


Superseded

Alberta  Government

**Quantification Methodologies for the Carbon
Competitiveness Incentive Regulation and the
Specified Gas Reporting Regulation**

Alberta Climate Change Office

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Summary of Revisions

Version	Date	Summary of Revisions
1.0	June 2018	First publication of chapters 1, 8, 12, 13, 14, and 17 and Appendix A, B, C, and D.
1.1	November 2018	<p>Revision 1 to chapters 1, 8, 12, 13, 14, and 17 and Appendix A, B, C, and D.</p> <ul style="list-style-type: none">• Updates and corrections to emission factors in Chapter 1 (Tables 1-1 to 1-4).• Added technology based emission factors for methane and nitrous oxide in Chapter 1 (Table 1-3).• Updates to the structure of methods and tier classification in Chapter 1 (Figures 1-1 and 1-2).• New methods introduced in Chapter 8 (Section 8.2.5) and Appendix C (Section C.6).• Updates to fuel properties in Appendix B.• Updates to production in Chapter 13 to include ethylene glycol and high value chemicals (HVC).• Updates to Section 17.3 in Chapter 17.• Other minor miscellaneous edits to various chapters.

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Introduction

The Carbon Competitiveness Incentive Regulation (CCIR) and the Specified Gas Reporting Regulation (SGRR) require the use of standard quantification methods for the reporting of greenhouse gas emissions under each respective regulation. The Alberta Climate Change Office *Quantification Methodologies for the CCIR and SGRR* provides the standard methods for activities that generate greenhouse gas emissions. Some methods prescribed in this document are only applicable to one of the regulations and the reporting of emissions and other parameters such as production and biomass emissions must follow the requirements under the respective regulation. Where quantification methods and emission factors are not prescribed or if deviations from prescribed methods are required, alternative methods may be proposed by the reporter and will be reviewed and approved by the Director on a case-by-case basis. Procedures to request for deviations and/or alternative methods are described in the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* for regulated facilities under CCIR.

For some activities, several methods are outlined to quantify greenhouse gas emissions, which may include mass balances, emission factors, engineering estimates, and/or direct emissions measurements. These methods have been identified as “tiers” of quantification methods. The *Specified Gas Reporting Standard* and the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* prescribes the “tier” method that is required for a facility that is reporting under SGRR and/or CCIR respectively.

The Alberta Climate Change Office *Quantification Methodologies for the CCIR and SGRR*, the *Specified Gas Reporting Standard*, and the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* will be updated from time to time. Regulated facilities are required to use the most up-to-date version of these documents in the reporting of greenhouse gas emissions under the respective regulations.

Scope and Applicability

The objective of the quantification methodologies is to ensure accuracy and consistency across reporters and sectors regulated under the CCIR and SGRR. The intention is also to align with methods that are prescribed by Environment and Climate Change Canada (ECCC) and other jurisdictions that regulate greenhouse gas emissions such as British Columbia, Ontario, Quebec, and California. Further, methodologies from organizations such as the Western Climate Initiative, Inc. (WCI) and the Intergovernmental Panel on Climate Change (IPCC) are referenced or adopted as appropriate for various activity types and modified to meet the needs of Alberta sectors.

Greenhouse gas emissions covered in these quantification methods include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), sulphur hexafluoride (SF₆), nitrogen trifluoride (NF₃), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). For a complete list of HFCs and PFCs, refer to the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports*.

For some reporting purposes facilities are required to apply the appropriate Global Warming Potential (GWPs) to the greenhouse gas in order to calculate the carbon dioxide equivalent (CO₂e). These GWPs are prescribed in the standards corresponding to the respective regulations.

Activity Type

This Alberta Climate Change Office *Quantification Methodologies for the CCIR and SGRR* provides quantification methods for the following activities:

Chapter 1:	Stationary Fuel Combustion
Chapter 2:	Flaring
Chapter 3:	Fugitives
Chapter 4:	Venting

Chapter 5:	On-Site Transportation
Chapter 6:	Waste and Digestion
Chapter 7:	Wastewater
Chapter 8:	Industrial Processes
Chapter 9:	HFCs, PFCs, SF ₆ , NF ₃
Chapter 10:	Formation CO ₂
Chapter 11:	Injected, Sent Offsite, Received CO ₂
Chapter 12:	Imports
Chapter 13:	Production
Chapter 14:	Carbon Dioxide Emissions from Combustion of Biomass
Chapter 15:	Reporting Requirements under CCIR and SGRR

The chapters below provide guidance for reporters:

Chapter 17:	Measuring, Sampling, Analysis and Data Management
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The following appendices provide support to the activities presented in the above chapters:

Appendix A:	References
Appendix B:	Fuel Properties
Appendix C:	General Calculation Instructions
Appendix D:	Conversion Factors

Application for Deviation Requests

Facilities that are unable to execute a prescribed method must request a time limited approval to deviate from the prescribed method. The application should include:

- A description of the alternative method to be used
- Evidence that the alternative method would tend to be conservative versus the prescribed method
- A plan for future adoption of the prescribed method

The Director will review the request to deviate and issue a letter indicating whether it is approved. This letter should be kept as record to support verification activities. For further information on this process please consult the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* for regulated facilities under CCIR.

