Alberta Greenhouse Gas Quantification Methodologies

Chapter 15: Aggregate Facilities

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TECHNOLOGY INNOVATION AND EMISSIONS
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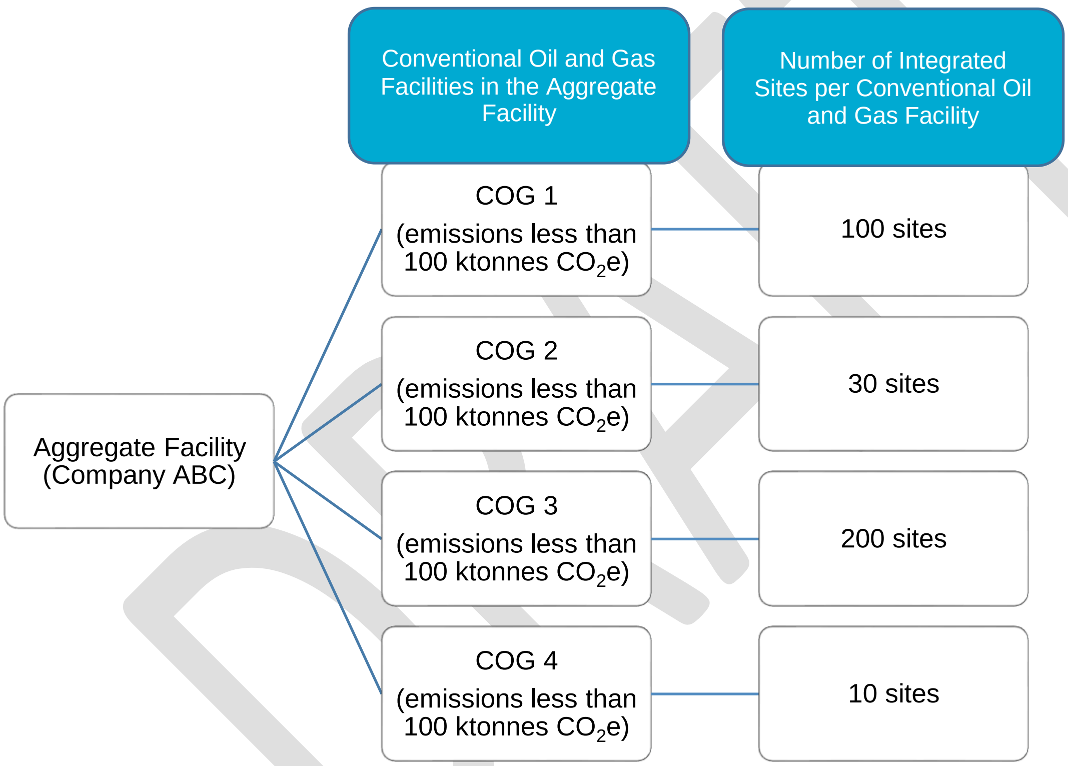
15. Aggregate Facilities

15.1. Introduction

This chapter provides quantification methodologies for stationary fuel combustion emissions, flaring emissions and production volumes for aggregate facilities regulated under the Technology Innovation and Emissions Reduction (TIER) Regulation. The quantification methodologies prescribed in this chapter are applicable for both benchmark applications and annual compliance reports. These methodologies are not applicable for other facilities regulated under TIER.

An aggregate facility consists of two or more conventional oil and gas (COG) facilities. Further, multiple sites may be integrated in operation and be identified as a single COG facility within an aggregate facility provided each site emits less than 100,000 tonnes CO_2e. Figure 15-1 provides an example of an aggregate facility.

FIGURE 15-1: EXAMPLE OF AN AGGREGATE FACILITY



Throughout this chapter, criteria are provided on how to remain consistent in the application of methodologies between the benchmark and compliance periods. Methods selected for COG facilities within the aggregate facility must be the same in the benchmark and compliance report. Should methods change following the benchmark setting period, a conservative methodology for re-benchmarking will apply.

Quantification methodologies for aggregate facilities are not classified by levels. The aggregate facilities should choose the most suitable methodologies for their operations and availability of data. Table 15-1 outlines the quantification methodologies used to quantify fuel consumption, emissions for stationary fuel combustion sources, flaring emissions and production for each COG within the aggregate.

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Table 15-1: Quantification Methodologies for Aggregated Conventional Oil and Gas Facilities

Categories	Methods
Fuel Consumption for SFC	Method 15-1 – Single gas stream approach
	Method 15-2 – Multiple gas stream approach
	Method 15-3 – Non-Petrinex fuel
Carbon Dioxide (CO_2) Emissions for SFC	Method 15-4 – Default CO_2 emission factor for fuel gas
	Method 15-5 – Default CO_2 emissions factors for non-variable fuels not reported in Petrinex
	Method 15-6 – CO_2 emissions based on Higher heating value correlation
	Method 15-7 – CO_2 emissions based on fuel gas carbon content
Methane (CH_4) and Nitrous Oxide (N_2O) Emissions for SFC	Method 15-8 – Non-variable fuel emission factors
	Method 15-9 – Variable fuel sector-based emission factors
	Method 15-10 – Variable fuel technology-based emission factors
Flaring CO_2 and CH_4 emissions	Method 15-11 – Default single flaring gas emission factor
	Method 15-12 – Multiple flare gas streams
Flaring N_2O Emissions	Method 15-13 – Emission Factors
Production	Method 15-14 – Petrinex production volumes

15.2. Stationary Fuel Combustion (SFC) Sources

SFC sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of providing useful heat or energy for industrial, commercial, or institutional use. Stationary fuel combustion sources include, but are not limited to boilers, simple and combined-cycle combustion turbines, engines, emergency generators, portable equipment, process heaters, furnaces and any other combustion devices or systems (e.g., blasting for mining purposes and drilling and completion activities). This source category does not include flare emission sources or waste incineration.

The primary greenhouse gases that are emitted from stationary fuel combustion are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

This section provides quantification methodologies of the fuel consumption and emissions for SFC. Based on the Table 15-1 SFC emission methods, the simplest approach for SFC emissions quantification is to apply:

- Method 15-1 for fuel consumption;
- Method 15-4 and/or Method 15-5 for carbon dioxide emissions; and
- Method 15-8 and/or Method 15-9 for methane and nitrous oxide emissions.

15.2.1. Fuel Consumption and Composition for SFC

Introduction

Fuel gas streams are characterized by varying gas compositions and higher heating values. Common fuels consumed at COGs include fuel gas and non-variable fuels such as propane, diesel, and gasoline.

Fuel consumption at individual COGs may be calculated using the following methods:

- Method 15-1 – Fuel gas consumption based on a single gas stream treatment for reported fuels in Petrinex.
- Method 15-2 – Multiple gas streams based on varying fuel gas compositions for reported fuels in Petrinex.

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- Method 15-3 – Fuel consumption of non-variable fuels or fuel gas not reported in Petrinex based on internal metering, third-party custody metering or invoices.

