaring	COMB	FLARE	Combustion - Flaring
	COMB	WTST	Combustion - Well Test Flaring
	COMB	MSW	Combustion - Municipal Solid Waste Incineration
Formation CO_2 Releases	RAW	N/A	Formation CO_2 Venting
Venting: Reported	VENT	VENTED	Venting - Reported Venting
Venting: Unreported	TANK	FLASHING	Storage Tank - Flashing Losses
	TANK	WORKING	Storage Tank - Working Losses
	TANK	BREATHING	Storage Tank - Breathing Losses
	LOAD	HVP	Loading/Unloading - NGLs
	LOAD	LVP	Loading/Unloading - Crude Oil
	DEHY	TYPICAL	Glycol Dehydrator Off-Gas using typical CAPP factors
	VENT	COMPRESSOR SEAL - TYPICAL	Compressor seal venting calculated using typical counts and factors
	VENT	PNEUMATIC PUMP -TYPICAL	Venting - Pneumatic pump emissions calculated using typical counts and factors
	VENT	PNEUMATIC INSTRUMENT - TYPICAL	Venting - Pneumatic instrument emissions calculated using typical counts and factors
	VENT	S POURING	Venting - Sulphur Pouring
	VENT	START GAS	Venting - Compressor Start Gas
Fugitives: Equipment and Other	LEAK	POPULATION FACTOR	Fugitive Equipment Leaks calculated using population-average emission factors that represent emission that can be detected by an IR Camera.
	LEAK	NO-LEAK FACTOR	Fugitive Equipment Leaks calculated using no-leak emission factors that represent emissions occurring below the IR Camera method detection limit.
	ACC	GMIG	Accidental venting due to gas migration
	ACC	RUPT	Accidental venting due to ruptures

Table 10: Emission categories and subcategories included in the inventory.

Source Name	Emission Category	Emission Subcategory	Description
	ACC	SCVF	Accidental venting due to well surface casing vents
	ACC	SPILL	Accidental venting due to spills
Indirect	ELEC	IND	Indirect Emissions - Electric Power Consumption

The database relation between operators, facilities and sources facilitates summation of emission results and uncertainties for most aggregate levels desired by the end user. A suite of automated and standardized Excel spreadsheet reports are available to meet project specific reporting needs. Alternatively, results can be queried on-demand by authorized engineers.

2.12.1 DATA TRANSFER MODULES (DTM)

The primary purpose of a DTM is to automatically transform input data uploaded from an external source into a form suitable for direct import into NirCalc. Thus, DTMs represent “hand-shakes” between client databases and NirCalc. DTMs require a standard input data file, a data map and consistent use of the standardized input file. The DTMs apply QA/QC tests to raw input data and return a status report, identifying the tests and their outcome, to the user. A custom set of DTM rules transforms raw input data into a dataset that can be subsequently imported into NirCalc. A record of the input data, output NirCalc tables, warning report and ticket associated with each DTM is archived on the Clearstone LAN.

Rather than produce custom code for each DTM, the approach we shall take is to specify the parameters and processes of a DTM in an external xml file. Each xml file will be used to produce customized code which will be compiled and incorporated into the running application. In this manner, the creation of new DTMs and the modification and maintenance of existing DTMs will be simplified.

Secondary purposes for DTMs are to provide:

- a means of tracking the process of importing data into NirCalc.
- file naming conventions to facilitate import data archiving.

2.12.2 ADDING SYNTHETIC EQUIPMENT

This routine adds theoretical equipment based on volumetric reporting by industry, metadata for the subject facilities and field inventory statistics representative of UOG infrastructure (Clearstone, 2018). It is intended to bridge gaps in the equipment data available from industry and eliminate manual interactions with the database (historically required to add certain sources).

2.12.3 KEY TABLE NAMES AND DESCRIPTION

A description of key NirCalc tables is provided in the following subsections.

2.12.3.1 FACILITIES TABLE

This table contains records for wells and facilities that emit hydrocarbons during a reporting year. An UOG site must be included in the Facilities table to be included in the emission inventory. NirCalc relies on identifiers regulated by the AER, primarily for production accounting purposes, to define each site according to its production and process type. A description of the AER classification systems used to determine facility subtypes and well status codes are presented Sections 2.12.3.1.1 and 2.12.3.1.2. In addition, the Facilities table contains surface location, area, operator, start date, and licence details. This meta-data is important for predicting process equipment used to estimate emissions as well as aggregating results for external audiences. Meta-data also supports determination of unitized emission and energy intensity nodes that can be leveraged for predictive nodal analysis or lifecycle assessments.

AER data structures provide details at a well-level or, in aggregate, at a battery-level. For example, production, fuel, flare and venting volumes reported for a battery include contributions from all of the upstream wells flowing into the battery. Leveraging well-level details enables very granular equipment predictions and insight regarding production types (i.e., conventional versus non-conventional). However, there is a corresponding step-change in effort to interpret, manage, specify and implement data decisions corresponding to hundreds of thousands of wells versus tens of thousands of facilities. Previous UOG national inventories (ECCC, 2014 and CAPP, 2005) accounted for fugitive emissions from wellhead components but otherwise relied on aggregate details (described in Section 2.12.3.1.1) reported at the battery level. The current project will account for battery **and** disaggregated well details (described in Section 2.12.3.1.2).

2.12.3.1.1 FACILITY SUBTYPE CODES

When operators apply for a production accounting facility identifier (Facility ID), the AER requires that a facility subtype by specified according to the descriptions listed in Tables 2 and 3 of Manual 011 (AER, 2016). Facility subtypes, codes and their 2017 populations are presented in Table 11 and grouped according to UOG industry segments. Although these facility descriptions don’t provide complete or definitive explanations of process equipment installed, they do provide some insight on the nature of processing activities at subject sites. When combined with volumetric flow data and field inventory statistics, the quantity and size of equipment at discrete sites can be estimated.

Table 11: Facility Subtypes defined in AER Manual 11 and 2017 population counts.

UOG Industry Segment	Subtype Code	Facility Type	Facility Subtype	Count
Well drilling, testing and servicing	381	Battery	Drilling and completing	6
	371	Battery	Gas test	17
Light and Medium Crude Oil Production	311	Battery	Crude Oil (Medium) Single	4263
	321	Battery	Crude Oil (Medium) Multiwell Group	368
	322	Battery	Crude Oil Multiwell Proration	1720
	501	Injection	Enhanced recovery scheme	656
	502	Injection	Concurrent production-cycling scheme	1
	508	Injection	Enhanced recovery scheme (issued by AER). No License Required.	1
Cold Heavy Crude Oil Production	331	Battery	Crude bitumen single-well	861
	341	Battery	Crude bitumen multiwell group	1263
	342	Battery	Crude bitumen multiwell proration	342
	343	Battery	Crude bitumen/heavy oil administrative grouping	5
	611	Custom Treating	Custom Treating Facility	41
Thermal Heavy Crude Oil Production	344	Battery	In-Situ Oil Sands battery	34
	345	Battery	In-Situ Oil Sands battery (Sulphur Reporting)	3
	506	Injection	In-Situ oil sands	43
	902	Battery	Water Source	85
Natural Gas Production	351	Battery	Gas Single	4226
	361	Battery	Gas Multiwell Group	2548
	362	Battery	Gas Multiwell effluent	355
	363	Battery	Gas Multiwell proration SE AB	412
	364	Battery	Gas Multiwell proration outside SE AB	691
	365	Battery	Gas Multiwell Group (issued by AER). No License Required.	52
	366	Battery	Gas Multiwell proration SE AB (issued by AER). No License Required.	6
	367	Battery	Gas Multiwell proration outside SE AB (issued by AER). No License Required.	9
Natural Gas Gathering	601	Compressor Station	Compressor Station	760
	621	Gas Gathering	Gas Gathering System	2573
	622	Gas Gathering	Gas Gathering System (compression < 75 kW. Issued by AER). No License Required.	35
Natural Gas	401	Gas Plant	Gas Plant Sweet	367

Table 11: Facility Subtypes defined in AER Manual 11 and 2017 population counts.				
UOG Industry Segment	**Subtype Code**	**Facility Type**	**Facility Subtype**	**Count**
Processing	402	Gas Plant	Gas Plant Sour (receives <1 t/d sulphur) - Flaring	55
	403	Gas Plant	Gas Plant Sour (receives >1 t/d sulphur) - Flaring	26
	404	Gas Plant	Gas Plant Sour - Injection	18
	405	Gas Plant	Gas Plant Sour - Recovery	43
	406	Gas Plant	Gas Plant Sweet - Straddle	6
	407	Gas Plant	Gas Plant fractionation	12
	504	Injection	Acid Gas Disposal	28
Natural gas transmission, storage and distribution	204	Pipeline	Gas transporter	6
	206	Pipeline	Gas distributor	9
	505	Injection	Underground gas storage	12
	631	Gas Gathering	Field Receipt meter station	739
	632	Gas Gathering	Disposition meter station	195
	633	Gas Gathering	Interconnected meter station	7
	634	Gas Gathering	Border crossing meter station	50
	637	Gas Gathering	NEB field receipt meter station	11
	638	Gas Gathering	NEB interconnect receipt meter station	0
	639	Gas Gathering	NEB interconnect disposition meter station	0
	640	Gas Gathering	Interconnect PL to PL disposition meter station	3
Petroleum Liquids Transportation	207	Pipeline	Oil pipeline	61
	208	Pipeline	NGL pipeline	12
	209	Pipeline	NEB Regulated Pipeline	7
	671	Tank Farm-Terminal	Tank loading and unloading terminal	146
	672	Tank Farm-Terminal	NEB regulated terminal	0
	673	Tank Farm-Terminal	Third-party tank loading and unloading terminal	4
	675	Tank Farm-Terminal	RailCar/Oil Loading And Unloading Terminal	4
Disposal and Waste Treatment	503	Injection	Water Disposal	679
	507	Injection	Disposal (approved as waste plant)	84
	509	Injection	Disposal (issued by AER). No License Required.	10
	612	Custom Treating	Custom Treating Facility (approved as waste plant)	40

2.12.3.1.2 WELL STATUS CODES

Because the emission inventory is driven by production accounting systems, wells are known according to production string identifiers. In Alberta, these are defined by codes consisting of “ABWI” followed by a 16 digit unique well identifier (UWI) constructed of the following location and event element sequence.

- SURVEY SYSTEM CODE (always "1" for Dominion Land Survey)
- LOCATION EXCEPTION (2 digits)
- LEGAL SUBDIVISION (2 digits)
- SECTION (2 digits)
- TOWNSHIP (3 digits)
- RANGE (2 digits)
- "W"
- MERIDIAN (1 digit)
- EVENT SEQUENCE (1 digit)
- Padding Character (always "0")

Together these define the approximate geographical location of the bottom of a drill hole and a specific drilling or producing event at the drill hole. To be clear, UWIs define bottom-hole locations not surface locations. Moreover, there may be multiple production strings (UWI) for a single surface wellhead. Because emission inventory details (e.g., component counts, pneumatic device counts, leak survey results, etc) are determined for surface wellheads (and not production strings) in pressurized hydrocarbon service, the well licence number[13] and production activities must also be considered when defining a single surface wellhead[14]. The total number of UWIs obtained from the AER ST37 report will overstate the actual number of surface wellheads and well emissions if used to drive emission inventory calculations.

There are a number of other attributes available for each production string (UWI) that enable equipment predictions, emission estimates and meaningful aggregations. In addition to meta-data listed above, UWI-specific details include well status, pool, formation, first and last production date, drilling depth, surface casing vent flows (SCVF) and a gas migration (GM) indicator. The SCVF reported by operators can be adopted to directly calculate corresponding fugitive emissions while a GM emission factor can be applied to subject wells. Drilling depth provides a basis for estimating the quantity of diesel fuel consumed by a drilling rig for the subject well. Well status identifies the activity and initial classification of a well and its fluid. This attribute is used by a 2017 field study to determine average process equipment (with corresponding components) and pneumatic device counts by well type (Carleton, 2018). Thus, well-site equipment details are predicted according to the well status assigned to each UWI that reports production activities for a subject month.

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[13] A well licence is a unique licence issued by the AER for a single wellhead (upon approval of a Directive 056 Schedule 4 application).

[14] This is managed when adding synthetic equipment to the Sources table as described in Section 2.2.2.

The four categories used to describe well status are:

- Fluid - the primary fluid the well produces or injects, such as oil or gas.
- Mode - the mechanism the well uses to produce or inject, such as flowing or pumping, or the inactive phases of a well, such as suspended or abandoned.
- Type - the well type reflects the well's purpose, such as injection or disposal.
- Structure - the well structure reflects when a well has multiple wells that have commingled production, or when a well is completed horizontal and the producing interval is open and draining into a common wellbore.

All four categories may not apply to every well status[15]. The most common well status records are presented in Figure 4 with example counts from December 2017. Moreover, the total UWI count for December (i.e., 183,465 production strings) is greater than the number of well Licences reporting hydrocarbon flows (i.e., 154,394 wellheads) that are included in the emission inventory. This occurs because some wellheads have multiple production strings; are suspended or shut-in but not assigned the corresponding mode[16]; or are simply not in hydrocarbon service (i.e., water wells). How these details are interpreted may explain variations in well counts applied by different models used to predict methane emissions for Alberta. As indicated by the population distribution, emission inventory refinements should focus on the top 9 well status codes that represent 99 percent of the relevant well population.

Knowledge of reservoir formation may enable determination of conventional versus non-conventional production. However, this feature has not yet been implemented.

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[15] A convention is applied that concatenates non-null records from each category into a single well status record for the subject UWI.

[16] Some wells appear to have active well status (e.g., Gas Flow) but don't actually report hydrocarbon flows and are likely suspended or shut-in.

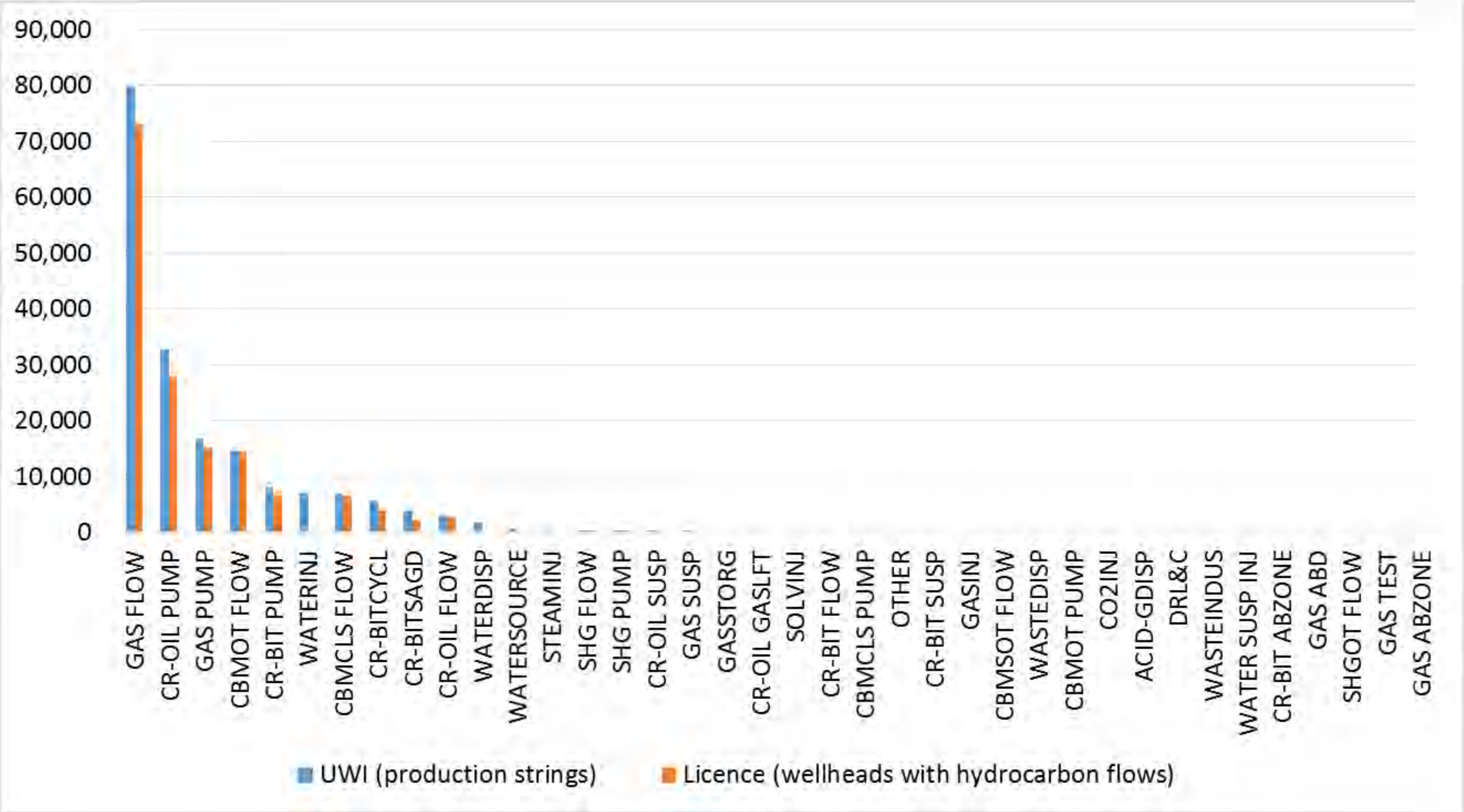

Figure 4: **Number of UWIs (representing production strings) and well licences (representing wellheads with hydrocarbon flows) for each well status code reported in Petrinex for December 2017.**

2.12.3.2 SOURCES TABLE

This table contains records for discrete emission sources that exist as a facility or well for a specified period (monthly resolution). Each source is characterized according to equipment type (e.g., compressor, flare, separator, pneumatic, etc.); applicable emission categories (e.g., fuel combustion, fugitives, venting, etc) and operating attributes (e.g., relevant emission factors, power rating, operating hours, process and fuel gas composition, etc.).

2.12.3.3 MONTHLYPRODUCTION TABLE

This table contains volumetric and well production hours reported by operators into Petrinex. The multitude of natural gas and oil process streams are defined by the activities and product codes specified in AER Manual 11 Appendix 1 and Appendix 2, respectively. In 2017, the 149 unique combinations listed in Table 12 were reported by operators to Petrinex.

Table 12: Process stream activities and products defined in AER Manual 011 and used in 2017.

Activity	Product	Description	Units
DISP	ACGAS	Acid Gas Disposition	1000 m^3
DISP	C4-MX	Butane Disposition	m^3
DISP	IC4-MX	Butane Disposition	m^3
DISP	NC4-MX	Butane Disposition	m^3
DISP	C4-SP	Butane Disposition	m^3
DISP	IC4-SP	Butane Disposition	m^3
DISP	NC4-SP	Butane Disposition	m^3
DISP	CO2	CO2 Disposition	1000 m^3
DISP	C2-MX	Ethane Disposition	m^3
DISP	C2-SP	Ethane Disposition	m^3
DISP	ENTGAS	Entrained Gas Disposition	1000 m^3
DISP	GAS	Gas Disposition	1000 m^3
DISP	C6-MX	Hexane Disposition	m^3
DISP	C6-SP	Hexane Disposition	m^3
DISP	C1-MX	Lite Mix Disposition	1000 m^3
DISP	CO2-MX	Lite Mix Disposition	1000 m^3
DISP	LITEMX	Lite Mix Disposition	1000 m^3
DISP	NGL	Natural Gas Liquids Disposition	m^3
DISP	COND	Condensate Disposition	m^3
DISP	Condensate	Condensate Disposition	m^3
DISP	OIL	Crude Oil Disposition	m^3
DISP	C5-MX	Pentane Disposition	m^3
DISP	IC5-MX	Pentane Disposition	m^3
DISP	NC5-MX	Pentane Disposition	m^3
DISP	C5-SP	Pentane Disposition	m^3
DISP	IC5-SP	Pentane Disposition	m^3
DISP	NC5-SP	Pentane Disposition	m^3
DISP	C3-MX	Propane Disposition	m^3
DISP	C3-SP	Propane Disposition	m^3

Table 12: Process stream activities and products defined in AER Manual 011 and used in 2017.			
Activity	**Product**	**Description**	**Units**
DISP	SAND	Sand Disposition	t
DISP	SPRILL	Sulphur Disposition	t
DISP	SUL	Sulphur Disposition	t
DISP	BRKWTR	Brackish Water Disposition	m^3
DISP	FSHWTR	Fresh Water Disposition	m^3
DISP	STEAM	Steam Disposition	m^3
DISP	WATER	Water Disposition	m^3
PURDISP	GAS	Gas Purchase Disposition	1000 m^3
FUEL	GAS	Natural Gas Fuel	1000 m^3
FUEL	ENTGAS	Entrained Gas Fuel	1000 m^3
FUEL	C2-SP	Ethane Fuel (liquid)	m^3
FUEL	C3-SP	Propane Fuel (liquid)	m^3
FUEL	GASOLINE	Gasoline Fuel	m^3
FUEL	DIESEL	Diesel Fuel	m^3
FUEL	PROCGAS	Process Gas Fuel	1000 m^3
FUEL	PURCHGAS	Purchased Natural Gas Fuel	1000 m^3
FLARE	GAS	Raw Gas Flared	1000 m^3
FLARE	ENTGAS	Entrained Gas Flared	1000 m^3
VENT	GAS	Natural Gas Venting	1000 m^3
VENT	CO2	CO2 Venting	1000 m^3
VENT	ENTGAS	Entrained Gas Venting	1000 m^3
FRAC	C4-MX	Butane fractionated yield	m^3
FRAC	C4-SP	Butane fractionated yield	m^3
FRAC	CO2-SP	Carbon dioxide fractionated yield	m^3
FRAC	CO2-MX	Carbon dioxide fractionated yield	m^3
FRAC	C2-MX	Ethane fractionated yield	m^3
FRAC	C2-SP	Ethane fractionated yield	m^3
FRAC	C1-MX	Methane fractionated yield	m^3
FRAC	C5-MX	Pentane fractionated yield	m^3
FRAC	C5-SP	Pentane fractionated yield	m^3
FRAC	C3-MX	Propane fractionated yield	m^3
FRAC	C3-SP	Propane fractionated yield	m^3
INJ	ACGAS	Acid Gas injection or disposal into a reservoir	1000 m^3
INJ	AIR	Air injection or disposal into a reservoir	1000 m^3
INJ	BRKWTR	Brackish water injection or disposal into a reservoir	m^3
INJ	CO2	CO2 injection or disposal into a reservoir	1000 m^3
INJ	COND	Condensate injection or disposal into a reservoir	m^3
INJ	Condensate	Condensate injection or disposal into a reservoir	m^3
INJ	ENTGAS	Entrained gas injection or disposal into a reservoir	1000 m^3
INJ	FSHWTR	Fresh water injection or disposal into a reservoir	m^3
INJ	GAS	Natural gas injection or disposal into a reservoir	1000 m^3
INJ	SOLV	Solvent injection or disposal into a reservoir	1000 m^3
INJ	SOLVENT	Solvent injection or disposal into a reservoir	1000 m^3
INJ	STEAM	Steam injection into a reservoir	m^3
INJ	WASTE	Waste injection or disposal into a reservoir	m^3
INJ	WATER	Water injection or disposal into a reservoir	m^3

Table 12: Process stream activities and products defined in AER Manual 011 and used in 2017.			
Activity	**Product**	**Description**	**Units**
LDREC	COND	Condensate recovered from well completion or service activity	m^3
LDREC	Condensate	Condensate recovered from well completion or service activity	m^3
LDREC	WATER	Water recovered from well completion or service activity	m^3
LDREC	OIL	Oil recovered from well completion or service activity	m^3
LDINJ	COND	Condensate injected for well completion or service purposes	m^3
LDINJ	Condensate	Condensate injected for well completion or service purposes	m^3
LDINJ	WATER	Water injected for well completion or service purposes	m^3
LDINJ	OIL	Oil injected for well completion or service purposes	m^3
PROC	C4-MX	Propane processed by plant	m^3
PROC	C4-SP	Propane processed by plant	m^3
PROC	BUTANE-MX	Propane processed by plant	m^3
PROC	BUTANE-SP	Propane processed by plant	m^3
PROC	CO2-SP	Carbon dioxide processed by plant	m^3
PROC	C2-MX	Pentane processed by plant	m^3
PROC	C2-SP	Pentane processed by plant	m^3
PROC	ETHANE-MX	Pentane processed by plant	m^3
PROC	ETHANE-SP	Pentane processed by plant	m^3
PROC	CO2-MX	Methane processed by plant	m^3
PROC	LITEMX	Methane processed by plant	m^3
PROC	LITE-MX	Methane processed by plant	m^3
PROC	OIL	Oil processed by plant	m^3
PROC	C5-MX	Ethane processed by plant	m^3
PROC	C5-SP	Ethane processed by plant	m^3
PROC	PENTANE-MX	Ethane processed by plant	m^3
PROC	PENTANE-SP	Ethane processed by plant	m^3
PROC	C3-MX	Butane processed by plant	m^3
PROC	C3-SP	Butane processed by plant	m^3
PROC	PROPANE-MX	Butane processed by plant	m^3
PROC	PROPANE-SP	Butane processed by plant	m^3
PROC	SUL	Sulphur processed by plant	t
PROD	GAS	Gas Production	1000 m^3
PROD	COND	Condensate Production	m^3
PROD	Condensate	Condensate Production	m^3
PROD	OIL	Crude Oil Production	m^3
PROD	WATER	Water Production	m^3
PROD	BRKWTR	Brackish Water Production	m^3
PROD	FSHWTR	Fresh Water Production	m^3
PROD	HOURS	Duration of well production activity	hours
PURREC	GAS	Gas Purchase Receipt	1000 m^3
REC	ACGAS	Acid Gas Receipts	1000 m^3
REC	C4-MX	Butane Receipt	m^3
REC	IC4-MX	Butane Receipt	m^3
REC	NC4-MX	Butane Receipt	m^3
REC	C4-SP	Butane Receipt	m^3
REC	CO2	CO2 Receipt	1000 m^3
REC	C2-MX	Ethane Receipt	m^3

Table 12: Process stream activities and products defined in AER Manual 011 and used in 2017.

Activity	Product	Description	Units
REC	C2-SP	Ethane Receipt	m^3
REC	ENTGAS	Entrained Gas Receipt	1000 m^3
REC	GAS	Gas Receipts	1000 m^3
REC	C6-MX	Hexane Receipt	m^3
REC	C6-SP	Hexane Receipt	m^3
REC	C1-MX	Lite Mix Receipt	m^3
REC	CO2-MX	Lite Mix Receipt	m^3
REC	LITEMX	Lite Mix Receipt	m^3
REC	COND	Condensate Receipt	m^3
REC	Condensate	Condensate Receipt	m^3
REC	OIL	Crude Oil Receipts	m^3
REC	C5-MX	Pentane Receipt	m^3
REC	IC5-MX	Pentane Receipt	m^3
REC	NC5-MX	Pentane Receipt	m^3
REC	C5-SP	Pentane Receipt	m^3
REC	C3-MX	Propane Receipt	m^3
REC	C3-SP	Propane Receipt	m^3
REC	PRILL	Sulphur Receipt	t
REC	SUL	Sulphur Receipt	t
REC	WASTE	Waste Receipt	m^3
REC	BRKWTR	Brackish Water Receipt	m^3
REC	FSHWTR	Fresh Water Receipt	m^3
REC	STEAM	Steam Receipt	m^3
REC	WATER	Water Receipts	m^3
RECYC	WATER	Water that entered the produced waste stream downstream of the wellhead and is not recovered	m^3
SHR	ACGAS	Acid Gas Production	1000 m^3
SHUTIN	NA	Shut-in facility with zero operating hours	Hours
SPILL	OIL	Spilled Oil	m^3

2.12.3.4 PROVINCIALFACILITYLISTMASTER TABLE

This table contains the entire population of Alberta facilities regulated by the AER, defines the inventory boundary and is used to validate incoming facility records. It's updated every month **and only contains the most recent data for a given year**. The table contains one Facility ID for a given year with records replaced when changes are reported by the provincial authority. The final record set and reporting responsibility (i.e., the Operator on December 31) for a given year is defined by the data download completed on January 21 of the new year.

2.12.3.5 PROVINCIALWELLLISTMASTER TABLE

This table is analogous to ProvincialFacilitiesListMaster and contains the entire population of Alberta wells regulated by the AER, defines the inventory boundary and is used to validate incoming well records. It's updated every month and **only contains the most recent data for a given year**. The table contains one UWI for a given year with records replaced when changes are reported by the provincial authority. The final record set and reporting responsibility (i.e., the Operator on December 31) for a given year is defined by the data download completed on January 21 of the new year.

2.13 QUALITY ASSURANCE/QUALITY CONTROL (QA/QC)

As a basic QA/QC measure, results were subjected to an internal review by senior engineering and environmental personnel to help ensure that no errors, omissions or double counting occurred. In addition, copies of the draft results were disseminated to the AER (and possibly other stakeholders) for review and comment on areas for improvement.

Where possible, the results were compared to previous baseline data and to other relevant corporate, industry and national inventories. Any apparent differences or anomalies were put in context relative to corresponding changes in activity levels, impacts of new regulatory requirements and voluntary industry initiatives.

Specific elements of the internal review conducted were:

- Confirmation that all useful sources of the required emission source, activity and emission factor data, calculation procedures and test methods were identified and properly referenced (both for the benefit of future updates and to provide a clear trail for resolving anomalies).
- Checks for recent updates or improvements in the selected calculation procedures and emission factors.
- Ranking of sources based on their emission and energy intensities to help identify anomalies.
- Checks to ensure that point source contributions were subtracted from area source category totals where appropriate.
- Confirmation of consistency between onsite equipment, products produced and connected infrastructure.
- Confirmation that combustion equipment was assigned to all sites with reported fuel use and none was assigned at sites with no fuel use.
- Tests for agreement between summaries of the activity data after being entered into the database application and corresponding published totals, where available.
- Manual checks of each type of calculation performed by the database application.
- Confirmation that zero in (emission factor or activity level) gave zero out.
- Gross checks to ensure that the amounts of reported and calculated emissions for each facility were reasonable compared to facility throughputs.

2.14 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.

2.14.1 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 15

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 16

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 16. 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 15 is used to evaluate the aggregate uncertainty for N sources of the same type and average strength, and Equation 16 is used to account for the fact the value N may have some uncertainty in it.

2.14.2 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 2.14.1.

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.

The applied uncertainty values generally remained unchanged from the values applied in the 2000 inventory (CAPP, 2004e).

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 source of published uncertainty values was the report on methane losses from the US natural gas industry sponsored by US EPA/GRI (1996). Additional uncertainty values were taken from IPCC (2000).

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 industry experts. The formal review of this document by the Project Steering Committee and other external reviewers was deemed to provide a reasonable mechanism for the critique of the presented uncertainty values.

2.14.3 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 15 and Equation 16, used for combining uncertainties, are applicable in cases where the variables are uncorrelated with a standard deviation of less than about 30% 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% confidence interval 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%, 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%, 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 15 and Equation 16. 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% would be assumed to have a lower uncertainty bound of U_{Lower} = -50%. In comparison, a quantity that is determined to have an upper uncertainty bound of U_{Upper} = +125% would be assumed to have a lower confidence limit of U_{Lower} = (100/125) * 100% = -80%. Similarly, an upper uncertainty bound of U_{Upper} = +200% would result in a lower uncertainty bound of U_{Lower} = (100/200) * 100% = -50%.

While use of the log normal 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.

2.14.4 UNCERTAINTY DATA

The emission factor uncertainties are included throughout this report wherever the emission factors are presented. Production volume uncertainties are provided in Table 13. Table 14 lists a number of other quantities used in emission calculations and their assumed uncertainty limits.

Table 13: Compilation of uncertainties associated with production volumes.

Facility Type	Quantity	Production Volume Range	Uncertainty (±%)
Oil Batteries[1]	Oil Production	< 100 m^3/d	1
		> 100 m^3/d	0.5
	Gas Production	> 16,900 m^3/d	5
		> 500 and <= 16,900 m^3/d	10
		< 500 m^3/d	20
Oil Proration[1]	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[1]	Gas Production	> 16,900 m^3/d	5
		<= 16,900 m^3/d	10
	Condensate	All	2
Gas Proration[1]	Gas Production	All	15
Gas Processing[1]	Gas Deliveries	All	2
	Hydrocarbon Liquid Deliveries	< 100 m^3/d	1
		> 100 m^3/d	0.5
All Facilities	Flared and Vented Volumes[1]	All	20
	Fuel Volumes[1]	> 500 m^3/d	5
		<= 500 m^3/d	20

Table 13: Compilation of uncertainties associated with production volumes.