Definitions

“*AB-CWB Methodology*” means the methodology based on CAN-CWB and adapted to Alberta framework.

“*Accuracy*” means the ability of a measurement instrument to indicate values closely approximating the true value of the quantity measured.

“*bbl/cd*” means barrels per calendar day

“*Bias*” means any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.

“*Biomass*” means organic matter consisting of, or recently derived from living organisms.

“*Biogenic emissions*” are derived from biomass, either through combustion or other processes.

“*Calibration*” means the process or procedure of adjusting an instrument so that its indication or registration is in satisfactorily close agreement with a reference standard.

“*CAN-CWB Methodology*” means the calculation methodology described in “The CAN-CWB Methodology for Regulatory Support: Public Report” dated January 2014, prepared by Solomon Associates.

“*Carbon content*” means the fraction of carbon in the material.

“*Consensus Based Standards Organization*” means ASTM International, the American Gas Association (AGA), the American Petroleum Institute (API), the CSA Group, the Gas Processors Association (GPA), the Canadian General Standards Board, the Gas Processors Suppliers Association (GPSA), the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB), International Organization for Standardization (ISO), British Standard Institution, Measurement Canada, or other similar standards organizations.

“*Compensation*” means the adjustment of the measured value to reference conditions (e.g. pressure compensation).

“*Continuous emission monitoring system (CEMS)*” means the equipment required to sample, analyze, measure, and provide, by means of monitoring at regular intervals, a record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

“*Cogeneration unit*” means a fuel combustion device which simultaneously generates electricity and either heat or steam.

“*FCC*” means Fluid Catalytic Cracker.

“*Fuel*” means solid, liquid or gaseous combustible material.

“*Fuel gas*” means typically a mixture of light hydrocarbon and other molecules (e.g. H₂, N₂) in a gaseous state that are consumed in fired heaters. Fuel gas is often a mixture of recovered gaseous molecules from plant operations and purchased natural gas.

“GHGs” means greenhouse gases.

“GWP” means global warming potential.

“HFCs” means hydrofluorocarbons.

“Higher Heating Value” or HHV means the amount of heat released by a specified quantity of fuel once it is combusted and the products have returned to the initial temperature of the fuel, which takes into account the latent heat of vaporization of water in the combustion products.

“Influence parameter” means any factor that impacts the performance of the measuring device, hence the uncertainty and accuracy of the measurement. Examples are process temperature, pressure, fluid composition, upstream straight length, etc.

“Inspection” means a visual assessment or mechanical activity (e.g. instrument lead line blow down or orifice plate cleanliness) that does not include comparison or adjustment to a reference standard.

“Instrument Verification” means the process or procedure of comparing an instrument to a reference standard to ensure its indication or registration is in satisfactorily close agreement, without making an adjustment.

“Landfill Gas” (LFG) means the mixture of methane and carbon dioxide generated by decomposing organic waste in Solid Waste Disposal Sites.

“Lower Heating Value” or LHV means the amount of heat released by combusting a specified quantity of fuel and returning the temperature of the combustion products to 150°C, which assumes the latent heat of vaporization of water in the reaction products is not recovered.

“Meter condition factor” means an estimate of additional uncertainty based on a technical judgment of the physical condition of the meter in lieu of the ability to inspect.

“Metering or measurement system” means a combination of primary, secondary and/or tertiary measurement components necessary to determine the flow rate.

“Municipal waste” is waste collected by municipalities or other local authorities. Typically, MSW includes: household waste, garden (yard) and park waste and commercial/institutional waste.

“NAICS” is the North American Industry Classification System.

“Negligible emission sources” are sources that represent less than 1% of a facility’s total regulated emissions (TRE) or output-based allocation (OBA) CO₂ equivalent emissions (CO₂e) and are not to exceed 5,000 tonne of CO₂e for a facility regulated under CCIR. Alternative methods may be used to assess the negligibility of these emissions.

“Performance” means the response of a measurement device to influence parameters such as operating conditions, installation effects, and fluid properties.

“Range of uncertainty” means the range or interval within which the true value is expected to lie with a stated degree of confidence.

“Standard Temperature and Pressure” or “STP conditions” or “standard condition” means conditions at 15.0 degrees Celsius and 1 atmosphere of absolute pressure.

“*Uncertainty*” means the description of the range of deviation between a measured value and the true value, expressed as a percentage. For example, a device with an accuracy of 2% would have an uncertainty of $\pm 2\%$.

“*2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines*”: 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Intergovernmental Panel on Climate Change National Greenhouse Gas Inventories Program. Available online at: <http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html>.

σ means the standard deviation.

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1.0 Quantification of Stationary Fuel Combustion Emissions

1.1 Introduction

Stationary fuel combustion 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. Methods for carbon dioxide (CO₂) emissions from biomass combustion are provided in Chapter 14, while methods for methane (CH₄) and nitrous oxide (N₂O) from biomass combustion are included in this chapter. 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 system (e.g. blasting for mining purposes). This source category does not include flare emission sources or waste incineration, which are discussed in Chapter 2 and Chapter 6, respectively.