One or a combination of methods may be used at an individual COG to determine fuel consumption if the COG has both Petrinex fuels and non-Petrinex fuels. However, for reported fuels in Petrinex, the person responsible may only use Method 15-1 or Method 15-2 for each COG, not both.

TIER is not intended to double price emissions from fuel consumption. If fuels used at an aggregate facility have already been subject to carbon pricing during a period when a federal fuel exemption certificate was in place, the emissions associated with these fuels should be excluded from the facility's direct emissions for compliance reporting.

Equation

Equation 15-1 is used for the summation of fuels by fuel type for each COG.

$$v_{fuel\ i,p} = \sum_{n=1}^{N} v_{fuel,i,p,n} \qquad \text{Equation 15-1}$$

Where:

$v_{fuel,\ i,\ p}$	=	Total volume of fuel consumed for fuel type i at a COG in cubic meters (m^3 or kl) at standard conditions (15ºC, 1 atm) during reporting period, *p*.
i	=	Fuel gas type
p	=	Reporting period
$v_{fuel,\ i,p,n}$	=	Volume of fuel for fuel type, i, combusted (m^3 or kl). For fuel gas, the volume must be at standard conditions (15ºC, 1 atm) at site, n, within the COG during the reporting period, *p*.
N	=	Total number of sites within the COG that uses fuel type i.

Method 15-1 – Single fuel gas stream approach

Introduction

For this method, fuel gas volumes reported in Petrinex for a COG may be assumed to have the same gas composition and higher heating value (i.e., single fuel gas stream). For these volumes of fuel gas, a default carbon dioxide emission factor would be applied to calculate the carbon dioxide emissions (refer to Method 15-4).

Equation

Using Equation 15-1, the fuels reported in Petrinex consumed by a COG are summed for the reporting period assuming that there is one fuel gas stream (i = 1) in the COG.

Method 15-2 – Multiple fuel gas stream approach

Introduction

For this method, a COG is required to quantify the fuel gas consumed for each fuel gas stream that is consumed at the COG. Fuel gas streams are characterized by different gas compositions and higher heating values (HHV). This method may be used with Method 15-6 or Method 15-7 to calculate the CO_2 emissions for the COG.

Equation

Using Equation 15-1, the total quantity of fuel gas consumed is calculated for each fuel gas stream (i >1) consumed at a COG for the reporting period.

Data requirements

- The separation of fuel gas streams must be demonstrated by metering and gas compositional analysis that is representative of the different fuel gas streams consumed by the COG in the reporting period.

- Quarterly sampling and analysis for fuel gas composition and/or HHVs is required to characterize the different fuel gas streams at a COG.

- The average gas composition and/or HHV must be calculated for each fuel gas stream using a weighted-average approach as described in Chapter 17.

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- Chapter 17 provides further guidance on acceptable analytical methods that may be used for gas composition or heating value analysis.

Method 15-3 – Non-Petrinex Fuel

Introduction

This method is required for quantifying fuel volumes that are not reported in Petrinex. Fuels that are typically not reported in Petrinex include non-variable fuels such as propane, diesel, and gasoline and these fuels are normally invoiced by third-party. As well, there may be fuel gases not reported in Petrinex that are measured by the facility internally or by a third-party supplier.

For volumes of non-variable fuels, default carbon dioxide emission factors are applied to calculate the carbon dioxide emissions (refer to Method 15-5). For volumes of fuel gases, the reporter may use Method 15-4, Method 15-6, or Method 15-7 to calculate the carbon dioxide emissions.

Equation

Using internally measured or third-party fuel volumes and Equation 15-1, the total fuel consumption is calculated for each type of non-variable fuel or fuel gas consumed at the COG for the reporting period.

Data requirements

- Evidence of third-party custody metering may be in the form of invoices or other third-party documentation.
- Fuel consumption may be provided on an energy or volume basis. If the consumption is in energy units, it must be based on the higher heating value of the fuel.
- Internal facility metering should follow the requirements prescribed in Chapter 17 of the AQM.

15.2.2. Stationary Fuel CO_2 Combustion Emissions

Method 15-4 – CO_2 emissions based on default fuel gas emission factor (EF)

CO_2 emissions quantification methods are provided for use if the required gas analysis is available in a COG. In a COG, the same methodologies must be applied.

The quantification methodologies in this chapter are adapted from Chapter 1 Stationary Fuel Combustion with some adjustments. It is assumed that solid fuels are not combusted at aggregate facilities therefore quantification methodologies for solid fuels are not prescribed in this chapter. If there are solid fuels combusted at an aggregate facility, quantification methodologies prescribed in Chapter 1 must be used.

Introduction

For this method, the CO_2 emissions are calculated assuming a single fuel gas stream and a default emission factor in tonnes of CO_2 emissions per cubic metre of fuel consumed (tCO_2/m^3). The default emission factors are presented in Table 15-2. This method is used with fuel gas volumes calculated by Method 15-1.

If this method is selected by using the default rich gas emission factor for a COG in the benchmark, it must be used for the compliance reports to keep the methodology consistent in the benchmark and compliance reports.

If the person responsible for an aggregate facility would like to apply different methodologies for a COG, they must revise their benchmark and/or compliance report to ensure that the same methodologies are applied for both the benchmark and compliance report, or a more conservative method is used for the benchmark than the compliance report.

The person responsible for a COG or group of COGs is required to apply a default sales gas emission factor for the benchmark period if the person would like to:

(1) apply gas compositions or HHV to calculate CO_2 emissions and do not have the required gas compositions or HHV for the benchmark period; or

(2) change methodologies from using the default CO_2 emission factor to gas composition or HHV to calculate CO_2 emissions for compliance reporting and do not have the required gas compositions or HHV for the benchmark period,

The default sales gas composition and emission factor is provided in Table 15-2 can only be applied for the above two scenarios.

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Equation

Using Equation 15-4, the carbon dioxide emissions for a COG are calculated using the fuel gas volumes calculated by Method 15-1 and the default emission factor presented in Table 15-2.

$$CO_{2,p} = v_{fuel,p} \times EF_{vol} \qquad \text{Equation 15-4}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions for total fuel combustion for the reporting period, *p* (tonnes CO_2) in a COG.

$v_{fuel,p,i}$ = Total volume of fuel consumed in cubic metres (m^3) for the reporting period, *p* at standard conditions (15ºC, 1 atm) calculated using Method 15-1.

EF_{vol} = Default CO_2 emission factor from Table 15-2 in tonnes of CO_2 per cubic metres (tCO_2/m^3).