Facility Type	Quantity	Production Volume Range	Uncertainty (±%)
	Acid Gas Volumes[1]	All	10
	Propane, diesel and gasoline Fuel[3]	All	25
	Other[3]	ALL	25

1. Based on maximum measurement accuracy requirements outlined in Tables 1.8.1 and 1.82 of AER Directive 017.
2. IPCC (2000) Good Practice Guidance and Uncertainty Management.
3. Based on engineering judgement and industry consultations.

Table 14: Compilation of uncertainties used in emission estimation calculations.

Item	Description	Uncertainty (±%)
Number of equipment units at a site and components per unit.	From industry surveys	Unit specific[17]
Speciation Profiles	Individual species mole fractions	10
Stream Molecular Weights	Calculated from speciation profiles	10
Stream High Heating Value	Calculated from speciation profiles	10
Fuel Proration	Calculated fraction of fuel associated with each gas fired unit at a site	25
Glycol Dehydrators	Emission Factors	25
Loading/Unloading	Emission Factors	25
	Vapour Pressures	25
	Loading Temperature	10
Storage Tanks	Vapour Pressures	25
	Storage Temperature	25

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

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[17] Equipment and component count uncertainties are available from Tables 3 to 5 of Clearstone, 2018.

large but when the emissions from many hundreds or thousands of facilities are aggregated the overall uncertainty may be very low.

3 FUEL COMBUSTION

3.1 UNIT-SPECIFIC EMISSIONS CALCULATION

The emissions from fuel use by a specific combustion device are calculated using the following general relation:

$$\boldsymbol{ER_{i,j} = \sum_{k=1}^{k=12} EF_{i,j} \times Q_i \times HHV \times (1 - CF_i) \times g_c}$$

Equation 17

Where,

$ER_{i,j}$ = emission rate of substance j from source i (t/y).
$EF_{i,j}$ = emission factor for source i (ng/J).
Q_i = fuel consumption by source i during study year (m^3/yr).
HHV = higher heating value of the fuel (MJ/m^3).
CF_i = control factor for a specific control measure or device applied to source i which indicates the fraction by which the emissions are reduced (kg/kg).
= 0 in the absence of any data.
g_c = a constant of proportionality used to convert the results to units of t/y.
= 10^{-9} (dimensionless)

3.2 DETERMINATION OF FUEL CONSUMPTION

3.2.1 GENERAL EQUATION

The general equation for estimation of the amount of fuel consumed by a specific combustion device is as follows:

$$\boldsymbol{Q_{k,i} = PF_i \times Q_{Reported}}$$

Equation 18

Where,

$Q_{k,i}$ = fuel consumed by source i during study year (m^3/yr).

PF_i = proration factor indicating the portion of the total reported fuel consumption at the site used by combustion source i (dimensionless) (see Table 15 for default values and Section 3.2.2 for procedures to development of site-specific values).

$Q_{Reported}$ = total reported fuel consumption at the site during study year (m^3/yr)

3.2.2 PRORATION OF TOTAL REPORTED FUEL CONSUMPTION

The following subsections delineate the methods used to prorate reported fuel gas consumption (i.e., fuel gas taken from the process) by combustion devices. The volumes of the different types of purchased fuels consumed (e.g., natural gas, propane and diesel) were estimated based on available trend data for a representative cross-section of the industry.

Operators are required, as part of normal production accounting requirements, to report the total amount of fuel taken from the process at each of their sites. In Alberta, purchased natural gas fuel is accounted in the same manner and subject to the requirements of AER Directives 007 and 017. The types of facilities where significant amounts of fuel may be purchased include thermal heavy oil and bitumen production facilities, as well as some minor field installations and wellsite facilities on sour systems where sweet process fuel is not available.

There are a wide variety of fuel-gas metering arrangements that may occur at facilities to determine reportable fuel consumption. This complicates production accounting requirements and introduces a potential for error. Often complexities in fuel gas metering and accounting are introduced as a result of additions and changes to existing facilities over time.

At many facilities, a single flow meter is installed to measure the total amount of reportable fuel withdrawn from the process. Sometimes secondary meters are installed to determine fuel disposition by major fuel-use categories but this additional information is usually only for internal use at such facilities and is not carried forward into the final production accounting statistics reported to government agencies.

In other cases, the available fuel gas meter or meters may measure only a portion of the fuel gas usage. For example, it is common practice for packaged compressor units to be supplied with a dedicated fuel gas meter. A facility might rely on these meters to determine fuel use by the compressor engines, and then simply estimate the amount of fuel consumption by all other sources (e.g., fuel for heaters, reboilers, incinerators, flare pilots, and for flare header purge and makeup gas).

Fuel gas used for non-combustion purposes (e.g., instrument gas, compressor start gas, dehydrator stripping gas, blow-case supply gas, and some blanket gas and equipment purging applications) may occur either upstream or downstream of available fuel gas meters, or a combination thereof.

Sometimes fuel gas is added to waste gas streams (e.g., to acid gas at flaring sour gas plants) to meet the minimum required heating value for stable flaring of the stream.

At small field installations (e.g., meter stations, field dehydrators and line heaters), total fuel use reported by companies may not be metered if it is less than 0.5 10^3 m^3 per day but rather estimated based on equipment duties and operating hours. The fuel use at well sites is normally allocated to the first downstream facility (e.g., battery) rather than reported at the well-site level. With the implementation of Petrinex in Alberta, this is beginning to change. It is now possible to report fuel use at the point where it is actually consumed (as specified in Section 4.3.3.1 of AER Directive 17).

In estimating emissions, it is important to determine the amount of purchased fuel consumption, the disposition of total reported and purchased fuel use by type of combustion device. This is most important for determining emissions of criteria air contaminants such as CO, NO_x, and PM, since the emission factors for these substances vary greatly according to the type of combustion device (i.e., reciprocating engine, turbine engine or heater/boiler). For GHG emissions it is less of an issue since CO_2 is the predominant contributor to GHG emissions from fuel combustion, and the emission factors for this substance vary little with the type of combustion device. Methane emission factors for fuel combustion do vary significantly with the type of combustion device and may contribute up to 17 percent of fuel-use GHG emissions. N_2O emissions from fuel combustion are a much less important contributor to fuel-use GHG emissions. Moreover, N_2O emission factors are not generally available for all types of combustion devices.

For natural gas, the composition of the fuel may vary appreciably from site to site but the actual carbon content of the fuel is much less sensitive. Typical values may range from 64 to 76 percent on a mass basis for different types of gas streams (e.g., raw gas, processed gas, tank vapours and dehydrator vent gas). For processed natural gas, the carbon content may only range from about 72 to 74 percent on a mass basis.

3.2.2.1 USE OF DEFAULT PRORATION FACTORS

At most facilities, natural gas, or sometimes even crude oil, is taken from the process and used as fuel. On an industry-wide basis, most of this fuel is used by compressor engines, pump engines, heaters and boilers. The disposition of this fuel by type of device is estimated based on fired equipment counts from Clearstone, 2018. For sites not surveyed in Clearstone, 2018 fuel dispositions are estimated according to Table 15 below.

Table 15: Disposition of burned fuel gas by sub-sector of the UOG industry.

Sub-Sector	Fraction of Fuel Burned (percent)

	Reciprocating Engines	Gas Turbines	Heaters/ Boilers
Heavy Crude Oil Thermal Prod.	0.7	0.0	99.3
Oil Terminals and Transport	25.0	0.0	75.0
Sweet Natural Gas Processing Plants	84.9	0.0	15.1
Sour Natural Gas Plants – Injection	96.1	0.0	3.9
Sour Natural Gas Plants – Flaring	82.0	0.0	18.1
Sour Natural Gas Plants – Recovery	15.6	10.2	74.3
Straddle Natural Gas Plant	0.0	92.6	7.4
Propane Consumption	40.0	0.0	60.0

Other fuel uses include make-up gas to flare gas streams to satisfy minimum heating value requirements for stable combustion, supplemental fuel for incinerators to achieve good destruction efficiencies and/or to maintain the minimum stack temperatures needed to achieve good atmospheric dispersion of the emitted substances, flare and incinerator pilot gas, flare and vent header purge gas, blanket gas for storage tanks, and the supply medium for gas operated devices (e.g., instrument control loops, chemical injection pumps and compressor starters).

In most cases, natural gas taken from the process is the principal type of fuel used for stationary combustion devices, while purchased liquid fuels are mostly used for mobile sources (e.g., construction equipment and motor vehicles). Purchased propane is sometimes used for small compressors, pump jack engines and portable heaters and torches.

3.2.2.2 DEVELOPMENT OF SITE-SPECIFIC PRORATION FACTORS

Three types of situations are encountered regarding reported fuel use at individual facilities:

- Information is available on the number, types and sizes of combustion equipment at the site. In these cases, calculations are performed to estimate the theoretical amount of fuel use by each device and the results are then used to develop factors for prorating the actual reported fuel use.
- No information is available on the number and sizes of combustion equipment at the site, but based on the type of facility it could be reasonably assumed that all fuel was consumed by a specific type of combustion device. For example, at a gas gathering compressor station it could reasonably be assumed that all fuel is consumed by one or more reciprocating engines. At an oil production facility with no gas conservation, the fuel could reasonably be assumed to be all consumed by process and tank heaters.
- No information is available on the number and sizes of combustion equipment at the site and it is likely that more than one type of combustion device is being used. In these cases, the fuel use is prorated using the average proration values determined for other facilities of the same type

for which such detailed information are available (see Table 15). Moreover, sites reporting natural gas fuel consumption less than 20 $10^3 m^3$ per year are only assigned heaters and boilers (i.e., engines and turbines are typically not located at sites consuming less than this).

The proration of reported fuel use based on theoretical fuel use is done using the following equation:

$$\boldsymbol{PR_i = \frac{Q'_i}{\sum_i Q'_i}}$$

Equation 19

where,

PR_i = developed proration factor for source i (dimensionless),
Q'_i = theoretical (or estimated) fuel combustion by combustion source i (GJ/yr)

The numerator in the above equation is the theoretical amount of fuel consumed by combustion source i annually. The denominator is the theoretical amount of fuel consumed by all combustion sources annual for the specified fuel of interest.

The procedures for calculating the theoretical amount of fuel consumption by a combustion device are presented in Sections 3.2.2.2.1 and 3.2.2.2.2.

3.2.2.2.1 THEORETICAL FUEL CONSUMPTION BASED ON MAXIMUM RATED POWER OUTPUT

In the absence of any better information, the theoretical fuel gas consumption by a stationary or portable combustion device is estimated based on its maximum rated power output, the heating value of the fuel and an appropriate thermal efficiency, load factor and operating factor as given by the following equation:

$$\boldsymbol{Q'_i = k_{L_i} \cdot k_{OT_i} \cdot \left(\frac{100\ HHV}{\eta\ LHV}\right) \cdot e_{max} \cdot g_c}$$

Equation 20

where,

Q'_i = theoretical (or estimated) fuel combustion by combustion source i (GJ/yr),
e_{max} = maximum rated power output of the combustion device (kW),

$k_{L,i}$ = fractional loading of combustion device i (dimensionless) (see Table 17 for default values),

$k_{OT,i}$ = fraction of the time that combustion device is operating during the study year (see Table 18 for default values),

η = thermal efficiency of the device based on the net heat/energy input rate (percent) (see Table 16 for default values),

HHV_F = higher (gross) heating value of the fuel gas (MJ/m^3),

LHV_F = lower (net) heating value of the fuel gas (MJ/m^3), and

g_c = factor to convert from units of kJ/s to GJ/y,

= 31.536.

Default thermal efficiency, load and operating factors are presented in Table 16 to Table 18, respectively.

Table 16: Typical input heat rates and thermal efficiencies (based on the net heating value of the fuel) for different types and sizes of natural gas-fueled equipment.

Source Type	Maximum Rated Power Output (kW)	Input Heat Rate (kJ/kW•h)	Thermal Efficiency (percent)
Reciprocating Engines	<325	12 857	28[1]
	325 to 600	11 250	32[1]
	600 to 2250	10 000	35[1]
	>2250	9 474	38[1]
Turbine Engines	All	10 909	33[2]
Industrial and Commercial Heaters and Boilers	<375 (Natural Draft)	4 736	76[3]
	<375 (Forced Draft)	4 500	80[2]
	≥375	4 500	80[2]
Residential Water Heaters	All	7 500	48[4]
Residential Furnaces	All	5 143	70[5]
Catalytic Heaters	Vented Outdoors	4 500	80[6]
	Vented Indoors	3 600	100
Thermoelectric Generators	All	100 000	3.6[2]

Note: The shaded entries in the table are used as defaults where no other information was supplied.

1. Adapted from Perry and Chilton (1973).
2. Estimated based on a review of current manufacturer's data for selected units (CAPP, 2004c).
3. Adapted from Fig 8-30 of GPSA Engineering Data Book, Volume 1, tenth Edition, 1987.
4. Adapted from Geller (1988).
5. Adapted from Baumeister et al. (1978).
6. Catalytic heaters emit radiant heat and discharge thermal heat with the combustion products. Thus, the thermal efficiency of a catalytic heater depends on the ability of the room to absorb the radiant

Table 16: Typical input heat rates and thermal efficiencies (based on the net heating value of the fuel) for different types and sizes of natural gas-fueled equipment.			
Source Type	**Maximum Rated Power Output (kW)**	**Input Heat Rate (kJ/kW•h)**	**Thermal Efficiency (percent)**

heat (i.e., on the absorptivity of the objects in the room). Based on discussions with one major manufacturer of catalytic heaters used in process buildings, actual unit efficiencies may range from 50 to 80 percent. Although, a value of 80 percent is typically used for design purposes. (CAPP, 2004c)

Table 17: Estimated load factors for combustion devices during actual running/firing periods[1].

Source Type	**Load Factor (k_L) (Fraction of Maximum Rated Power Output)**
Reciprocating Engines	0.75
Turbine Engines	0.90
Industrial and Commercial Heaters and Boilers	1.0
Residential Water Heaters	1.0
Residential Furnaces	1.0
Catalytic Heaters	1.0
Thermoelectric Generators	1.0

1. Based on engineering estimates and personal experience originally published in (CAPP, 2004c).

Table 18: Typical portion of the time combustion devices are actually running/operating.

Source Type	**Fractional Time In Operation**	**Annual Operating Hours**
Reciprocating Engines	0.79[1]	6920
Turbine Engines	0.81[1]	7096
Industrial and Commercial Heaters and Boilers <29 MW	0.50[2]	4380
Industrial and Commercial Heaters and Boilers >29 MW	1.0	8760
Residential Water Heaters	0.17[3]	1489
Residential Furnaces	0.25[4]	2190
Catalytic Heaters	0.50[5]	4380
Thermoelectric Generators	0.95[6]	8322

1. Mean of data collected by Legge and Baker (1987) for equipment at oil and gas facilities in Alberta.
2. Arbitrarily determined based on typical sizing practice for the types of applications usually encountered at gas facilities originally published in (CAPP, 2004c).
3. Based on hot water usage only during normal day-time working hours (i.e., 8 hours per day for 5 days per week), and an assumed 50 percent duty during this period originally published in (CAPP, 2004c).

Table 18: Typical portion of the time combustion devices are actually running/operating.		
Source Type	**Fractional Time In Operation**	**Annual Operating Hours**

4. Based on use only during the colder half of the year and on an assumed 50 percent duty during this period originally published in (CAPP, 2004c).
5. Based on use only during the colder half of the year and on an assumed 100 percent duty during this period originally published in (CAPP, 2004c).
6. Based on use an assumed 100 percent duty except for a 2 to 3 week shutdown period each year originally published in (CAPP, 2004c).

3.2.2.2.2 THEORETICAL FUEL CONSUMPTION BASED ON ACTUAL WORK OR HEAT OUTPUT

If sufficient data are available (e.g., temperatures, pressures and flows), then the amount of fuel consumed by each type of combustion devices was determined based on the estimated amount of process work they were performing and their typical thermal efficiencies..

The calculations were performed using process simulations of each unit operation.

Equipment manufacturers typically report specific fuel requirements based on the net heating value of the fuel rather than the gross heating value as considered herein. Consequently, where fuel consumption is estimated from equipment performance curves, the results are converted to a gross-heating-value basis before being used with the equations and emission factors provided in this document.

3.3 EMISSION FACTORS

3.3.1 CO_2 AND SO_2 EMISSION FACTORS

The CO_2 emission factor for a fuel is assessed using Equation 7.

3.3.2 COMPRESSOR ENGINES

3.3.2.1 SOURCE CHARACTERIZATION

Both reciprocating and turbine engines are used as prime movers for natural gas compressor units, and are described in the following subsections.

Many natural gas-fuelled engines have been retrofit with NO_x emission control features. But little information is available to document the extent of these actions. Furthermore, where catalytic converters (3-way catalytic converters can reduce NO_x, CO and CH_4 emissions) have been installed few companies have implemented formal programs to maintain these systems so their average performance is uncertain. As a likely conservative approximation, NO_x emission controls are only assumed to be in use where documentation is available.

Additionally, the general experience from performance tests conducted on engines used in the UOG industry has been that those at larger manned facilities are better maintained and tuned than those at small unmanned facilities. This contributes to the uncertainties in the applied emission factors.

When installed, the most common post-combustion NO_x reduction treatment is selective catalytic reduction (SCR). This reduces NO_x emissions approximately 80 percent, but is expensive and requires the operator to store large quantities of ammonia. SCR selectively reduces NO_x emissions by injecting ammonia into the exhaust upstream of the catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O with unreacted NH_3 emitted to the atmosphere.

3.3.2.1.1 RECIPROCATING ENGINES

Natural gas-fuelled reciprocating engines used in compressor applications may range in size from about 30 to 3500 kW, and typically operate at speeds of 800 to 1800 rpm. Some low-speed (i.e., 360 to 525 rpm) single-cylinder and two-cycle units also are available.

Reciprocating engines are available in both naturally-aspirated (NA) and turbocharged-after-cooled (TA) configurations. Additionally, both high and low compression ratio versions are available for most engines. The high compression ratio pistons are used on TA engines to reduce brake-specific fuel consumption (BSFC) and emissions, but can only burn a very narrow range of fuels. The low compression ratio pistons are used on both TA and NA standard engines.

Any combination of aspiration type, compression ratio, fuel composition and emission control technology can change the rating of a given engine. So, where actual configuration data are available unit-specific performance and emission factor data are applied.

Optimum combustion conditions (maximum power) are obtained when the air-fuel ratio is close to stoichiometric. Current natural gas engines are generally designed to run lean. The excess air promotes more complete combustion of the fuel, which helps to improve fuel efficiencies and reduce the thermal load on the engine. Fuel efficiency varies as a function of actual power output and engine speed.

Unfortunately, the conditions that tend to promote maximum power output and fuel efficiency also create the highest combustion temperature, which promotes the formation of NO_x emissions. The common method to limit emissions on gas engines is called lean burn, a technology developed in the 1980s. Lean-burn engines use the turbocharger to run 50 to 100 percent excess air (above the stoichiometric requirement) through the combustion chamber. Excess air reduces combustion temperatures resulting in lower NO_x but higher CO, CH_4 and THCs when compared with the rich-burn engine. It is critical to maintain a nearly constant air-fuel ratio in order to maintain emission levels of an engine.

3.3.2.1.2 GAS TURBINES

Stationary gas turbine engines are available in sizes up to a current maximum capacity of 220 MW but typical sizes tend to be in the range of 1 to 25 MW for most industrial applications. In the gas industry they tend to be used in processing and transmission rather than gathering applications.

The rated thermal efficiency of turbine engines is typically 30 to 35 percent and can be as high as 42 percent for new gas turbine models with smaller units tending to the lower end of the range. The input heat rates required to achieve the manufacturer’s published power outputs for each unit are referenced at standard conditions and on the net heating value of the fuel, and must be derated to site conditions. Differences in ambient air temperature, altitude, barometric pressure and humidity should all be accounted when making these adjustments. No power correction is normally required.

The gas turbine, in general, is a low emitter of exhaust gas air contaminants relative to reciprocating engines in similar service (e.g., methane emissions are roughly an order of magnitude lower for gas turbines than for similarly rated reciprocating engines). This is because the fuel is burned with ample excess air to ensure essentially complete combustion at all but minimal load conditions.

The amount of NO_x emissions produced by turbine engines is a function of the fuel burned, firing temperature, exhaust discharge temperature and residence time in the combustion zone. Since the trend towards high turbine efficiencies leads to higher pressure ratios and firing temperatures, the emission rates of NO_x are higher for these units.

The normal method for reducing NO_x formation in turbines is to reduce combustion temperatures. Maintaining an operating temperature in the combustor at 1500ºC or below virtually eliminates production of NO_x; however, this is not achievable by conventional combustion control methods such as steam or water injection, or premixing air and natural gas prior to entering the combustor (this process is referred to as lean premix or dry-low-NO_x [DLN]). Presently, the low combustion temperatures are only achieved through catalytic combustion (e.g., the XONON combustion system by Catalytica Combustion Systems Inc.).

3.3.2.2 DEFAULT EMISSION FACTORS

Table 19 presents average CAC, GHG and other priority substance emission factors for natural gas-fuelled reciprocating engines published in the US EPA AP-42 Compilation of Air Pollutant Emission Factors (EPA, 1998). Corresponding factors are presented for natural gas-fuelled turbines in Table 20. Actual manufacturer's data and available test data for specific makes and models of compressor engines are available from Volume 4 of ECCC, 2014.

Table 19: Emission factors for CACs, GHGs and other priority substances from stationary natural gas-fueled reciprocating engines[1].

Substance	2-Stroke Lean-Burn (ng/J)	4-Stroke Lean-Burn (ng/J)	4-Stoke Rich-Burn (ng/J)
NO_x	1363 (834)[2]	1754 (364)[2]	950 (976)[2]
N_2O[3]	5.72	5.72	5.72
CO	166 (152)[2]	136 (240)[2]	1600 (1509)[2]
TOC	705	632	154
VOC	52	51	13
Methane	624	538	99
PM_{10} (Filterable)	16.5	0.033	4.1
$PM_{2.5}$ (Filterable)	16.5	0.033	4.1
NH_3	3.83[4]	3.83[4]	3.83[4]
Benzo(a)pyrene	2.442E-06	none	none
Benzo(b)fluoranthene	3.659E-06	7.138E-05	none
Benzo(k)fluoranthene	1.832E-06	none	none
Indeno(1,2,3-c,d)pyrene	4.270E-06	none	none
hexachlorobenzene	none	none	none

Table 19: Emission factors for CACs, GHGs and other priority substances from stationary natural gas-fueled reciprocating engines[1].			
Substance	**2-Stroke Lean-Burn (ng/J)**	**4-Stroke Lean-Burn (ng/J)**	**4-Stoke Rich-Burn (ng/J)**
Dioxins	none	none	none
Furans	none	none	none

none – no emission factor is published for these pollutants and combustion devices in U.S. EPA (2000) or http://cfpub.epa.gov/webfire/index.cfm?action=fire.main. Emissions factors for natural gas fired boilers presented in Table 23 are used instead.

1. Adapted from U.S. EPA (2000): Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.2-1 to 3.2-3.
2. Bracketed value is at <90% load and the other value is at 90 to 105% load.
3. Adapted from CAPP (1999): A Detailed Inventory of CH_4 and VOC emissions from Upstream Oil and Gas Operations in Canada. CAPP Pub. # 1999-0010.
4. Only applied to engines with SCR post-combustion NOx reduction technology (Battye et al., 1994)

Table 20: Summary of U.S. EPA average emission factors for different types of natural gas-fueled turbine engines[1].

Substance	Uncontrolled (ng/J)	With Water/ Steam Injection (ng/J)	Lean-Premix (ng/J)
NO_x	138	56	43
N_2O[2]	1.29	1.29	1.29
CO	35[3]	13	6.5
TPM, PM_{10}, $PM_{2.5}$[4]	0.82	0.82	0.82
CH_4	3.69	3.69	3.69
THC	4.73	4.73	4.73
VOC	0.90	0.90	0.90
NMHC[5]	1.04	1.04	1.04
NH_3	3.83[6]	3.83[6]	3.83[6]
Benzo(a)pyrene	none	none	none
Benzo(b)fluoranthene	none	none	none
Benzo(k)fluoranthene	none	none	none
Indeno(1,2,3-c,d)pyrene	none	none	none
hexachlorobenzene	none	none	none
Dioxins	none	none	none
Furans	none	none	none

none – no emission factor is published for these pollutants and combustion devices in U.S. EPA (2000) or http://cfpub.epa.gov/webfire/index.cfm?action=fire.main. Emissions factors for natural gas fired boilers presented in Table 22are used instead.

1. Adapted from U.S. EPA (2000): Supplement to Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 3.1-1 and 3.1-2
2. Adapted from CAPP (1999): A Detailed Inventory of CH_4 and VOC emissions from Upstream Oil and Gas Operations in Canada. CAPP Pub. # 1999-0010.
3. It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation
4. All PM (total, condensable and filterable) is assumed to be less than 2.5 µm in diameter. Therefore, the PM emission factors presented here may be used to estimate PM2.5 or PM10 emissions. Total PM is the sum of the filterable and condensable PM. Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.
5. Calculated as the difference between THC and methane emission factors originally published in (CAPP, 2004c).
6. Only applied to engines with SCR post-combustion NOx reduction technology (Battye et al., 1994)

3.3.3 PROCESS HEATERS AND BOILERS

This category includes boilers, choke heaters, line heaters, reboilers and utility heaters. These are mainly indirect fired units.

3.3.3.1 SOURCE CHARACTERIZATION

Two general types of fired heaters and boilers are used in the natural gas industry (GPSA, 1987): watertube and firetube. Watertube units are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. Firetube units are designed such that the hot combustion gases flow through tubes which heat a liquid circulated outside of the tubes. Firetube boilers range in duty from 10 kW (e.g., small utility heaters) to 3 500 kW (e.g., gas pipeline line heaters). The design, controls, and operation of firetube heaters varies widely from vary simple natural draft designs to well-instrumented forced air units. Good fuel efficiency is achieved through low stack temperatures, low excess air, and insulation of the unit.

Basic design features may include:

- Multi-pass fire tubes.
- Forced or natural draft combustion air systems.
- Smaller units (10 to 75 kW) tend to have on-off firing while larger units often have full modulation firing.
- Air dampers may include single-blade, rotary and multi-blade designs.
- Only the larger sizes of boilers would tend to have any kind of emission control. These may include low-NO_x burners and internal flue gas recirculation (FGR). Post combustion control techniques generally are not used on boilers with energy inputs less than 30 MW.

A boiler's excess air supply provides for safe operation above stoichiometric conditions. A typical burner is usually set up with 10 to 20 percent excess air (2 to 4 percent excess O_2). NO_x controls that require higher excess air levels can result in fuel being used to heat the air rather than converting it to usable energy.

3.3.3.2 DEFAULT EMISSION FACTORS

Except where unit-specific emission factors are known, all heaters and boilers are assumed to be represented by the average emission factors presented in Section 3.3.3. Average emission factors from the US EPA AP-42 Compilation of Air Pollutant Emission Factors (EPA, 1998) for natural gas -fuelled heaters and boilers are presented in Table 21 and Table 22. Table 23 presents some additional factors presented by one manufacturer for common air contaminants from low-NO_x natural gas-fuelled heaters and boilers. Emission factors for GHGs from propane- and butane-fuelled heaters and boilers are presented in Table 24.

Table 21: Emission factors for nitrogen oxides (NOx) and carbon monoxide (CO) from natural gas-fuelled heaters and boilers[1].

Source Types	Size (MW)	Emission Controls	NO_x (ng/J)[2]	CO (ng/J)
Wall-fired Units	>29	Uncontrolled - Pre-NSPS[3]	118	35
		Uncontrolled - Post-NSPS[3]	80	35
		Controlled - Low NO_x Burners	59	35
		Controlled - Flue Gas Recirculation	42	35
	≤29	Uncontrolled	42	35
		Controlled - Low NO_x Burners	21	35
		Controlled - Low NO_x Burners/Flue Gas Recirculation	13	35
Tangential-Fired Units	All	Uncontrolled	72	10
		Controlled - Flue Gas Recirculation	32	41
Residential Furnaces	<0.088	Uncontrolled	40	17

Note: The shaded entries in the table are used as defaults where no other information was supplied.

1. Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-1.
2. Expressed as NO_2. For large and small wall-fired boilers with SNCR control, apply a 24 percent reduction to appropriate NO_x emission factor. For tangential-fired boilers with selective non-catalytic reduction (SNCR) control, apply a 13 percent reduction to the appropriate NO_x emission factor.
3. NSPS = New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 73 MW of heat input that commenced construction modification or reconstruction after August 17, 1971, and units with heat input capacities between 29 and 73 MW that commenced construction modification or reconstruction after June 19, 1984.

Table 22: Emission factors for CACs, GHGs and other priority substances from natural gas combustion by heaters and boilers[1].	
Substance	**Emission Factor (ng/J)**
N_2O (Uncontrolled)	0.9
N_2O (Controlled-low-NO_x burner)	0.3
TPM, PM_{10}, $PM_{2.5}$[2]	0.80
TOC	4.6
Methane	1.0
VOC	2.3
NH_3[3]	1.349
Benzo(a)pyrene[4]	5.059E-07
Benzo(b)fluoranthene[4]	7.588E-07
Benzo(k)fluoranthene[4]	7.588E-07
Indeno(1,2,3-c,d)pyren[4]e	7.588E-07
hexachlorobenzene	none
Dioxins	none
Furans	none

None – no emission factor is published for these pollutants and combustion devices in U.S. EPA (2000) or http://cfpub.epa.gov/webfire/index.cfm?action=fire.main

1. Adapted from U.S. EPA (1998): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.4-1.
2. All PM (total, condensable and filterable) is assumed to be less than 1.0 micrometres in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ and PM_1 emissions. Total PM is the sum of the filterable and condensable PM. Condensable PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.
3. Adapted from Battye et al., 1994 (Table 7-4) and applied to all heaters and boilers.

Table 23: Manufacturer's emission factors for common air contaminants from natural gas-fueled commercial firetube boilers for different NOx control levels.					
Substance	**Emission Factors (ng/J)**				
	Uncontrolled[1]	**60 ppm[2] NO_x**	**30 ppm[2] NO_x**	**25 ppm[2] NO_x**	**20 ppm[2] NO_x**
CO	64	64	17/47[3]	17/47[3]	64
NO_x	52	30	15	13	10
THC	6.9	6.9	6.9	6.9	6.9
PM	4.3	4.3	4.3	4.3	4.3

1. Equivalent to a NO_X value of 100 ppm.
2. ppm levels are given on a dry volume basis and corrected to 3 percent oxygen (15 percent excess air).
3. The low CO value applies when the boiler is operated at greater than 50 percent of rated capacity, and the higher CO value applies to all lesser load values.

Table 24: Emission factors for LPG-fueled heaters and boilers[1].				
Substances	**Butane[1] Fuelled Commercial and Industrial (0.1 to 30 MW)**		**Propane[1] Fuelled Commercial and Industrial Units (0.1 to 30 MW)**	
	(ng/J)	**(g/L)**	**(ng/J)**	**(g/L)**
TPM, PM_{10}, $PM_{2.5}$[2,3]	0.8	0.02	0.9	0.02
SO_2[4]	423 x S	0.011 x S	417 x S	0.012 x S
NO_x[5]	63.2	1.8	61.1	1.6
N_2O[2,6]	3.8	0.1	4.2	0.1
CO_2[6]	60 830	1730	59 660	1510
CO	35.4	1.0	35.2	0.9
VOC	3.8	0.1	3.8	0.1
CH_4[6]	0.8	0.02	0.9	0.02

Note: The shaded entries in the table are used as defaults where no other information was supplied.