1.2 Carbon Dioxide

1.2.1 Introduction

For each fuel type combusted, calculate the mass of CO₂ emissions from fuel combustion for the reporting period, using one of the four quantification methodologies specified in this section. Various methods to calculate CO₂ emissions from different fuel types are presented in this section. A facility must use the method that corresponds with the tier classification that is assigned to the facility as illustrated in Figure 1.1. A facility must also apply the sampling and measurement requirements in Chapter 17 that corresponds with the facility's tier classification.

Figure 1-1 Tier classification and methodology mapping

		Tier Classification			
		1	2	3	4
Fuel Types	Non-Variable	Method 1			Method 4
	Natural Gas	Method 2			
	Variable	Method 3			

1.2.2 Method 1 - A fuel-specific default CO₂ emission factor for non-variable fuels

(1) Introduction

This method is used for fuels that are non-variable in composition and based on a default CO₂ emission factor and the quantity of fuel consumed. This method can be used for tiers 1, 2, or 3 as illustrated in Figure 1-1. Non-variable fuels that are acceptable to be used under this methodology include ethane, propane, butane, diesel, and gasoline. For diesel and gasoline that is subject to the Renewable Fuels Standard (RFS), the default CO₂ emission factors take into account the biofuel that is required as part of the fuel composition. Under the RFS, gasoline and diesel must contain 5% and 2% biofuel, respectively. Note the biofuels are included in the chapter for CO₂ from biomass combustion. The quantity of fuel consumed may be measured on a volume or energy basis, which can be provided by a third party supplier (i.e. invoices) or measured by the facility using the methods prescribed in Chapter 17 and Appendix C. Fuel consumption measured or provided in units of energy must be based on the higher heating value (HHV) of the fuel. Table 1-1 provides the emission factors for these fuels in mass of CO₂ emitted per gigajoules (GJ) or kilolitres (kl).

For facilities that have the HHV of the fuel, measured or supplied by the third party supplier, Equation 1-1 is used to convert the volume of the fuel to the energy of the fuel based on the HHV and then multiplied by the appropriate energy based emission factor from Table 1-1 to calculate the CO₂ mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-1a can be used directly to calculate the CO₂ mass emissions based on the appropriate energy based emission factor from Table 1-1.

Facilities must use measured or supplied HHVs to determine the fuel consumption if this data is available; however in cases where a facility is unable to obtain this information, a facility may apply Equation 1-1a using the fuel quantity in volume basis with the appropriate volume based emission factor from Table 1-1 to calculate the CO₂ mass emissions.

(2) Equations

For a liquid or gaseous fuel, use Equation 1-1 or Equation 1-1a to calculate the CO₂ mass emissions for the reporting period.

$$CO_{2,p} = v_{fuel,p} \times HHV \times EF_{ene} \quad \text{Equation 1-1}$$

$$CO_{2,p} = v_{fuel,p} \times EF_{vol} \text{ or } ENE_{fuel,p} \times EF_{ene} \quad \text{Equation 1-1a}$$

Where:

CO_{2,p} = CO₂ mass emissions for the specific fuel type for the reporting period, *p* (tonnes CO₂).

v_{fuel,p} = For Equation 1-1 and 1-1a, the volume of fuel combusted in kilolitres (kl) combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.

ENE_{fuel,p} = For Equation 1-1a, energy of fuel in gigajoules (GJ) combusted during reporting period, *p*.
Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.

HHV = Measured or supplied higher heating value in gigajoules per kilolitres (GJ/kl).

EF_{vol}, EF_{ene} = Fuel-specific default CO₂ emission factor, from Table 1-1 in tonnes of CO₂ per volume units (kl) or energy units (GJ).

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.

1.2.3 Method 2 - CO₂ emissions from combustion of natural gas

(1) Introduction

This method is adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements for calculating CO₂ mass emissions from natural gas combustion based on the measured HHV. This method can be used for tiers 1 and 2 as illustrated in Figure 1-1. Tier 3 facilities must use Method 3 for natural gas.

Calculate the CO₂ mass emissions for the reporting period based on the natural gas HHV provided by the fuel supplier or measured by the facility using Equation 1-2.

(2) Equation

For marketable natural gas, where the measured HHV is available, but not the carbon content, use Equation 1-2:

$$CO_{2,p} = v_{fuel,p} \times (60.554 \times HHV_p - 404.15) \times 10^{-6} \quad \text{Equation 1-2}$$

Where:

$CO_{2,p}$	=	CO ₂ mass emissions for the marketable natural gas combusted during the reporting period, p (tonnes CO ₂).
$v_{fuel,p}$	=	Volume of fuel (m ³) at standard conditions combusted during reporting period, p , calculated in accordance with Chapter 17 and Appendix C.
HHV_p	=	Weighted average measured higher heating value of fuel (MJ/m ³) at standard conditions as defined in Appendix C.
$(60.554 \times HHV_p - 404.15)$	=	Empirical equation adapted from ECCC (grams of CO ₂ per cubic meter of natural gas) representing relationship between CO ₂ and volume of natural gas determined through higher heating value using a discreet set of data collected by ECCC.
10^{-6}	=	Mass conversion factor (t/g).

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.

1.2.4 Method 3 - CO₂ emissions from variable fuels based on the measured fuel carbon content

(1) Introduction

This method is used for variable fuels based on a mass balance approach using the measured fuel carbon content. This method can be used for tiers 1, 2, or 3. Variable fuels are those that have varying composition and require testing for carbon content. All fuels not listed as non-variable fuels are to be considered variable fuels. The quantity of fuel consumed and/or the carbon content may be provided by the third party supplier (i.e. invoices or third party documentation) or measured by the facility using the methods prescribed in Chapter 17 and Appendix C.