Table 15-2: Default Fuel Gas and Carbon Dioxide (CO_2) Emission Factors

Parameter	Default Values
For Benchmarking and Compliance Reporting[1]:	
Default Carbon Dioxide Emission Factor (volume basis (tCO_2/m^3)	0.00233
Default Rich Gas Composition (vol%)	
Methane (CH_4)	80
Ethane (C_2H_6)	15
Propane (C_3H_8)	5
Default Higher Heating Value (GJ/m^3)	0.04477
For Benchmarking only[2]:	
Default Carbon Dioxide Emission Factor (volume basis) (tCO_2/m^3)	0.00190
Default Sales Gas Composition (vol%)	
Methane (CH_4)	98
Ethane (C_2H_6)	1
Propane (C_3H_8)	0.3
Butane (C_4H_{10})	0.1
Carbon Dioxide (CO_2)	0.3
Nitrogen (N_2)	0.3
Default Higher Heating Value (GJ/m^3)	0.03825

1. **The prescribed CO_2 emission factor must be used for the benchmark and compliance report.**
2. **If a COG would like to use gas compositions or HHV to calculate CO_2 for compliance reporting but does not have gas compositions or HHV data for the benchmark period, the COG must apply this default emission factor for benchmarking.**

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Method 15-5 – CO_2 emissions for non-variable fuels not reported in Petrinex

Introduction

This method is used to calculate carbon dioxide emissions from non-variable fuels that are not reported in Petrinex for an aggregate. These fuels include propane, diesel, and gasoline that are purchased for onsite operations. The compositions of these fuels are assumed to be fairly constant and therefore are provided default carbon dioxide emission factors. This method is used with fuel quantities calculated using Method 15-3.

Note that on-site transportation emissions should not be included with the stationary fuel combustion emissions.

Fuel consumption may be provided by the third-party supplier on a volume or energy basis. Emission factors based on tonnes of CO_2 emissions per volume basis or energy basis are provided in Table 15-3.

Equation

Using Equation 15-5 or 15-5a, the CO_2 emissions are calculated using the fuel volumes calculated by Method 15-3 and the default emission factor for the non-variable fuel presented in Table 15-3 for an aggregate.

$$\boldsymbol{CO_{2,p,i} = v_{fuel,p,i} \times HHV_i \times EF_{ene,i}} \qquad \text{Equation 15-5}$$

$$\boldsymbol{CO_{2,p,i} = (v_{fuel,p,i} \times EF_{vol,i})\ or\ (ENE_{fuel,p,i} \times EF_{ene,i})} \qquad \text{Equation 15-5a}$$

Where:

$CO_{2,\,p,\,i}$	=	CO_2 mass emissions for the non-variable fuel type *i* for the reporting period, *p* (tonnes CO_2) for an aggregate.
$v_{fuel,\,p,i}$	=	For Equations 15-5 and 15-5a, the volume of fuel for fuel type *i* combusted in kilolitres (kl) combusted during reporting period, *p*, for an aggregate
$ENE_{fuel,p,i}$	=	For Equation 15-5a, energy of fuel for fuel type *i* in gigajoules (GJ) combusted during reporting period, *p*, for an aggregate
$HHV_{p,i}$	=	Measured or supplied higher heating value in gigajoules per kilolitres (GJ/kl) for fuel type *i* for the reporting period, *p*, for an aggregate
$EF_{vol,i}$ $EF_{ene,i}$	=	Fuel-specific default CO_2 emission factor for fuel type *i* from Table 15-3 in tonnes of CO_2 per volume units (kl) or energy units (GJ).

Table 15-3: Carbon Dioxide (CO_2) Emission Factors for Non-Variable Fuels

Non-Variable Fuels	CO_2 Emission Factor[2]	
	tonne/kl	tonne/GJ
Diesel	2.681	0.0699
Diesel in Alberta[1]	2.610	0.06953
Gasoline	2.307	0.069
Gasoline in Alberta[1]	2.174	0.06540
Butane	1.747	0.0614
Ethane	0.986	0.0573
Propane	1.515	0.0599

1. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content.
2. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements

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Method 15-6 – CO_2 emissions based on higher heating value correlation

Introduction

This method is consistent with ECCC's Canada's Greenhouse Gas Quantification Requirements for calculating CO_2 mass emissions from fuel gas combustion based on the measured HHV. The volumes of fuel gas consumed by a COG is calculated based on Method 15-2 or Method 15-3.

Equation

Using Equation 15-6, the CO_2 emissions for a COG are calculated based on the HHV of the fuel gas provided by the fuel supplier or measured by the facility.

$$\boldsymbol{CO_{2,p,i} = v_{fuel,i,p} \times (65.53 \times HHV_{p,i} - 581.9) \times 10^{-6}} \qquad \text{Equation 15-6}$$

Where:

$CO_{2,\,p,i}$	=	CO_2 mass emissions for the fuel type *i* combusted during the reporting period, *p* (tonnes CO_2), for a COG
$v_{fuel,i\ p}$	=	Volume of fuel (m^3) for fuel type *i* at standard conditions (15ºC, 1 atm) combusted during reporting period, *p*, for a COG
$HHV_{p,i}$	=	Weighted average higher heating value of fuel type *i* (MJ/m^3) at standard conditions (15ºC, 1 atm) for the reporting period, *p*, for a COG
($65.53 \times HHV_{p,i}$ - 581.9)	=	Empirical equation adapted from ECCC (grams of CO_2 per cubic meter of natural gas) representing relationship between CO_2 and volume of gas determined through higher heating value using a discrete set of data collected by ECCC.
10^{-6}	=	Mass conversion factor (t/g).

Data requirements

- Quarterly sampling and analysis for the fuel gas HHVs is required for each fuel gas stream identified in the COG. Sampling frequencies prescribed in Table 17.1 of Chapter 17 does not apply for this method.
- The HHV must be calculated for each fuel gas stream using a weighted-average approach. Chapter 17 provides guidance for calculating weighted averages and acceptable analytical methods than can be used for heating value analysis.

Method 15-7 – CO_2 emissions based on fuel gas carbon content

Introduction

This method is used for variable fuels and is based on the complete oxidation of the measured carbon content in the fuel gas. The volumes of fuel gas consumed by a COG is calculated using Method 15-2 or Method 15-3.

Equation

Using Equation 15-7a or Equation 15-7b, the CO_2 emissions are calculated based on the carbon content of each fuel gas type consumed during the reporting period.

For gaseous fuels, where fuel consumption is measured on a volume (m^3) basis, use Equation 15-7a:

$$\boldsymbol{CO_{2,p,i} = v_{fuel\,(gas),i,p} \times CC_{gas,p,i} \times 3.664 \times 0.001} \qquad \text{Equation 15-7a}$$

For gaseous fuels, where fuel consumption is measured on an energy (GJ) basis, use Equation 15-7b:

$$\boldsymbol{CO_{2,p,i} = \frac{ENE_{fuel\,(gas),i,p} \times CC_{gas,p,i} \times 3.664 \times 0.001}{HHV_{p,i}}} \qquad \text{Equation 15-7b}$$

Where:

$CO_{2,p,i}$	=	CO_2 mass emissions for fuel type *i* combusted during the reporting period, *p* (tonnes CO_2), for a COG.

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$v_{fuel(gas),i,p}$ = Volume of fuel (m^3) for fuel type *i* at standard conditions (15ºC, 1 atm) combusted during reporting period, *p*, for a COG

$ENE_{fuel(gas),p}$ = Energy of fuel (GJ) for fuel type, *i* at standard conditions (15ºC, 1 atm) combusted during reporting period, *p*, for a COG.