1. Based on a gross heating value of 28.429 MJ/m^3 for liquid butane and 25.503 MJ/m^3 for liquid propane. Assumes emissions (except SO_2 and NO_x) are the same, on a heat input basis, as for natural gas combustion. The NO_x emission factors have been multiplied by a correction factor of 1.5, which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions.
2. Adapted from U.S. EPA (2008): Compilation of Air Pollutant Emission Factors, Volume 1 - Stationary Point and Area Sources. Table 1.5-1.
3. Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. For natural gas, a fuel with similar combustion characteristics, all PM is less than 10 µm in aerodynamic equivalent diameter (PM_{10}).
4. S equals the sulphur content of the fuel expressed in grains/100 ft^3 of vapour.
5. Expressed as NO_2.
6. From WCI.20 Table 20-2.
7. VOC is assumed to be TOC (total organic carbon) minus methane.

4 FLARING

4.1 SOURCE CHARACTERIZATION

A flare is an open flame used for routine or emergency disposal of a hazardous waste gas stream. There are a variety of different types of flares including: flare pits, flare stacks, enclosed flares and ground flares.

Flaring is currently used in a number of oil and gas operations, both upstream and downstream. Flaring is usually differentiated depending on whether or not it involves acid gas.

Since 1999, AER has been pursuing an initiative to substantially reduce flaring of all kinds in Alberta, particularly flaring of solution gas at crude oil production facilities. Initially, this initiative was primarily driven by concerns about toxic products of partial or incomplete combustion that may be formed in flares. Expansion of gas conservation regulations to include venting sources was due to concerns related to GHG and VOC emissions.

Flaring and venting must be reported if it exceeds 0.1 10^3 m^3 per month per facility and metered if it exceeds 0.5 10^3 m^3 per day (AER, 2016). Ultrasonic flow meters and optical flow meters have been gaining popularity on emergency flare systems where the use of obstructive flow meters (e.g., orifice meters) can cause plugging or introduce excessive backpressure to the system. These meters also provide accurate results over the wide range of flow rates that may occur.

Where flows are not known, excessive flaring is usually noticed only when the flame size at the flare tip increases substantially or valves connected to the header system provide visible (e.g., condensation or ice formation on the valve body) or audible indications of appreciable leakage past the valve seat. Unfortunately, significant gas losses may occur into a flare system without triggering either of these two crude indicators, and such flows normally are not accounted for in any reporting efforts.

4.1.1 ACID GAS

Acid gas is a by-product of the gas sweetening process employed at natural gas processing plants. Depending on the composition of the raw gas stream, acid gas is typically composed of CO_2 and H_2S with small amounts of residual hydrocarbons. If the acid gas does not contain regulated concentrations of H_2S the acid gas may be vented to the atmosphere. This is sometimes the case at sweet gas processing plants that must remove CO_2 to meet pipeline specifications. More frequently, however, the acid gas contains significant H_2S and must be flared, processed by a sulphur recovery unit or disposed of by injection into a suitable underground formation, depending on the regulatory requirements, costs involved and site-specific constraints. The formation CO_2 in acid gas streams passes through each of these disposal/treatment systems unchanged and, with the exception of disposal by underground injection, is ultimately released to the atmosphere.

The amount of acid gas production is usually metered and the CO_2 content, although not normally tracked by regulatory agencies, is known by the facility operators. The allowable options for disposal of the acid gas depend on the sulphur inlet rate. In Alberta, where most of the acid gas is estimated to occur, the AER and Alberta Environment regulate the disposition or treatment of acid gas under Interim Directive AER ID 2001-03. At new plants, acid gas may be flared if the sulphur inlet rate is less than 1 tonne per day, otherwise the acid gas must be processed by a sulphur recovery unit. The required design sulphur recovery efficiency varies between 70 and 99.8 percent, depending on the sulphur inlet rate. The higher the sulphur inlet rate, the greater the required recovery efficiency. Existing facilities are being gradually de-grandfathered over time.

Acid gas injection is an alternative approach to meeting the sulphur recovery requirements that has an effective recovery efficiency of nearly 100 per cent if operated successfully. It is usually less costly than sulphur recovery for small to medium sized applications (e.g., for a sulphur inlet rate of up to at least 400 tonnes per day) and, consequently, is the preferred choice for new gas processing facilities. At existing facilities, the economics generally do not favour switching to acid gas injection unless there is a need for substantial upgrades or changes to the sulphur recovery unit (e.g., when a unit becomes oversized or undersized for an application due to changes in the facility throughput). In all cases, economic access to a suitable disposal reservoir is usually the determining factor.

4.1.2 THERMAL OXIDZIERS

Thermal oxidizers are combustion devices used to dispose of waste streams. These devices may include conventional open-flame flare systems, enclosed or shielded flares and incinerators. Incinerators are distinguished by their use of a refractory-lined combustion chamber to contain the flame heat and create a finite post flame combustion zone. The incinerator will, at a minimum, feature stack-top temperature control, but may also feature oxygen control and possibly a continuous stack emission monitoring system. Enclosed flares simply feature a shield or enclosure to provide protection from thermal radiation and to keep the flame form public view.

Properly designed and operated open-flame flares are able to achieve a destruction efficiency of 98 percent, while incinerators are able to achieve destruction efficiencies of greater than 99.9 percent. Work by Strosher (1996) has shown that, for open flares, actual combustion efficiencies may be substantially lower. Differences between the destruction efficiency and the combustion efficiency are due to the formation of products of partial or incomplete combustion. The amount and types of incomplete combustion products formed is dependent on a number of factors including: burner/flare tip design, exit velocities, wind conditions, amount of condensation or liquid carry-over through to the flare tip, and the waste gas composition. Presently, there is no reliable means of predicting such emissions. The assessment of these emissions through measurements is difficult and currently deemed to be impracticable. The potential for products of incomplete combustion is more apt to be an issue when burning heavier molecular weight streams as may be encountered at oil and solution gas production facilities, than the dry natural gas streams normally handled by gas production and processing facilities.

At natural gas facilities open-flame flare systems are primarily used for disposal of waste gas volumes from purging and blowdown events, and, at gas transmission and distribution facilities, are generally only used if the gas is odourized or is sour. Otherwise, common practice for many companies is to dispose of the waste gas by controlled venting. Small enclosed flares or incinerators are sometimes used to dispose of compressor packing-case or seal vent gas.

4.2 EMISSIONS CALCULATION

4.2.1 CONVENTIONAL FLARES

Atmospheric emissions from flaring are assessed using Equation 21 presented below:

$$\boldsymbol{ER_{Flare,i} = Q_{Flare} \cdot HHV_{Flare} \cdot EF_{Flare,i} \cdot g_c}$$

Equation 21

Where:

$ER_{Flare,I}$ = annual emissions of component i (tonnes of substance i)
Q_{Flare} = reported volume of gas flared per year (10^3 m^3/year)
HHV_{Flare} = Higher heating value of flared gas (MJ/m^3).
$EF_{Flare,i}$ = Emissions factor for component i (ng/J). Factors for N_2O, CO, NOx and PM are presented below. CO2 factors are determined by mass balance as described in Section 2.5. CH_4, H_2S and VOC emission factors are determined by mass balance in Equation 24.
g_c = constant of proportionality
= 10^{-6} (t/g)

4.2.2 ACID GAS FLARES

The emissions of SO_2 from acid gas flares are reported to the provincial regulatory authorities as a condition of their operating approvals as well as the NPRI. These reported values are applied in the inventory. Emissions of H_2S are estimated using Equation 21.

4.2.3 FORMATION CO_2 EMISSIONS FROM ACID GAS FLARES & TAIL GAS INCINERATORS

Formation carbon dioxide (CO_2) is naturally occurring CO_2 present in crude oil and natural gas at the time of production (primarily in the gas phase). Its contribution to vented and leaked emissions is accounted for in the applied speciation profiles (Section 2.10).

Most emissions of formation CO_2 result from the processing of acid gas streams at sulphur recovery plants or from acid gas disposal by vent or flare systems. Formation CO_2 may also be emitted as a waste by-product of deep cut extraction processes at these same natural gas processing plants. In the latter two cases, the amount of CO_2 emissions are taken directly from survey responses provided by industry for individual facilities and calculated with the following equation.

$$\boldsymbol{ER_{CO_2} = Q_{Acid\ Gas} \cdot Y_{CO_2} \cdot \rho_{CO_2}}$$

Equation 22

Where:

ER_{CO2} = Acid gas emissions of CO_2 (t/y)
$Q_{Acid\ Gas}$ = Acid gas flow rate (10^3 m^3/y)
ρ_{CO2} = Density of CO_2 (1.861 kg/m^3 at standard conditions of 101.325 kPa and 15 ^oC).
Y_{CO2} = Mole fraction of CO_2 in the acid gas

In the absence of any responses, CO_2 emission can be estimated based on a mass balance that considers the total amount of formation CO_2 in the facility inlet and sales streams, and the fate of the removed formation CO_2. The concentrations of formation CO_2 in the inlet gas streams can be calculated based on the sources and amount of production linked to each facility and the corresponding pool-specific gas analyses available from regulatory agencies and production accounting registries. If the sales gas concentrations are not provided by the industry survey, the sales gas at each facility is assumed to contain less than 0.25 percent formation CO_2 (a typical value observed in natural gas transmission systems).

$$\boldsymbol{ER_{CO_2} = \left[Q_{Gas\ Receipts} \cdot y_{Gas\ Receipts_{CO_2}} - (Q_{Gas\ Sales} + Q_{Fuel\ Gas}) \cdot y_{Gas\ Sales_{CO_2}}\right] \frac{MW_{CO_2} \cdot 10^3}{V_{STP}}}$$

Equation 23

Where,

ER_{CO2} = Emission rate of formation CO_2 (t/y)
$Q_{Gas\ Receipts}$ = Total natural gas receipts (10^6 m^3/y)
$Q_{Gas\ Sales}$ = Total natural gas sales (10^6 m^3/y)

$Q_{\text{Fuel Gas}}$ = Total fuel gas withdrawn from the process (10^6 m^3/y)
$y_{\text{Gas Receipts, CO2}}$ = mol fraction of CO2 in the raw inlet gas (mol fraction)
$y_{\text{Sales Gas, CO2}}$ = mol fraction of CO_2 in the final sales gas (mol fraction)
= 0.0025 kmol/kmol
MW_{CO2} = Molecular weight of CO2 (kg/kmol).
= 44.01 kg/kmol
V_{STP} = Volume of 1 kmol of gas at standard temperature and pressure of 15°C and 101.325 kPa (m^3/kmol)
= 23.6444813 m^3/kmol

4.2.4 PURGE, PILOT AND ENRICHING GAS

All flares are assumed to consume approximately 11.7 kJ/s of pilot fuel gas. Any purge, pilot and enriching gas used in flare systems is understood to be accounted for in the reported fuel volume. Any fuel gas added to the flare system is normally subtracted from the measured flare volumes if total flare gas measurement is used downstream of the fuel gas entry point. Emissions are calculated and reported as natural gas fuel combustion which results in some incorrect categorization of emissions. However, such errors are not expected to be material since the purge, pilot and enriching gas volumes are normally small compared to other fuel uses at most oil and gas facilities.

4.3 EMISSION FACTORS

4.3.1 PRODUCTS OF INCOMPLETE COMBUSTION

$$\boldsymbol{EF_{Flare,i} = \frac{y_{i,j} \cdot MW_i}{V_{STP}} \cdot \frac{(1 - CE)}{HHV_{Flare}} \cdot g_c, for\ i\ \neq CO_2, SO_2, or\ N_2}$$

Equation 24

Where:

$ER_{Flare,i}$ = emission rate of component i (ng CH_4/J of flared gas)
y_i = Mole fraction of component i (kmol/kmol)
MW_i = Molecular weight of component i (kg/kmol)
V_{STP} = Volume occupied by 1 kmole of gas at 15˚C and 101.325 kPa (m^3/kmol)
= 23.6444813 m^3/kmole
CE = Combustion Efficiency equal to 0.98 (API, 2009)
HHV_{Flare} = Higher heating value of the flared gas.

4.3.2 GHG EMISSIONS

The CH_4 emission factor is determined using Equation 24 above while the CO_2 emission factor is assessed using Equation 7. The N_2O factor, based on WCI.363(k), equals 0.0952 ng/J.

4.3.3 CRITERIA AIR CONTAMINANTS

The VOC emission factor is determined using Equation 24 above. Other default emission factors for estimating criteria air contaminant emissions from flares are presented in Table 25.

Table 25: Default CAC emission factors for flare operations[1,2].

Component	Emission Factor (ng/J)
CO	159.1
NO_x	29.2
TPM, PM_{10}, $PM_{2.5}$[4]	57

1. Adapted from Table 13.5-1 of AP-42 (U.S. EPA, 1995).
2. Based on tests using crude propylene containing 80% propylene and 20% propane.
3. U.S. EPA Fire 6.22 database. Flaring of Landfill Gas.

4.3.4 OTHER PRIORITY SUBSTANCES

Emissions of other organic priority substances are determined using Equation 26 if the substance is reported in the raw gas flared. Otherwise, natural gas boiler emission factors presented in Table 22 are used to estimate organic and inorganic emissions.

5 VENTING EMISSIONS

A brief description of the different types of venting and purging activities included in this category is given in Section 5.1. Much of this discussion also applies to flaring activities (often waste gas is vented if it is sweet and flared if it is sour or malodorous). The average emission factors for assessing the amount of these emissions are delineated in Section 5.4. Venting from glycol dehydrators (i.e., still-column off-gas emissions) is addressed separately in Section 6.

5.1 SOURCE CHARACTERIZATION

Vent (and flare) systems exist in essentially all segments of the oil and gas industry and are used for two basic types of waste gas disposal: intermittent and continuous. Intermittent applications may include the disposal of waste volumes from emergency pressure relief episodes, operator initiated or instrumented depressurization events (e.g., depressurization of process equipment for inspection or maintenance purposes, or depressurization of piping for tie-ins), plant or system upsets, well servicing and testing, pigging events, purging activities and routine blowdown of instruments, drip pots and scrubbers.

Continuous or frequent applications may include disposal of associated gas, treater off-gas and/or tank vapours at oil production facilities where gas conservation is uneconomical or until such economics can be evaluated, casing gas at heavy oil wells, process waste or byproduct streams that either have little or no value or are uneconomical to recover (e.g., vent gas from glycol dehydrators, acid gas from natural gas sweetening units, and sometimes stabilizer overheads), and vent gas from gas-operated devices where natural gas is used as the supply medium (e.g., instrument control loops, chemical injection pumps, samplers and compressor starter motors). Typically, waste gas volumes are flared if they can support stable combustion or incinerated if they pose an odour, health or safety concern. Otherwise, they are vented.

In all provinces companies are required to conserve natural gas wherever it is economical to do so; however, the level of enforcement and the requirements of companies in evaluating the feasibility of natural gas conservation varies. At the same time, many companies operate in multiple regions and tend to develop company-wide polices designed to accommodate the most stringent requirements.

The current AER Directive 060 requirements with respect to venting are as follows:

- In accordance with the objective hierarchy, licensees, operators, and approval holders must evaluate the following three options:
    - Can flaring, incinerating, and venting be eliminated?
    - Can flaring, incinerating, and venting be reduced?
    - Will flaring, incinerating, and venting meet performance standards?

- Operators must eliminate or reduce flaring and venting by using decision tree analysis for:
    - Oil facilities and all solution gas flares and vents greater than 900 m^3/day
    - Gas facilities and all flares, incinerators, and vents regardless of volume except for intermittent small sources (e.g., less than 100 m^3 per month such as pig trap depressuring, gas analyzers and pneumatics)
- If continuous vent volumes are sufficient to support combustion, the gas must be burned or conserved.
- Venting of gas containing H_2S to the atmosphere must not result in exceedance of Alberta Ambient Air Quality Objectives and Guidelines (AAAQO) or Occupational Exposure Levels for H_2S.
- All facilities where the gas contains more than 10 mol/kmol H_2S, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., sour water or condensate tank flash-gas) and intermittent (e.g., emergency depressuring) sources. Continuous venting of gas containing H_2S and other odourous compounds must not result in odours outside the lease boundary.
- The true vapour pressure of hydrocarbon product stored in atmospheric storage tanks shall not exceed 83 kilopascals where such tanks are vented to the atmosphere.
- Vented gas from gas dehydrators is subject to limitations on benzene emissions, as detailed in AER, Directive 039. Cumulative emissions from all sources (dehydrators plus other sources) at the facility or lease site will not exceed:
    - 1.0 tonnes per year for facilities commissioned after January 1, 2007; or
    - 3.0 tonnes per year for facilities commissioned between 1 January 1999 and 1 January 2007; or
    - 5.0 tonnes per year for facilities commissioned prior to 1 January 2001.

For purposes of the current inventory, venting has been separated into those forms that are generally reported and those which are not.

- Reported venting is the sum of all vented volumes stated in production accounting statistics. These volumes are assumed to comprise, where applicable, casing gas venting, waste associated gas flows, treater and stabilizer off-gas and gas volumes discharged during process upsets and equipment depressurization events (i.e., blowdowns).

- Unreported venting is the sum of all miscellaneous vented volumes not normally included in reported vented volumes and not otherwise accounted for in the developed emissions inventory. This may include instrument vent gas, compressor start gas, purge gas and blanket gas that is discharged directly to the atmosphere, dehydrator still column off-gas, storage and loading/unloading losses.

In most provinces, all vented (and flared) gas is required to be reported monthly to the nearest 0.1 x 10^3m^3/month (~0.304 x 10^{-3} kt CO_2E/month), adjusted to 101.325 kPa and 15°C, as part of routine production accounting procedures. The requirement to report all gas vented (or flared) includes emissions from routine operations, emergency conditions, and the depressuring of pipeline, compression, and processing systems. Vented gas excludes fugitive emissions from piping and equipment leaks.

Typically, separate reports are submitted to the provincial governments for crude oil and natural gas production facilities, natural gas gathering systems, and natural gas processing plants. Some venting (and flaring) data and other information on oil and natural gas transmission systems and natural gas distribution systems are also reported to Statistics Canada and the National Energy Board. The production accounting reporting requirements in Alberta are detailed in the AER's Directive 007 and Manual 011.

Although there have been substantial improvements in reporting practices in recent years, there remains significant uncertainty in many reported vented (and flared) volumes. The main sources of uncertainty are as follows:

- There are inconsistencies in what individual companies are actually including in their reported vented and flared volumes. In some cases this is due to differences in reporting requirements between provinces. For example, companies operating in Alberta are required to report all gas usage for instrumentation and pumps as fuel use, even if it is vented afterwards (per AER Directive 017 Section 4.3.3.1). Whereas companies operating in BC gas used to operate instrumentation or drive chemical pumps must be reported as vented gas. In other cases, it is due to a lack of specificity in the current requirements, and limited auditing of the results.

  All measured quantities are likely to be fully accounted; however, flow meters are normally only installed on larger continuous vent or flare systems (> 0.5 10^3 m^3/day). Where there is no measurement data the volumes must be estimated. Although CAPP Estimation Guidelines (CAPP, 2002) are available, the application of estimates by operators and source types is inconsistent.

In Alberta, the AER has established standards for measurement of flaring and venting at pipeline and natural gas processing facilities (i.e., AER Directive 017). The following single point and maximum monthly volume uncertainties are based on facility type and throughput:

- Oil systems
    - Single point measurement uncertainty:
      > 16.9 10^3 m^3/d = 3.0%
      > 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d = 3.0%
      ≤ 0.50 10^3 m^3/d = 10.0%
    - Maximum uncertainty of monthly volume
      > 16.9 10^3 m^3/d = 5.0%
      > 0.50 10^3 m^3/d but ≤ 16.9 10^3 m^3/d = 10.0%
      ≤ 0.50 10^3 m^3/d = 20.0%
- Gas systems
    - Single point measurement uncertainty = 5.0%
    - Maximum uncertainty of monthly volume = 20.0% (the maximum uncertainty of the monthly volume is set at 20.0%, to allow for the erratic conditions associated with flare measurement.)
- Acid Gas
    - Single point measurement uncertainty = 10.0% for low pressure acid gas before compression, and = 3.0% after compression
    - Maximum uncertainty of monthly volume = N/A

Routine flare sources are defined as those sources that, by process design, are used on a daily basis to dispose of low-pressure or waste gases. The definition excludes flare sources used solely for emergency shutdown or overpressure protection. Where all solution gas is flared or vented from conventional or heavy oil production facilities, produced gas measurements (minus measured fuel gas use) can be used to report volumes flared or vented. In such situations, specific flare or vent gas meters are not required.

- Historically, there has been a problem with some vented volumes being reported as flared. The actual split has a significant impact on the total CO_2-equivalent (CO_2E) emissions from these activities since unburned CH_4 contributes approximately 21 times more radiative forcing on a 100-year time horizon than fully combusted CH_4. Production accounting forms for production facilities, the major source of venting and flaring, provide separate cells for reporting of vented volumes and flared volumes. These values are often automatically estimated by production accounting systems based on reported liquid volumes and reported or estimated gas-to-oil ratios or solution gas factors. An informal review of the production accounting systems of several operators indicates that calculated results have often been reported as flared volumes by default, which may often be incorrect.

- At natural gas processing plants, acid gas volumes are reported separately from other venting or flaring volumes; however, the latter amounts are reported as a single aggregated value. Venting and flaring from natural gas gathering systems is also reported as a single aggregate value.

- Some operators have tended to use vented and flared entries as balancing terms to achieve reasonable metering differences when completing production accounting reports.

5.2 EMISSIONS CALCULATION

5.2.1 REPORTED VENTING

Reported vented volumes are referenced directly from the available production accounting records for a given facility. The emissions of a particular component of the vented gas are calculated using the following relation:

$$ER_{i,j} = Q_{Reported_i} \cdot \frac{Y_{i,j}MW_j}{V_{STP}}$$

Equation 25

Where,

$ER_{i,j}$ = emission rate of substance j from source i (t/y).
$Q_{Reported,i}$ = reported vented volume for source i during the study year (10^3 m^3/yr).
$Y_{i,j}$ = mole fraction of substance j in the gas vented by source i (kmol/kmol).
V_{STP} = volume of one kmol of gas at standard conditions of 101.325 kPa and 15°C (m^3/kmol).
= 23.6444813 m^3/kmole
MW_j = molecular weight of component j (kg/kmol).

5.2.2 UNREPORTED VENTING

Unreported venting emissions of a particular component are estimated using the following relation:

$$ER_{i,j} = EF_i \cdot A_i \cdot \frac{Y_{,i,j} \cdot MW_j}{V_{STP}} \cdot (1 - CF_i) \cdot OF_i \cdot g_c$$

Equation 26

Where,

$ER_{i,j}$ = emission rate of substance i from source j (t/y).
EF_j = emission factor for source j (m^3/unit of activity).
A_j = activity value for source j (unit activity per unit of time).
$Y_{i,j}$ = mole fraction of substance i in the gas vented by source j (kmol/kmol).
V_{STP} = volume of one kmol of gas at standard conditions of 101.325 kPa and 15°C (m^3/kmol).
= 23.6444813 m^3/kmole
MW_i = molecular weight of component i (kg/kmol).
CF_j = control factor for a specific control measure or device applied to source j which indicates the fraction by which the emissions are reduced (kg/kg).
OF_j = operating factor which indicates the fraction of the time that source j is active (d/d).
g_c = a constant of proportionality used to convert the results to units of t/y.

5.3 ACTIVITY FACTORS

The following subsections summarize the emission factors used to estimate emission contributions by the sources and activities which are assumed to be generally unaccounted for in a facility’s reported vented or flared volumes.

5.3.1 GAS ANALYZERS

An online gas analyzer normally draws a continuous stream of sample. It uses some fraction of this stream and then vents both the unused and spent portions to the atmosphere. Depending on the type of analyzer, the used portion of sample may be released unchanged or as products of combustion. Consequently, the amount of emissions depends on the sampling rate and the characteristics of the analyzer. A value of 0.0985 m^3/h was determined for one analyzer system on a natural gas transmission pipeline (unpublished report).

5.3.2 GAS-OPERATED DEVICES

Use of gas-operated devices is a direct source of emissions if the supply medium is natural gas. The common types of devices at oil and gas facilities include the following:

5.3.2.1 GAS-OPERATED CONTROL LOOPS

There are two main sources of emissions associated with a gas-operated control loop: bleeding actions of the flapper nozzle detector used in each pneumatic instrument (e.g., controllers, transmitters, positioners and transducers), and exhausting of gas pressure from the actuator during stroking of the control device (usually a valve or a set of louvres). The total amount of gas emitted by a single control loop is determined by the number of bleeding instrument components, the number of actuators, the design of these components, and the level of control activity.

Typically, the loop comprises an input sensing device (e.g., pressure, temperature or liquid level transducer), a controller, and a control device operated by an actuator. The sensing device monitors the process variable to be controlled. The controller regulates the energizing and de-energizing of the actuator based on the output from the sensing device and the specified control settings. The actuator converts the energy changes it experiences into mechanical adjustments to the control device. In some instances the actuator is equipped with a positioner to ensure precise adjusting of the control device. If some of the instruments in the control loop are electronic rather than pneumatic, then I/P (electric current to pneumatic pressure) or E/P (voltage to pneumatic pressure) positioners may also be incorporated in the control loop.

Instances where natural gas may be used as the supply medium for pneumatic control loops include facilities without electrical connection as well as some industrial sales points, liquid-level controllers on inlet scrubbers, mainline control valves, and compressor recycle valves. In most other instances, compressed air is used.

The total amount of gas emitted by a single control loop is determined by the number of bleeding instrument components, the number of actuators, the design of these components, and, for intermittent bleed devices, the level of control activity.

Average natural gas consumption rates for pneumatic instrument device types in Table 26 are applied to predicted device populations. These factors are based on device populations observed in 2017 and 2016 (Clearstone, 2018) and mean bleed rates published in other studies (Prasino, 2013 and Spartan, 2018[18]). The factor labeled ‘generic pneumatic instrument’ includes high and low-bleed instruments that continuously vent. The ‘generic pneumatic instrument’ vent rate of 0.3217 m^3/hr is greater than the ‘generic high bleed controller’ vent rate published in the Prasino study (0.2605 m^3/hr) largely because of the revised level controller factor published by Spartan (i.e., 0.46 m^3/hr ± 22% versus the Prasino factor of 0.2641 m^3/hr ± 34%) and the large number of level controllers in the study population. Interestingly, the ‘generic pneumatic instrument’ vent rate is only 9 percent less than the rate applied in the last national inventory (i.e., 0.354 m^3/hr in ECCC, 2014). The same isn’t true for chemical pumps, a rate of 0.236 m^3/hr was applied in the last national inventory which is 4 times less than the rate presented in Table 26.

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[18] Level controllers were investigated by Spartan (with the support of PTAC) because of concerns that the 2013 Prasino study did not adequately capture emission contributions from the transient sate. The mean vent rate from Spartan (0.46 m^3/hr ± 22% based on 72 samples) is used to determine level controller rate in Table 26 instead the Prasino factor (0.2641 m^3/hr ± 34% based on 48 samples).

Table 26: Sample-size weighted average vent rates for pneumatic device types observed during 2016 and 2017 field campaigns.

Device Type	Average Vent Rate (m^3 natural gas/hour)	95% Confidence Interval (% of mean)
Level Controller	0.3508	31.68
Positioner	0.2627	39.02
Pressure Controller	0.3217	35.95
Transducer	0.2335	22.54
Generic Pneumatic Instrument	0.3206	31.53
Chemical Pump	0.9726	13.99

5.3.2.2 GAS-OPERATED STARTER MOTORS

Gas operated starter motors are widely used to start the reciprocating or turbine engines on natural gas compressors. The supply medium is the natural gas from the pipeline. The vent from the starter motor is usually open to the atmosphere; although, sometimes it may be connected to a flare system.

Specific starting gas requirements for engine-driven compressors will vary according to the pressure of the start gas, the size of the compressor and the condition of the engine. A gas turbine-driven compressor may require as much as 325 m^3 (Solar, 2006) while reciprocating compressors require approximately 22 m^3 (Clearstone, 2012) of natural gas for each start attempt. Compressors are typically started thirty times per year (Clearstone, 2012).

5.3.3 GAS-OPERATED CHEMICAL INJECTION PUMPS

Some of the most common applications where gas-driven pumps may be used are:

- injection of methanol and other chemicals into gas pipelines,
- high-pressure bearing lubrication,
- lubrication of mechanical seals,
- circulation of glycol on glycol dehydrators, and
- odourization systems.

The basic unit comprises a unitized gas motor and pump. The gas motor operates by expanding the supply gas against a diaphragm or piston and rod assembly which in turn drives the pump plunger. The expanded supply gas is then vented to atmosphere or into a collection system and the cycle repeated. Pumping capacities of less than 3 L/d to more than 3 m^3/d, and injection pressure capabilities of up to 62 000 kPa_g are available through a range of pump sizes and models.

Some gas-driven pumps are designed to operate off low uniform supply pressures of 345 kPa_g or less and others are designed to operate off high or erratic pressures up to 10 340 kPa_g.

The amount of gas consumption is determined by the change in pressure of this gas in passing through the gas motor, the pumping rate and the required chemical injection pressure. As much as 7.5 m^3 of gas may be require to pump each litre of liquid; however, most applications will require much less gas than this (i.e., typically only half as much).

The emissions contributions by gas-operated or energy exchange glycol circulation pumps used on glycol dehydrators are accounted for as part of the dehydrator vent gas assessment as delineated in Section 6.

5.4 EMISSION FACTORS

For reported venting volumes, emissions are calculated by mass balance and speciated using the molar speciation profile. For the unreported venting sources discussed above, the default factors presented above are applied to estimate volumes. The composition of the vented gas will usually comprise CH_4, some CO_2 and varying amounts of ethane and heavier hydrocarbons. Unless an extended analysis has been performed on the source, the amount of trace constituents such as benzene, toluene, ethylbenzne and xylene will not be known, but would be expected to be presented in most natural gas mixtures.

5.5 SPECIATION PROFILES

Site-specific speciation profiles were applied wherever these were available. Otherwise, the applicable values presented in Section 2.10 were used.

6 GLYCOL DEHYDRATORS

6.1 SOURCE CHARACTERIZATION

Glycol dehydration is a continuous liquid desiccant process in which water or water vapour is removed from hydrocarbon streams by selective absorption and the glycol is regenerated or reconcentrated by thermal desorption. The use of triethylene glycol (TEG) and ethylene glycol (EG) are standard for dehydration of natural gas.

This process is widely used in gas production and processing operations for removing water vapour from natural gas, but, normally, it is not required during the subsequent transmission and distribution stages. However, if the processed gas is placed in an underground storage cavern enroute to market, it may be necessary to re-dehydrate the gas upon removal from the cavern.

The primary causes of organic emissions from a glycol dehydrator are secondary absorption/desorption by the glycol, entrainment of some gas from the contactor in the rich glycol, and use of stripping gas in the reboiler. These sources are the focus of this section. Other sources of methane emissions on a glycol dehydrator include fugitive equipment leaks (see Section 7), venting by gas-operated devices (see Section 5.3.2), and combustion emissions if it has a gas-fired reboiler (see Section 3).

The basic TEG dehydration process is as follows. Wet gas is brought into contact with a counterflow of lean TEG in a vertical trayed contactor (or absorption column) to promote absorption of the water by the TEG. The wet gas flows in at the bottom of the tower and leaves at the top as dry gas, while the lean TEG enters at the top of the tower and exits at the bottom as rich TEG. The rich TEG is subsequently regenerated by the addition of heat in the reboiler and is returned to the top of the tower to repeat the circuit. The TEG circulation rate is determined by the gas flow rate, the amount of water to be removed, the temperature and pressure in the tower, actual purity of the glycol at the inlet to the contactor, number of trays or packing height in the contactor, and the desired dew point depression (API, 1990). Typical values for plant applications are 17 to 50 L TEG/kg H_2O removed. At 6900 kPa_g, glycol can absorb up to 7.5 standard litres of gas for every litre of glycol circulated (Sams, 1992).

A low-pressure flash separator is sometimes installed between the contactor and the regenerator (reboiler) to release any solution gas that may be entrained in the rich (wet) glycol, especially if a glycol energy exchange pump is used in the system. This type of pump uses pressure energy in the rich glycol to pump lean glycol into the contactor. The gas separated in the flash separator may be used to supplement the fuel and stripping gas required for the reboiler. Any excess flash gas is discharged through a back-pressure valve to atmosphere.