For FCC processes, the emissions are considered to be stationary fuel combustion; however, there are no quantification methodologies currently prescribed. Facilities performing these processes may develop their own quantification methodologies or apply existing quantification methodologies until such methodologies are provided in this chapter.

Calculate the CO₂ mass emissions for the reporting period for each fuel based on Equation 1-3a, Equation 1-3b, Equation 1-3c, or Equation 1-3d depending on the type of fuel combusted.

(2) Equations

For gaseous fuels, where fuel consumption is measured in units of volume (m³), use Equation 1-3a:

$$CO_{2,p} = v_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001 \quad \text{Equation 1-3a}$$

For gaseous fuels, where fuel consumption is measured in units of energy (GJ), use Equation 1-3b:

$$CO_{2,p} = \frac{ENE_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV} \quad \text{Equation 1-3b}$$

Where:

$CO_{2,p}$	=	CO ₂ mass emissions for the gaseous fuel combusted during the reporting period, p (tonnes CO ₂).
$v_{fuel(gas),p}$	=	Volume of fuel (m ³) at standard conditions combusted during reporting period, p , calculated in accordance with Chapter 17 and Appendix C.
$ENE_{fuel(gas),p}$	=	Energy of fuel (GJ) at standard conditions combusted during reporting period, p , calculated in accordance with Chapter 17 and Appendix C.
HHV	=	Weighted average higher heating value of fuel (GJ/m ³) at standard conditions as defined in Appendix C.
$CC_{gas,p}$	=	Weighted average carbon content of the gaseous fuel during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m ³).
3.664	=	Ratio of molecular weights, CO ₂ to carbon.
0.001	=	Mass conversion factor (t/kg).

For a liquid fuel, where fuel consumption is measured in units of volume (kilolitres), use Equation 1-3c:

$$CO_{2,p} = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664 \quad \text{Equation 1-3c}$$

Where:

$CO_{2,p}$	=	CO ₂ mass emissions for the liquid fuel during the report period, p (tonnes CO ₂).
$v_{fuel(liq),p}$	=	Volume of liquid fuel combusted during the reporting period p , calculated in accordance with Chapter 17 and Appendix C (kilolitres).
$CC_{liq,p}$	=	Weighted average carbon content of the liquid fuel during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of tonnes of carbon per kilolitre of liquid fuel (tonnes C/kl).
3.664	=	Ratio of molecular weights, CO ₂ to carbon.

For a solid fuel, where fuel consumption is measured in units of mass (tonnes), use Equation 1-3d:

$$CO_{2,p} = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664 \quad \text{Equation 1-3d}$$

Where:

$CO_{2,p}$	=	CO ₂ mass emissions for the solid fuel during the report period, p (tonnes CO ₂).
$m_{fuel(sol),p}$	=	Mass of solid fuel combusted during the reporting period p , calculated in accordance with Chapter 17 and Appendix C (tonnes).

$CC_{sol,p}$	=	Weighted average carbon content of the fuel during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of tonnes of carbon per tonnes of solid fuel (tonnes C/tonnes).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(3) Data requirements

- Facilities must ensure that the proper units of fuel consumption, carbon content, and HHV are applied in the equations provided in this section.
- Fuel consumption measured or supplied in units of energy must be based on the HHV of the gaseous fuel.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.
- For coal combustion used for electricity generation, an oxidation factor of 99.48% is applied. This factor may be applied in Equation 1-3d to calculate carbon dioxide emissions. This oxidation factor was derived from a study conducted by ECCC on oxidation factors for coal combustion in Canada.

1.2.5 Method 4 - Continuous emissions monitoring systems

(1) Generality

For tier 4, calculate the CO_2 mass emissions for the reporting period from all fuels combusted in a unit, by using data from a CEMS as specified in (a) through (g). This methodology requires a CO_2 monitor (or O_2 monitor) and a flow monitoring subsystem, except as otherwise provided in paragraph (c). CEMS shall use methodologies provided in reference [8] in Appendix A or by another document that supersedes it. Facilities that are assigned a lower tier may choose to apply Method 4 to quantify their CO_2 emissions from fuel combustion.

- (a) For a facility that operates CEMS in response to federal, provincial or local regulation (i.e. required by the facility's Alberta Energy Regulator (AER) or Environmental Protection and Enhancement Act (EPEA) approval), use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies required by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) or in accordance with reference [8] in Appendix A.
- (b) Report CO_2 emissions for the reporting year in tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to tonnes.
- (c) An O_2 concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations. This may be used if the effluent gas stream monitored by the CEMS consists of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the combustion products) and only if the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.
 - (1) If the unit combusts waste-derived fuels (e.g. waste oils, plastics, solvents, dried sewage, municipal solid waste, tires), emissions calculations shall not be based on O_2 concentrations.
 - (2) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that the calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative

Accuracy Test Audit (RATA) requirements in reference [8] in Appendix A or Alberta CEMS Code.