$HHV_{p,i}$ = Weighted average higher heating value of fuel type *i* (GJ/m^3) at standard conditions (15ºC, 1 atm) for the reporting period, *p*, for a COG

$CC_{gas,p}$ = Weighted average carbon content of fuel type *i* at standard conditions (15ºC, 1 atm) during the reporting period *p*. CC_p is in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m^3), for a COG.

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Mass conversion factor (t/kg).

Data requirements

- The carbon content may be provided by the third-party supplier or measured by the facility.
- Quarterly sampling and analysis for gas composition is required for each fuel gas stream identified in the COG. The gas composition must be calculated for each fuel gas stream using a weighted-average approach. Chapter 17 provides guidance on calculating weighted averages and acceptable analytical methods that can be used for gas compositional analysis. Note that sampling frequencies in Table 17.1 of Chapter 17 do not apply for this method.

15.2.3. Stationary Fuel Combustion CH_4 and N_2O Emissions

For all COGs, the following methods are used to calculate the CH_4 and N_2O mass emissions based on default emission factors that are volume or energy basis.

There are three types of default CH_4 and N_2O emission factors specified under three methods. Method 15-8 provides emission factors for non-variable fuels; while Methods 15-9 and 15-10 provides emission factors for variable fuels that are sector-based and technology-based, respectively.

Method 15-8 – Non-variable Fuel Emission Factors

For all non-variable fuels such as propane, diesel, and gasoline, methane and nitrous oxide emission factors are prescribed in Table 15-4.

Table 15-4: Default Emission Factors for Non-variable Fuel Types

Non-Variable Fuel	CO_2 Emission Factor[1]		CH_4 Emission Factor[1]		N_2O Emission Factor[1]	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel for All industry	2.681	0.0699	7.8E-05	2.0E-06	2E-05	5.8E-07
Diesel in Alberta[2]	2.610	0.06953	See note 3			
Biodiesel for all industry	See note 4		7.8E-05	2.2E-06	2E-05	6.3E-07
Gasoline	2.307	0.069	1E-04	3.0E-06	2E-05	6E-07
Gasoline in Alberta[2]	2.174	0.06540	See note 5			
Ethanol	See note 4		1E-04	4.3E-06	2E-05	8.5E-07
Butane	1.747	0.0614	2.4E-05	8.4E-07	1.08E-04	3.8E-06
Ethane	0.986	0.0573	2.4E-05	1.4E-06	1.08E-04	6.3E-06

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Non-Variable Fuel	CO_2 Emission Factor[1]		CH_4 Emission Factor[1]		N_2O Emission Factor[1]	
	tonne/kl	**tonne/GJ**	**tonne/kl**	**tonne/GJ**	**tonne/kl**	**tonne/GJ**
Propane	1.515	0.0599	2.4E-05	9.5E-07	1.08E-04	4.3E-06

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.
2. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content. If the actual biofuel composition is known, a facility may use the gasoline or diesel CO2 emission factor for the non-biofuel component and the CO2 emission factor prescribed in Chapter 14 for the biofuel component.
3. Diesel CH4 and N2O emission factors are used.
4. CO2 emission factors are provided in Table 14-1 in Chapter 14. CO2 emissions from biodiesel and ethanol should be reported under the biomass emissions.
5. Gasoline CH4 and N2O emission factors are used.

15.2.4. Variable Fuel Emission Factors

Two types of emission factors are presented for variable fuels. Sector-based emission factors and technology-based emission factors are described in Method 15-9 and 15-10 respectively.

Method 15-9 – Variable fuel sector-based emission factors

For variable fuels, the person responsible may select sector-based emission factors that are presented in Table 15-5, if the selection criteria below have been met.

Method 15-10 – Variable fuel technology-based emission factors

For variable fuels, the person responsible may select technology-based emission factors provided in Table 15-6 for various equipment present at a COG, if the selection criteria below have been met.

Selection Criteria for Method 15-9 or 15-10

For variable fuels, the person responsible may select sector-based (Method 15-9) or technology-based (Method 15-10) methane and nitrous oxide emission factors. The following are the selection criteria:

- The person responsible must apply either the sector-based emission factors (Table 15-5) at a COG or technology-based emission factors (Table 15-6) for equipment at a COG.
- The person responsible must apply the same methodologies selected for each COG in the benchmark and compliance report.
- If technology-based emission factors are selected for any COG, technology-based emission factors may be different between the benchmark and compliance report to reflect technologies that are present at the sites during the benchmark or compliance periods. For example, the person responsible may use a NOx uncontrolled boiler emission factor for the benchmark, but apply a NOx controlled boiler emission factor in the compliance report to reflect technologies used during the compliance period. As well, different technology-based emission factors may be applied within a compliance or benchmark period if technologies were replaced within the compliance or benchmark period.
- If a facility has the HHV for the fuel, the energy-based emission factor (tonnes of emissions per gigajoules) must be used to calculate the methane and nitrous oxide emissions. Otherwise, the facility may use the volume-based emission factors (tonnes of emissions per cubic metre) if heating value data is not available.

Equation

Using Equation 15-8 or Equation 15-8a, the CH_4 or N_2O emissions are calculated based on volumes calculated by Method 15-1, Method 15-2, or Method 15-3.

$$CH_{4,p} or\ N_2O_p = Fuel_p \times HHV \times EF_{ene}$$ Equation 15-8

$$CH_{4,p} or\ N_2O_p = Fuel_p \times (EF_{vol}\ or\ EF_{ene})$$ Equation 15-8a

Where:

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$CH_{4,\mathbf{p}}$ or $N_2O_{\mathbf{p}}$	=	CH_4 or N_2O mass emissions for the specific fuel type for the reporting period, *p,* (tonnes CH_4 or N_2O).
$Fuel_p$	=	For Equation 15-8, the quantity of fuel combusted in kilolitres or cubic metres (kl or m^3) at standard conditions (15ºC, 1 atm) combusted during reporting period, *p*. For Equation 15-8a, energy of fuel in gigajoules or quantity of fuel in kilolitres, or cubic metres (GJ, kl, or m^3) combusted during reporting period, *p*.
HHV_p	=	Measured or supplied higher heating value in gigajoules per kilolitres or cubic metres (GJ/kl or GJ/m^3) at standard conditions (15ºC, 1 atm) for the reporting period, *p*.
EF_{vol}, EF_{ene}	=	Fuel-specific default emission factor, from Table 15-4, Table 15-5, or Table 15-6 in tonnes of CH_4 or N_2O per energy units (GJ) or volume units (kl or m^3).

Table 15-5: Sector-based CH_4 and N_2O Emission Factors for Fuel Gas

Sectors	**CH_4 Emission Factor[2]**		**N_2O Emission Factor[2]**	
	tonne/m^3	**tonne/GJ**	**tonne/m^3**	**tonne/GJ**
Oil and Gas Sector and Producer Consumption[1]	6.4E-06	1.4E-04	6.0E-08	1.3E-06

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.