From the flash separator, the rich glycol then flows to a packed stripping still attached to the top of a reboiler. In the still column, the wet glycol flows down to the reboiler while contacting hot gases (mostly water vapour and glycol) rising up from the reboiler. The mixing of these two streams helps to preheat the wet glycol and to condense and recover any glycol vapours before the gases are vented from the top of the still.

In the reboiler the glycol is heated to approximately 175^o to 205^oC to remove enough water vapour to reconcentrate it to 99.5 percent or more. Sometimes a small amount of natural gas (i.e., stripping gas) is injected into the bottom of the reboiler to help strip water vapour from the glycol. The water vapour rises through the stripping still and the lean glycol, finally, is cooled and returned to the top of the absorber column.

It is assumed that still-column off-gas emissions typically are not included in reported vented and flared volumes at oil and gas facilities.

6.2 EMISSIONS CALCULATION

Perhaps the most convenient method of estimating venting emissions from a glycol dehydrator is to use the simulation program GRI-GLYCalc (Thompson et al., 1994). GRI-GLYCalc is primarily presented as a tool for estimating the amount benzene, toluene, ethyl benzene and xylene (BTEX) emitted by a glycol dehydrator (significant amounts of this material may be preferentially absorbed by the glycol and released off the flash tank and still column). However, in performing a rigorous simulation of the dehydration process, the program also provides information on the amount of methane and other organic emissions. Moreover, the program can assess the emission reduction that may be achieved from use of selected control devices (e.g., condensers and incinerators).

The required input data includes:

- gas composition and flow rate,
- glycol circulation rate,
- temperature and pressure in the absorber column,
- type of glycol pump,
- operating pressure of the flash tank (if one is used) and amount of flash gas used by the process (if at all),
- type of glycol (TEG or DEG), and
- stripping gas usage.

Since the above information is generally not available on a site-by-site basis, GRI-GLYCalc is used here to develop average emission factors for application to glycol dehydrators in different segments of the upstream oil and gas industry (see Section 6.3). The emissions are then estimated using the Equation 26.

6.3 EMISSION FACTORS

The emission factors for estimating emissions from dehydrator vents are summarized in Table 27 below.

Table 27: Summary of the factors used to estimate gas venting by glycol dehydrators.

Emission Source	THC Emission Factor	Units
Glycol Dehydrators[1]		
- Still Column Off-Gas (Flash Tank)	0.00357	
- Still Column Off-Gas (No Flash Tank)	0.1751	m^3/1000 m^3 of gas production
- Stripping Gas Factor	0.670	
- Pump Factor[2]	0.1777	

1. Estimated based on simulation results for conditions of 28° C and 7000 kPa in the absorber column, a glycol circulation rate of 45 L/kg of H_2O removed. It is assumed that no flash tank or stripping gas is used.
2. Work sponsored by GRI/U.S EPA (Myers and Harrison, 1996) indicates Kimray pumps (the most commonly used type of glycol circulation pump) exhaust about 0.178 m^3 of natural gas per 10^3 m^3 of gas processed at gas plants. This factor assumes that 33 percent of the dehydrators are equipped with flash tanks and that 10 percent have combustion vent controls.

6.4 SPECIATION PROFILES

Benzene emissions reported to AB regulators are included directly in the inventory. Otherwise, site-specific speciation profiles were generally not available and the applicable values presented in Section 2.10 were used.

7 FUGITIVE EQUIPMENT LEAKS

7.1 SOURCE CHARACTERIZATION

Equipment leaks may be defined as any loss of process fluids to the environment past seals, packings, valve seats and mechanical connections (e.g., compressor seals and rod packings, valve-stem packing, block-valve seats, etc.). Formal definitions for leaks and vents are provided in the Section 14 Appendix. Most equipment components emit some amount of process fluid. However, only a few percent of the potential sources at a site experience sufficient fluid losses at any time to be in need of repair or replacement (i.e., to be classified as leakers). If the number of leakers is less than two percent of the total number of potential sources, the facility is normally considered to be well maintained and equipment leaks properly controlled.

In Canada and the United States, the leak status of an equipment component is expressed in terms of the maximum concentration (screening value) of organic material that can be measured at the leakage point (or interface) using a portable organic vapour analyser or if it can be visualized using a leak-imaging infrared camera . Prior to 2007 there were no requirements for companies in the Canadian upstream oil and gas industry to conduct formal leak management programs; however, since that date, CAPP has established a best management practice for managing emissions from fugitive equipment leaks and regulatory requirements to apply this best management practice were implemented in AER Directive 060.

The following are some of the noteworthy characteristics of equipment leaks:

- There is a strong correlation between the rate of leakage and the type of service (e.g., gas/vapour and light liquid/two-phase streams) (Wetherold and Provost, 1979). However, there is no clear relationship between the size of a component and the rate of leakage (U.S. EPA, 1983).

- The potential for leakage increases with operating pressure and ambient temperature, but is generally independent of operating temperature or elevation above grade (Langley et al., 1981).

- Control valves have a greater potential to leak than block valves. For block valves, the gate design has the most potential for leakage, while plug and ball designs have the least potential.

- Off-line compressor units that have been depressurized and are left open to the atmosphere through the vent line leak more than ones that have not been depressurized or that are online (especially for reciprocating compressors) (Hummel et al., 1996). In the first case, the leakage is past the seats of upstream and downstream block valve. In the latter case, it is past the seat of the blowdown valve.

- Repaired components usually achieve a normal leak potential if the leaks do not recur during the first few weeks after repair (Eaton et al., 1980).

- At natural gas facilities it is noteworthy that most of the fugitive emissions from equipment leaks often come from only one or two problem leakers at a given site rather than many small to moderate leaks. The results of a measurement program sponsored by Gas Technology Canada member companies (Ross and Picard, 1996) determined that 42 percent of total emissions measured were from the single largest source at each of the 183 sites surveyed. Similar trends have also been observed in the U.S.

Leakage may often be an indication of wear, damage, defects, severe process conditions, abusive environments, inadequate design, or improper installation. Some components, like mechanical seals, are designed to leak a small amount to provide some lubrication of, as well as remove heat and debris from, the contact surfaces. Seal designs can be implemented for some services that do not normally transmit any hydrocarbons directly to the atmosphere (i.e., leaked fluid can be collected and directed to a control device).

Equipment components that may produce leaks in the oil and gas industry are defined in Section 14 Appendix and include:

- reciprocating compressor packing systems,
- centrifugal compressor seals,
- valves (i.e., the stem packing system plus fittings and seams on the valve body),
- pump seals,
- connectors (i.e., threaded, flanged or gasketed surfaces),
- pressure regulator diaphragms,
- pressure-relief devices (i.e., the seated surfaces), and
- open-ended valves and lines (i.e., valve seats where there is process fluid on one side and the other side is open to the atmosphere).

An important feature of the UOG industry is that much of the equipment in hydrocarbon service tends to be associated with many smaller facilities and field installations rather than a few large plants. As a result, fugitive emissions are widely dispersed and often difficult to adequately quantify and control.

7.2 EMISSIONS CALCULATION

The fugitive emissions from equipment leaks are estimated using the average emission factor method (U.S. EPA, 1995b). This approach consists of applying average THC emission factors to an inventory of all potential fugitive emission sources (i.e., equipment components in hydrocarbon service) using the equation below:

$$\boldsymbol{ER_i = \sum_{j}\sum_{k}\sum_{m} EF_{j,m} \cdot N_{Comp_{j,k,m}} \cdot \left(1 - CF_j\right) \cdot \frac{X_{i,k}}{1 - X_{Inorganic,k}} \cdot OF_k}$$

Equation 27

where,

ER_i = emissions of substance I from all equipment components in hydrocarbon service (t/y).
$EF_{j,m}$ = average emission factor for equipment components of type j in service category m (kg/h).
$N_{Comp,j,k,m}$ = number of equipment components of type j in service m on stream k (dimensionless).
CF_j = average leakage control factor for components of type j (fraction).
$X_{i,k}$ = mass fraction of substance i in stream k (fraction).
$X_{Inorganic,k}$ = total mass fraction of inorganic substances in stream k (fraction)
OF_k = operating factor for equipment components on stream k (fraction of the time the components are in pressurized service).

7.3 EMISSION FACTORS

Emission factors for estimating fugitive equipment leaks normally are evaluated by type of component and service category within an industry sector. This allows the factors to be broadly applied within the sector provided component populations are known. The advantage of this level of disaggregation is that it allows facility differences. A simpler approach which introduces additional uncertainties is to develop factors by type of process unit and area, or by type of facility; however, these higher-level factors are not considered here.

There are two basic types of emission factors that may be used to estimate emissions from fugitive equipment leaks: those that are applied to the results of leak detection or screening programs (e.g., leak/no-leak and stratified emission factors), and those that those that do not require any screening information and are simply applied to an inventory of the potential leak sources (i.e., population average emissions factors). This inventory uses 2018 population-average[19] and no-leak emission

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[19] Population-average factors from Clearstone, 2018 equal total measured hydrocarbon emissions divided by the number of potential leak sources. Unlike other population-average factors (CAPP, 2014 and EPA, 2016), emission contribution from leaks below minimum detection limits (i.e., no-leak factors) are not included in the population average.

factors presented in Table 28. This enables the delineation of detectable equipment leaks versus leakage below the minimum detection limit of infrared (IR) cameras.

Table 28: Summary 2018 population average leak factors (kg THC/h/source) and comparison with historic factors for the Canadian UOG industry.

Sector	Component Type	Service	CAPP (1992) No-Leak EF[b]	2017 Field Measurements			2017 Combined EF	CAPP (2014)				CAPP (2005)			
				EF	95% Confidence Limit (% of mean)			EF	95% Confidence Limit (% of mean)		EF Ratio (2017/2014)	EF	95% Confidence Limit (% of mean)		EF Ratio (2017/2005)
					Lower	Upper			Lower	Upper			Lower	Upper	
Gas	Compressor Rod-Packing[c]	PG	0.00175	0.16736	51%	87%	0.16882	0.04669	41%	44%	3.62	0.71300	36%	36%	0.24
Gas	Connector	PG	0.00061	0.00012	36%	57%	0.00073	0.00082	36%	250%	0.88	0.00082	32%	32%	0.88
Gas	Connector	LL[a]	0.00013	0.00001	71%	114%	0.00014	0.00016	54%	378%	0.86	0.00055	90%	111%	0.25
Gas	Control Valve	PG	0.00023	0.00301	68%	103%	0.00324	0.03992	44%	44%	0.08	0.01620	23%	23%	0.20
Gas	Meter	PG	0.00061	0.00149	52%	80%	0.00209	No emission factor				No emission factor			
Gas	Open-Ended Line	PG	0.00183	0.09630	95%	233%	0.09796	0.04663	42%	45%	2.10	0.46700	62%	161%	0.21
Gas	Pressure Relief Valve	PG[a]	0.00019	0.00399	54%	85%	0.00417	0.00019	55%	420%	21.97	0.01700	98%	98%	0.25
Gas	Pump Seal	PG	0.00023	0.00261	54%	82%	0.00284	0.00291	50%	367%	0.97	0.02320	74%	136%	0.12
Gas	Regulator	PG	0.00061	0.00077	52%	83%	0.00137	0.03844	45%	45%	0.04	0.00811	72%	238%	0.17
Gas	Valve	PG	0.00023	0.00062	66%	119%	0.00085	0.00057	38%	163%	1.50	0.00281	15%	15%	0.30
Gas	Valve	LL[a]	0.00081	0.00015	72%	122%	0.00096	0.00086	55%	442%	1.12	0.00352	19%	19%	0.27
Oil	Compressor Rod-Packing[c]	PG	0.00175	0.76120	92%	257%	0.76226	0.01474	60%	66%	51.71	0.80500	36%	36%	0.95
Oil	Connector	PG	0.00023	0.00019	37%	58%	0.00042	0.00057	27%	96%	0.74	0.00246	15%	15%	0.17
Oil	Connector	LL	0.00013	0.00001	71%	143%	0.00014	0.00013	36%	282%	1.05	0.00019	90%	111%	0.72
Oil	Control Valve	PG	0.00008	0.00962	66%	94%	0.00970	0.09063	87%	87%	0.11	0.01460	21%	21%	0.66
Oil	Meter	PG[a]	0.00061	0.00105	47%	73%	0.00165	No emission factor				No emission factor			
Oil	Open-Ended Line	PG[a]	0.00183	0.06700	91%	219%	0.06870	0.15692	47%	47%	0.44	0.30800	78%	129%	0.22
Oil	Pressure Relief Valve	PG	0.00019	0.00756	55%	87%	0.00775	0.00019	38%	313%	40.79	0.01630	80%	80%	0.48
Oil	Pump Seal	PG[a]	0.00023	0.00761	73%	142%	0.00783	0.00230	38%	294%	3.41	0.02320	74%	136%	0.34
Oil	Regulator	PG	0.00061	0.00154	79%	133%	0.00215	0.52829	38%	38%	0.00	0.00668	72%	238%	0.32
Oil	Thief Hatch	PG	0.00061	0.15852	77%	140%	0.15904	No emission factor				No emission factor			
Oil	Valve	PG	0.00008	0.00009	83%	158%	0.00017	0.00122	44%	48%	0.14	0.00151	79%	79%	0.11
Oil	Valve	LL	0.00058	0.00021	73%	125%	0.00079	0.00058	37%	288%	1.36	0.00121	19%	19%	0.65
All	SCVF	PG	0.00183	0.09250	98%	204%	0.09427	0.1464	Not Available		0.64	0.1464	Not Available		0.64

[a] Insufficient sample size for 2017 to determine confidence limits for this sector, component and service type. Therefore, results presented for 2017 include samples from both oil and gas sectors.

[b] No-leak factors are not available from CAPP, 1992 for Regulator, Meter, SCVF and Thief Hatch components so reasonable analogues are selected.

[c] Reciprocating compressor rod-packing emission factors are calculated on a per rod-packing basis and exclude compressors that are tired into a flare or VRU (because these rod-packings are controlled and have a very low probability of ever leaking to atmosphere). Rod-packings are defined as vents in Directive 060 (AER, 2018).

7.4 COMPONENT COUNTS

Process equipment inventories are used to determine component populations and drive equipment leak emission calculations. Algorithms described in Section 2.12.2 apply average process equipment counts presented in Table 29 and Table 30 to facility and well records from Petrinex according to their subtype or well status code. Component counts for process equipment types from Table 31 are then applied to estimate component populations.

This approach is enhanced for the following process equipment based on production data indicators.

- Natural gas fuelled engines, turbines, heaters and boilers.
- Flares.
- Production storage tanks.

For example, if a flare volume is reported for a facility then a flare stack is added to the list of emission sources. The algorithm is more complicated for determining the type and size of natural gas fired equipment but the basic logic is the same: if natural gas fuel is reported, add combustion units to the list of emission sources. The average counts in Table 29 and Table 30 identify fired equipment types applicable to each facility subtype and well status code plus provide a ‘first guess’ regarding the number of units installed. The quantity of fired units at a specific site is adjusted according to the volume of natural gas fuel reported for the site versus theoretical fuel determined from reported production hours and typical power ratings.

Table 29: Average (mean) process equipment counts and confidence intervals per facility subtype.

Facility SubType Code	Process Equipment Type	Facility SubType Count	Process Equipment Count	Average Equipment Count	95% Confidence Limit (% of mean)	
					lower	upper
321	Catalytic Heater	10	13	1.296	77%	85%
321	Flare KnockOut Drum	10	2	0.200	100%	149%
321	Gas Boot	10	1	0.100	100%	201%
321	Gas Pipeline Header	10	1	0.101	100%	197%
321	Incinerator	10	1	0.099	100%	204%
321	Line Heater	10	4	0.397	100%	102%
321	Liquid Pipeline Header	10	1	0.101	100%	197%
321	Pig Trap (Gas Service)	10	2	0.199	100%	151%
321	Pop Tank	10	1	0.101	100%	198%
321	Production Tank (fixed roof)	10	13	1.302	54%	77%
321	Screw Compressor	10	1	0.101	100%	198%
321	Separator	10	7	0.703	72%	85%
322	Catalytic Heater	33	136	4.125	35%	44%
322	Flare KnockOut Drum	33	10	0.303	50%	50%
322	Gas Boot	33	2	0.060	100%	151%
322	Gas Pipeline Header	33	7	0.212	57%	71%
322	Gas Sample and Analysis System	33	2	0.061	100%	199%
322	Gas Sweetening: Amine	33	1	0.031	100%	197%
322	Line Heater	33	6	0.181	67%	100%
322	Liquid Pipeline Header	33	31	0.942	32%	38%
322	Liquid Pump	33	10	0.304	80%	109%
322	Pig Trap (Gas Service)	33	9	0.273	67%	77%
322	Pig Trap (Liquid Service)	33	14	0.424	57%	72%
322	Pop Tank	33	7	0.211	71%	87%
322	Power Generator (natural gas fired)	33	1	0.031	100%	197%
322	Production Tank (fixed roof)	33	85	2.580	28%	32%
322	Propane Fuel Tank	33	2	0.061	100%	149%
322	Reciprocating Compressor	33	7	0.212	100%	143%
322	Reciprocating Compressor - Electric Driver	33	3	0.091	100%	100%
322	Screw Compressor	33	5	0.151	100%	181%
322	Screw Compressor - Electric Driver	33	3	0.091	100%	167%
322	Scrubber	33	1	0.030	100%	201%
322	Separator	33	81	2.452	30%	30%

Table 29: Average (mean) process equipment counts and confidence intervals per facility subtype.

Facility SubType Code	Process Equipment Type	Facility SubType Count	Process Equipment Count	Average Equipment Count	95% Confidence Limit (% of mean)	
					lower	upper
322	Tank Heater	33	1	0.030	100%	202%
322	Treater	33	20	0.607	35%	35%
341	Catalytic Heater	12	6	0.498	50%	51%
341	Gas Pipeline Header	12	4	0.334	75%	75%
341	Production Tank (fixed roof)	12	13	1.076	92%	132%
341	Propane Fuel Tank	12	1	0.084	100%	198%
341	Screw Compressor	12	7	0.583	43%	43%
341	Tank Heater	12	9	0.748	78%	90%
342	Catalytic Heater	13	1	0.078	100%	197%
342	Heavy Liquid Pipeline Header	13	2	0.154	100%	150%
342	Production Tank (fixed roof)	13	20	1.540	25%	35%
342	Propane Fuel Tank	13	36	2.776	50%	55%
342	Screw Compressor	13	14	1.076	21%	22%
342	Tank Heater	13	20	1.540	35%	45%
361	Catalytic Heater	29	14	0.481	57%	65%
361	Flare KnockOut Drum	29	1	0.035	100%	199%
361	Gas Pipeline Header	29	5	0.172	80%	80%
361	Pig Trap (Gas Service)	29	7	0.241	71%	86%
361	Pop Tank	29	1	0.034	100%	204%
361	Production Tank (fixed roof)	29	8	0.276	63%	75%
361	Reciprocating Compressor	29	2	0.069	100%	152%
361	Separator	29	6	0.207	67%	67%
362	Catalytic Heater	12	25	2.081	60%	68%
362	Flare KnockOut Drum	12	2	0.167	100%	199%
362	Gas Pipeline Header	12	4	0.332	75%	76%
362	Pig Trap (Gas Service)	12	7	0.587	86%	99%
362	Production Tank (fixed roof)	12	5	0.415	100%	141%
362	Reciprocating Compressor	12	1	0.083	100%	201%
362	Separator	12	10	0.835	50%	60%
362	Tank Heater	12	2	0.165	100%	203%
363	Catalytic Heater	11	5	0.453	100%	141%
363	Gas Meter Building	11	1	0.092	100%	195%
363	Gas Pipeline Header	11	3	0.271	100%	101%
363	Separator	11	3	0.274	100%	99%
364	Catalytic Heater	20	65	3.256	77%	123%
364	Flare KnockOut Drum	20	3	0.150	100%	167%

Table 29: Average (mean) process equipment counts and confidence intervals per facility subtype.						
Facility SubType Code	Process Equipment Type	Facility SubType Count	Process Equipment Count	Average Equipment Count	95% Confidence Limit (% of mean)	
					lower	upper
364	Gas Pipeline Header	20	14	0.700	50%	50%
364	Gas Sweetening: Amine	20	2	0.100	100%	201%
364	Pig Trap (Gas Service)	20	10	0.498	70%	81%
364	Power Generator (natural gas fired)	20	2	0.099	100%	151%
364	Production Tank (fixed roof)	20	6	0.299	83%	101%
364	Reciprocating Compressor	20	5	0.246	100%	205%
364	Screw Compressor	20	5	0.249	80%	81%
364	Separator	20	13	0.650	62%	92%
364	Storage Bullet	20	2	0.100	100%	201%
601	Catalytic Heater	16	43	2.689	44%	51%
601	Flare KnockOut Drum	16	1	0.063	100%	200%
601	Gas Pipeline Header	16	5	0.314	60%	79%
601	Gas Sample and Analysis System	16	1	0.062	100%	203%
601	Pig Trap (Gas Service)	16	5	0.312	100%	140%
601	Pop Tank	16	1	0.062	100%	204%
601	Production Tank (fixed roof)	16	3	0.188	100%	100%
601	Reciprocating Compressor	16	13	0.817	54%	68%
601	Reciprocating Compressor - Electric Driver	16	1	0.062	100%	202%
601	Screw Compressor	16	7	0.438	57%	57%
601	Separator	16	12	0.748	58%	76%
611	Catalytic Heater	4	1	0.249	100%	201%
611	Flare KnockOut Drum	4	1	0.254	100%	195%
611	Gas Meter Building	4	1	0.253	100%	197%
611	LACT Unit	4	4	0.990	100%	203%
611	Liquid Pump	4	3	0.751	100%	100%
611	Pig Trap (Gas Service)	4	1	0.251	100%	199%
611	Pop Tank	4	2	0.500	100%	100%
611	Production Tank (fixed roof)	4	14	3.503	43%	64%
611	Screw Compressor - Electric Driver	4	3	0.752	100%	199%
611	Scrubber	4	2	0.501	100%	99%
611	Separator	4	2	0.498	100%	101%
611	Treater	4	4	1.000		

Table 29: Average (mean) process equipment counts and confidence intervals per facility subtype.						
Facility SubType Code	**Process Equipment Type**	**Facility SubType Count**	**Process Equipment Count**	**Average Equipment Count**	**95% Confidence Limit (% of mean)**	
					lower	**upper**
621	Catalytic Heater	34	69	2.026	48%	55%
621	Flare KnockOut Drum	34	7	0.205	57%	72%
621	Gas Meter Building	34	5	0.148	80%	99%
621	Gas Pipeline Header	34	28	0.824	25%	25%
621	Liquid Pump	34	1	0.030	100%	194%
621	Pig Trap (Gas Service)	34	12	0.353	67%	92%
621	Pig Trap (Liquid Service)	34	3	0.088	100%	166%
621	Process Boiler	34	1	0.030	100%	194%
621	Production Tank (fixed roof)	34	11	0.325	64%	72%
621	Reciprocating Compressor	34	24	0.709	46%	54%
621	Reciprocating Compressor - Electric Driver	34	6	0.176	83%	100%
621	Screw Compressor	34	2	0.059	100%	147%
621	Screw Compressor - Electric Driver	34	2	0.059	100%	150%
621	Separator	34	30	0.884	30%	33%

Table 30: Average (mean) process equipment counts and confidence intervals per well status.

Well Status Code	Process Equipment Type	Well Status Count	Process Equipment Count	Average Equipment Count	95% Confidence Limit (% of mean)	
					lower	upper
CBMCLS FLOW	Catalytic Heater	14	7	0.502	57%	57%
CBMCLS FLOW	Pig Trap (Gas Service)	14	5	0.355	80%	101%
CBMCLS FLOW	Wellhead (CBM Flow)	14	13	0.929	15%	8%
CBMOT FLOW	Catalytic Heater	21	6	0.286	67%	67%
CBMOT FLOW	Pig Trap (Gas Service)	21	1	0.048	100%	197%
CBMOT FLOW	Wellhead (CBM Flow)	21	21	1.000		
CBMOT PUMP	Pig Trap (Gas Service)	1	1	1.000		
CBMOT PUMP	Wellhead (Gas Pump)	1	1	1.000		
CR-BIT ABZONE	Well Pump	1	1	1.000		
CR-BIT ABZONE	Wellhead (Bitumen Pump)	1	1	1.000		
CR-BIT PUMP	Catalytic Heater	85	1	0.012	100%	200%
CR-BIT PUMP	Gas Pipeline Header	85	1	0.012	100%	197%
CR-BIT PUMP	Production Tank (fixed roof)	85	30	0.352	30%	34%
CR-BIT PUMP	Propane Fuel Tank	85	15	0.177	60%	73%
CR-BIT PUMP	Screw Compressor	85	2	0.023	100%	151%
CR-BIT PUMP	Tank Heater	85	28	0.330	32%	36%
CR-BIT PUMP	Well Pump	85	69	0.812	10%	10%
CR-BIT PUMP	Wellhead (Bitumen Pump)	85	84	0.988	2%	1%
CR-BIT SUSP	Well Pump	2	2	1.000		
CR-BIT SUSP	Wellhead (Bitumen Pump)	2	2	1.000		
CR-OIL FLOW	Catalytic Heater	21	6	0.286	83%	100%
CR-OIL FLOW	Production Tank (fixed roof)	21	1	0.047	100%	202%
CR-OIL FLOW	Separator	21	4	0.191	75%	99%
CR-OIL FLOW	Well Pump	21	2	0.096	100%	149%
CR-OIL FLOW	Wellhead (Oil Flow)	21	21	1.000		

Table 30: Average (mean) process equipment counts and confidence intervals per well status.						
Well Status Code	**Process Equipment Type**	**Well Status Count**	**Process Equipment Count**	**Average Equipment Count**	**95% Confidence Limit (% of mean)**	
					lower	**upper**
CR-OIL PUMP	Catalytic Heater	103	47	0.456	34%	38%
CR-OIL PUMP	Gas Pipeline Header	103	2	0.019	100%	150%
CR-OIL PUMP	Gas Sample and Analysis System	103	1	0.010	100%	202%
CR-OIL PUMP	Liquid Pipeline Header	103	1	0.010	100%	199%
CR-OIL PUMP	Pig Trap (Gas Service)	103	2	0.019	100%	151%
CR-OIL PUMP	Pig Trap (Liquid Service)	103	14	0.136	43%	50%
CR-OIL PUMP	Pop Tank	103	7	0.068	57%	71%
CR-OIL PUMP	Production Tank (fixed roof)	103	20	0.194	40%	45%
CR-OIL PUMP	Propane Fuel Tank	103	1	0.010	100%	198%
CR-OIL PUMP	Screw Compressor	103	3	0.029	100%	134%
CR-OIL PUMP	Scrubber	103	1	0.010	100%	201%
CR-OIL PUMP	Separator	103	28	0.272	32%	36%
CR-OIL PUMP	Well Pump	103	24	0.232	33%	38%
CR-OIL PUMP	Wellhead (Oil Pump)	103	103	1.000		
GAS FLOW	Catalytic Heater	127	112	0.882	20%	20%
GAS FLOW	Flare KnockOut Drum	127	1	0.008	100%	195%
GAS FLOW	Gas Meter Building	127	7	0.055	71%	85%
GAS FLOW	Gas Pipeline Header	127	5	0.039	80%	100%
GAS FLOW	Line Heater	127	1	0.008	100%	200%
GAS FLOW	Pig Trap (Gas Service)	127	9	0.071	55%	67%
GAS FLOW	Pop Tank	127	1	0.008	100%	198%
GAS FLOW	Production Tank (fixed roof)	127	27	0.213	33%	37%
GAS FLOW	Reciprocating Compressor	127	2	0.016	100%	147%
GAS FLOW	Separator	127	57	0.449	19%	19%
GAS FLOW	Wellhead (Gas Flow)	127	127	1.000		

Table 30: Average (mean) process equipment counts and confidence intervals per well status.