- (d) If both biomass and fossil fuels (including fuels that are partially biomass) are combusted during the year, determine the biomass CO₂ mass emissions separately, as described in Chapter 14.
- (e) For any units using CEMS data, industrial process and stationary combustion CO₂ emissions must be provided separately. Determine the quantities of each type of fossil fuel and biomass fuel consumed for the reporting period, using the fuel sampling approach in Section 17.3 in Chapter 17.
- (f) If a facility subject to requirements for continuous monitoring of gaseous emissions chooses to add devices to an existing CEMS for the purpose of measuring CO₂ concentrations or flue gas flow, select and operate the added devices using appropriate requirements in accordance with reference [8] in Appendix A for the facility, as applicable in Alberta under the Alberta CEMS Code.
- (g) If a facility does not have a CEMS and chooses to add one in order to measure CO₂ concentrations, select and operate the CEMS using the appropriate requirements in accordance with reference [8] in Appendix A or equivalent requirements as applicable in Alberta under the Alberta CEMS Code.

(2) Data requirements

No additional data requirements are needed.

1.3 Methane and Nitrous Oxide

1.3.1 Introduction

Calculate the CH₄ and N₂O mass emissions for the reporting period from stationary fuel combustion sources, for each fuel type including biomass fuels, using the methods specified in this section. Figure 1-2 provides additional requirements for facilities based on sector and tier classification.

Figure 1-2 Additional requirements for natural gas emission factors based on sector and tier classification

		Tier Classification		
		1	2	3
Sectors	Oil and gas ¹	Method 1 Sector or technology based emission factors	Method 1 Technology based emission factors only (Table 1-3)	Method 2
	All other sectors			

¹Oil and gas sector includes conventional (NAICS: 211113) and non-conventional (NAICS: 211114) oil and gas facilities.

1.3.2 Method 1- Default CH₄ and N₂O emission factor

(1) Introduction

This method calculates the CH₄ and N₂O mass emissions based on default emission factors that are based in energy or physical units of fuel consumed. CH₄ and N₂O generated from combustion of biomass is included in this section. The quantity of fuel consumed can be provided by a third party supplier (i.e. invoices) or measured by the facility using the methods prescribed in Chapter 17 and Appendix C. Fuel consumption measured or provided in units of energy must be based on the HHV of the fuel. Tables 1-1, 1-2, 1-3, and 1-4 provide the emission factors for these fuels in mass of CH₄ and N₂O emitted per GJ, kilolitres, cubic metres, or tonnes of fuel. For a fuel that is not prescribed an emission factor in these tables, the facility may use an emission factor from an alternative source or perform engineering estimates to quantify these emissions.

For facilities that have the HHV of the fuel, measured or supplied by the third party supplier, Equation 1-4 is used to convert the volume of the fuel to the energy of the fuel based on the HHV and then multiplied by the appropriate energy based emission factor from Tables 1-1, 1-2, 1-3, or 1-4 to calculate the CH₄ and N₂O mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-4a can be used directly to calculate the CH₄ and N₂O mass emissions based on the appropriate energy based emission factor from Tables 1-1, 1-2, 1-3, and 1-4.

Facilities must use measured or supplied HHVs to determine the fuel consumption if this data is available; however in cases where a facility is unable to obtain this information, a facility may apply Equation 1-4a using the fuel quantity in volume basis with the appropriate volume based emission factor from Tables 1-1, 1-2, 1-3, or 1-4 to calculate the CH₄ and N₂O mass emissions.

This method is used for tiers 1, 2, and 3. Figure 1-2 provides additional requirements for natural gas emission factors based on the sector and tier classification for the facility.

(2) Equations

For a solid, liquid and gaseous fuel, use Equation 1-4 or Equation 1-4a.

$$CH_{4,p} \text{ or } N_2O_p = Fuel_p \times HHV \times EF_{ene} \quad \text{Equation 1-4}$$

$$CH_{4,p} \text{ or } N_2O_p = Fuel_p \times EF_{vol} \text{ or } EF_{ene} \quad \text{Equation 1-4a}$$

Where:

CH_{4,p} or N₂O_p = CH₄ or N₂O mass emissions for the specific fuel type for the reporting period, *p*, (tonnes CH₄ or N₂O).

Fuel_p = For Equation 1-4, the quantity of fuel combusted in kilolitres, cubic metres, or tonnes (kl, m³, tonnes) combusted during reporting period, *p*. For Equation 1-4a, energy of fuel in gigajoules or quantity of fuel in kilolitres, cubic metres, or tonnes (GJ, kl, m³, or tonnes) combusted during reporting period, *p*. Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.

HHV = Measured or supplied higher heating value in gigajoules per kilolitres, cubic metres, or tonnes (GJ/kl, GJ/m³, or GJ/tonne).

EF_{vol}, EF_{ene} = Fuel-specific default emission factor, from Tables 1-1, 1-2, 1-3, or 1-4 in tonnes of CH₄ or N₂O per energy units (GJ), volume units (kilolitres or cubic metres), or mass units (tonnes).