Table 15-6: Technology-based CH_4 and N_2O Emission Factors for Fuel Gas

Natural Gas	**CH_4 Emission Factor[1]**		**N_2O Emission Factor[2]**	
	tonne/m^3	**tonne/GJ[3]**	**tonne/m^3**	**tonne/GJ[3]**
Boilers/Furnaces/Heaters				
NOx Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07
NOx Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07
Internal Combustion Engine				
Turbine	1.4E-07	3.7E-06	5E-08	1E-06
2 stroke lean	2.37E-05	6.23E-04	-	-
NOx 90-105% Load	-	-	7.77E-07	2.04E-05
NOx < 90% Load	-	-	4.75E-07	1.25E-05
4 stroke lean	2.04E-05	5.37E-04	-	-
NOx 90-105% Load	-	-	1.00E-06	2.63E-05
NOx < 90% Load	-	-	2.07E-07	5.46E-06
4 stroke rich	3.76E-06	9.89E-05	-	-
NOx 90-105% Load	-	-	5.41E-07	1.43E-05
NOx < 90% Load	-	-	5.56E-07	1.46E-05

1. For emission factors adapted from USEPA AP-42, the default emission factor is based on a natural gas heating value of 1,020 British thermal units per standard cubic feet (Btu/scf) for the volume-based emission factor.
2. Emission factors are adapted from USEPA AP-42 Chapters 1 and 3.
3. The energy-based emission factor should be used if the fuel consumption on an energy basis is available. The volume-based emission factor should only be used if the higher heating value or energy of the fuel is not available.
4. The N_2O emission factor is based on 1.5% of the NOx emission factor, as provided in AP-42.

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15.3. Flaring Emissions

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced at the facility, used for routine, non-routine or emergency disposal of a hazardous waste stream, where the main purpose is not energy production. There are a variety of flare and incineration technologies including flare pits, ground flares, flare stacks, enclosed flares and incinerators and combustors. Methodologies for flaring/incineration of liquid fuel streams are not presented in this chapter.

Typical gases that are flared or incinerated include, but are not limited to waste petroleum gas, refinery or still gas, purge gas, pilot or assistance gas, and biogas. Flaring or incineration commonly occurs at the following types of operations:

- well testing;
- natural gas gathering system;
- processing plant operations;
- crude oil production;
- pipeline operations.

Note that carbon dioxide (CO_2) that is entrained in the fuel (or previously referred to as formation CO_2) is reported as an emission in the respective categories that the fuel is consumed in. For example, if there is entrained CO_2 within a fuel that is combusted or flared, it would be included in the CO_2 that is emitted in the stationary fuel combustion or flaring categories, respectively.

The flare combustion efficiency is defined as the mole or volume fraction of combustible carbon in the flare gas that is converted to CO_2 during the flaring process, which can be expressed as a percentage of carbon combusted or oxidized.

For the quantification of flaring emissions, the following flare combustion efficiencies were adopted from flare efficiency and thermal oxidizer studies conducted and published by the USEPA:

- 98.0% flare combustion efficiency for unassisted flares. These flares are typically found in remote oil and gas production operations;
- 99.5% flare combustion efficiency for properly operated, highly-turbulent, air- or steam-assisted flares. These flares are typically found in gas plants, upgraders, petroleum refineries, and chemical plants; and
- 100.0% flare combustion efficiency for incinerators, oxidizers, or other “external combustion” units that operate like boilers. As a conservative approach, methane emissions based on emission factors are still applied.

Sampling and measurement frequency requirements for different methods are presented in this chapter.

15.3.1. Method 15-11 – Flaring CO_2 and CH_4 Emissions for Single Flare Gas Stream based on Default Emission Factors

Introduction

Carbon dioxide emissions from flares are generated from the oxidization of carbon in the flare gas and from any carbon dioxide entrained in the flare gas. Methane in the flare gas that is un-oxidized is released as methane emissions.

The Default Emission Factor Method is based on default CO_2 and CH_4 emission factors which were developed for different fuel gas types (lean to rich condensate), non-variable fuels (ethane, propane and butane).

This method provides default emission factors for facilities that do not have gas analysis but have knowledge of the flare gas properties whether it is rich or lean gas being sent to flare stack. CO_2 emission factors are provided in Table 15-7 based on the representative rich gas and sale gas compositions in Alberta.

Methane emission factors are provided in Table 15-8 representing the un-combusted CH_4 in the flare gas based on the flare combustion efficiency. For incineration, methane emissions are conservatively added even though the flare combustion efficiency was assumed to be 100%.

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Equations

For each flare source, use Equation 15-9a or Equation 15-9b to calculate the CO_2 and CH_4 mass emissions.

$$GHG = \sum_{F=1}^{N} V_{FL,F} \times EF_{vol,F} \times 10^{-6}$$

Equation 15-9a

$$GHG = \sum_{F=1}^{N} ENE_{FL,F} \times EF_{ENE,F} \times 10^{-6}$$

Equation 15-9b

Where:

GHG	=	CO_2 or CH_4 mass emissions from flaring (tonnes) for the reporting period.
F	=	Flare gas stream.
N	=	Total number of flare gas streams.
$V_{FL,F}$	=	Volume of the flare gas stream, F, at a flare source (standard cubic meters, sm^3) at standard conditions for the reporting period.
$ENE_{FL,F}$	=	Energy of the flare gas stream, F, at a flare source (MJ) for the reporting period.
$EF_{vol,F}$	=	Default CO_2 or CH_4 emission factor, selected from Table 15-7 or Table 15-8 (g/m^3).
$EF_{ENE,F}$	=	Default CO_2 or CH_4 emission factor, selected from Table 15-7 or Table 15-8 (g/MJ).
10^{-6}	=	Mass conversion factor (tonne/g).

Table 15-7: Default CO_2 Flaring Emission Factors for Different Flare Gas Types

Flare Gas Type	CO_2 Emission Factors						
	Higher Heating Value (MJ/m^3)	Open Flares				Incinerators	
		Unassisted		Assisted			
		98.0% Efficiency		99.5% Efficiency		100% Efficiency	
		(g/m^3)	(g/MJ)	(g/m^3)	(g/MJ)	(g/m^3)	(g/MJ)
Mixed Gas Types							
Sales gas	38.02	1,853	48.75	1,882	49.49	1,900	49.74
Rich gas	44.77	2,280	50.93	2,315	51.70	2,330	51.96
Non-Variable Gas Types							
100% Methane (C1)	37.708	1,824	48.37	1,852	49.11	1,861	49.36
100% Ethane (C2)	66.065	3,648	55.22	3,704	56.07	3,723	56.35
100% Propane (C3)	93.936	5,472	58.25	5,556	59.15	5,584	59.44
100% Butane (C4)	121.600	7,296	60.00	7,408	60.92	7,445	61.23