Well Status Code	Process Equipment Type	Well Status Count	Process Equipment Count	Average Equipment Count	95% Confidence Limit (% of mean)	
					lower	upper
GAS PUMP	Catalytic Heater	62	93	1.502	17%	18%
GAS PUMP	Flare KnockOut Drum	62	1	0.016	100%	205%
GAS PUMP	Gas Pipeline Header	62	3	0.049	100%	132%
GAS PUMP	Pig Trap (Gas Service)	62	3	0.049	100%	164%
GAS PUMP	Production Tank (fixed roof)	62	20	0.322	35%	35%
GAS PUMP	Propane Fuel Tank	62	1	0.016	100%	196%
GAS PUMP	Separator	62	33	0.532	24%	24%
GAS PUMP	Wellhead (Gas Pump)	62	61	0.984	3%	2%
GAS STORG	Separator	2	1	0.499	100%	100%
GAS STORG	Wellhead (Gas Storage)	2	2	1.000		
SHG FLOW	Catalytic Heater	1	1	1.000		
SHG FLOW	Separator	1	1	1.000		
SHG FLOW	Wellhead (Gas Flow)	1	1	1.000		

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Catalytic Heater	Regulator	Process Gas	651	721	1.159	7%	8%
Catalytic Heater	Valve	Process Gas	651	745	1.197	9%	11%
Catalytic Heater	Connector	Process Gas	651	756	1.212	29%	32%
Dehydrator - Glycol	Control Valve	Process Gas	20	25	1.310	58%	71%
Dehydrator - Glycol	Valve	Process Gas	20	576	30.118	37%	47%
Dehydrator - Glycol	Valve	Light Liquid	20	29	1.528	88%	136%
Dehydrator - Glycol	Meter	Process Gas	20	22	1.153	41%	47%
Dehydrator - Glycol	Control Valve	Light Liquid	20	6	0.312	98%	141%
Dehydrator - Glycol	Open-Ended Line	Process Gas	20	8	0.416	97%	151%
Dehydrator - Glycol	Regulator	Process Gas	20	104	5.457	42%	48%
Dehydrator - Glycol	Connector	Process Gas	20	4130	215.836	35%	39%
Dehydrator - Glycol	Connector	Light Liquid	20	227	11.980	88%	137%
Dehydrator - Glycol	PRV/PSV	Process Gas	20	50	2.621	40%	49%
Flare KnockOut Drum	Valve	Process Gas	29	244	8.844	56%	90%
Flare KnockOut Drum	Meter	Process Gas	29	1	0.036	100%	308%
Flare KnockOut Drum	Control Valve	Process Gas	29	5	0.181	96%	141%
Flare KnockOut Drum	Regulator	Process Gas	29	30	1.083	57%	71%
Flare KnockOut Drum	Control Valve	Light Liquid	29	1	0.036	100%	308%
Flare KnockOut Drum	Connector	Process Gas	29	1516	54.764	45%	58%
Flare KnockOut Drum	Connector	Light Liquid	29	530	19.086	48%	59%
Flare KnockOut Drum	Valve	Light Liquid	29	84	3.036	51%	64%
Flare KnockOut Drum	PRV/PSV	Process Gas	29	5	0.180	100%	169%
Flare KnockOut Drum	Open-Ended Line	Light Liquid	29	19	0.684	100%	291%
Gas Boot	Valve	Process Gas	3	3	1.042	100%	163%
Gas Boot	Valve	Light Liquid	3	20	6.944	77%	103%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.							
Process Equipment Type	**Component Type**	**Service Type**	**Process Equipment Count**	**Total Component Count**	**Average Component Count**	**95% Confidence Limit (% of mean)**	
						lower	**upper**
Gas Boot	Connector	Light Liquid	3	77	26.739	76%	87%
Gas Boot	PRV/PSV	Process Gas	3	1	0.348	100%	263%
Gas Boot	Connector	Process Gas	3	15	5.178	76%	92%
Gas Meter Building	Valve	Process Gas	14	255	19.100	50%	64%
Gas Meter Building	Valve	Light Liquid	14	12	0.891	100%	299%
Gas Meter Building	Meter	Process Gas	14	18	1.352	54%	81%
Gas Meter Building	Meter	Light Liquid	14	4	0.296	100%	316%
Gas Meter Building	Control Valve	Process Gas	14	7	0.529	93%	124%
Gas Meter Building	Regulator	Process Gas	14	22	1.643	79%	107%
Gas Meter Building	Connector	Process Gas	14	1277	95.873	54%	69%
Gas Meter Building	Connector	Light Liquid	14	76	5.618	100%	309%
Gas Meter Building	Open-Ended Line	Process Gas	14	2	0.149	100%	305%
Gas Meter Building	PRV/PSV	Process Gas	14	15	1.118	72%	100%
Gas Pipeline Header	Valve	Process Gas	82	2346	29.916	31%	38%
Gas Pipeline Header	Valve	Light Liquid	82	123	1.604	98%	183%
Gas Pipeline Header	Meter	Process Gas	82	40	0.511	65%	96%
Gas Pipeline Header	Control Valve	Process Gas	82	34	0.436	71%	133%
Gas Pipeline Header	Connector	Process Gas	82	8289	105.826	33%	40%
Gas Pipeline Header	Connector	Light Liquid	82	487	6.272	100%	234%
Gas Pipeline Header	Open-Ended Line	Process Gas	82	5	0.063	100%	169%
Gas Pipeline Header	PRV/PSV	Process Gas	82	26	0.334	61%	83%
Gas Pipeline Header	Regulator	Process Gas	82	60	0.761	70%	115%
Gas Sweetening: Amine	Valve	Process Gas	3	106	37.046	90%	194%
Gas Sweetening: Amine	Valve	Light Liquid	3	3	1.046	75%	86%
Gas Sweetening: Amine	Regulator	Process Gas	3	3	1.042	75%	84%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Gas Sweetening: Amine	Connector	Process Gas	3	253	87.596	76%	100%
Gas Sweetening: Amine	Connector	Light Liquid	3	9	3.126	85%	127%
Gas Sweetening: Amine	PRV/PSV	Process Gas	3	2	0.691	100%	264%
Heavy Liquid Pipeline Header	Valve	Heavy Liquid	2	24	12.388	95%	186%
Heavy Liquid Pipeline Header	Connector	Heavy Liquid	2	56	29.379	91%	129%
Incinerator	Valve	Process Gas	1	8	8.404	100%	153%
Incinerator	Regulator	Process Gas	1	3	3.137	100%	151%
Incinerator	Control Valve	Process Gas	1	2	2.098	100%	150%
Incinerator	Connector	Process Gas	1	53	56.333	100%	147%
LACT Unit	Valve	Process Gas	4	2	0.528	100%	158%
LACT Unit	Valve	Light Liquid	4	102	26.675	68%	82%
LACT Unit	Meter	Light Liquid	4	14	3.701	84%	125%
LACT Unit	Control Valve	Process Gas	4	3	0.787	100%	184%
LACT Unit	Control Valve	Light Liquid	4	10	2.602	78%	115%
LACT Unit	Connector	Process Gas	4	92	23.527	100%	161%
LACT Unit	Connector	Light Liquid	4	469	123.323	72%	94%
LACT Unit	PRV/PSV	Process Gas	4	2	0.525	100%	271%
LACT Unit	PRV/PSV	Light Liquid	4	2	0.520	100%	276%
Line Heater	Valve	Process Gas	11	127	12.129	60%	101%
Line Heater	Control Valve	Process Gas	11	3	0.286	100%	207%
Line Heater	Valve	Light Liquid	11	28	2.663	81%	121%
Line Heater	Meter	Process Gas	11	2	0.193	100%	188%
Line Heater	Regulator	Process Gas	11	41	3.885	55%	70%
Line Heater	Connector	Process Gas	11	1082	103.033	51%	69%
Line Heater	Connector	Light Liquid	11	124	11.812	80%	106%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.							
Process Equipment Type	**Component Type**	**Service Type**	**Process Equipment Count**	**Total Component Count**	**Average Component Count**	**95% Confidence Limit (% of mean)**	
						lower	**upper**
Line Heater	PRV/PSV	Process Gas	11	7	0.659	84%	131%
Liquid Pipeline Header	Meter	Light Liquid	33	1	0.031	100%	311%
Liquid Pipeline Header	Valve	Light Liquid	33	1066	33.770	33%	41%
Liquid Pipeline Header	Control Valve	Light Liquid	33	14	0.438	100%	168%
Liquid Pipeline Header	Connector	Light Liquid	33	3734	118.561	32%	36%
Liquid Pump	Valve	Process Gas	14	9	0.673	100%	302%
Liquid Pump	Valve	Light Liquid	14	203	15.162	51%	70%
Liquid Pump	Meter	Light Liquid	14	6	0.454	81%	116%
Liquid Pump	Pump Seal	Light Liquid	14	14	1.045	37%	39%
Liquid Pump	Connector	Light Liquid	14	819	61.322	44%	57%
Liquid Pump	Connector	Process Gas	14	60	4.606	100%	297%
Liquid Pump	PRV/PSV	Light Liquid	14	8	0.595	70%	87%
Pig Trap (Gas Service)	Valve	Process Gas	74	574	8.106	25%	33%
Pig Trap (Gas Service)	Connector	Process Gas	74	1565	22.153	27%	35%
Pig Trap (Gas Service)	PRV/PSV	Process Gas	74	2	0.029	100%	207%
Pig Trap (Liquid Service)	Valve	Light Liquid	31	153	5.137	34%	40%
Pig Trap (Liquid Service)	Connector	Light Liquid	31	508	17.157	31%	34%
Pop Tank	Valve	Light Liquid	20	25	1.311	50%	64%
Pop Tank	Connector	Process Gas	20	45	2.356	92%	176%
Pop Tank	Connector	Light Liquid	20	110	5.765	53%	66%
Pop Tank	Open-Ended Line	Light Liquid	20	19	0.998	36%	41%
Power Generator (natural gas fired)	Valve	Process Gas	3	32	11.179	94%	137%
Power Generator (natural gas fired)	Control Valve	Process Gas	3	2	0.688	100%	272%
Power Generator (natural gas fired)	Regulator	Process Gas	3	9	3.157	86%	153%
Power Generator (natural gas fired)	Connector	Process Gas	3	301	103.754	98%	143%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Process Boiler	Valve	Process Gas	1	15	15.725	100%	150%
Process Boiler	Regulator	Process Gas	1	4	4.224	100%	148%
Process Boiler	Connector	Process Gas	1	64	66.510	100%	150%
Process Boiler	PRV/PSV	Process Gas	1	1	1.039	100%	155%
Production Tank (fixed roof - heavy oil)	Open-Ended Line	Heavy Liquid	63	1	0.017	100%	319%
Production Tank (fixed roof - heavy oil)	PRV/PSV	Process Gas	63	1	0.017	100%	317%
Production Tank (fixed roof - heavy oil)	Connector	Heavy Liquid	63	2280	37.905	22%	24%
Production Tank (fixed roof - heavy oil)	Valve	Heavy Liquid	63	857	14.218	19%	20%
Production Tank (fixed roof - Light/Medium Oil)	Valve	Process Gas	213	88	0.431	37%	46%
Production Tank (fixed roof - Light/Medium Oil)	Thief Hatch	Light Liquid	213	82	0.399	83%	229%
Production Tank (fixed roof - Light/Medium Oil)	Thief Hatch	Process Gas	213	50	0.246	31%	34%
Production Tank (fixed roof - Light/Medium Oil)	Valve	Light Liquid	213	1087	5.340	17%	21%
Production Tank (fixed roof - Light/Medium Oil)	Regulator	Process Gas	213	49	0.241	30%	33%
Production Tank (fixed roof - Light/Medium Oil)	Connector	Process Gas	213	785	3.850	36%	46%
Production Tank (fixed roof - Light/Medium Oil)	Connector	Light Liquid	213	4444	21.815	14%	15%
Production Tank (fixed roof - Light/Medium Oil)	Open-Ended Line	Process Gas	213	3	0.015	100%	166%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Production Tank (fixed roof - Light/Medium Oil)	PRV/PSV	Light Liquid	213	1	0.005	100%	297%
Production Tank (fixed roof - Light/Medium Oil)	PRV/PSV	Process Gas	213	49	0.241	30%	33%
Production Tank (fixed roof - Light/Medium Oil)	Open-Ended Line	Light Liquid	213	3	0.015	100%	239%
Propane Fuel Tank	Valve	Process Gas	56	115	2.148	23%	27%
Propane Fuel Tank	Regulator	Process Gas	56	56	1.045	19%	19%
Propane Fuel Tank	Connector	Process Gas	56	721	13.467	22%	23%
Reciprocating Compressor	Valve	Process Gas	54	1860	35.982	25%	31%
Reciprocating Compressor	Valve	Light Liquid	54	327	6.334	38%	44%
Reciprocating Compressor	Meter	Process Gas	54	15	0.290	56%	66%
Reciprocating Compressor	Control Valve	Light Liquid	54	36	0.699	55%	64%
Reciprocating Compressor	Control Valve	Process Gas	54	110	2.131	33%	37%
Reciprocating Compressor	Regulator	Process Gas	54	293	5.662	31%	36%
Reciprocating Compressor	Compressor Rod-Packing	Process Gas	54	157	3.045	23%	25%
Reciprocating Compressor	Connector	Light Liquid	54	2786	53.869	43%	54%
Reciprocating Compressor	Open-Ended Line	Process Gas	54	28	0.545	67%	90%
Reciprocating Compressor	PRV/PSV	Process Gas	54	190	3.676	24%	26%
Reciprocating Compressor	Connector	Process Gas	54	31600	612.150	22%	23%
Reciprocating Compressor - Electric Driver	Valve	Process Gas	10	175	18.293	53%	65%
Reciprocating Compressor - Electric Driver	Regulator	Process Gas	10	1	0.103	100%	306%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Reciprocating Compressor - Electric Driver	Valve	Light Liquid	10	89	9.387	60%	79%
Reciprocating Compressor - Electric Driver	Meter	Process Gas	10	4	0.417	90%	117%
Reciprocating Compressor - Electric Driver	Control Valve	Process Gas	10	3	0.312	100%	202%
Reciprocating Compressor - Electric Driver	Control Valve	Light Liquid	10	15	1.568	79%	102%
Reciprocating Compressor - Electric Driver	Connector	Process Gas	10	3933	412.058	45%	51%
Reciprocating Compressor - Electric Driver	Compressor Rod-Packing	Process Gas	10	30	3.120	56%	65%
Reciprocating Compressor - Electric Driver	Connector	Light Liquid	10	560	58.561	60%	92%
Reciprocating Compressor - Electric Driver	PRV/PSV	Process Gas	10	23	2.400	46%	54%
Screw Compressor	Valve	Process Gas	46	1124	25.556	31%	38%
Screw Compressor	Valve	Light Liquid	46	200	4.559	55%	74%
Screw Compressor	Meter	Process Gas	46	43	0.976	37%	41%
Screw Compressor	Control Valve	Process Gas	46	50	1.135	44%	54%
Screw Compressor	Control Valve	Light Liquid	46	7	0.159	87%	126%
Screw Compressor	Regulator	Process Gas	46	182	4.135	26%	30%
Screw Compressor	Connector	Process Gas	46	14934	339.208	29%	37%
Screw Compressor	Connector	Light Liquid	46	1559	35.562	53%	71%
Screw Compressor	Open-Ended Line	Process Gas	46	25	0.567	63%	85%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Screw Compressor	PRV/PSV	Process Gas	46	150	3.407	25%	27%
Screw Compressor - Electric Driver	Valve	Process Gas	8	130	17.000	55%	69%
Screw Compressor - Electric Driver	Control Valve	Process Gas	8	9	1.182	88%	118%
Screw Compressor - Electric Driver	Valve	Light Liquid	8	27	3.534	77%	102%
Screw Compressor - Electric Driver	Meter	Process Gas	8	3	0.396	100%	200%
Screw Compressor - Electric Driver	Regulator	Process Gas	8	1	0.132	100%	288%
Screw Compressor - Electric Driver	Connector	Process Gas	8	1582	208.041	58%	77%
Screw Compressor - Electric Driver	Connector	Light Liquid	8	279	36.610	69%	88%
Screw Compressor - Electric Driver	Open-Ended Line	Process Gas	8	2	0.260	100%	188%
Screw Compressor - Electric Driver	PRV/PSV	Process Gas	8	12	1.569	68%	84%
Scrubber	Valve	Process Gas	4	46	12.000	98%	183%
Scrubber	Connector	Process Gas	4	290	76.711	96%	186%
Scrubber	PRV/PSV	Process Gas	4	2	0.522	100%	164%
Separator	Valve	Process Gas	288	5548	20.126	15%	16%
Separator	Control Valve	Process Gas	288	244	0.885	19%	21%
Separator	Valve	Light Liquid	288	3407	12.373	13%	14%
Separator	Meter	Process Gas	288	299	1.085	13%	15%
Separator	Control Valve	Light Liquid	288	200	0.726	19%	22%
Separator	Meter	Light Liquid	288	115	0.417	22%	23%
Separator	Connector	Light Liquid	288	18762	68.110	14%	16%
Separator	Regulator	Process Gas	288	689	2.501	17%	18%
Separator	Connector	Process Gas	288	29929	108.724	11%	12%
Separator	Open-Ended Line	Process Gas	288	33	0.120	51%	60%
Separator	PRV/PSV	Process Gas	288	460	1.670	11%	13%
Storage Bullet	Valve	Light Liquid	2	40	20.924	91%	107%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Storage Bullet	Control Valve	Light Liquid	2	4	2.088	92%	106%
Storage Bullet	Connector	Light Liquid	2	160	83.719	92%	106%
Tank Heater	Valve	Process Gas	60	450	7.847	22%	27%
Tank Heater	Meter	Process Gas	60	1	0.017	100%	307%
Tank Heater	Regulator	Process Gas	60	226	3.939	21%	22%
Tank Heater	Connector	Process Gas	60	3109	54.248	20%	22%
Treater	Valve	Process Gas	24	465	20.286	38%	47%
Treater	Valve	Light Liquid	24	394	17.206	42%	51%
Treater	Meter	Process Gas	24	21	0.916	49%	57%
Treater	Control Valve	Process Gas	24	18	0.783	47%	55%
Treater	Control Valve	Light Liquid	24	23	1.007	52%	63%
Treater	Meter	Light Liquid	24	11	0.477	65%	85%
Treater	Regulator	Process Gas	24	112	4.887	40%	47%
Treater	Connector	Process Gas	24	4548	197.835	34%	38%
Treater	Connector	Light Liquid	24	2181	95.200	39%	47%
Treater	Open-Ended Line	Process Gas	24	5	0.216	100%	304%
Treater	Open-Ended Line	Light Liquid	24	14	0.612	100%	212%
Treater	PRV/PSV	Process Gas	24	36	1.571	42%	54%
Well Pump	Valve	Process Gas	98	591	6.305	18%	20%
Well Pump	Regulator	Process Gas	98	191	2.036	17%	18%
Well Pump	PRV/PSV	Process Gas	98	28	0.300	40%	45%
Well Pump	Connector	Process Gas	98	4781	51.104	18%	19%
Wellhead (Bitumen Pump)	Valve	Heavy Liquid	87	747	8.983	17%	18%
Wellhead (Bitumen Pump)	Valve	Process Gas	87	630	7.573	18%	20%
Wellhead (Bitumen Pump)	Connector	Heavy Liquid	87	3025	36.393	18%	19%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.

Process Equipment Type	Component Type	Service Type	Process Equipment Count	Total Component Count	Average Component Count	95% Confidence Limit (% of mean)	
						lower	upper
Wellhead (Bitumen Pump)	Regulator	Process Gas	87	39	0.469	34%	38%
Wellhead (Bitumen Pump)	Open-Ended Line	Process Gas	87	12	0.144	59%	71%
Wellhead (Bitumen Pump)	Connector	Process Gas	87	2307	27.725	20%	21%
Wellhead (Bitumen Pump)	PRV/PSV	Process Gas	87	24	0.289	43%	46%
Wellhead (CBM Flow)	Valve	Process Gas	34	331	10.167	32%	48%
Wellhead (CBM Flow)	Meter	Process Gas	34	8	0.245	69%	87%
Wellhead (CBM Flow)	Regulator	Process Gas	34	2	0.063	100%	196%
Wellhead (CBM Flow)	Connector	Process Gas	34	1024	31.475	28%	32%
Wellhead (CBM Flow)	Open-Ended Line	Process Gas	34	10	0.307	62%	75%
Wellhead (CBM Flow)	PRV/PSV	Process Gas	34	2	0.062	100%	198%
Wellhead (Gas Flow)	Valve	Process Gas	128	1543	12.613	17%	18%
Wellhead (Gas Flow)	Meter	Process Gas	128	8	0.065	72%	92%
Wellhead (Gas Flow)	Regulator	Process Gas	128	50	0.417	95%	263%
Wellhead (Gas Flow)	Open-Ended Line	Process Gas	128	1	0.008	100%	312%
Wellhead (Gas Flow)	PRV/PSV	Process Gas	128	6	0.049	82%	107%
Wellhead (Gas Flow)	Connector	Process Gas	128	5383	43.948	16%	18%
Wellhead (Gas Pump)	Valve	Process Gas	62	855	14.435	23%	27%
Wellhead (Gas Pump)	Meter	Process Gas	62	20	0.336	45%	50%
Wellhead (Gas Pump)	Regulator	Process Gas	62	33	0.557	54%	71%
Wellhead (Gas Pump)	Connector	Process Gas	62	4300	72.591	24%	28%
Wellhead (Gas Pump)	Open-Ended Line	Process Gas	62	2	0.034	100%	208%
Wellhead (Gas Pump)	PRV/PSV	Process Gas	62	27	0.456	51%	60%
Wellhead (Gas Storage)	Valve	Process Gas	2	18	9.340	93%	135%
Wellhead (Gas Storage)	Connector	Process Gas	2	59	30.684	92%	103%
Wellhead (Oil Flow)	Valve	Process Gas	21	250	12.417	58%	74%

Table 31: Average component counts (mean) and confidence intervals per process equipment type.							
Process Equipment Type	**Component Type**	**Service Type**	**Process Equipment Count**	**Total Component Count**	**Average Component Count**	**95% Confidence Limit (% of mean)**	
						lower	**upper**
Wellhead (Oil Flow)	Meter	Process Gas	21	1	0.050	100%	314%
Wellhead (Oil Flow)	Valve	Light Liquid	21	139	6.915	49%	57%
Wellhead (Oil Flow)	Connector	Process Gas	21	714	35.342	55%	70%
Wellhead (Oil Flow)	Connector	Light Liquid	21	623	31.109	51%	58%
Wellhead (Oil Pump)	Valve	Process Gas	103	385	3.918	35%	39%
Wellhead (Oil Pump)	Valve	Light Liquid	103	990	10.038	19%	21%
Wellhead (Oil Pump)	Meter	Process Gas	103	2	0.020	100%	212%
Wellhead (Oil Pump)	Regulator	Process Gas	103	11	0.112	71%	93%
Wellhead (Oil Pump)	Open-Ended Line	Process Gas	103	1	0.010	100%	306%
Wellhead (Oil Pump)	Connector	Process Gas	103	1793	18.177	34%	39%
Wellhead (Oil Pump)	Connector	Light Liquid	103	4847	49.139	19%	20%
Wellhead (Oil Pump)	Pump Seal	Light Liquid	103	103	1.047	14%	14%
Wellhead (Oil Pump)	PRV/PSV	Process Gas	103	4	0.041	100%	180%

7.5 SPECIATION PROFILES

Site-specific speciation profiles were applied wherever these were available. Otherwise, the applicable values are presented in Section 2.10.

7.6 CONTROL FACTORS

Control factors are not used to estimate fugitive emission management and control.

7.7 OPERATING FACTORS

In the absence of any site-specific information, it is assumed that all facilities are in active service during the months for which production is reported, and that they are in primarily pressurized service during months in which no production is reported.

8 STORAGE LOSSES

8.1 SOURCE CHARACTERIZATION

Fixed-roof tanks are the primary equipment for storing hydrocarbon liquids (oil and condensate) in the upstream oil and gas industry. Limited use of floating-roof tanks also occurs (primarily at pipeline terminals, large oil sands facilities and larger gas processing plants). The storage losses from the first type of tank are estimated as described below. The losses from floating-roof tanks are estimated using the empirical correlations developed by API (1990 and 1994). If a tank is equipped with a vapour collection system, there is still a potential for some emissions due to potential inefficiencies of the vapour collection system; for example, due to overloading of the system due to inadequate sizing for peak emission rates, down time of the end control device, fouling of the vapour collection piping, etc. Additionally, tanks connected to vapour collection systems are a source of fugitive equipment leaks (mostly due to leakage around the thief hatch). The amount of leakage is assessed as described in Section 7.2 (Fugitive Equipment Leaks).

The storage losses from fixed-roof tanks comprise 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 vented 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 vaporize). The material that vaporizes during this process is called solution gas.

Breathing and working losses occur for both stable and unstable products. However, if the product is unstable, the latter type of loss is obscured by the flashing losses. Accordingly, storage losses at oil batteries are taken to be the sum of breathing and flashing losses. Storage losses at gas processing plants and pipeline terminals (i.e., facilities storing stable products) are taken to be the sum of breathing and working losses.

Unless information to the contrary was provided by the industry survey, all storage tanks used at oil and gas production facilities and at gas processing plants are assumed to have fixed roofs. The number and sizes of these tanks are estimated based on typical design practices and on the maximum throughput reported for each facility. The physical dimensions of each tank size are assumed to be those presented in Table 32 and the colour of the tanks is assumed to be white (unless these data were provided on the industry survey).

Tanks used at terminals on crude oil and LVP pipelines are delineated based on data provided by the operating companies. A mixture of fixed-roof and floating-roof tanks are in use.

The use of underground storage tanks and the resulting emissions are assumed to be negligible.

Table 32: Summary of the commonly used tank sizes in the oil and gas industry, and the dimensions of these tanks.

Nominal Capacity		Diameter (m)	Height (m)
(bbl)	(m^3)		
100	17.077	2.438	3.658
200	32.033	3.658	3.048
400	64.065	3.658	6.096
500	79.711	4.877	4.267
750	120.093	4.572	7.315
1000	160.116	6.096	5.486
1500	243.372	7.315	5.791
2000	320.238	7.315	7.620

8.2 EMISSIONS CALCULATION

8.2.1 FLASHING LOSSES

Storage tank flashing losses are calculated using Equation 28:

$$ER_{i,} = SGF \cdot Q_O \quad \cdot Y_i \cdot \rho_i \cdot (1 - CF) \cdot g_c$$

Equation 28

Where:

ER_i = annual flashing emissions of substance i (t/y)
Q_o = oil production during the study year (m^3/yr).
ρ_i = density of substance I at standard conditions of 101.325 kPa and 15˚C (kg/m^3)
= 1.861 kg/m^3 for CO_2, 0.678 kg/m^3 for CH_4 and may be calculated using Equation 29.
Y_i = mole fraction of substance i in the tank vapour (kmol/kmol).
CF = control factor (dimensionless fraction)
= 0 for free-venting tanks and 0.95 for tanks with vapour control.
g_c = constant of proportionality
= 10^{-3} (tonnes/kg).
SGF = solution gas factor (Sm^3 gas/m^3 oil).
= the amount of natural gas dissolved in the oil exiting the first pressure vessel located upstream of the storage tank.

The density of substance may be determined using the following equation:

$$\rho_i = \frac{101.325 \cdot MW_i}{R \cdot (273.15 + 15)}$$

Equation 29

Where,

R = Ideal gas constant ($kPa \cdot kmol^{-1} \cdot m^3 \cdot K^{-1}$)

= 8.3145 $kPa \cdot kmol^{-1} \cdot m^3 \cdot K^{-1}$

MW_i = molecular weight of substance i.

8.2.2 EVAPORATION LOSSES FROM WEATHERED OR STABILIZED PRODUCTS

The total mass emissions of product vapours from tanks (i.e., breathing and working) containing weathered or stabilized hydrocarbon liquids are estimated using the ‘Evaporative Loss from Fixed-Roof Tanks’ method (EPA, 2006); available data on the tank and product characteristics, and throughput volumes.

8.2.2.1 WORKING LOSSES

$$L_W = 4.17 \text{x} 10^{-4} M_V P_V Q_o K_N K_C$$

Equation 30

Where:

L_W = Working loss (kg/y)

M_V = Tank vapour molecular weight (kg/kmol)

P_V = True vapour pressure at bulk liquid temp (kPa) determined by Equation 31.

$$P_V = 6.8929 \exp\left[\left(\frac{1555}{T} - 2.227\right)\left(\log_{10}(RVP) - 0.8384\right) - \frac{4033.89}{T} + 12.82\right]$$

Equation 31

RVP = Reid Vapour Pressure of liquid (kPa)

T = Average liquid temperature (K)

Q_0 = Tank throughput (m^3/yr)

N = Number of turnovers per year = Q/V

K_N = Turnover (saturation) factor

K_C = Product factor 0.84 for crude oil; 1.0 for organic liquids

$$\text{If } N > 36, K_N = \frac{180 + N}{6N}$$

$$\text{If } N \leq 36, K_N = 1$$

When calculating working losses on a monthly basis (instead of yearly), Kn is determined as follows to reproduce the curve presented in Figure 7.1-18 of the EPA ‘Evaporative Loss from Fixed-Roof Tanks’ method (EPA, 2006).

$$= \begin{cases} \frac{15+N}{6N} & if\ N > 3 \\ 1 & if\ N \leq 3 \end{cases}$$

8.2.2.2 BREATHING LOSSES

$$L_B = \quad 0.1093 \times M_V \left(\frac{P_V}{P_A - P_V} \right)^{0.68} D^{1.73}\ H^{0.51}\ \Delta T^{0.5}\ F_P\ C\ K_C$$

Equation 32

Where:

L_B = Breathing loss (kg/y)
M_V = Tank vapour molecular weight (kg/kmol)
P_V = True vapour pressure at bulk liquid temp (kPa) determined by Equation 31
P_a = Atmospheric Pressure (default 92.3 kPa)
D = Tank Diameter (m)
H = Average Vapour Space Height (m)
ΔT = Average Ambient Temperature Change (default is 12.47)
F_p = Paint factor (default to 1 for white)
C = Small Tank Adjustment Factor (default to 1 because L_B may underestimate emissions)
K_c = Product Factor
= 0.65 for crude oil and = 1.0 for other organic liquids

The emissions of individual compounds from each tank are determined by applying a representative vapour speciation profile for the stored product to the total amount of vapour emissions determined for the tank. This is done using the following equation:

$$\boldsymbol{ER_{i,j} = ER_i \times X_{i,j} \times g_c}$$

Equation 33

Where:

$ER_{i,j}$ = emission rate of substance j from tank i (t/y).
ER_i = total vapour emissions from tank i determined using the US EPA TANKS model (kg/h).
$X_{i,j}$ = mass fraction of substance j in the vapour emissions from tank i (kg/kg).
g_c = 10^{-3} x 24 x365 ($t \cdot kg^{-1} \cdot y^{-1} \cdot h$).
= 8.76 ($t \cdot kg^{-1} \cdot y^{-1} \cdot h$).

8.2.3 EVAPORATION LOSSES FROM TANKS CONNECTED TO A VAPOUR RECOVERY UNIT (VRU)

The emissions from tanks connected to a VRU are estimated using Equation 28 where the control factor is set to a value of 0.95 which is the minimum performance required by CCME (1995) for vapour control systems.

8.3 SOLUTION GAS FACTOR

Where the operating pressure and temperature of the first vessel upstream of the storage tank were known, the SGF is estimated using the Vasquez and Beggs correlation presented below (i.e., **Equation 34**). The Vasquez and Beggs correlation is accurate to within ±10 percent more than 85 percent of the time when the specific gravity of the oil is in the range of values listed in **Table 34** (Vazquez and Beggs 1980).

$$SGF = C_1 \gamma_{gs} P^{C_2} \exp\left(\frac{C_3}{\gamma_o T} - \frac{C_4}{T}\right)$$

Equation 34

Where:

γ_{gs} = γ_g corrected at 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 associated gas with respect to air (dimensionless),

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

P = absolute pressure upstream of the storage tank of interest (kPa (abs)),

T = temperature upstream of the storage tank of interest (K), and

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

$$= \frac{141.5}{131.5 + °API}$$

C_1, C_2, C_3, C_4 = correlation parameters (see Table 33).

Table 33: Values of the Vasquez Beggs correlation parameters.

Parameter	**$\gamma_o < 0.876$**	**$\gamma_o > 0.876$**
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 34: Range of reservoir data used to develop Vasquez & Beggs flashing correlations.

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

When site specific stream properties are not available, typical properties from Table 35 are applied.

Table 35: Typical atmospheric and upstream conditions applied to storage tank loss calculations.

Condition	Typical Value	Unit
Average Ambient Temperature	2.3	°C
Average Ambient Pressure	92.3	kPa
Average Ambient Temperature change	12.47	°C
Upstream Temperature	30	°C
Upstream Pressure	441	kPaa

8.4 SPECIATION PROFILES

Site-specific speciation profiles were applied wherever these were available. Otherwise, the applicable values presented in Section 2.10 were used.

9 HANDLING LOSSES BY TANKERS

9.1 SOURCE CHARACTERIZATION

The losses from tankers are classified based on the type of product moved: high vapour pressure (HVP) or low vapour pressure (LVP).

9.1.1 HIGH VAPOUR PRESSURE CARRIERS

Rail tank cars and tank trucks that transport HVP products use special high-pressure storage systems to contain these products. Certain losses occur during the loading and unloading of these vehicles (i.e., venting of the gauge assembly and loss of material that is left in the transfer lines).

9.1.2 LOW VAPOUR PRESSURE CARRIERS

These carriers may transport crude oil, condensate and pentanes-plus. Emissions result from evaporation losses during loading and transit activities. The amount of emissions depends on the vapour pressure of the liquid product, the recent loading history and the method of loading. Submerged loading and dedicated normal service are assumed.

9.2 EMISSIONS CALCULATION

Some losses may occur during transit due to leaking equipment components (e.g., valves, and flanged and threaded connections); however, these are likely small by comparison and, therefore, are neglected.

9.2.1 HIGH VAPOUR PRESSURE CARRIERS

In the absence of appropriate published procedures, the loading and unloading losses are determined using the following developed equations:

$$\boldsymbol{ER_{L,i,j} = Q_{S,i} \cdot LF_j \cdot \left[EF_{G,j} + EF_{L,j} \cdot \left(1 + TF_{S,j} \cdot 1.5\right)\right] \cdot X_{j,i} \cdot g_c}$$

Equation 35

and,

$$\boldsymbol{ER_{U,i,j} = Q_{R,j} \cdot LF_j \cdot EF_{U,j} \cdot \left(1 + TF_{R,j} \cdot 1.5\right) \cdot X_{j,i} \cdot g_c}$$

Equation 36

where,

$ER_{L,I,j}$, $ER_{U,I,j}$, = total emissions of substance i associated with loading (L) and unloading (U) of liquefied product type j (t/y),

$Q_{S,j}$, $Q_{R,j}$ = volume of liquefied product type i shipped (S) and received (R), respectively during the study year(m^3/yr),

LF_j = number of rail cars typically used per unit volume of liquefied product type j transported (i.e. load factor) (cars/m^3),

$EF_{G,j}$ = average emission factor for gauging losses during loading of liquefied product type j (kg/car),

$EF_{L,j}$, $EF_{U,j}$ = average emission factors for losses from depressurizing the transfer line upon completion of loading (L) and unloading operations (U) involving liquefied product type j, and

$TF_{S,j}$, $TF_{R,j}$ = fraction of the volume of liquefied product type i that is shipped or received by truck.

$X_{j,I}$ = mass fraction of substance I in the emissions associated with liquefied product j (kg/kg).

g_c = constant of proportionality to convert the results to units of t/y
= 0.001 t/kg

The numeric value of 1.5 in the above equations accounts for the fact a tank truck must make two to three times as many trips as a rail car to move the same volume of liquefied material. Values for the load, emission, and trucking factors are presented in Table 37 for liquefied ethane, propane and butane.