For facilities that combust biomass for steam generation and the steam generated is measured, use Equation 1-5:

$$CH_{4,p} \text{ or } N_2O_p = \text{Steam} \times B \times EF \quad \text{Equation 1-5}$$

Where:

- $CH_{4,p}$ or N_2O_p = CH_4 and N_2O mass emissions for the specific fuel type for the reporting period, p (tonnes CH_4 or N_2O).
- Steam = Total steam generated by biomass fuel or biomass combustion during the reporting period (tonnes steam), in GJ and calculated in accordance with Chapter 17 and Appendix C.
- B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity in GJ per GJ calculated in accordance with Chapter 17.
- EF = Fuel-specific default CH_4 and N_2O emission factor, from Table 1-4, in tonnes of CH_4 and N_2O per GJ.

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Facilities that use internal combustion engines are required to use technology based emission factors for internal combustion engines to calculate the CH_4 and N_2O emissions from those equipment.

1.3.3 Method 2 – Continuous emissions monitoring systems

(1) Introduction

The CH_4 or N_2O emissions for the reporting period attributable to the combustion of any type of fuel used in stationary combustion units may be calculated using data from CEMS including a gas volumetric flow rate monitor and a CH_4 or N_2O concentration monitor, in accordance with reference [9] in Appendix A or in accordance with the manufacturer's specifications.

1.4 Emission factors

The tables in this section provide the emission factors to be used in the equations outlined in the above sections.

Table 1-1 Default emission factors by fuel type for non-variable fuels

Non-Variable Fuels	HHV (GJ/kl) ¹	CO ₂ Emission Factor ⁴		CH ₄ Emission Factor ⁴		N ₂ O Emission Factor ⁴	
		tonne/kl	tonne/GJ	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel ²	38.35	2.681	0.0699	-	-	-	-
<19kW	-	-	-	7.3E-05	1.9E-06	2.0E-05	5.8E-07
>=19kW, Tier 1-3	-	-	-	7.3E-05	1.9E-06	2.0E-05	5.8E-07
>=19kW, Tier 4	-	-	-	7.3E-05	1.9E-06	2.3E-05	5.9E-06
Diesel in Alberta ³	37.83	2.610	0.06953		see note 5		
Biodiesel	35.16	-	-		see note 5		
Gasoline	33.43	2.307	0.069	-	-	-	-
2-stroke	-	-	-	1.1E-02	3.0E-04	1.3E-05	3.6E-07
4-stroke	-	-	-	5.1E-03	1.5E-04	6.4E-05	1.8E-06

Non-Variable Fuels	HHV (GJ/kl) ¹	CO ₂ Emission Factor ⁴		CH ₄ Emission Factor ⁴		N ₂ O Emission Factor ⁴	
		tonne/kl	tonne/GJ	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Gasoline in Alberta ³	33.24	2.174	0.06540			see note 6	
Butane	28.45	1.747	0.0614	2.4E-05	8.4E-07	1.08E-04	3.8E-06
Ethane	17.21	0.986	0.0573	2.4E-05	1.4E-06	1.08E-04	6.3E-06
Propane	25.29	1.515	0.0599	2.4E-05	9.5E-07	1.08E-04	4.3E-06

¹For facilities that are unable to obtain the HHV of their fuel, this column presents the default HHV for the non-variable fuels.

²Tiers adapted from USEPA requirements.

³Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content.

⁴Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (Reference [3] in Appendix A).

⁵Diesel CH₄ and N₂O emission factors are used.

⁶Gasoline CH₄ and N₂O emission factors are used.

Table 1-2 Sector based default CH₄ and N₂O emission factors for natural gas

Natural Gas ¹	CH ₄ Emission Factor ²		N ₂ O Emission Factor ²	
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ
Electric Utilities	4.9E-07	1.3E-05	4.9E-08	1.3E-06
Industrial	3.7E-08	9.8E-07	3.3E-08	8.7E-07
Oil and Gas Sector and Producer Consumption (Non-marketable) ¹	3.7E-08	9.8E-07	3.5E-08	9.0E-07
Pipelines	1.9E-06	5.0E-05	5.0E-08	1.3E-06
Cement	3.7E-08	9.8E-07	3.4E-08	9.0E-07
Manufacturing Industries	3.7E-08	9.8E-07	3.3E-08	8.7E-07
Residential, Construction, Commercial/Institutional, Agriculture/Other	3.7E-08	9.8E-07	3.5E-08	9.0E-07

¹Marketable gas is considered to be gas that is saleable for consumption.

²Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (Reference [3] in Appendix A).

Table 1-3 Technology based default CH₄ and N₂O emission factors for natural gas

Natural Gas	CH ₄ Emission Factor		N ₂ O Emission Factor		Reference ¹
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ	
Boilers/Furnaces/Heaters:					
NO _x Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07	AP-42 Table 1.4-2
NO _x Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07	AP-42 Table 1.4-2
Internal Combustion Engine ³ :					
Turbine	1.4E-07	3.7E-06	4.9E-08	1.3E-06	AP-42 Table 3.1-2a
2 stroke lean	2.37E-05	6.23E-04			AP-42 Table 3.2-1
NO _x 90-105% Load	-	-	7.77E-07	2.04E-05	AP-42 Table 3.2-1
NO _x < 90% Load	-	-	4.75E-07	1.25E-05	AP-42 Table 3.2-1
4 stroke lean	2.04E-05	5.37E-04			AP-42 Table 3.2-2
NO _x 90-105% Load	-	-	1.00E-06	2.63E-05	AP-42 Table 3.2-2
NO _x < 90% Load	-	-	2.07E-07	5.46E-06	AP-42 Table 3.2-2
4 stroke rich	3.76E-06	9.89E-05			AP-42 Table 3.2-3

Natural Gas	CH ₄ Emission Factor		N ₂ O Emission Factor		Reference ¹
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ	
NOx 90-105% Load	-	-	5.41E-07	1.43E-05	AP-42 Table 3.2-3
NOx < 90% Load	-	-	5.56E-07	1.46E-05	AP-42 Table 3.2-3

¹For 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).