1. Flare combustion efficiencies have been applied in the emission factor.
2. Molecular weights and HHVs are from Gas Processors Association 2145-09.
3. Default gas compositions used in the development of the emission factors are:
   Sales gas - 98% CH_4, 1% C_2H_6, 0.3% C_3H_8, 0.1% C_4H_{10}, 0.3% CO_2, 0.3% N_2
   Rich gas - 80% CH_4, 15% C_2H_6, 5% C_3H_8

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Table 15-8: Default CH_4 Flaring Emission Factors for Different Flare Gas Types

Flare Gas Type	Higher Heating Value (MJ/m^3)	Methane Emission Factors					
		Open Flares				Incinerators	
		Unassisted		Assisted			
		(98.0% Efficiency)		(99.5% Efficiency)		(100% Efficiency)	
		(g/m^3)	(g/MJ)	(g/m^3)	(g/MJ)	(g/m^3)	(g/MJ)
Mixed Gas Types							
Sales gas	38.02	13.27	0.35	3.32	0.09	0.037	0.0010
Rich gas	44.77	10.83	0.24	2.71	0.06	0.044	0.0010
Non-Variable Gas Types							
100% Methane	37.708	13.54	0.36	3.39	0.09	0.037	0.001
100% Ethane (C2)	66.065	0.00	0.00	0.00	0.00	0.00	0.00
100% Propane (C3)	93.936	0.00	0.00	0.00	0.00	0.00	0.00
100% Butane (C4)	121.600	0.00	0.00	0.00	0.00	0.00	0.00

1. Flare combustion efficiencies have been applied in the emission factor.
2. Methane emission factors for flaring of fuel gases and non-variable gases using incinerator technology are based on Canada's Greenhouse Gas Quantification Requirements, ECCC GHGRP, December 2019 and are adjusted by HHV of the different fuel types. Molecular weights and HHVs for each single compound are from Gas Processors Association 2145-09.
3. Default gas compositions used in the development of the emission factors are:
- Sales gas - 98% CH_4, 1% C_2H_6, 0.3% C_3H_8, 0.1% C_4H_{10}, 0.3% CO_2, 0.3% N_2
- Rich gas - 80% CH_4, 15% C_2H_6, 5% C_3H_8

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Data requirements

- The flaring volume can be based on the flaring volume reported to Petrinex by the facility. The volumetric emission factors can then be applied based on the type of flare gas.
- The total flare gas volumes of different flaring efficiencies should align with the reported flaring volumes in Petrinex.
- If a facility finds errors in the reported Petrinex flare volumes or missed flare volumes reported to Petrinex, the facility should correct the Petrinex data before applying the corrected flare volumes for an aggregate benchmark and compliance reports.
- The methods used for benchmark and compliance reports should be consistent for a conventional oil and gas (COG) of the aggregate facility.
- If a COG of the aggregate facility uses gas analysis for compliance reports and the gas analysis is not available in the benchmark development, the facility must use the sale gas emission factor for the benchmark.
- Based on the facility's knowledge of the flare gas composition and flare technology, select the flare gas type that would best align with the flare gas consumed and the appropriate emission factors from Tables 15-7 and 15-8.

15.3.2. **Method 15-12 – Flaring CO_2 and CH_4 Emissions for Multiple Flared Gas Streams**

Introduction

This method uses estimated or measured gas volumes and compositions for all or part of flare gas streams to calculate CO_2 and CH_4 emissions. The method is applicable for multiple flare gas streams that are flared under routine or non-routine conditions.

Flare gas streams may have measured volumes and compositions of gases that are routinely flared such as assistant gas, pilot gas, or purge gas streams and unmeasured streams from venting sources or emergent blowdowns. These measured flare gas streams may be equipped with online analyzers or measured regularly. Unmeasured volumes or compositions of flare gas may be calculated based on engineering estimates, manufacturer specifications or fuel mass balance method.

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Equations

For each flare source, use Equation 15-10a and 15-10b to calculate the total CO_2 mass emissions from the flaring of multiple flare gas streams that are combined.

$$\boldsymbol{CO_{2,flaring} = \sum_{F=1}^{N} \frac{V_{FL,F}}{MVC} \times \left(CC_F \times \; CE_{FL} + MF_{CO_2}\right) \times MW_{CO_2} \times 0.001} \qquad \text{Equation 15-10a}$$

$$\boldsymbol{CC_F = \sum_{i=1}^{I} MF_{i,F} \times NC_{i,F}} \qquad \text{Equation 15-10b}$$

Where:

$CO_{2,\ flaring}$	=	Total CO_2 mass emissions from a flare source including entrained CO_2 for the reporting period (tonnes).
N	=	Total number of flare gas streams.
F	=	Flare gas stream.
$V_{FL,F}$	=	Measured or estimated vvolume of the flare gas stream, *F*, (sm^3) at standard conditions for the reporting period.
MVC	=	Standard molar volume conversion at standard molar volume as defined in Appendix B, Table B-2 (23.645 m^3/kmol).
CC_F	=	Average carbon content for flare gas stream, F, ($kmol_{carbon}/kmol_{flare\ gas,\ F}$) for the reporting period. This excludes carbon from entrained CO_2 in the flare gas.
MF_{CO2}	=	CO_2 mole fraction in flare gas stream, F.
MW_{CO2}	=	Molecular weight of CO_2 (kg/kmol), as provided in Appendix B.
0.001	=	Mass conversion factor (tonne/kg).
I	=	Total number of components in the flare gas stream, F.
i	=	Type of component.
CE_{FL}	=	Flare combustion efficiency (%).
$MF_{i,F}$	=	Normalized mole fraction of component, i, based on the estimated or measured weighted average flare gas composition in the flare gas stream, F, ($kmol_i/kmol_{flare\ gas}$) for the reporting period.
$NC_{i,F}$	=	Number of carbons in component, i, in the flare gas stream, F.

For methane emissions, use Equation 15-11 to calculate un-combusted methane from the flare gas:

$$\boldsymbol{CH_{4,flaring} = \sum_{F=1}^{n} [V_{FL,F} \times MF_{CH4,F}] \times (1 - CE_{FL}) \times \frac{CH_4}{MVC} \times 0.001} \qquad \text{Equation 15-11}$$

Where:

$CH_{4,\ flaring}$	=	Total CH_4 mass emissions from a flare source for the reporting period (tonnes);
$V_{FL,F}$	=	Measured or estimated volume of flare gas stream, F*,* (sm^3) at standard conditions for the reporting period.

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$MF_{CH4,F}$	=	Normalized mole fraction of CH_4 in estimated or measured average flare gas composition for flare gas stream, F ($kmol_{CH4}/kmol_{GAS}$) for the reporting period.
n	=	Number of flare gas streams.
F	=	Flare gas stream.
CE_{FL}	=	Flare combustion efficiency (%).
CH_4	=	Molecular weight of CH_4 (kg/kmol), as provided in Appendix B.
MVC	=	Standard molar volume conversion at standard conditions as provided in Appendix B, Table B-2 (23.645 m^3/kmol).
0.001	=	Mass conversion factor (tonne/kg).