9.2.2 LOW VAPOUR PRESSURE CARRIERS

The loading losses for low-vapour-pressure (LVP) carriers are calculated using the equation presented below and the factors published by U.S. EPA (2008). Losses that occur during the transit of LVP products are not evaluated. (There are no known factors or procedures available for estimating losses from transport of crude oil or natural gas liquids by tanker vehicles.)

$$\boldsymbol{ER_{i,j} = \frac{0.120 \cdot SF_j \cdot P_j \cdot Y_{i,j} \cdot MW_i \cdot Q_j}{(T_j + 273.15) \cdot 1000} \cdot (1.0 - CF_j)}$$

Equation 37

where,

$ER_{i,j}$ = emission rate of substance i due to evaporation losses from loading of LVP product j (t/y),

SF_j = normal saturation factor for LVP product j to account for the effects of the method of loading (dimensionless) (see Table 36),

P_j = true vapour pressure of the loaded LVP product j (kPa),

MW_i = molecular weight of substance i present in the emitted vapours from the loaded LVP product (kg/kmole),

T_j = bulk temperature of the LVP product j loaded (˚C),

Q_j = Annual volume of the LVP product j loaded (m^3), and

CF = average control factor for the LVP product j loaded (dimensionless).

9.3 SATURATION FACTORS

Typical saturation factors are presented in Table 36 below.

Table 36: Saturation factors for calculation of petroleum liquid loading losses.

Cargo Carrier	Mode of Operation	Saturation Factor (Dimensionless)
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapour balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapour balance service	1.00

Source: Adapted from Table 5.2-1 (Saturation [S] Factors for Calculation Petroleum Liquid Loading Losses), of US EPA (2008).

9.4 PRODUCT VAPOUR PRESSURES

The typical Reid vapour pressure of the different potential LPV products is summarized, by type of product, in Table 38 below. The Reid vapour pressure (RVP) of crude oils and condensates having an RVP value of 13.8 to 103.4 kPa is converted to a true vapour pressure using the following relation (adapted from the equation presented in Figure 7.1-13b of US EPA [2006]):

$$\boldsymbol{P = exp\left\{\left[\left(\frac{1,555}{T + 273.15}\right) - 2.227\right] log_{10}\left(\frac{RVP}{6.895}\right) - \left(\frac{4,033.9}{T + 273.15}\right) + 14.751\right\}}$$

Equation 38

Where,

P = true vapour pressure of the crude oil or other unrefined hydrocarbon product at the specified product temperature (kPa).
T = temperature of the crude oil or other unrefined hydrocarbon product (°C).
RVP = Reid vapour pressure of the crude oil or other unrefined hydrocarbon product (kPa).

The Reid vapour pressure (RVP) of refined products having an RVP value of 6.9 to 137.9 kPa is converted to a true vapour pressure using the following relation (adapted from the equation presented in Figure 7.1-14b of US EPA [2006]):

$$\mathrm{P} = \exp\left\{\left[0.7553 - \left(\frac{229.4}{\mathrm{T} + 273.15}\right)\right] \cdot (1.8 \cdot \mathrm{S})^{0.5} \cdot \log_{10}\left(\frac{\mathrm{RVP}}{6.895}\right) - \left[1.854 - \left(\frac{578.9}{\mathrm{T} + 273.15}\right)\right] \cdot (1.8 \cdot \mathrm{S})^{0.5} + \left[\left(\frac{1,342.2}{\mathrm{T} + 273.15}\right) - 2.013\right] \cdot \log_{10}\left(\frac{\mathrm{RVP}}{6.895}\right) - \left(\frac{4,856.7}{\mathrm{T} + 273.15}\right) + 17.5708\right\}$$

Equation 39

Where,

S = slope of the ASTM distillation curve at 10 percent evaporated (°C/vol%) [see Table 39]

The saturation factor for submerged loading of rail tank cars and tank trucks under normal dedicated service is 0.60 (i.e., the gas that is displaced from the tank vehicle contains 60 percent as much organic material as it can hold at thermodynamic equilibrium).

Loading losses are controlled using vapour exchange or vapour recovery systems. These devices are not widely used in the upstream oil and gas industry; therefore, a control factor of zero is used for the emission calculations.

Table 37: Summary of the factors for estimating emissions from rail tank cars due to the loading and unloading of LPG products (ethane, propane and butane).

Liquefied Petroleum Gas	Load Factor[1] (cars/m^3)	Trucking Factor[1] (m^3/m^3)	Emission Factors (kg/car)		
			Gauging[2] Assembly	Loading Line[3]	Unloading Line[3]
C_2	0.0048	0.00 (S)[4] 0.00 (R)[5]	34.8[6]	2.10	2.10

Table 37: Summary of the factors for estimating emissions from rail tank cars due to the loading and unloading of LPG products (ethane, propane and butane).

Liquefied Petroleum Gas	Load Factor[1] (cars/m^3)	Trucking Factor[1] (m^3/m^3)	Emission Factors (kg/car)		
			Gauging[2] Assembly	Loading Line[3]	Unloading Line[3]
C_3	0.0085	0.49 (S) 0.87 (R)	34.8	2.99	0.21
C_4	0.0085	0.18 (S) 0.42 (R)	11.2	3.38	0.07

1. Estimated based on data supplied by Transport Dangerous Goods Directorate, Transport Canada (1987) on LPG movements by CP Rail and CN Rail in Alberta during 1986.
2. Calculated using the universal gas sizing equation adapted for vapours. It is assumed that the gauge vents through a needle valve with a 1/4" port size. Furthermore, the valve is 25 percent open and the loading takes 1.5 hours. The effects of friction in the gauge rod are neglected. Actual values may vary greatly, depending on the valve design and the size of the valve opening.
3. The values reflect loss of material when the transfer line are depressurized and disconnected. The line is assumed to be 3 m long, 5 cm in diameter, filled with liquid at the end of a loading procedure and filled with vapour at the end of an unloading procedure.
4. S denotes shipments.
5. R denotes receipts.
6. Losses are arbitrarily assumed to be comparable to those from loading of propane.

Table 38: Liquid product properties used in tank flashing and loading/unloading emission estimates.

Liquid Product	Oil Specific Gravity	Reid Vapour Pressure (RVP) (kPa)	Vapour Molecular Weight (kg/kmole)
Condensate	0.715	76.6	28.2
Light/Medium Crude Oil	0.8315	54.8	44.2
Heavy Crude Oil	0.9153	40.5	19.9
Thermal Crude Oil	0.9153	40.5	30.6
Cold Bitumen	0.9282	39.7	23.3

Table 39: ASTM distillation slope for selected refined petroleum stocks.

Refined Petroleum Stock	Reid Vapour Pressure (kPa)	ASTM-D86 Distillation Slope at 10 Volume Percent Evaporated (°C/vol%)
Aviation gasoline	ND	1.11
Naphtha	13.8 to 55.2	1.39
Motor gasoline	ND	1.67
Light naphtha	62.1 to 96.5	1.94

Source: Table 7.1-4 of US EPA (2006).

9.5 SPECIATION PROFILES

The applicable values presented in Section 2.10 are used.

10 ACCIDENTAL RELEASES

10.1 SOURCE CHARACTERIZATION

Accidental releases are unintentional releases that are not part of normal operational or maintenance activities and that the system has not been designed for (they exclude such releases as, for example, relief valve emissions).

The only significant types of natural gas and vapour emissions in this category are those from pipelines as a result of ruptures, spills of hydrocarbon liquids, well-blowouts, gas migration around the outside of the well casing and surface casing vent flows.

It is assumed that all emissions from accidental releases are accounted for in the related environmental reporting by facilities to government agencies.

10.2 EMISSIONS CALCULATION

Emissions from accidental releases are taken to be the total of reported unrecovered spills and releases to the environment.

10.3 SPECIATION PROFILES

Default speciation profiles for application to the reported spills and releases are provided in Section 2.10.

11 AN OVERVIEW OF THE INDUSTRY BY SECTOR AND ACTIVITY

The following sections give a brief description of the different emission sources in each subject oil and gas activity, the assumptions used to estimate the number of these sources and determine their characteristics and activity levels in the absence of reported values, and some general comments regarding the emission assessment procedures which have been applied. The detailed emission calculation procedures and emission factors have been delineated in Sections 3 through 10.

In evaluating each subject activity, an effort was made to be as thorough and complete as possible and to build upon the previous inventory efforts sponsored by CAPP (Picard *et al.*, 1992, Ross et al., 1999; CAPP, 2004; ECCC, 2014). Each emission source was assumed to be important (due to size or number) until proven otherwise.

11.1 WELL DRILLING AND ASSOCIATED TESTING

The drilling of wells for crude oil and natural gas in Alberta is a seasonal activity that is highly variable in terms of the numbers of wells drilled, the geographic areas of activity, the target resource (light/medium crude oil, conventional heavy crude oil, bitumen or natural gas), the classification of the well (sweet, sour, critical sour), the depths that are drilled, and the geological conditions that are encountered. Each of these variables impacts the drilling procedures that are used and, in turn, the type, source and amount of emissions that occur. In general, the emissions may be ascribed to fuel consumption by the drilling rigs, completion pumps and maintaining drilling fluid temperatures as well as venting and flaring activities during drill-stem tests.

11.1.1 DRILLING RIGS

There are two potential sources of emissions associated with drilling rigs: fugitive emissions due to leaking equipment components, and combustion emissions from operation of the engines and heaters used by the rigs and any associated camp facilities.

The first source is assumed to be negligible due to the lack of hydrocarbon-containing lines, except for the brief period during which drill-stem tests are conducted.

The latter source of emissions is assessed based on fuel consumption data reported by CAODC (1989, 1995). These statistics give the average amount of diesel fuel consumed by engines and by boilers according to the depth range of the hole. Drilling depth and duration data are available for all wells drilled.

This activity is outside the inventory boundary so activity data is not presented at this time.

11.1.2 DRILLING FLUIDS

There are two potential causes for GHG emissions from drilling fluids: entrainment of solution natural gas and volatilization of invert drilling fluids. These are described in the sections below; however, a brief description of drilling fluids and their use is given first.

As a hole is being drilled, fluid is injected down the centre of the drill stem and allowed to return up the annulus (the space between the drill stem and the walls of the hole). The drill stem is a column of steel pipe that transfers torque generated by the rig to the bit. The fluid is usually water or an aromatic-based mixture; air, nitrogen or natural gas may also be used (under balanced drilling). The purposes of the fluid include removal of cuttings from the hole, cooling of the bit, lubrication of the hole and balancing of down-hole pressures. At the surface, the returning fluid flows into a tank (the mud tank) where it is brought to atmospheric pressure and the cuttings are removed by screening. Chemicals and clay materials may be added to adjust the rheological properties of the fluid before it is recirculated.

11.1.2.1 ENTRAINMENT OF SOLUTION GAS

When natural gas bearing zones are encountered, there is a potential for some natural gas to dissolve in, or become entrained with, the drilling fluid. When the fluid is brought to atmospheric pressure in the mud tank, this gas separates from the drilling fluid. If it is anticipated that sour natural gas zones will be encountered, vapours from the mud tank are collected and subsequently flared. Otherwise, the vapours are typically vented to atmosphere.

The total amount of solution gas from a drilling operation is relatively small as the flows are normally too low to maintain a flare except when gas zones are first penetrated. The net emissions from entrainment of solution gas are therefore considered to be insignificant compared to those from other sources at the drill site (e.g., drill stem tests [see Section 13.1.3]), regardless of whether the solution gas is flared or vented.

11.1.2.2 VOLATILIZATION OF INVERT DRILLING FLUIDS

Typically, the temperature of the ground increases markedly with depth. Consequently, significant amounts of heat may be transferred to the drilling fluid as the hole deepens. This heating of the drilling fluid has the potential to volatilize any aromatic compounds used in the fluid. Drilling fluids that use an aromatic base are called invert fluids. Usually, invert fluids are composed of about 80 percent diesel fuel and 20 percent water, by volume.

The emissions from use of invert fluids can be estimated by calculating the evaporation rate in the mud tanks, and applying the result to the total number of operating hours accumulated in the reference year. The evaporation rate is estimated using the API correlations for fixed-roof storage tanks (1991). It is assumed that each rig has three active mud tanks; each tank has a rectangular surface area of 22.3 m^2, and the average temperature of the fluid in the tanks is 60^o C.

The total hours of operation are estimated based on the number of wells drilled, their average drilling time and the percentage of wells that used invert fluids. The number of wells drilled, and the average number of days required to drill a well are taken from appropriate provincial statistics. Based on the relative contribution of this source to total THC emissions in the 1989 inventory (i.e., 0.0003 percent of total THC emissions from the industry in Alberta) no further effort was made to determine if the use of invert drilling fluids had changed since that time. Moreover, the emission contribution from this source is deemed negligible and therefore not quantified for 2018 inventory.

11.1.3 DRILL-STEM TESTING

When the target zone is reached, a drill-stem test may be performed to determine the production potential. The results of these tests are available from the provincial regulatory body in Alberta. During a test, the zone is produced through the centre of the drill stem. At the surface, the gas and liquid phases are separated and measured. Before a drill-stem test is conducted, a clean-up operation is performed. This consists of producing the well overnight to allow any drilling fluid and debris that may have penetrated the zone to be removed. A preliminary assessment of the flow potential may be performed using a flow prover (an orifice meter). If the well shows potential, the proper separation and metering facilities required for a drill-stem test are brought on site.

In Alberta, gas flowing off the separator is typically flared or incinerated as specified in AER Directive 060 (first issued in June 1999). The AER does not consider venting an acceptable alternative to flaring or incinerating. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved. Moreover, all flaring, incinerating, and venting at a well site (including well tests) must be recorded on the well file and reported to Petrinex of Alberta as specified in AER Directive 007. There is some uncertainty regarding the delineation of volumes by well activity (i.e., clean-up, completion flowback, testing versus production) which may result in inconsistent reporting categorization (e.g., completion flaring may be reported as production flaring). However, it is understood that all flaring and venting volumes greater than 0.1 10^3m^3/month are recorded and reported in Petrinex. Alberta flaring and venting volumes may be obtained directly from the Petrinex and are identified by facility subtypes = 371 (i.e., Gas test battery).

11.2 WELL SERVICING AND TESTING

This component of well-related activities comprises well completions, testing, workovers and abandonments. The emissions produced by these activities are perhaps evaluated best in terms of the fuel consumption by the major types of equipment that are employed (service rigs, pumping units and wireline units) and specific venting that occurs.

11.2.1 SERVICE RIGS

The total number of hours logged by service rigs in Alberta for 2018 were obtained from the Canadian Association of Oilwell Drilling Contractors (CAODC, 2013). Based on data supplied by two service rig operators, service rigs consume about 29.1 L of diesel per hour of operation. Approximately 35 percent of this fuel is consumed by boilers and the remainder is consumed by reciprocating engines. Also, small amounts of propane are used in the winter for space heating. On an annual basis, this amounts to about 1.9 L per hour of operation (Picard *et al*., 1992).

11.2.2 PUMPING UNITS

Pumping units are used in the supply of cementing and chemical treatment services as well as high pressure liquids for hydraulic fracturing activities. In the previous inventory, pumping units were determined to be a relatively insignificant source of CO_2, CH_4 and VOC emissions (i.e., < 0. 2 percent of Canada's CO_2E emissions) (CAPP, 2004). However, given the development of unconventional reserves and propagation of hydraulic fracturing since 2000; further effort has been applied to better understand and quantify these emissions.
Hydraulic fracturing--or fracking--is a well treatment process which involves the high-pressure injection of water, sand, and chemicals into geologic formations to open or enlarge and prop open fractures in the surrounding rock. Fracking technology significantly increases the ability to extract natural gas from shale and coal bed deposits around the world. Pumping represents the primary energy requirement and is typically supplied by diesel fuelled engines at the well site. The volume of diesel fuel burned during a fracturing job is estimated to be 0.0245 m^3 per m^3 of fluid injected. Multiplying this factor with frac fluid injection volumes maintained by the AER produces diesel consumption volumes for Alberta.
The diesel consumption factor is based on diesel fuel volumes provided to Clearstone for 22 completion jobs and corresponding fluid injection volumes obtained from Petrinex in Alberta (under Activity LDINJ). Because diesel fuel is not tracked by specific activity during completion jobs, the factor also includes diesel consumed during fluid heating; wireline pumping and rig operation; carrier water mixing with chemicals, sand and gels; data and office trailers; lights; etc. and is therefore conservative.

Bi-fuel technology that allows equipment to run on diesel and natural gas simultaneously as well as electrification of pumps have gained industry attention as promising approaches for reducing emissions. However, examples of these during the inventory periods are limited to pilot projects and not accounted.

11.2.3 WIRELINE UNITS

Wireline units are used to lower special tools and instruments down hole for repair, inspection, retrieval and testing purposes. In Alberta, the industry is dominated by one large company, followed by several medium sized companies and many smaller companies. Unfortunately, there was not enough information available to evaluate fuel consumption by this source category (except during fracturing activities described in Section 11.2.2).

11.2.4 FLARING AND VENTING DURING WELL SERVICING

The emissions from flaring and venting during well servicing are divided into three categories based on the type of service operations: unconventional service work (i.e., hydraulic fracturing), conventional service work (i.e., well repairs and inspections, cementing operations, and formation treatments) and blowdown treatments for shallow natural gas wells. Flaring and venting volumes are reported to provincial regulators, as discussed in Section 11.1.3 above, and used to calculate emissions. However, provincial data sources do not consistently correlate volume records with well activities and emission results may not be correctly allocated to their sub-sector (i.e., well drilling, servicing, testing or production phases).

11.2.4.1 UNCONVENTIONAL SERVICE WORK

Flaring and venting emissions may occur during the flowback period following hydraulic fracturing (described in Section 11.2.2). Flowback of the fracturing fluids typically takes from 1 to 4 days per well and is normally done through a special erosion resistant valve called a choke and a temporary test separator. The separator is a large pressure vessel that allows the flowback fluid enough residence time for the proppant, liquids and gas to separate. In some areas, where a lot of proppant is flowed back, a special sand separator may be used; otherwise the sand accumulates in the main separator and is cleaned out after the job. Early flowback is mainly fracturing fluid but gradually changes composition until formation water and hydrocarbons are produced.

Gas produced during the flowback is typically flared or conserved. An upfront “tie-in” is often economically justified for multi-well development pads (which are common in shale plays) especially when the pad already features producing wells. This is sometimes referred to as an “inline test” or more recently as a ‘green completion’. If frac fluid is energized with nitrogen or carbon dioxide, the gas mixture directed to flare may not contain sufficient hydrocarbons to support combustion at first and some methane may be released unburnt depending on the design of the flare. However, the duration of this period is typically short (hours) and not a noteworthy hydrocarbon emission source. Flowback liquids from the separator are routed to atmospheric storage tanks which are also an emission source. Most of the lighter hydrocarbons (i.e., methane) flash off in the separator so that tank vapours are primarily heavier VOCs. Storage tank losses are estimated based on oil production reported to provincial regulators following methodology described in Section 8.

11.2.4.2 CONVENTIONAL SERVICE WORK

A well is normally killed at the start of any conventional well-servicing operation by circulating an inhibited fluid such as water or oil downhole to counter-balance the pressure in the producing formation. This helps control the well and greatly reduces the potential for emissions. The emissions that occur are usually limited to the release of some solution gas from the mud tanks. Typically, the gas is vented if it is sweet, and flared if it is sour. The volumes involved are small and are considered to be negligible. An additional source of emissions occurs on some oil wells where gas pressure may be relieved to the atmosphere prior to injecting the kill fluid (this helps prevent gas from being released during rig operations). However, the extent of this practice is not known.

A well may not be killed if only simple wireline work is to be performed (especially if there is potential for damage to the formation), or if the well can be depressurized quickly and easily by venting it to atmosphere (e.g., some heavy oil wells).

If wireline work is performed under pressure, a device, called a lubricator, is mounted on the wellhead and used to maintain a seal around the wire line as the work is performed. Each time the wireline tool is removed from the hole, the master valve on the wellhead is closed to isolate the lubricator, then the lubricator is opened to the atmosphere to depressurize. For each depressurization event about 10 m of pipe is vented to the atmosphere. Unfortunately, there was not enough information available to assess the extent to which lubricators are used.

Depressurization of the well is practical for some steam-stimulated crude bitumen wells. Initially, the well is vented to atmosphere to determine if pressure support from neighbouring wells is occurring. Based on data provided by one operator, a typical blowdown time to atmosphere is 15 to 20 minutes or until casing pressure drops to acceptable limits, and this procedure is performed annually on about 3.6 percent of crude bitumen wells. There is not enough pressure and/or flow rate data available to assess the emissions from these wells; however, the resultant value is anticipated to be small. Furthermore, much of the material that is emitted is suspected to be steam.

11.2.4.3 BLOWDOWN TREATMENTS FOR LIQUID UNLOADING OF NATURAL GAS WELLS

Some natural gas wells must be blown down periodically to remove water that has accumulated in the production tubing. These are primarily shallow (less than 1000 m deep), low-pressure (less than 2000 kPa) gas wells. There are three different blowdown treatments that are applied to these wells: unassisted blowdowns, swabbing and coiled tubing clean-outs.

During an unassisted blowdown, the well is opened to atmosphere so the down-hole pressures may blow the water from the tubing. Sometimes, sticks of soap are inserted down the production tubing beforehand. This causes a frothing action to occur when the well is opened, which helps to remove the water. The swabbing process consists of lifting water mechanically from the well using an endless tubing unit. A coiled tubing clean-out involves injecting compressed gas down-hole to help lift the water by increasing the effective pressure in the well.

In general, venting during liquid unloading is considered an historic practise. Liquids are typically separated inline and gas is delivered to the sales pipeline. However, venting can sometimes occur at older wells where the down-hole pressure has decreased to the point where there is insufficient pressure drop to drive liquids to the surface (gathering system pressure). In these cases, sufficient pressure drop is obtained by relieving the well into an atmospheric vessel where liquids/gases are separated and gas is directed to a flare or vent.

11.2.5 FUGITIVE EMISSIONS FROM WELL SERVICING

Except during tests performed to determine the absolute open flow (AOF) potential of a well, there are few (if any) lines containing hydrocarbon gases and/or liquids during well servicing and associated testing. Therefore, it is assumed there is no significant potential for fugitive emissions from leaking equipment components.

The equipment used for AOF tests may include a portable test separator, flare and temporary storage tanks. However, the frequency and duration of AOF tests typically amount to much less than one percent of a well's production time, and the equipment that is brought on site is insignificant compared to the existing production equipment. Therefore, fugitive emissions from AOF tests are also assumed to be negligible.

11.3 LIGHT/MEDIUM CRUDE OIL PRODUCTION

The production of light- and medium-density crude oils (i.e., crude oils with a density of less than 900 kg/m^3) is discussed in this section.

11.3.1 LIGHT/MEDIUM CRUDE OIL WELLS

In 2018, there were a total of 37,410 wells and 8,268 batteries that produced light/medium crude oil in Alberta. Each of these wells is a source of emissions from equipment leaks. These are estimated using emission factors and typical equipment schedules. Also, some pumping wells are a source of combustion emissions (i.e., those that are driven by internal combustion engines). Emissions from natural gas combustion are estimated at the source-category level based on reported fuel consumption statistics. Pumping units are occasionally fuelled with propane. These combustion emissions are calculated using the emission factors summarized in Section 3.

Table 40: Summary of Alberta light/medium crude oil production wells and batteries for 2011 and 2018 (ECCC, 2014 and AER, 2019a).

Inventory Year	Wells	Batteries
2011	37,132	10,050
2018	37,410	8,268

Accurate identification of light/medium versus cold bitumen is not always possible given the AER facility sub type codes available (AER, 2015 Table 2). Consequently, cold-flow heavy oil outside of the designated oil sands areas are sometimes grouped with light/medium crude oil production.

11.3.2 LIGHT/MEDIUM CRUDE OIL FLOW LINES

There are two potential sources of emissions associated with crude oil flow lines: pigging operations and well tie-ins.

The emissions from pigging operations are attributed to the opening of pig traps and pig launchers. For simplification purposes, these sources are treated as equipment leaks. A calculated emission factor is used to estimate the amount of gas that is liberated when each canister is opened (see Section 7). The liquid phase is assumed to be collected. To estimate the total number of canisters, it is assumed that: each well that is connected to a flow line has a launcher, each satellite battery has a trap and a launcher, and each battery has a trap. The number of batteries is determined as described in Sections 11.3.3, 11.3.4 and 11.3.5.

If an active pipeline must be cut to tie a well in, normally it is drained and purged with an inert material (e.g., N_2 or H_2O) beforehand. Consequently, there are no noteworthy sources of emissions associated with this activity.

11.3.3 SINGLE-WELL LIGHT/MEDIUM CRUDE OIL BATTERIES

A crude oil battery is a unit where the production from a crude oil well(s) is separated into its constituent phases (natural gas, crude oil and water) for metering and appropriate disposition.

The natural gas is either vented, flared, re-injected, or compressed into a nearby natural gas gathering system, depending on the type of oil recovery scheme and the economics of the situation. The last two options would require that compression and, possibly, dehydration facilities be installed. The water is re-injected as part of an enhanced recovery scheme, or is shipped to a nearby disposal well. Equipment associated with solution natural gas disposal or re-injection is taken to be part of crude oil production. Equipment associated with solution natural gas conservation is taken to be part of natural gas production.

The crude oil is pumped into a nearby crude oil pipeline, or is shipped by truck to a location where this may be done. A treater is used to remove any emulsified water from the crude oil before it is put in the crude oil pipeline.

A single-well crude oil battery is the simplest type of crude oil battery. Typically, each is inspected once per day; otherwise, it is unattended. As a minimum, it is equipped with separation, metering, storage, loading and flaring facilities. Depending on the amount and nature of the production, it may also comprise selected treatment, pumping and compression facilities.

The emission sources that may occur at a single-well crude oil battery and the methods that are used to assess these emissions are given below:

(1) **Combustion Equipment** - Emissions from the use of combustion equipment (e.g., glycol reboilers, treaters and flares) are assessed as described in Section 11.6.2. Typical distribution of natural gas fuel between combustion devices is presented in Table 15.

(2) **Venting** - Venting emissions are attributed to the use of fuel gas to operate instrument controllers and chemical injection pumps, and to the venting of waste gas from glycol dehydrators. As a close approximation, it is assumed that fuel gas is used as the supply medium for all gas-operated devices (i.e., compressed air is unavailable). The number of controllers on site is determined based on the number of each major equipment type (e.g., separator, treater, dehydrator, compressor, etc.) and the number of controllers usually associated with each of these. If the natural gas is sour and to be conserved, it is assumed that there is one chemical injection pump in continuous operation to inject corrosion inhibitor into the natural gas pipeline.

    As a conservative estimate, gas-operated devices are assumed to be in continuous operation throughout the year.

    The volume of waste gas released by glycol dehydrators is determined as described in Section 11.6.2.3. The resultant amount is assumed to be vented, not flared. (As indicated in Item (1) above, it is presumed that dehydrators are used only in sweet applications.)

(3) **Equipment Leaks** - The total number of potential leakage points is determined by applying a minimum equipment schedule to each single-well crude oil battery, and by making certain site-specific allowances for any additional equipment that may be in use.

Batteries that are reporting natural gas deliveries are assumed to be conserving solution natural gas and, therefore, to have compression facilities. Further, if the battery is sweet and is conserving natural gas, it is assumed to have a glycol dehydrator on site to dry the natural gas. If it is sour and the natural gas is conserved, it is assumed that the natural gas gathering system is a heated type and that the line heaters are already taken into account, as outlined in Section 11.6.2.

Crude oil batteries that are connected to a crude oil pipeline are assumed to have two treaters on site (one test treater and one production treater). All other crude oil batteries are assumed to typically have only separation and storage facilities (i.e., no oil treating facilities). In these cases the crude oil is treated at a suitable off-site location where a crude oil pipeline may be accessed (usually another battery).

The number of single-well batteries that are connected to a crude oil pipeline is determined by cross-referencing the battery code listing with the pipeline attribute file (AER, 2012d). The total production through these batteries is determined from the Petrinex Volumetric Facility Activity Report (AER, 2012b). The ratio of crude oil transported from single-well batteries by pipeline to that by surface (i.e., tanker trucks) is assumed to be the same for all other provinces.

(4) **Storage Tanks** - The emissions from crude oil storage tanks are estimated in two parts. First, the amount of solution natural gas that is released when produced crude oil is brought to stock tank conditions is determined. Then, the amount of normal evaporation losses are estimated. The resultant volume of natural gas is assumed to be flared if it is sour, and vented if it is sweet. If the vapours are collected and flared then the thief hatch on the storage tanks is treated as a potential leakage point. An emission factor is used to estimate the amount of leakage, and the result is added to the total for leaking equipment components.

Some sour water storage tanks may be connected to the flare system and may have fuel gas blanketing to prevent oxygen ingress. The thief hatches on these tanks are also potential leakage points. However, the number of such tanks and, consequently, the amount of emissions, is considered to be small. Thus, these additional leakage points are omitted for simplification purposes.

The solution natural gas emissions are estimated by applying the Vasquez and Beggs correlation (see Section 8.3) to the volume of oil that is produced at each battery. The appropriate temperature and pressure used in the correlation is based on whether oil-treating facilities are used on site.

The evaporation losses are estimated using empirical correlations published by American Petroleum Institute (API 1991). These correlations relate evaporation losses to tank size, type of tank, throughput and certain design, and environmental factors.

The total number of crude oil storage tanks in use and the sizes of these are estimated based on the following assumptions:

- Each battery has a minimum of four tanks: one pop tank, one water storage tank, one crude oil storage tank and one crude oil over-flow tank.
- Batteries that have oil-treating facilities on site have one additional tank, an oil recycle tank.
- The pop tank has a capacity of either 100 bbl or 400 bbl and is sized for a minimum of 24 hours of storage capacity up to the 400 bbl limit. (Batteries above this size tend to be manned continuously during the day and, thus, require less storage capacity.)
- All other tanks are 400 bbl in size, or larger.
- Batteries that are tied into crude oil pipelines have a minimum of 24 hours of production capacity; otherwise, the batteries have a minimum of 3 days of production capacity.
- Standard tank sizes are used in all applications. According to a local tank manufacturer, the most common tank sizes for conventional oil production are 100, 400, 750, 1000, 1500, and 2000 bbl.

All crude oil storage tanks are assumed to be above-ground and have fixed roofs. The amount of throughput for each is estimated by prorating total crude oil production according to storage capacities.

11.3.4 SATELLITE LIGHT/MEDIUM CRUDE OIL BATTERIES

A satellite crude oil battery is an intermediate production facility. It is located between a group of wells and a group (or central) crude oil battery, and, usually, it is inspected once per day. There are two separators and associated sets of metering equipment at each satellite battery. One train is used to compile proration data on the commingled effluent from all but one of the group of wells. The other is used to test the remaining well. A regular test is performed on each of the wells.

After separation and measurement, the production is often recombined into a single flow line for shipment to the central battery. Sometimes, however, each phase is transported in a separate pipeline. In this case a dehydrator may be required for the gas pipeline. For simplicity, it is assumed there are no dehydrators at satellite batteries.

Typically, there are no storage nor treatment facilities at satellite batteries, and no natural gas is flared. Consequently, the only sources of emissions are equipment leaks and the use of fuel gas to operate instrument controllers. The emissions from these sources are assessed as described in Sections 7 and 5.3.2. It is assumed there are no chemical injection pumps.

11.3.5 GROUP (OR CENTRAL) LIGHT/MEDIUM CRUDE OIL BATTERIES

A group (or central) battery is the same as a single-well battery except that it receives production from more than one well and is usually much larger. Often, it is manned continuously during the day. The sources of emissions are the same as those for a single-well battery and they are evaluated as described in Section 11.3.3.

Offshore oil production platforms are considered group oil batteries in this inventory. Emissions are calculated accordingly with the exception that turbines are used instead of reciprocating engines for compression and power generation.