Table 1-4 Default CH₄ and N₂O emission factors by fuel type

Liquid Fuels ¹	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Kerosene				
Electric Utilities	6.0E-06	2.0E-07	3.1E-05	8.3E-07
Industrial	6.0E-06	2.0E-07	3.1E-05	8.3E-07
Producer Consumption ¹	6.0E-06	1.6E-07	3.1E-05	8.2E-07
Forestry, Construction and Commercial/Institution	2.6E-05	7.0E-07	3.1E-05	8.3E-07
Light Fuel Oil				
Electric Utilities ¹	1.8E-04	4.6E-06	3.1E-05	7.99E-07
Industrial	6.0E-06	2.0E-07	3.1E-05	8.0E-07
Producer Consumption ¹	6.0E-06	1.6E-07	3.1E-05	7.99E-07
Forestry, Construction and Commercial/Institution	2.6E-05	6.7E-07	3.1E-05	8.0E-07
Heavy Fuel Oil				
Electric Utilities	3.4E-05	8.0E-07	6.4E-05	1.5E-06
Industrial	1.2E-04	2.8E-06	6.4E-05	1.5E-06
Producer Consumption ²	1.2E-04	2.8E-06	6.4E-05	1.506E-06
Forestry, Construction and Commercial/Institution	5.7E-05	1.3E-06	6.4E-05	1.5E-06
Solid Fuels ¹	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ
Petroleum Coke - Refinery Use	1.2E-04	2.6E-06	2.8E-05	5.9E-07
Petroleum Coke - Upgrader Use	1.2E-04	3.0E-06	2.4E-05	5.9E-07
Coal	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/tonne	tonne/GJ	tonne/tonne	tonne/GJ
Coal				
Electric Utilities				
Anthracite	2.0E-05	8.0E-07	3.0E-05	1.0E-06
Canadian Bituminous	2.0E-05	8.0E-07	3.0E-05	1.0E-06
Foreign Bituminous	2.0E-05	7.0E-07	3.0E-05	1.0E-06
Lignite	2.0E-05	1.0E-06	3.0E-05	2.0E-06
Sub-bituminous	2.0E-05	1.0E-06	3.0E-05	2.0E-06

	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/tonne	tonne/GJ	tonne/tonne	tonne/GJ
Industry and Heat and Steam Plants				
Anthracite	3.0E-05	1.0E-06	2.0E-05	7.0E-07
Canadian Bituminous	3.0E-05	1.0E-06	2.0E-05	7.0E-07
Foreign Bituminous	3.0E-05	1.0E-06	2.0E-05	7.0E-07
Lignite	3.0E-05	2.0E-06	2.0E-05	1.0E-06
Sub-bituminous	3.0E-05	2.0E-06	2.0E-05	1.0E-06
Residential, Public Administration				
Anthracite	4.0E-03	1.0E-04	2.0E-05	7.0E-07
Canadian Bituminous	4.0E-03	1.0E-04	2.0E-05	7.0E-07
Foreign Bituminous	4.0E-03	1.0E-04	2.0E-05	7.0E-07
Lignite	4.0E-03	2.0E-04	2.0E-05	1.0E-06
Sub-bituminous	4.0E-03	2.0E-04	2.0E-05	1.0E-06
Coke	3.0E-05	1.0E-06	2.0E-05	7.0E-07
Biomass Fuels¹				
	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/tonne	tonne/GJ	tonne/tonne	tonne/GJ
Wood Waste	9.0E-05	5.0E-06	6.0E-05	3.0E-06
Spent Pulping Liquor	2.0E-05	1.0E-06	2.0E-05	3.0E-06
Peat ²	NA	1.0E-06	NA	1.5E-06
Gaseous Fuels¹				
	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ
Coke Oven Gas	4.0E-08	2.0E-06	4.0E-08	2.0E-06
Still Gas ^{3,4}	3.1E-08	9.1E-07	2.0E-08	6.0E-07

¹Unless specified otherwise, emission factors are adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (Reference [3] in Appendix A).

²WCI Table 20-2 or 20-7.

³Adapted from IPCC (2006) and CIEEDAC (2014).

⁴SGA (2000).

8.0 Quantification of Industrial Process Emissions

8.1 Introduction

Industrial process (IP) emissions are direct emissions of specified gases generated from an industrial process involving chemical or physical reactions other than combustion, and where the primary purpose of the industrial process is not energy production. Emissions from the unavoidable combustion of carbon black in production of carbon black and ethylene in production of ethylene oxide are also included as IP emissions. IP emissions are typically generated from processes in chemical, mineral, and metal production. This chapter is used for the following industrial process sources:

- CO₂ from Hydrogen Production;
- CO₂ from Calcining Mineral Carbonates;
- CO₂ from Carbonate Use;
- CO₂ from Ethylene Oxide Production;
- CO₂ from Thermal Carbon Black Production;
- CO₂ from Carbon Consumption; and
- N₂O from Nitric Acid Production.