Data Requirements

The following data requirements are applicable:

- The total flare volumes for all multiple flare streams should be equal to the reported flare volumes in Petrinex.
- For a flare gas stream that is measured, if there is an online continuous flow measurement device or a continuous gas composition analyzer, the measured flow volumes and gas composition must be used to calculate emissions for the flare gas stream.
    - The volume and gas composition measurements must be taken daily if there is online instrumentation (i.e., flow meter and gas analyzer) or monthly if no online instrumentation is available.
    - A weighted gas composition must be used in calculating emissions and is based on the minimum sampling frequency that the samples are conducted. If the sampling frequency is higher than the prescribed frequency, the facility must apply the higher frequency in the weighted average.
- Volumes and compositions of flare gas streams must be measured using:
    - One of the analytical methods required by AER Directives and other applicable regulatory requirement; or
    - The most appropriate method published by a consensus-based standards organization.
- For pilot or assistance gas used for flaring,
    - Where the fuel type is known (i.e., propane, butane, rich gas, sales gas, etc.), the facility may use the default gas composition of the fuel type listed in Table 15-7 and Table 15-8.
    - The volume or gas composition of the flare pilot or assistance gas may be calculated using a mass balance approach as described in Method 1-4 in Section 1.2.5 in Chapter 1.
    - If they are measured, may apply measured gas compositions consistent with the sampling or measurement frequencies outlined in Table 17-1 of the AQM.
- The volume and gas composition of the remaining unmeasured flare gas streams may be estimated using engineering estimates, a mass balance, or manufacturer specifications.
- For a waste gas flare stream where the volume is not measured, but the flare gas stream is from a controlled venting emission source, the venting volume may be quantified using quantification methodologies provided in Chapter 4 Venting. Refer to the data requirements in Section 2.3.2 (Method 2-1).
- If flare gas volumes and/or gas composition measurements are missing in a reporting period, the missing data procedures outlined in Section 17.5.2 of Chapter 17 should be followed.
- The facility must select a default flare combustion efficiency that best represents the flare technology that is applied at the facility. The selection must be supported by manufacturer specification or test data. The default flare combustion efficiencies are described in the section 15.3.

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- If the sum of the mole fractions of components do not add up to 1.000 because smaller components are excluded from the analysis or are not measurable, facilities must normalize the mole fractions of the measured components in order for the sum of the mole fractions to equal 1.000.

15.3.3. Method 15-13 – Flaring N_2O Emissions

Introduction

Default N_2O emission factors are assumed to be independent of the flare combustion efficiencies and dependant on flare gas type.

Equations

For each flare source, calculate the N_2O mass emissions using Equation 15-12a or Equation 15-12b.

$$\boldsymbol{N_2O = \sum_{F=1}^{N} V_{FL,F} \times EF_{vol,F} \times 10^{-6}}$$ **Equation 15-12a**

$$\boldsymbol{N_2O = \sum_{F=1}^{N} ENE_{FL,F} \times EF_{ENE,F} \times 10^{-6}}$$ **Equation 15-12b**

Where:

N_2O	=	N_2O mass emissions from a flare source for the reporting period (tonnes of N_2O).
F	=	Flare gas stream.
N	=	Total number of flare gas streams.
$V_{FL,F}$	=	Volume of the flare gas stream, F, at a flare source (sm^3) at standard conditions for the reporting period. Volumes for non-variable fuel types such as ethane, propane and butane are measured in gas phase.
$ENE_{FL,F}$	=	Energy of the flare gas stream, F, at a flare source (MJ) for the reporting period.
$EF_{vol,F}$	=	Default N_2O emission factor, selected from Table 15-9 (g/m^3).
$EF_{ENE,F}$	=	Default N_2O emission factor, selected from Table 15-9 (g/MJ).

Table 15-9: Default N_2O Emission Factors for Different Flare Gas Types

Flare Gas Type	N_2O	
	(g/m^3)	**(g/MJ)**
Hydrocarbon gas (sales gas and rich gas)[1]	0.033	0.00087
100% Ethane (C_2)[3]	0.00050	0.0063
100% Propane (C_3)[3]	0.00035	0.0043
100% Butane (C_4)[3]	0.00027	0.0038

Note:

1. Natural gas combustion emission factor for the industrial sector adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (December 2019).
2. Emission factors are adapted from the Western Climate Initiative (WCI) Final Essential Requirements of Mandatory Reporting 2011 Amendment.
3. Natural gas combustion emission factor for the industrial sector adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (December 2019) and adjusted by the HHV of the fuel for an energy-based emission factor.
4. Emission factors adapted from Canada's National Inventory Report (NIR) 2016.

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Data requirements

- The flare volume can be based on the flare volume reported to Petrinex by the facility. The volumetric emission factors from Table 15-9 can then be applied.
- If a facility finds errors in the reported Petrinex flare volumes or missed reporting flare volumes to Petrinex, the facility should correct the Petrinex data before applying the corrected flare volumes for an aggregate benchmark and/or compliance reports.
- For flaring using method 15-12 with gas measurements for CO_2 emissions calculations for certain gas streams, the same measured volumes as used for CO_2 calculation must be used for N_2O calculation.

15.4. Aggregate Facility Production Quantification

Product data quantification and reporting procedures for aggregate facility will be tied to production accounting volumes, referred to as Method 15-14.

15.4.1. Method 15-14 – Petrinex production volumes

The production type that an aggregate facility will report on is based on a benchmark unit assigned or approved by the department. Aggregate facilities production volumes for the product unit should be quantified using the reported volumes in Petrinex for each COG and reported as oil equivalent in cubic meters (OE m^3) in the compliance report under TIER. Refer to Chapter 9 of the Standard for Developing Benchmarks for benchmark units (section 9.1.2) and oil equivalent (OE) conversion factors (Table 6) for each product.

COG facilities in Alberta report volumetric data to Petrinex. Each volumetric submission must identify the activity, the product and the associated volume. Please refer to Appendix 1, 2, and 3 from Manual 011, published by the Alberta Energy Regulator for the activity and products required to be reported to Petrinex. These volumetric submissions will be the used for quantification and reporting under TIER. Figure 15-2 shows the volumetric submission for an example COG facility in Alberta.