11.4 HEAVY CRUDE OIL FROM COLD PRODUCTION

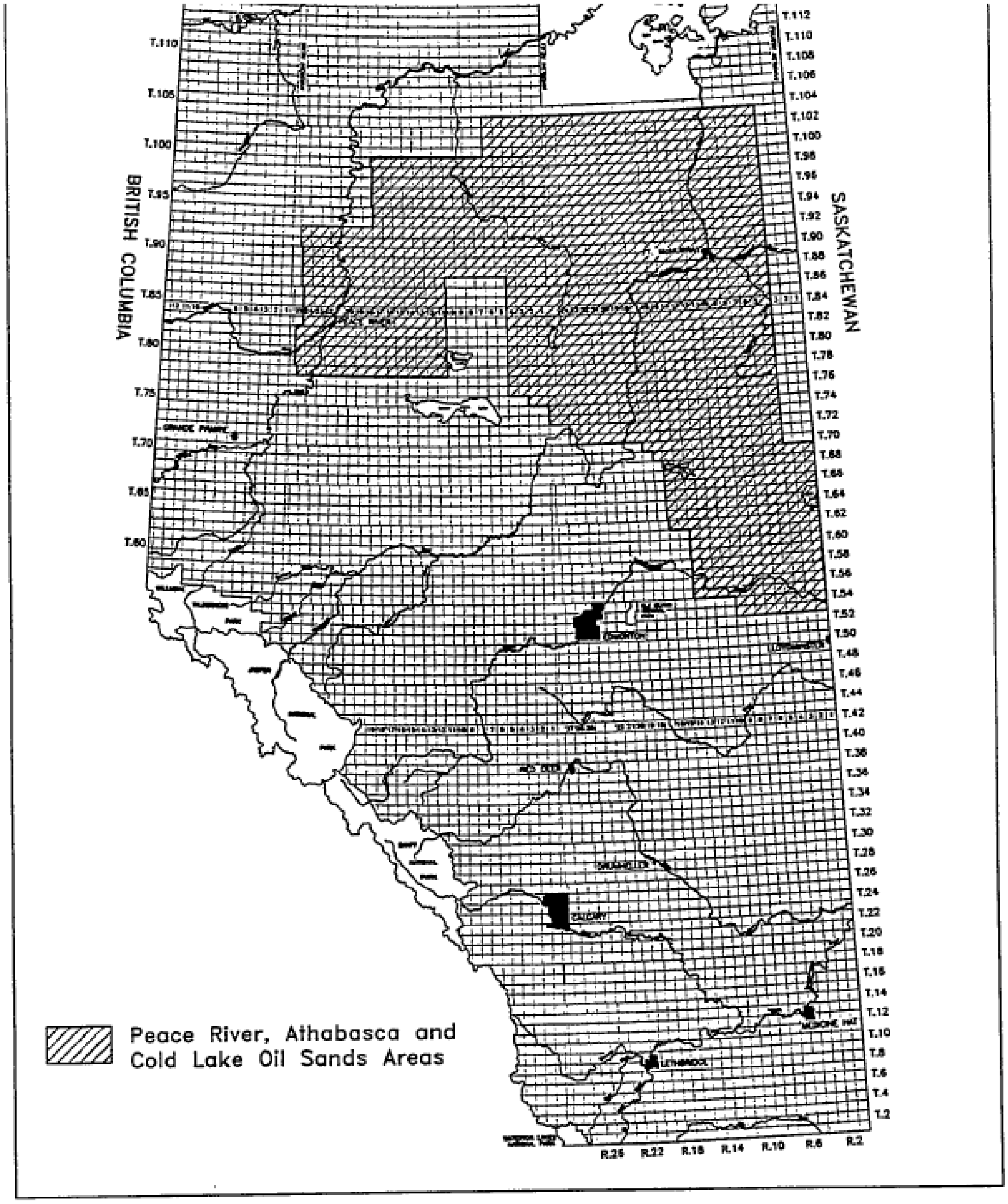
Crude oil is generally designated as heavy if it has a density of greater than, or equal to, 900 kg/m^3 (or alternately expressed, an API gravity of less than, or equal to, 25°). Crude oil with a density of greater than, or equal to, 1000 kg/m^3 (or alternately expressed, an API gravity of less than, or equal to, 10°) is often termed bitumen. Heavy crude oil which is lighter than bitumen is often termed conventional heavy crude oil.

Although it flows with greater difficulty than light or medium crude oil at normal temperature and pressure, conventional heavy crude oil is often produced using non-thermal (that is, "cold") recovery techniques. Conventional heavy crude oil is produced primarily from wells in the Lloydminster area of east central Alberta.

The Province of Alberta has delineated areas in northeast Alberta (see Figure 5) and labelled them designated oil sands areas, wherein all non-natural gas and non-coal hydrocarbon resources are deemed to be "crude bitumen". Most so deemed "crude bitumen" would qualify as bitumen and so requires the application of thermal recovery techniques to produce. However, some of this crude bitumen may be recovered by primary or secondary (i.e., non thermal) recovery techniques. This "crude bitumen" (produced using non-thermal recovery techniques) is often referred to as "cold bitumen". In 2018, there were a total of 12,766 wells and 2,294 batteries that produced cold bitumen in Alberta.

Table 41: Summary of Alberta cold bitumen production wells and batteries for 2011 and 2018 (ECCC, 2014 and AER, 2019a).

Inventory Year	Wells	Batteries
2011	32,894	4,915
2018	12,766	2,294



Peace River/Cold Lake/Athabasca Oil Sands Area

Figure 5: **Designated Oil Sands Areas of Alberta.**

11.4.1 COLD PRODUCTION HEAVY CRUDE OIL WELLS

There are two potential sources of emissions associated with each type of well:

(1) **Venting** – Cold production heavy crude oil wells are relatively shallow (typically 300 to 900 m deep) and, thus, are characterized by low reservoir pressures (typically 4000 kPa or less). To achieve

reasonable flow potential it is necessary to relieve natural gas pressure from the well bore (down-hole pressure of about 250 kPa is maintained). Appropriately, the wells usually are not equipped with a production packer (a device that isolates the annulus from the formation). This allows the well pressure to be controlled using the casing vent.

Determination and reporting of casing gas flows and end use (i.e., vented, flared or conserved) is a requirement of AER Directive 060. Emission inventory results are based directly on volumetric data reported to Alberta regulators.

(2) **Equipment Leaks** - These emissions are estimated as described in Section 11.3.1for light/ medium crude oil wells.

11.4.2 COLD PRODUCTION HEAVY CRUDE OIL FLOW LINES

It is assumed that cold production heavy crude oil is typically moved by truck and that any emissions that may result from the use of pipelines are insignificant.

11.4.3 COLD PRODUCTION HEAVY CRUDE OIL SINGLE-WELL BATTERIES

At single-well batteries, the cold production heavy crude oil is stored in a heated tank located on site. Tank trucks are used to haul the heavy crude oil to a cleaning plant (central battery) where it is treated to remove sand and water. The water is disposed of by deep-well injection. The sand and tank bottoms are placed in ecology pits and the heavy crude oil is shipped to market, normally by pipeline.

The sources of emissions at these batteries are:

(1) **Combustion Equipment** - Emissions are attributed to the use of tank heaters. These emissions are assessed as described in Section 3.

(2) **Equipment Leaks** - These emissions are assessed by applying published emission factors and typical equipment schedules to the total number of single-well batteries.

(3) **Storage Tanks** - Each battery usually is equipped with a single storage tank (typically a 500 or 750 bbl tank). The emissions from each tank are attributed to the release of solution natural gas. Evaporation losses are calculated using the API correlations (see Section 8) and appropriate physical properties for the produced oil. If crude oil property data were supplied by facility operator, they were used. Otherwise, default values from Table 38 in Section 9.4 were used. Solution natural gas emissions are estimated based on the flashing loss calculation method described in Section 8.2.

11.4.4 COLD PRODUCTION HEAVY CRUDE OIL SATELLITE BATTERIES

The emissions from these facilities are attributed to equipment leaks and to the venting of casing natural gas. The use of incinerators to dispose of casing natural gas is assumed to be negligible.

Heavy oil satellite batteries are functionally identical to light/medium oil satellite batteries. They are located between a group of wells or a well pad and a central battery or cleaning plant. They are comprised of a valve header to direct the flow from one well to the test train and the commingled flow to the group train. The well flow directed to the test train is typically changed daily either by manually switching valves on the inlet header or by means of an automatic multi-way valve.

After separation and measurement, the production is often recombined into a single flow line for shipment to the central battery. Typically, there are no storage nor treatment facilities at satellite batteries, and no natural gas is flared. Consequently, the only sources of emissions are equipment leaks and the use of fuel gas to operate instrument controllers. The emissions from these sources are assessed as described in Section 11.3.3. It is assumed there are no chemical injection pumps.

11.4.5 COLD PRODUCTION HEAVY CRUDE OIL CENTRAL BATTERIES (CLEANING PLANTS)

A cleaning plant is a group heavy crude oil battery that is equipped with facilities for removing sand and water from the heavy oil. The typical process flow is as follows:

- The combined (oil, gas and water) from the single well or satellite batteries enters the facility via pipeline or is trucked by tanker. Any production that is trucked in will consist of predominantly oil and water; most of the solution gas will have evolved upstream of this point.
- The production is pumped into a free-water knock-out which is usually heated. Here the majority of produced water and most of the remaining solution gas are separated. Depending on the amount of solution gas present in the raw oil, the solution gas may be simply vented to the atmosphere. If it is not vented it may be either flared or conserved.
- The oil phase usually still contains some water in emulsion. Therefore, it is passed through an emulsion treater where heat and residence time break the emulsion and separate out the remaining water.
- The sales oil is then pumped into heated storage tanks and the produced water into water storage tanks. The oil is typically shipped to market via pipeline and the produced water is disposed of by underground injection.

The emissions from these facilities are assessed as follows:

(1) **Combustion Equipment** - The combustion equipment at a cleaning plant includes emulsion treaters, tank heaters, glycol reboilers and flare systems. The emissions from these are assessed as described in Section 11.6.2.2.

(2) **Venting** – Unless otherwise specified in the industry survey, it is assumed that all cleaning plants use compressed air to operate instrument controllers and chemical pumps. Thus, there are no venting emissions.

(3) **Equipment Leaks** - These emissions are assessed by applying a typical equipment schedule and appropriate emission factors to the equipment located at cleaning plants.

11.5 HEAVY CRUDE OIL FROM THERMAL PRODUCTION

The production of heavy crude oil and bitumen using thermal recovery techniques occurs mainly in the lower Athabasca and Cold Lake areas of east central Alberta and in the Peace River area of northwest Alberta, and in west central Saskatchewan.

A typical heavy crude oil thermal production scheme comprises many satellite batteries that feed into a large central cleaning facility. Each satellite is fed by a small cluster of pumping wells (typically 20 to 30) at a well pad. The casing gas is either vented/incinerated at each satellite or conserved using an electric-drive compressor. The conserved natural gas is sent to the cleaning facility by pipeline for use as fuel. Since the steam generation demands are very large, produced fuel gas usually needs to be supplemented with purchased fuel. The produced heavy crude oil is moved to a cleaning plant by pipeline where it is cleaned and then shipped, normally by pipeline, to a petroleum processing facility (upgrader or refinery). In 2018, there were a total of 12,766 wells and 2,294 batteries that produced thermal heavy oil in Alberta.

Table 42: Summary of Alberta thermal heavy oil wells and batteries for 2011 and 2018 (ECCC, 2014 and AER, 2019a).

Inventory Year	Wells	Batteries
2011	6,049	36
2018	3,724	37

11.5.1 THERMAL PRODUCTION HEAVY CRUDE OIL WELLS

Although, emissions from these wells are predominantly from equipment leaks, some locations may vent or flare the casing gas. The amount of emissions from fugitive equipment leaks is estimated as described in Section 11.3.1 for light/medium crude oil wells. The pumpjack on each well is usually driven by an electric motor; therefore, there are no direct combustion emissions.

11.5.2 CRUDE OIL FLOW LINES AND NATURAL GAS GATHERING SYSTEMS

The crude oil flow lines and the gathering systems that are used to conserve casing natural gas from some satellite batteries are primarily sources of equipment leaks. However, virtually all the pertinent equipment components are located at the ends of the pipelines. Therefore, these components are treated as part of the satellite batteries and cleaning plants. The resulting emissions are accounted for in Sections 11.5.3 and 11.5.4, respectively.

11.5.3 THERMAL PRODUCTION HEAVY CRUDE OIL SATELLITE BATTERIES

Satellite batteries are the type most often used in thermal recovery schemes. In addition to providing test separation facilities for production accounting purposes, each satellite serves as a control point for selectively cycling wells between injection and production cycles. This is done using an elaborate valve system. Up to 30 wells are tied into each satellite battery. Each well is connected to the satellite battery by a flow line and a steam line. A steam line, fuel gas line and flow line connect the satellite to a central cleaning plant where the oil is cleaned, steam is generated and natural gas is dehydrated for fuel. Since production for thermal operations is aggregated to the main cleaning plant, emissions from the satellites have been accounted for at that level (see Section 11.5.4).

11.5.4 THERMAL PRODUCTION HEAVY OIL CLEANING PLANTS

As with cold heavy oil production, thermal cleaning plants have oil, gas and water separation equipment, emulsion treating, oil and water storage, water disposal and oil shipping equipment. However, most of the emissions at thermal heavy oil cleaning plants result from the generation of the steam used in the thermal recovery of the oil by natural gas fired steam generators. The emissions are attributed to:

(1) **Combustion Equipment** – Since solution gas production from these operations is generally not sufficient to meet the fuel demands of the steam generators, supplemental fuel must be either purchased. In some cases, production from nearby shallow gas wells can be used for supplemental fuel. As purchased fuel is not reported in production data reported to the government, actual fuel use by the site was taken from the industry survey. Emissions from the steam generators (and other combustion equipment that may be on site) are estimated by applying the equations described in Section 3. Since the produced fuel may contain significant CO_2, actual fuel analyses were used to estimate combustion CO_2 emissions.

(2) **Venting** – Unless the industry survey indicated otherwise, it was assumed that no process venting occurs at these facilities, and that compressed air is used to operate all gas-operated instruments and devices.

(3) **Equipment Leaks** – These are assessed by assuming that each plant may be subdivided into one or more modules (or phases), and that the size of each module is the same for all plants. A typical

equipment schedule and appropriate emission factors are then applied to the total number of modules.

(4) **Storage Tanks** – Unless the operator indicated otherwise in the industry survey, it is assumed that all storage tanks have vapour collection systems and that the collected gas is flared. Also, it is assumed that some leakage occurs around the thief hatch on each tank. The amount of leakage is estimated as described in Section 11.5.3 for storage tanks at thermal heavy oil batteries. The total number of tanks is determined based on a typical equipment schedule for a single module.

(5) **Surface Impoundments** – Ecology pits are used to store sedimentary material that has been removed from the oil and some facilities. The material in these pits is relatively nonvolatile. Thus, negligible emissions are considered to occur.

11.6 NATURAL GAS PRODUCTION

Natural gas production comes from natural gas wells, as well as light/medium crude oil, and heavy crude oil production units with natural gas conservation schemes. The number of gas production wells, batteries, compressor stations, gathering systems and gas plants that operated in Alberta during 2018 and 2011 are presented in Table 43.

Table 43: Summary of Alberta gas wells and facilities for 2011 and 2018 (ECCC, 2014 and AER, 2019a).

Inventory Year	Wells	Batteries	Compressor Stations	Gathering Systems	Gas Plants
2011	147,995	12,682	773	2,904	639
2018	116,412	9,249	827	2,755	507

11.6.1 NATURAL GAS WELLS

Natural gas wells are primarily sources of fugitive emissions due to leaking seals and fittings on the well head. Additional sources are introduced if pumpjacks are used on the well (i.e., leaking pump seals and combustion emissions where a gas-driven engine is used to drive the pumpjack). However, the use of pumpjacks on natural gas wells is rare and, so, is assumed not to occur.

The amount of fugitive emissions from each wellhead is estimated by applying appropriate emission factors (see Section 7.1) to a typical schedule of equipment components. Schedules for the following well status codes are applied (Clearstone, 2018). Where multiple producing zones (represented by multiple UWI) flow to a single wellhead, the well licence is considered to ensure only one wellhead applied to the emission inventory (because fugitives occur at wellheads not downhole production zones).

11.6.2 NATURAL GAS GATHERING SYSTEMS

There are basically three types of natural gas gathering systems used: low-pressure, heated and dehydrated. Natural gas may also be conserved and gathered from light and medium crude oil production facilities, cold heavy crude oil production facilities and thermal crude oil operations. The number of gas gathering systems that operated in 2011 and 2018 is presented in Table 43. A description of the types of natural gas gathering systems is presented in the sections that follow.

11.6.2.1 LOW PRESSURE GATHERING SYSTEMS

There is a substantial network of pipelines used to gather production from the low pressure natural gas wells described in Section 11.6.1. These systems are often operated at very low pressures (e.g., less than 525 kPa). As the natural gas is produced, some lines have a problem with water condensing and accumulating in low spots. Periodically, it becomes necessary to remove the water from these lines. On long sections of pipeline this is done by pigging (i.e., a specially-designed obstruction is placed in the line, and upstream natural gas pressure is used to push it and any liquid in front of it through to an appropriate discharge point). However, due to the low operating pressures of these pipelines, sometimes it is necessary to open the discharge end of the pipeline to atmosphere. This creates enough pressure differential to drive the pig.

On short sections of pipeline, water may be removed effectively by simply venting the pipeline briefly (about 10 seconds) to atmosphere through a storage tank. This is called "pulling back on the pipeline".

Both approaches result in natural gas being vented to the atmosphere. Additionally, natural gas is vented to atmosphere when sections of pipeline are depressurized for repairs or to tie new wells into the system. To estimate the total amount of natural gas that is vented from low-pressure natural gas systems, it is assumed (based on data provided by one operating company) that:

- The described venting activities are limited to low-pressure natural gas gathering systems.
- About 43 m of 88.9 mm diameter pipe with an average pressure of 525 kPa is vented to atmosphere per year per well due to pigging operations, pipeline tie-ins and repair work.
- About 0.1 pull-backs are performed per month per well and each results in the release of approximately 0.6 m^3 of natural gas.

Because this venting contribution is very small (2 m^3 per year), total emissions from pigging of low-pressure natural gas pipelines are considered to be insignificant and, so, are disregarded for simplification purposes.

The total number of shallow natural gas wells is determined as described in Section 11.6.1.

As a close approximation, it is assumed there are no dehydrators or line heaters on low-pressure natural gas gathering systems. Any dehydration that is required to meet market specifications is done at natural gas batteries.

11.6.2.2 HEATED GATHERING SYSTEMS

Hydrate control is an important consideration in the design of high-pressure natural gas gathering systems. Hydrates are solid crystalline ice-like structures composed of water and hydrocarbon molecules that can form in pipelines and stop the flow. There are two main designs that are used: heated and dehydrated systems. The latter type is addressed in Section 11.6.2.3.

Heated natural gas gathering systems guard against the formation of hydrates by maintaining the natural gas temperature above some critical value. This critical value is dependent on the composition and pressure of the natural gas; consequently, it varies from one system to the next.

The emissions from heated systems are assessed as follows:

(1) **Combustion Equipment** – Combustion emissions result from fuel consumption by line heaters and certain flaring activities. These emissions are estimated at the facility level using appropriate emission factors, and fuel consumption and flaring statistics. In doing this, the fuel data are first corrected to exclude the total amount of fuel gas used by pressure-activated devices. The resulting fuel volume is prorated using disposition factors derived from fuel consumption data supplied by ten major gas producers. These data are used to determine the amounts used by boilers, reciprocating engines and turbine engines (see Section 3). Also, the flaring data are corrected to exclude the amount of natural gas that is vented, not flared.

(2) **Venting** – Venting may be attributed to pigging operations and the use of fuel gas as the supply medium for gas-operated devices (e.g., instrument controllers and chemical injection pumps). The only emissions that result from pigging a high-pressure natural gas pipeline occur when the launch and receiver chambers are opened for insertion/removal of the pig. (Each type of chamber is about 1 m long and 5 cm larger in diameter than the pipeline). Unlike low pressure systems, the liquids that are cleared from the pipeline by pigging are captured using a separator, and the natural gas is conserved. Typically, one launcher is located on each trunk line and a single receiver is located at the plant. The amount of natural gas that is released from opening the launchers and receiver may be determined based on the operating pressure of the system, the volume of each canister, the number of canisters and the frequency of the pigging operation. A survey of about a third of the plants indicated that only 40 percent of all systems (sweet and sour) are pigged. For these, the pigging frequency varies from once per week to once per year. The average frequency is from four to six times per year. Based on these low percentages and the small volume of emissions that results for each occurrence, total emissions from pigging of high-pressure natural gas pipelines are considered to be insignificant and, so, are disregarded for simplification purposes.

    Chemical injection pumps (small gas-operated plunger pumps) are a source of emissions if the supply gas is vented to atmosphere after use, and fuel gas is the medium that is used. Fuel gas is used only if compressed air is not available. On sour systems, it is common practice to inject a corrosion inhibitor at each line heater and field installation to help protect the pipeline. Also, facilities may be provided for injecting methanol to help prevent hydrates from forming during start-ups.

The total amount of gas vented by chemical injection pumps is estimated by applying an appropriate emission factor (see Section 6.3) to the total number of pumps in active service. In doing this it is assumed that:

- Corrosion inhibitor is injected at every line heater.
- Compressed air is unavailable and fuel gas is used as the supply medium.
- Methanol injection only occurs during start-ups and these occasions are too brief and infrequent for the associated emissions to be significant.

(Note: some pumps are powered by electricity and in some applications methanol is injected on a continuous basis.)

The resultant volume of vented natural gas is corrected to account for the amount of time the pumps are in operation. It is assumed that the pumps are only operating when the natural gas processing plants are on stream. This approach may be conservative since not all wells are necessarily operated when the associated plants are operated. From the monthly natural gas processing plant production statistics for Alberta EUB, 2000c,d), it is estimated that the average plant was processing natural gas about 95 percent of the time.

The amount of natural gas that is vented from instrument controllers is estimated in the same manner as described for chemical injection pumps. However, it is assumed there is only one controller associated with each line heater. This controller is used to operate a pressure control valve (choke).

(3) **Equipment Leaks** – The emissions from leaking equipment components are determined by applying emission factors to a schedule of equipment components for a typical line heater. The results then are applied to an estimate of the total number of line heaters used on heated systems.

11.6.2.3 DEHYDRATED GATHERING SYSTEM

This type of gathering system prevents the formation of hydrates by removing water vapour from the process natural gas. There are several different dehydration technologies that are used: absorption using diethylene or triethylene glycol; adsorption using solid desiccants such as activated alumina, gels, or molecular sieve; and the chem-sorption process using calcium chloride. The glycol-based absorption process is the most widely used.

For simplification purposes, it is assumed that glycol dehydrators are used on all dehydrated natural gas gathering systems. The location and number of dehydrators is determined primarily from the annual Dehydrator Benzene Inventory List maintained by provincial regulators (AER). Glycol dehydrators are targeted by a government initiative to reduce atmospheric emissions of benzene (a toxic compound as defined by the Canadian Environmental Protection Act). AER has issued specific source performance standards for glycol dehydrators (AER Directive 039). The complete inventory of glycol dehydrators and their associated benzene emissions are included in the subject national inventory. Accompanying each dehydrator is a separator to remove any free water and other liquids from the gas before dehydration. Liquids from the separator are assumed to be stored in an underground storage tank or a single fixed-roof storage tank (100 bbl storage capacity). At high-pressure well sites where a choke is required to reduce the gas pressure to pipeline conditions, a small line heater may be provided to prevent hydrates from forming across the choke. The dehydrator is located downstream of the choke.

An inherent problem with glycol dehydrators is that in addition to absorbing water from the process gas, the glycol has a strong affinity for BTEX (benzene, toluene, ethylbenzene, and xylenes) and hydrogen sulphide. TEG has a stronger affinity than DEG for these compounds. When the glycol is regenerated the absorbed substances are released as a waste gas. Typically, the waste gas is vented to the atmosphere; however, the presence of even small amounts of H_2S in the process gas can result in dangerous concentrations of H_2S being released from the regenerator still column. Thus, the use of dehydrated systems is usually limited to sweet natural gas applications. If dehydrators are used where H_2S is present or benzene emissions exceed AER Directive 039 limits, a flare or incinerator often is used to dispose of the waste gas.

The sources of emissions on each dehydrated system, and the methods and assumptions used to estimate these emissions are listed below.

(1) **Fuel Consumption** – Fuel is consumed by both the line heaters and the glycol reboilers where these are used. The resulting emissions are estimated based on proration of actual reported fuel consumption and application of published emission factors (see Section 3).

(2) **Venting** – Emissions are attributed to the use of fuel gas to operate pressure-activated devices (e.g., instrument controllers and chemical injection pumps), to the venting of waste gas from the dehydrator and to the depressurization of pipeline segments for repair/tie-in purposes. The emissions from the first source are estimated by applying appropriate emission factors and a typical schedule of gas-operated devices to the total number of dehydrators. The resultant value is corrected to reflect the actual amount of operating time as described in Section 11.6.2.2.

Glycol dehydrators include both conventional systems that utilize an absorption tower or contactor, and systems that inject glycol into the pipeline to provide hydrate control in refrigeration plants. In both cases, the glycol is recovered and regenerated which ultimately results in still-column off-gas emissions. All still-column off-gas from the dehydrators is assumed to be vented, not flared. The amount of hydrocarbons released is estimated by applying an emission factor (see Section 6.4) to the natural gas throughput of the system.

All field dehydration units are assumed to use energy exchange glycol pumps (e.g., Kimray-style pumps) to pump lean glycol from the reboiler back to the absorber column. Accordingly, a glycol pump gas consumption factor is also applied to the total throughput. Dehydrators located at plants or at larger production facilities tend to use electric-drive glycol pumps which have no associated gas venting. Some facilities also may use gas-drive pumps; however, these have high gas consumption/venting rates and therefore are usually avoided.

When a new well is connected to an existing gathering system it is preferable to do so at a location where valving may be used to isolate the tie-in point. If such a location does not exist or is too far away, it is necessary to cut into the pipeline. This may be done using a hot tap procedure (a method of some risk that allows a tie-in to be performed while the line is under pressure). Often, however, the target line is isolated and depressurized to allow a cut-out to be performed. It is estimated by one major operating company that, on average, some 4 000 m^3 of natural gas is released each time part of a gathering system is depressurized. This is equivalent to depressurizing about 3 km of 168.3 mm diameter pipeline that has an initial pressure of 7 000 kPa. For sweet gathering systems, it is assumed that the released volume of gas is usually vented. For sour gathering systems, it is assumed that it is flared. As a first order approximation, it is assumed that one tie-in is required for each sweet natural gas well drilled in 2000. This is conservative since sometimes multiple wells may be tied into a system at once, thus, requiring only a single depressurization event, and some wells may be tied directly into a new facility without the need for a depressurization event.

(3) **Equipment Leaks** – These emissions are evaluated as described in Section 11.6.2.2.

(4) **Storage Tanks** – The emissions from storage of condensate at various points along the gathering system (e.g., at well sites and compressor stations) are accounted for at the location the condensate is reported in the production accounting data. This is usually at the gas gathering system level or at a gas battery (see Section 11.6.3).

11.6.2.4 OTHER GATHERING SYSTEM FIELD INSTALLATIONS

In addition to line heaters and dehydrators, there are some other types of field installations that may occur on natural gas gathering systems. These include injection stations (i.e., gas reinjection facilities), meter/regulator stations, meter stations and regulator stations.

The emissions from the identified field facilities are assessed as follows:

(1) **Venting** – Venting may result from the use of fuel gas to operate pressure-activated devices (chemical injection pumps and instrument controllers), depressurization and purging activities, and start-up of compressors.

The total amount of gas that is vented from pressure-activated devices is estimated by applying appropriate emission factors and a typical schedule of gas operated devices to each facility. The resultant value is corrected to account for the amount of time that the facilities are operating (see Section 11.6.2.2). Fuel gas is assumed to be used as the supply medium at all field facilities. Conservation of the vented gas or disposal by flaring or incineration is assumed to be negligible.

Not all field facilities have flare systems. When the equipment at these facilities must be depressurized for repair/maintenance work, a temporary flare system may be employed. Frequently, however, the gas is simply vented to atmosphere. These volumes should be estimated and reported by the production accountant.

(2) **Equipment Leaks** – Each type of installation is considered to be a source of equipment leaks. The emissions from these are estimated based on typical equipment schedules and average emission factors.

(3) **Storage Tanks** – Some compressor stations will have a tank for storing liquids from the suction and interstage scrubbers. For simplicity, it is assumed that these liquids are produced into tanks at the natural gas processing plants and that the emissions may be adequately accounted for at that level.

11.6.3 NATURAL GAS BATTERIES

A natural gas battery is a production unit that is used when natural gas processing is not required. Only compression and treating (e.g., dehydration or sweetening) may be needed to upgrade raw natural gas to market specifications. Typically, this type of natural gas comes from low-pressure, shallow natural gas wells. It is characterized by low concentrations of non-methane hydrocarbons and is called "dry gas."

The basic functions of a natural gas battery are to separate the effluent from one or more natural gas wells into natural gas and water, measure the flow rate of each of these phases from each well, and provide any treating and compression that may be required. The water is then disposed and the marketable natural gas is sent to market.

The number of gas batteries in Alberta is presented in Table 43. Each of these is assumed to comprise separation, metering, dehydration, compression and water storage facilities. Data regarding the numbers of single-well and group natural gas batteries and the associated equipment located at them is available for Alberta (AER, 2019a). Other data sources and assumptions are delineated below.

- Compressor units are allocated to batteries when natural gas fuel is reported in provincial production data. Operators are required to report fuel consumption at the location where it took place (e.g. AER Directive 017).

- The number of dehydration units at natural gas batteries is defined by the Dehydrator Benzene Inventory List maintained by the AER.

The emissions from natural gas batteries are assessed as follows:

(1) **Combustion Equipment** – Combustion emissions are evaluated as described in Section 11.6.2.2.

(2) **Venting** – Venting is attributed to the use of fuel gas to operate instrument controllers and compressor starters. These emissions are assessed using emission factors and typical instrument schedules.

(3) **Equipment Leaks** – These are estimated by applying appropriate emission factors and typical equipment schedules to each battery.

(4) **Storage Tanks** – The results of a process simulation indicate that virtually no hydrocarbons are released as solution gas from the water storage tanks, even for high pressures in the separator. Some emissions may occur due to the entrainment of hydrocarbon liquids and gas bubbles in the water; however, these emissions are assumed to be small. Water storage tanks are more important as a source of H_2S emissions in sour applications.

11.7 NATURAL 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). Some compression may also be required. Each facility may comprise a variety of treatment and extraction processes, and for each of these there is often a range of technologies that may be used.

There are basically five types of natural gas processing facilities: 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. The first four types are fed by natural gas gathering systems and prepare natural gas for transmission to market. The last type is located on major natural gas transmission lines and is used to extract residual ethane and heavier hydrocarbons from the natural gas in the pipeline.

Gas processing plants are designated as sweet when the raw inlet gas to the plant contains less than 0.01 mole/kmole (10 ppm on a volume basis) of H_2S. Conversely, gas processing plants are designated as sour when the H_2S concentration in the inlet gas contains greater than 0.01 mole/kmole. Sour plants are further classified by how they handle the acid gas stripped from the raw inlet gas. The simplest method of acid gas disposal is by flaring. Acid gas flaring plants are limited by regulations on the SO_2 emissions that arise from combustion of the acid gas. When the acid gas volume (and H_2S concentration) is sufficient to preclude acid gas flaring, two options are left; the plant may inject the acid gas (predominantly CO_2 and H_2S) into a suitable reservoir or it may operate a sulphur recovery unit to produce elemental sulphur. When a sulphur recovery unit is used SO_2 emissions are greatly reduced (by 70 to 99 percent depending on the total inlet sulphur rate) but the CO_2 in the acid gas (formation CO_2) is still released to the atmosphere through the tail gas incinerator stack.

The emissions from each type of plant are attributed to:

(1) **Combustion Equipment** – All combustion emissions are assessed at the individual facility level as described in Section 11.6.2.2.

(2) **Venting** – Venting may result from the use of fuel gas to operate instrument controllers and chemical injection pumps, from the use of glycol dehydrators (i.e., venting of waste gas from the still column), and from purging activities during plant turnarounds and maintenance work. Formation CO_2 stripped from the inlet gas at sour natural gas processing plants may also be vented.

    The total amount of gas that is vented from gas-operated devices is estimated by applying appropriate emission factors to a typical schedule of instrument controllers and chemical injection pumps to each process unit. The resultant value is corrected to account for the extent to which fuel gas is used as the supply medium. Information from the industry survey provided data on the use of air and natural gas for pneumatic devices and on the use of low-bleed and no-bleed devices. In the absence of company specific data all sour plus all large and medium plants (throughput of more than 20 $10^3m^3/d$) use air for devices and all small plants (throughput below 20 $10^3m^3/d$) use fuel gas for this purpose. Overall, about 10 percent of gas processing plants use fuel gas to operate pneumatic instruments.

    In the absence of specific information, all plants that dehydrate gas are assumed to use molecular sieve systems unless a glycol dehydrator is identified in the Dehydrator Benzene Inventory List. The gas production is assumed to be dehydrated in the field for sweet plants (see Section 11.6.2.3) and at the plants for sour facilities. The emissions are estimated by applying calculated emission factors (see Section 6.3) to the relative amounts of production. All glycol dehydration units at gas processing plants are assumed to be equipped with a flash tank and electric glycol pumps. Therefore, these units are not sources of emissions from glycol pumps.

    When a process unit is depressurized for maintenance or repair work, the gas in the vessels and piping is normally flared. However, before any vessels are opened, the system usually is purged to remove any residual toxic or explosive gases. A similar procedure may be performed to remove air before the system is put back in service. Depending on the plant and the procedures that are used, the flame at the flare stack may be extinguished as a safety precaution during certain periods (e.g., when fuel gas is used to purge air from the system). This may result in some organic material being emitted. Blowdown volumes should be estimated and submitted as venting in monthly production accounting reporting.

    Formation CO_2 emissions are estimated as described in Section 2.7.

(3) **Equipment Leaks** – These are assessed based on the total number of plants and the types of process units that are used at each plant. A typical equipment schedule and appropriate emission factors are applied to each unit at each plant. The number of equipment components associated with a given type of unit is assumed to be constant and, thus, is independent of design capacity. (Usually, design capacity only impacts the size of the equipment components and not the number of components on a given process unit.)

The processes used at each natural gas processing plant were determined from the AER ST50 report.

Storage Tanks – These are used at natural gas processing plants to store produced water and pentanes-plus. The results of process simulations show that there are virtually no hydrocarbon emissions from the water tanks; however, significant emissions may occur from storage of pentanes-plus. These emissions are estimated using correlations published by API (1991) for evaporation losses from fixed-roof storage tanks. Pentanes-plus is a stabilized product so there are no solution gas emissions. To apply the correlations it is necessary to determine the amount of pentanes-plus produced at each plant, and the corresponding numbers and sizes of storage tanks that are used. The volumes of produced pentanes-plus are determined from the gas plant production statistics where data are available. The numbers and sizes of storage tanks are estimated by assuming:

- Each plant has a minimum of two tanks (one shipping tank and one overflow tank).
- The tanks are sized for a minimum of 24 hours of storage capacity (the design pentanes-plus production rates specified in the Oilweek gas plant listing are used for this purpose).
- Standard API tank sizes of 100, 400, 750, 1000, 1500, and 2000 bbl are used.

(4) **Surface Impoundments** – Some plants have evaporation ponds where surface run-off, sludge and small amounts of produced water may be disposed of. The emissions that result from these activities are considered to be small and are not estimated.

11.8 NATURAL GAS TRANSMISSION, STORAGE AND DISTRIBUTION

The natural gas transmission system conducts 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).

The storage facilities accommodate fluctuating differences between gas supply and demand rates. These facilities usually feature an underground cavern with multiple wells for injection/ removal of the gas. In addition, they include compressors to recompress stored gas when it is removed from the cavern, and dehydration facilities for removal of any moisture the gas may have picked up in the cavern. In some cases the re-produced natural gas may also contain natural gas liquids that must be extracted prior to re-introduction of the gas into the transmission system.

There are also some storage facilities in Canada where natural gas is liquefied and stored in spherical vessels. These types of storage facilities are normally located near the start of gas distribution systems. They feature a liquefaction plant at the inlet to the storage vessels and a vapourizer and compression at the outlet to the vessels. Natural gas transmission systems transport processed natural gas to market.

To assist its members in preparing GHG emission inventories, the Canadian Energy Partnership for Environmental Innovation (CEPEI) (formerly GRI Canada) regularly enhances a methodology manual (*Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*) and software package that implements many of the methodologies described in the manual (CEPEI, 2016). This consolidated manual is part of an on-going commitment by the Canadian gas industry to harmonize its atmospheric-emissions inventorying efforts. The overall aim is to provide a flexible framework in which individual companies may assess their emissions, and to establish a base set of terms, source categories and nomenclature to facilitate inter-company comparisons and allow easy aggregation/disaggregation of the results for future industry reporting initiatives. In preparing the 2017/2018 GHG and CAC emission inventory from gas transmission, storage and distribution, the various companies used a common methodology to calculate emissions. The company results, rolled-up to provincial totals, will be requested from CEPEI.

The methodologies described in the handbooks listed above cover the following direct emission sources:

- Fuel Combustion (compressor engines and heaters/boilers),
- Process Venting,
- Fugitive Equipment Leaks,
- Pipeline Leaks,
- Glycol Dehydrators, and
- Accidental Releases.

Methodologies for the listed source types are described in the sections below.

(1) **Combustion** – All combustion emissions are assessed at process unit level using the methodology described in Section 3.

(2) **Venting** – Emissions from process venting includes the following individual sources:
    - Mainline blowdowns (very infrequent),
    - Pipeline purging (very infrequent),
    - Station blowdowns (several times per year),
    - Scrubber blowdowns (typically less than once per year),
    - Booster vents (monthly), and
    - Compressor starts (usually several times per month).

These emissions are assessed using the methodology described in Section 6.3. Where possible emissions are based on volumes that are either measured or estimated based on the physical characteristics of the venting event.

(3) **Fugitive Equipment Leaks** – Emissions from fugitive equipment leaks are assessed using the methodology described in Section 7.1. For each facility, a listing of the process equipment at that site is prepared. The applied methodology requires average emission factors and equipment schedules appropriate to gas transmission and distribution systems (GRI, 1998). The activity level details are not available.

(4) **Pipeline Leaks** – Fugitive pipeline leaks consist of emissions from underground valves and other buried fittings attached to a pipeline and emissions through the pipe wall. Emissions through the pipe wall may be due to small openings in the pipe wall (usually as a result of a crack or corrosion) and emissions through the molecular structure of the pipe itself (in the case of plastic pipe used in some distribution systems).

Emissions from pipeline leaks are calculated based on the type of pipeline, the average frequency of pipeline leaks, the average emission rate of a leak and correction factors to account for the methane content of the gas, oxidation of methane by the soil and an equivalent leak factor. The equivalent leak factor accounts for the fact that there may have been undetected leaks, and corrects for the leaking time duration of those leaks that either started leaking after the start of the year or were repaired before the end of the year or both.

Leakage due to permeability of plastic pipelines is assessed using a simple equation that relates the leak rate to the permeability of the pipeline material to methane, the surface area and wall thickness of the pipe, the pipeline pressure and the lapsed time. The appropriate equation is (AGA, 1994 and GRI, 1998):

$$\dot{m}_{CH_4} = c \cdot x_{CH_4} \cdot P_g \cdot L \cdot 10^{-2}$$

Equation 40

where,

$\dot{m}_{CH_4}$ = mass emission rate of methane (tonnes per year),

c = a factor to account for permeation losses from plastic pipe (see GRI, 1998),

x_{CH_4} = mass fraction of methane in the gas,

P_g = pipeline operating gauge pressure (kpag),

L = length of pipeline (km).

For a more detailed description of the application of these factors see GRI 1998.

(5) **Glycol Dehydrators** – Emissions from glycol dehydration systems are assessed using the basic methodology delineated in Section 6.4.

(6) **Accidental Releases** – Accidental releases are releases that occur as a result of accidents that are not part of the normal operational or maintenance activities of the system. The only significant types of natural gas emissions in this category are those from pipelines as a result of external damage to the pipe wall – so called third-party damages or dig-ins.

These emissions are very difficult to quantify since the emitted volume depends on a large number of variables including the extent and shape of damage to the pipe wall, operating pressure, geometry and length of the pipeline segment, the capacity of the system feeding the pipeline segment and the length of time before the release is controlled. These emissions are usually estimated on an incident by incident basis.

11.9 PETROLEUM LIQUIDS AND CRUDE OIL TRANSPORTATION

This category addresses emissions from the use of pipelines, tanker vehicles and terminal stations to move crude oil, natural gas liquids (NGLs) and liquefied petroleum gas (LPG). The associated emissions in the present inventory are from the loading and unloading of tanker vehicles and from sampling activities. Emissions from transit losses may also occur but these have not been included here as there are no established procedures, nor emission factors available for the products that are considered in this category.

Crude oil pipeline facilities are regulated by both the National Energy Board, for inter-provincial pipelines, and provincial agencies (e.g., Alberta Energy Resources and Conservation Board) for pipelines entirely within one province. The numbers and types of pipeline facilities (e.g., pipeline terminals, tank farms and pump stations) were determined from facility types reported in provincial production data. CAC, H_2S and speciated VOC emissions from petroleum liquids and crude oil pipeline and terminal facilities are obtained directly from NPRI databases (to be completed). GHG emissions from these facilities are small (2000 inventory results indicate this Sector represents less than 0.04 percent of total GHG emissions) and therefore estimated based on the ratio of methane to VOCs typically observed in tank vapours. This approach is considered more reliable and accurate than estimating emissions from equipment and throughput data.

11.9.1 NATURAL GAS LIQUID/LIQUIFIED PETROLEUM SYSTEMS

Three types of petroleum gases are marketed in liquefied form: ethane, propane, and butane. Each of these substances has a high vapour pressure (HVP) (6 000, 1 341, and 377 kPa, respectively at 40^{o} C); therefore, it must be stored and transported in pressurized vessels. NGLs/LPG are transported by road, rail and pipeline.

Natural gas processing plants connected to LPG pipelines are assumed to be shipping LPGs by pipeline. Otherwise, rail or truck tankers are assumed to be used and loading/unloading emissions are included. These emissions are calculated as described below and have been attributed to the natural gas processing plant.

11.9.1.1 SURFACE TRANSPORTATION (ROAD AND RAIL)

Since LPG is contained in pressurized systems, there are no storage or transit losses. The emissions here result from equipment leaks, venting procedures and purging of equipment prior to performing service work.

(1) **Combustion Equipment** – There are currently two facilities in Alberta where LPG rail cars are repaired and serviced: one in Edmonton and one in Red Deer. The operating procedures at each facility are quite similar.

Before any service work is performed on an LPG car, the vessel is drained of residual liquids, depressurized and subsequently purged using an inert material (e.g., nitrogen or steam). The liquids are recovered and later recycled. The waste vapours from the last two steps are flared/incinerated. Approximately 1100 LPG cars were processed in this manner in Alberta in 1989. It is estimated, based on information provided by the two repair yards, that the average initial pressure in each car is about 350 kPa (actual values range from 0 to about 700 kPa), and the volumetric capacity of each car is about 130 m^3.

(2) **Venting** – Venting of LPG material may result from gauging activities during loading operations, and from depressurization of transfer hoses at the end of each loading or unloading operation. These activities are delineated below. The amount of emissions that occur is estimated by applying calculated emission factors (see Section 9) to the amount of each type of material that is moved by surface transportation. During loading operations, a gauging assembly is used to monitor the level of the liquid product. This assembly comprises a graduated length of pipe (the gauge rod) that extends vertically into the rail car vessel. A clamping mechanism on the vessel may be adjusted to allow the gauge to be moved up or down. The rod has a 1/4" needle valve at the top which normally is kept closed (some valves may be fitted with a special orifice). During the filling operation, the gauge is adjusted to the desired fill level, and the valve is opened slightly (about 25 percent). Initially, vapour product escapes through the valve. When liquid product begins to spew out, the tank is filled. Typically, 1 to 1.5 hours are required to load a rail car, and the gauge assembly is vented during this entire period. The amount of material that is vented is dependent on the vapour pressure of the product, friction losses in the gauge rod, and the flow coefficient for the open valve.

The hose that is used during product transfers is typically 3 m in length and has an inside diameter of about 5 cm. At the end of a loading operation it is usually filled with liquid product, and at the end of an unloading operation it is usually filled with vapour product. When the hose is disconnected the material inside the line is released to the atmosphere. At some plant locations the transfer lines may be depressurized to a flare system; however, this is assumed to be uncommon.

(3) **Equipment Leaks** – There are no known emission factors available for estimating emissions due to equipment leaks on pressurized tanker vehicles. Transport Canada, in conjunction with CN Rail and CP Rail, has studied the problem of leaking rail car equipment. However, the data is of a qualitative nature and not suitable for determining the amount of emissions. Some qualitative data are given below.

An unpublished study conducted by CN Rail identified 19 potential leakage points on LPG rail cars (Note: the visible leaks are denoted by an L): liquid eduction valve (L), vapour eduction valve (L), loading valve, thermometer well, gauging device assembly (L), heater coils, sampling line valve (L), safety valve (L), tank shell (L), manway cover bolts (L), manway cover gasket (L), safety vent (L), bottom outlet cap, bottom outlet gasket, bottom outlet valve, frangible disk, bottom outlet connections, unloading valve and other location (L). Over a four-year period (1984 to 1987) visible leaks were reported for ten of the categories. The most frequently-occurring leaks were from the liquid eduction valve, vapour eduction valve and gauging device assembly.

11.9.1.2 HIGH VAPOUR PRESSURE PIPELINES

LPG products are transported underground by HVP pipelines. The emissions that result from operating these systems are evaluated as follows:

(1) **Combustion Equipment** – Typically, the pumps used on these systems are driven by electric motors. Consequently, there are no combustion emissions. The use of fuel for space-heating requirements is assumed to be negligible.

(2) **Venting** – Before any work is performed that may require a line to be opened, all product is pigged from the affected segment using an inert material (e.g., N_2). Therefore, no emissions occur when the line is opened.

(3) **Equipment Leaks** – The pipeline attribute file is used to determine the total number and type of installations used on HVP pipelines in Alberta. The emission factors for natural gas processing plants and typical equipment schedules are applied to these installations.

11.9.2 PENTANES-PLUS SYSTEMS

Pentanes-plus is a low-vapour-pressure (LVP) product that is produced primarily by gas processing plants. It may be stored and transported at atmospheric conditions. In Alberta, pentanes-plus is moved by both surface transportation and LVP pipelines. An analysis of plants that are connected to pentanes-plus pipelines (according to the pipeline attribute file) and the production of pentanes-plus by plant indicate that about 80 percent of the total amount produced in 2005 was moved by surface transportation and about 20 percent was moved by pipeline.

11.9.2.1 SURFACE TRANSPORTATION

Typically, this mode of transportation is used to move LVP material to LVP pipeline terminals where it is loaded into tanks and subsequently pumped into the pipeline for transport to market. The emissions that result from the surface transportation are attributed to loading and transit losses. Some emissions may be associated with the unloading of the material. These are either taken into account by the LVP pipeline system (see Section 9), or are assumed to be part of the downstream oil and gas industry; thus, they are excluded from this study.

The loading and transit losses are estimated using emission factors published by U.S. Environmental Protection Agency (U.S. EPA, (1995a) for transport and marketing of petroleum liquids. In applying these factors it is assumed that all tank vehicles are filled by submerged loading (dedicated normal service). The factors are the same for both tank trucks and rail tank cars, so it is not necessary to assess the disposition of product by mode of surface transportation.

11.9.2.2 LOW VAPOUR PRESSURE PIPELINES

Operating LVP pipelines is very similar to operating HVP pipelines, with the exception that LVP systems have storage tanks at each terminal. The emissions from all sources, except from storage tanks, are assessed as described in Section 9. The emissions from storage tanks are typically estimated using empirical correlations published by API (1991, 1990 and 1994). Data for larger terminal tank types (floating-roof or fixed-roof), design, number of tanks at each terminal, and volume of material handled by the tanks are generally not available. Therefore, CAC emissions are obtained from their NPRI submissions for the target reporting years (Environment Canada, 2013a). Methane emissions are estimated based on the ratio of methane to VOCs typically observed in terminal tank vapours.

11.10 ACCIDENTS AND EQUIPMENT FAILURES

This section addresses emissions due to human error and extraordinary equipment failures (that is, it excludes leakage at connections, seals and packings). The emissions are classified by type of incident or failure: pipeline ruptures, well blowouts, spills, surface casing vent flows and gas migration to the surface.

11.10.1 PIPELINE RUPTURES, WELL BLOWOUTS AND SPILLS

AER produces a database containing information on oil and gas well blowouts, pipeline ruptures and spills in Alberta (AER, 2018c).

For pipeline ruptures and spills, both the total spill volume and volume recovered are reported. All unrecovered volumes of hydrocarbons are assumed to eventually enter the atmosphere.

11.10.2 SURFACE-CASING VENT FLOWS

Surface casing is a steel liner used to protect the integrity of the well bore as the hole is being drilled and to prevent contamination of any aquifers that may be a source of potable water. It is installed during the initial stages of the drilling program and is cemented in place by pumping cement down the centre of the pipe and forcing it to return up around the outside wall. The depth to which the surface casing extends is determined by regulations and the geological conditions at the site (surface casing may not be required on some shallow wells). When the well is completed, the production casing is run down the centre of the surface casing and cemented in place in a similar manner. Current practice is to leave the surface open at the bottom. This allows any gas or other fluids that may flow out from the surrounding formation or up from below to flow into the casing annulus rather than migrate up around the outside of the surface casing and possibly contaminate aquifers above. To allow easy monitoring for leaks, a vent and pressure gauge are installed at the well head.

If a vent flow occurs, the exact cause of the flow may be difficult to determine and the required repairs are often costly. The material emitted from a vent flow may consist of gas, oil, fresh water, salt water or drilling mud. Some vent flows eventually die out. In some cases the vent flow is produced, in others either it is vented/flared or the vent is blocked in and pressure is allowed to build-up in the casing.

SCVF rates are reported by operators to the AER (in units of m^3 per day) as required by ID 2003-1 and adopted to calculate emissions. In some cases, the rate is not available and a leak factor is required to bridge the data gap. The ‘leaker’ emission factor (3.74 m^3 per **hour** per well -97% +189%) from Clearstone, 2018 is applied to subject SCVF records.

11.10.3 GAS MIGRATION TO THE SURFACE

This emission source results from the flow of gas around the outside of a well. The flow may be caused by a leak in the production string at some point below the surface casing, or by the migration of material from one or more of the gas bearing zones that were penetrated (e.g., a coal seam). The problem is most pronounced in the Lloydminster region of east central Alberta and west central Saskatchewan. Data compiled by AER indicate that approximately 7.8 percent of heavy oil wells have gas migration problems.

Husky Oil Operations conducted a series of 119 tests to measure gas migration from 34 wells in this area (Erno and Schmitz, 1996 and Schmitz *et al.*, 1996). Based on the data presented in these papers, an average methane flow rate of 3.85 m^3/d per well was been determined. Emissions are calculated by applying this emission factor to wells with gas migration identified in the AER database (as reported via ID 2003-1).

11.11 WASTE OIL RECLAIMING AND DISPOSAL

Efforts by government and industry are underway to reduce the volumes of oily wastes being generated, and to recover as much of the oil or crude bitumen as possible. The types of wastes that may occur include tank bottoms, treater bottoms, scrapings from pigging operations, sludge from vessels, sludge from surface impoundments, drilling fluids, oil spill debris, and oily sand and sedimentary material.

The emissions that result from the disposal of these wastes may be ascribed to four source categories: transportation contractors, waste reclaimers, land farms, and road oiling. Unfortunately, very little information exists on the amount or type of waste material that is disposed of. Consequently, the resulting emissions could not be assessed; however, they are likely small compared to those from other source-categories.

The following sections delineate each source category and identify some relevant studies that have been conducted.

11.11.1 OILFIELD-WASTE TRANSPORTERS

Unpublished data compiled by Monenco Consultants Limited (provided by W.A. Siemieniuk, June 21, 1990) indicate that there are 16 contractors that transport oilfield wastes. Some of these companies operate from more than one location.

11.11.2 WASTE-OIL RECLAIMERS

Waste-oil reclaiming facilities are regulated by AER Directive 047. According to AER's Active Facility List, there were 180 approved oilfield waste management facilities in Alberta in 2017 (AER, 2017). Due to the nature of the products generally handled by these facilities (i.e., low volatility waste and sludges), emissions from this sector are expected to be negligible.

11.11.3 LAND TREATMENT FACILITIES

Land treatment facilities dispose of oily wastes by biodegradation which is achieved through controlled application to designated land areas. However, a significant amount of the applied material and the degradation products that are formed may be released to the atmosphere through normal evaporation. A current concern in the United States is that the resulting emissions may contain high concentrations of volatile hazardous air contaminants. A study by Woodward-Clyde Consultants (1989) showed mass emissions of monoaromatic compounds (benzene, toluene, total xylene, and ethylbenzene) at one site to be 8 to 17 percent of the applied waste load.

Alberta Environment has published a set of guidelines for land treatment of industrial wastes (AENV, 1988), and maintains design and operating data on land treatment facilities in Alberta. Unfortunately, this information is not currently in an easy-to-use format. Consequently, it is not clear how much waste is being disposed of in the Province by land treatment. Furthermore, detailed characterization data for these wastes are not readily available.

11.11.4 ROAD OILING

The application of heavy asphaltic oils to roads is an accepted treatment for suppressing dust and enhancing the road surfaces. It is done on both municipal roads and secondary highways. AER, however, does not consider the substitution of oil-containing wastes in these applications to be an acceptable long-term waste-disposal strategy (Information Letters IL 85-16 and IL 95-04). As a result, only selected disposal programs of this type are approved. These programs are limited primarily to the use of waste crude bitumen and heavy oil. Table 44 provides a summary of the typical composition of the hydrocarbon content of these wastes. The characterization criteria for oily by-product material applied to roads are as follows (EUB IL 95-04):

- No free water.
- Oil shall have a density greater than 920 kg/m^3. Material with less than five percent residual hydrocarbon is unacceptable as road mix.
- pH ≥ 6.
- Total salts (loading limits): Na ≤ 5 500 kg/ha
  Cl ≤ 7 000 kg/ha
- Total metals (concentration in sample): Cd ≤ 3 mg/kg
  Pb ≤ 375 mg/kg
  Ni ≤ 150 mg/kg
  Cu ≤ 150 mg/kg
  Zn ≤ 600 mg/kg

The amount of atmospheric emissions that may result from the disposal of wastes on roads has not been an issue. The primary concerns are related to the leaching of some waste materials (e.g., metals and salts) and to future reclamation problems where wastes are applied to lease sites.

Table 44: Composition of the organic fraction of Lloydminster petroleum wastes[1].

Component	Number of Samples	Concentration (weight %)	
		Average	Range
Asphaltenes	9	15.0	5 to 19
Resins	7	13.3	9 to 25
Acids	9	1.8	0.1 to 13

Table 44: Composition of the organic fraction of Lloydminster petroleum wastes[1].

Component	Number of Samples	Concentration (weight %)	
		Average	Range
Bases	7	0.4	0.4 to 1
Neutral Nitrogens	7	16.5	12 to 25
Aromatics	7	17.5	11 to 23
Aliphatics	7	36.6	28 to 39

[1] Varmen, M.L., and K.S. Ng. 1983. Potential Environmental Affects of Heavy Oil Waste Disposal: An Assessment of the Characteristics of Lloydminster Petroleum Wastes. Report of the Analysis and Toxicity Project Group to the Sask-Alta Waste Disposal Co-operative Technical Sub-Committee.

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13 APPENDIX I – GLOSSARY

ASTM Slope -	The slope of the ASTM-D86 distillation data at 10 volume percent evaporated.
Bitumen -	A naturally occurring viscous mixture consisting of hydrocarbons heavier than pentane and other contaminants, such as sulphur compounds, which in its natural state will not flow under reservoir conditions or on the surface. Bitumen occupies the lower end of the range of heavy crude oils and is sometimes referred to as ultra-heavy crude oil.
Blanket Gas -	Storage tanks are equipped with gas blanket systems to reduce vapour emissions (especially when the vapours are sour) and to ensure that oxygen does not enter the vapour space of the tank when it is connected to a flare system or vapour recovery unit. The blanket gas is usually fuel gas but any other inert gas could be used. Storage tanks with gas blanket systems are usually connected to a flare or vapour recovery system, but in some cases (if the gas is not sour) the tank vapours and blanket gas may be released untreated to the atmosphere through a vent system.
Breather Pressure Setting –	The pressure set-point at which the breather will begin to open to relieve pressure by venting gases from the tank vapour space to the atmosphere.
Breather Vent Vacuum Setting -	The vacuum set-point at which the breather will begin to open to allow ambient air to flow into the tank vapour space to relieve a vacuum condition.
Diesel Fuel -	A general term covering light fuel oil derived from gas oil used in diesel engines.
Diluent -	Light petroleum liquids used to dilute heavy crude oil, particularly bitumen, so that it can flow more easily through pipelines.
Diluted Bitumen -	Bitumen blended with diluent.

Hydrocarbons -	All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.
Products of Incomplete Combustion -	These are any compounds, excluding CO_2, H_2O, SO_2, HCl and HF, which contain C, H, S, Cl or F and occur in combusted gases. These compounds may result from thermodynamic, kinetic or transport limitations in the various combustion zones. All input combustibles are potential products of incomplete combustion. Intermediate substances formed by dissociation and recombination effects may also occur as products of incomplete combustion (CO is often the most abundant combustible formed).
Reid Vapour Pressure -	A liquid's vapour pressure at 100ºF (37.8ºC) as determined by the test method ASTM-D-323. It is an indication of the propensity of the liquid to evaporate.
Reduced Sulphur Compounds (RSCs) -	Any compounds containing the sulphur atom in its reduced oxidation state. These are taken to be any sulphur-containing compounds except SO_x.
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.
Sulphur Oxides (SO_x) -	Usually, almost all sulphur input to a combustion process as part of the fuel or waste materials being burned is converted to SO_x. Only a few percent of the available sulphur is emitted as sulphate particulate and other products of incomplete combustion. The produced SO_x is comprised mostly of SO_2 (typically 95 percent) with the rest being SO_3. For simplification purposes it is assumed throughout this document that all input sulphur is converted to SO_2.

Synthetic Crude Oil -	A high quality, light, usually sweet, crude oil derived by upgrading heavy crude oil, particularly bitumen, through the addition of hydrogen or removal of carbon. It comprises mainly pentane and heavier hydrocarbons.
Tailings -	A combination of water, sand, silt and fine clay particles that are a byproduct of removing the bitumen from the oil sand.
Total Hydrocarbons (THC) -	The aggregate concentration of all hydrocarbon compounds.
Total Organic Compounds (TOC) -	TOC comprises all VOCs plus all non-reactive organic compounds (i.e., methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons).
Total Reduced Sulphur (TRS) -	The aggregate concentration of all reduced sulphur compounds.
True Vapour Pressure -	the equilibrium partial pressure exerted by a stored liquid as a function of temperature.
Upgrader -	A facility for upgrading heavy oil and crude bitumen into a lighter, sweeter, high-quality synthetic crude oil either through the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).
Volatile Organic Compounds (VOC) -	Any compound of carbon, excluding carbon monoxide and carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, acetone, many fluorocarbons, and certain classes of per fluorocarbons.

14 APPENDIX II: FUGITIVE EMISSION DEFINITIONS

This glossary provides definitions relevant to the classification of venting and fugitive emissions sources.

14.1 EMISSION TYPES

Emission types are defined as follows:

14.1.1 LEAK

It is important that an objective leak definition be established for application in a leak management program and that this definition meet or exceed common industry or regulatory standards. 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 10,000 ppmv or more), or detected by any other techniques with similar or better detection capabilities.

The IR camera is not always as sensitive as screening using organic vapour analyzers, but has been demonstrated to be sufficiently sensitive to detect the big leaks that are contributing most of the emissions.

14.1.2 VENT

An intentional release of hydrocarbon gas directly to the atmosphere. Venting does not include partial products of combustion that might occur during flaring or other combustion activities.

14.2 COMPONENT TYPES

Component types relevant to the classification of fugitive emission leaks are defined as follows:

14.2.1 COMPRESSOR SEALS (ROD-PACKINGS)

A reciprocating compressor is deemed to have one seal associated with each compressor cylinder regardless of whether it is really a single or tandem seal. A centrifugal compressor has two seals, one on each side of the housing where the shaft penetration occurs. Other components on the compressor and on any associated cooler (e.g., valves, connectors, pressure relief valves, open-ended valves and lines, and gas-operated instruments) need to be accounted for separately.

14.2.2 CONNECTORS

Each threaded, flanged, mating surface (cover) or mechanical connection is counted as a single connector. Welded or backwelded connections are not counted. Some types of components may have more than one set of connections associated with them. For example a union may have 3 sets of connecting surfaces (2 end connections and a center connection), a nipple or reducer may have 2 (one at each end), and tee may have 3 (one at each end). If all 3 connection points on a union are threaded then a union would be classified as 3 connectors. A union that has welded end connections would be counted as only one connector.

14.2.3 CONTROL VALVE

A valve equipped with an actuator for automated operation to control flow, pressure, liquid level or other relevant process parameter. This category accounts for leakage from around the valve stem and from all fittings on the valve body. The end connections and any internal leakage past the valve seat are counted separately (see connectors and open-ended valves or lines, respectively).

14.2.4 METERS

A flow measurement device is counted as a single component. The connections on the upstream and downstream sides of the device are counted as separate components.

14.2.5 OPEN-ENDED LINES

Each valve in hydrocarbon service that has process fluid on one side and is open to the atmosphere on the other (either directly or through a line) is counted as an open-ended line. If the open side of the valve is fitted with a properly installed cap, plug, blind flange or second closed block valve, or is connected to a control device, then it is no longer considered to be open-ended. A drain valve that discharges into a free-venting storage tank or sump is counted as an open-end line. The valve stem and body, and the connector on the process side of the valve are counted as separate components.

14.2.6 PRESSURE-RELIEF VALVE

Each pressure-relief valve that discharges directly to the atmosphere or through a vent system is counted as a single component. If the valve discharges to a control device (e.g., flare or thermal oxidizer), or has a rupture disk installed upstream along with a monitoring system to indicate when the rupture disk has failed, then the valve is not counted. The connection on the upstream side of the valve is counted as a separate component. The connection on the downstream is not counted unless there is gas pressure on that side.

14.2.7 PUMP SEALS

Each pump in hydrocarbon service may leak from around the pump shaft and is typically controlled a packing material, with or without a sealant. It may be used on both the rotating and reciprocating pumps. Specially designed packing materials are available for different types of service. The selected material is placed in a stuffing box and the packing gland is tightened to compress the packing around the shaft.

14.2.8 REGULATORS

Most regulators are equipped with a vent where gas is released in the event the diaphragm inside becomes damaged. Often, this venting either goes unnoticed or is assumed to be normal operation of the regulator. All regulators should be checked for such leakage. Leakage from around the connections to the regulator should be classified as connectors

14.2.9 THIEF HATCH

Storage tanks connected to a VRU or flare do not emit gas unless the internal tank pressure exceeds the PRV or thief hatch set pressures (and intermittent venting occurs). When the tank pressure drops, the PRVs return to a closed position and typically don’t leak. However, once opened, thief hatches remain partially open until an operator closes the hatch. Gas loss from partially open thief hatches is unintentional and therefore classified as a leak.

Gas losses from storage tanks open to the atmosphere (i.e., not connected to a VRU or flare) are classified as a process vent (not a leak).

14.2.10 VALVES

A valve that is **not** a control valve. This category accounts for leakage from around the valve stem and from all fittings on the valve body. The end connections and any internal leakage past the valve seat are counted separately (see connectors and open-ended valves or lines, respectively).

14.3 SERVICE TYPES

Service types relevant to the classification of fugitive emission leaks are defined as follows and refer to the hydrocarbon in contact with the leaking component:

14.3.1 FUEL GAS

Natural gas used as fuel by combustion devices. Fuel gas composition and speciated emissions can be very different than process gas and therefore defined separately.

14.3.2 HEAVY LIQUID

Process fluid that is a hydrocarbon liquid at the operating conditions and has a vapour pressure of less than 0.3 kPa at 15ºC. Heavy crude oil and crude bitumen fall into this category.

14.3.3 LIGHT LIQUID

Process fluid that is a hydrocarbon liquid at the operating conditions and has a vapour pressure of 0.3 kPa or greater at 15ºC. Light/medium crude oil, condensate and NGLs fall into this category.

14.3.4 PROCESS GAS

Process fluid that is a hydrocarbon gas at the operating conditions and is not fuel gas.