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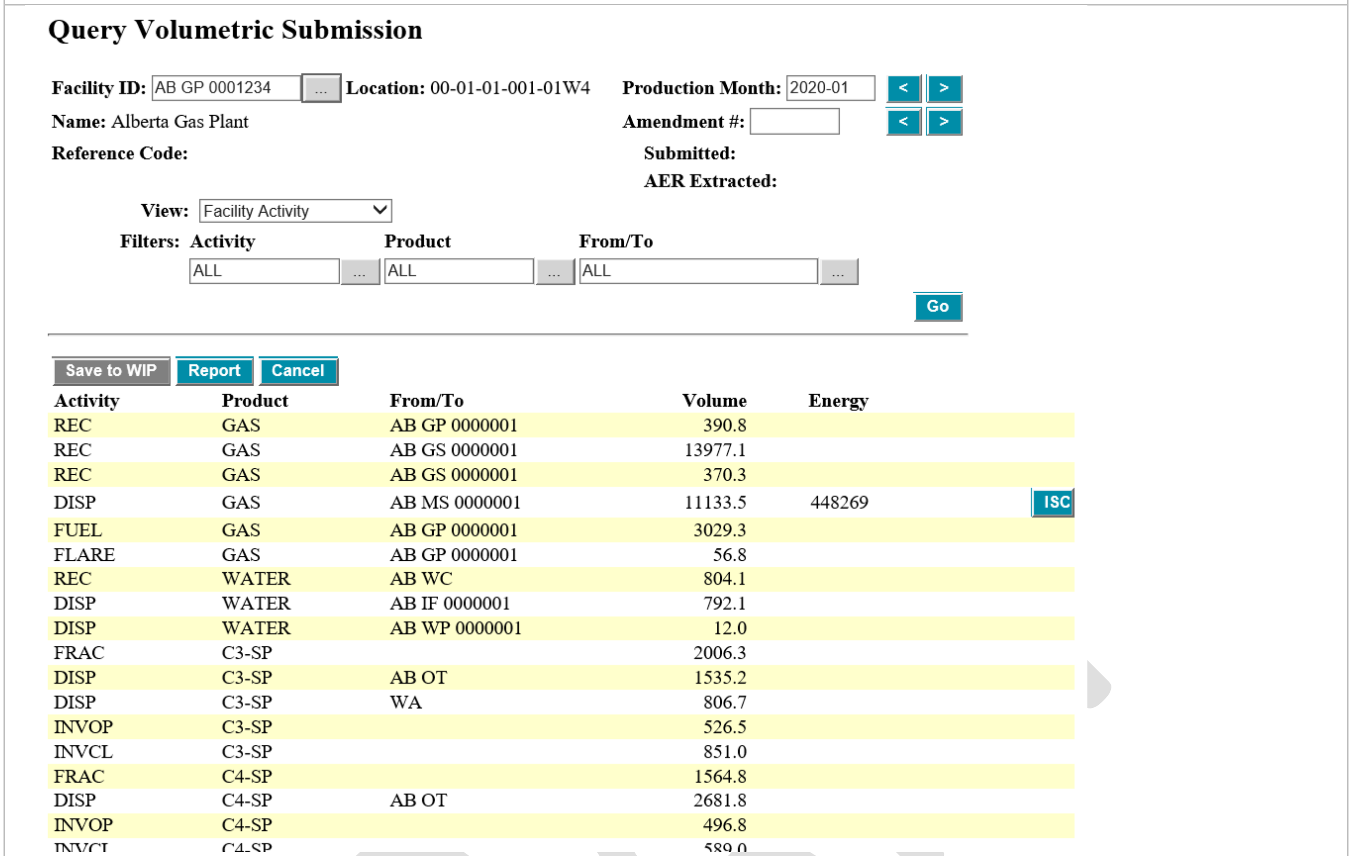
FIGURE 15-2: AN EXAMPLE OF THE FACILITY ACTIVITY PAGE FOR A TYPICAL COG FACILITY


Query Volumetric Submission

Facility ID: AB GP 0001234 **Location:** 00-01-01-001-01W4 **Production Month:** 2020-01

Name: Alberta Gas Plant **Amendment #:**

Reference Code: **Submitted:**

AER Extracted:

View: Facility Activity

Filters: Activity: ALL Product: ALL From/To: ALL

Go

Save to WIP Report Cancel

Activity	Product	From/To	Volume	Energy	
REC	GAS	AB GP 0000001	390.8		
REC	GAS	AB GS 0000001	13977.1		
REC	GAS	AB GS 0000001	370.3		
DISP	GAS	AB MS 0000001	11133.5	448269	ISC
FUEL	GAS	AB GP 0000001	3029.3		
FLARE	GAS	AB GP 0000001	56.8		
REC	WATER	AB WC	804.1		
DISP	WATER	AB IF 0000001	792.1		
DISP	WATER	AB WP 0000001	12.0		
FRAC	C3-SP		2006.3		
DISP	C3-SP	AB OT	1535.2		
DISP	C3-SP	WA	806.7		
INVOP	C3-SP		526.5		
INVCL	C3-SP		851.0		
FRAC	C4-SP		1564.8		
DISP	C4-SP	AB OT	2681.8		
INVOP	C4-SP		496.8		
INVCL	C4-SP		589.0		

Appendix B

TABLE B-1: TABLE OF PHYSICAL PROPERTIES FOR HYDROCARBONS AND OTHER COMPOUNDS[1]

Component	Chemical Formula	HHV [GJ/e3m3]	Carbon [atoms]	Molar Mass [t/t-mol]
Hydrogen	H_2	12.102	0	2.0159
Oxygen	O_2	0.000	0	31.9988
Helium	He	0.000	0	4.0026
Nitrogen	N_2	0.000	0	28.0134
Hydrogen Sulphide	H_2S	23.784	0	34.0809
Carbon dioxide	CO_2	0.000	1	44.0095
Carbon monoxide	CO	11.964	1	28.0100
Methane	CH_4	37.708	1	16.0425
Ethane	C_2H_6	66.065	2	30.0690
Propane	C_3H_8	93.936	3	44.0956
Isobutane	C_4H_{10}	121.406	4	58.1222
n-Butane	C_4H_{10}	121.794	4	58.1222

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Component	Chemical Formula	HHV [GJ/e3m3]	Carbon [atoms]	Molar Mass [t/t-mol]
Isopentane	C_5H_{12}	149.363	5	72.1488
n-Pentane	C_5H_{12}	149.656	5	72.1488
Hexane	C_6H_{14}	177.550	6	86.1754
Heptane	C_7H_{16}	205.424	7	100.2019
Octane	C_8H_{18}	233.284	8	114.2285
Nonane	C_9H_{20}	261.191	9	128.2551
Decane	$C_{10}H_{22}$	289.067	10	142.2817
Acetylene	C_2H_2	55.038	2	26.0373
Ethylene	C_2H_4	59.724	2	28.0532
Propylene	C_3H_6	86.099	3	42.0797
Hexene	C_6H_{12}	174.068	6	84.1595
Benzene	C_6H_6	139.689	6	78.1118
Toluene	C_7H_8	167.056	7	92.1384
Heptane	C7H16	205.424	7	95.00
o-Xylene	C8H10	194.484	8	106.1650
m-Xylene	C8H10	194.413	8	106.1650
p-Xylene	C8H10	194.444	8	106.1650

1. GPSA Engineering Handbook Section 23 - Physical Properties.

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TABLE B-2: TABLE OF PROPERTIES OF GASES

Component	Description	Value	Units
MVC	Standard Molar Volume for a gas at standard conditions (as defined in Appendix C)	23.645	m^3/kmol
MWC	Molecular Weight of Carbon	12.01	t/t-mol

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