Facilities that generate industrial process emissions from a source that is not included in this chapter may use a method that is based on facility specific data or engineering estimates. The methodology used to calculate these emissions must be included in the facility's Quantification Methodology Document (QMD) for reporters under the CCIR.

In this chapter, there may be one or more methodologies prescribed for a process that are not tiered and therefore, are considered to be acceptable for use by a facility under any tier classification.

8.2 CO₂ from hydrogen production

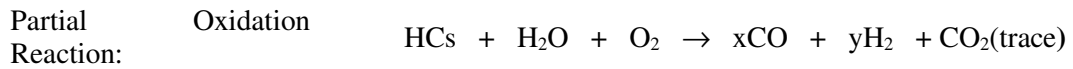
8.2.1 Introduction

Hydrogen is produced at bitumen upgraders, petroleum refineries, chemical plants, stand alone facilities and fertilizer plants, where it is needed for purification or synthesis of substances. In Alberta, hydrogen is produced from gaseous hydrocarbon feeds (typically natural gas) through a process of steam-methane reforming (SMR), followed by shift reactions. The primary and secondary reforming reactions produce carbon monoxide (CO) and hydrogen (H₂). Subsequent shift reactions convert CO to CO₂ to produce additional hydrogen. CO₂ is a by-product of the net reaction:



Any CO₂ generated as a by-product of the above reaction is considered an IP emission. However, under the SGRR these by-product CO₂ emissions must be reported as venting emission instead of IP, if the hydrogen production is at a fossil fuel production or processing facility, such as an upgrader or refinery. This is aligned with requirements of Canada's Greenhouse Gas Reporting Program. The CO₂ by-product produced through reaction can be removed by physical adsorption (e.g. Pressure-Swing Adsorption, PSA) or chemical absorption (e.g. amines, potassium carbonate).

Please note that hydrogen can also be generated through the partial oxidation of hydrocarbons to synthesis gas ("syngas" containing CO and H₂). This process can occur as shown in the first equation above (steam-methane reforming) or the same reaction with pure oxygen added, as follows:



As above, any CO₂ generated as a by-product of the above reaction are considered an IP emission. Syngas can be combusted as a fuel but the CO₂ generated from syngas combustion are considered stationary fuel combustion emissions and must be reported under that source category.

CO₂ entrained in the feed are not included in the IP CO₂ emissions total; instead these emissions are classified as formation CO₂ and should be reported under a separate category.

Four methods are provided for IP CO₂ emissions from hydrogen production. These methods are acceptable to be used for any tier classification.

8.2.2 Direct feed oxidation method

(1) Introduction

The Direct Feed Oxidation Method is applicable only for hydrogen production situations where there is no PSA unit to remove and recycle impurities (CO₂, CO, CH₄, C₂H₆) for fuel use. This method assumes that all feed carbon is oxidized to CO₂, which is removed by a chemical absorption process. The method calculates gross IP CO₂ from hydrogen production based on the quantity of reactor feed and its composition. Any inert CO₂ contained in the reactor feed does not participate in the steam-methane reforming reaction and, therefore, is not included in the gross IP CO₂ calculation. The calculation assumes 100% oxidation efficiency for the oxidizable carbon in the feed.

(2) Equations

For each hydrogen production unit where there is no PSA unit to remove and recycle impurities for fuel use, calculate IP CO₂ emissions using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (v_{Feed,i} \times EF_{CO_2,i}) \times 0.001 \quad \text{Equation 8-1}$$

Where:

- CO_{2,p} = IP CO₂ mass emissions in the reporting period, *p* (tonnes CO₂).
- i* = Measurement period for reactor feed gas analysis.
- N* = Number of reactor feed gas analysis measurement periods, *i*, in reporting period.
- v_{Feed,i} = Volume of reactor feed gas in measurement period *i* (standard cubic metres, sm³), calculated in accordance with Chapter 17 and Appendix C.
- EF_{CO₂,i} = Feed-specific CO₂ emission factor calculated from the measured reactor feed gas composition analysis results for measurement period *i* (kgCO₂/sm³) as defined by Equation 8-1a.
- 0.001 = Mass conversion factor (t/kg).

$$EF_{CO_2,i} = \sum_{k=1}^K (MF_{k,i} \times NC_k) \times \rho_{CO_2} \quad \text{Equation 8-1a}$$

Where:

- EF_{CO₂,i} = IP CO₂ emission factor for measurement period *i* (kgCO₂/sm³).
- i* = Measurement period for reactor feed gas analysis.
- k* = Individual carbon-based oxidizable component of reactor feed gas.

K	=	Number of measured carbon-based, oxidizable components (e.g. hydrocarbons, CO, COS, CS ₂) having non-zero molar fractions in feed gas. Note: CO ₂ contained in the feed gas is not included.
MF _{k,i}	=	Mole fraction of carbon-based oxidizable component k in reactor feed gas in measurement period i. Note: The mole fraction of CO ₂ contained in the feed gas is not included.
NC _k	=	Number of carbons contained in carbon-based oxidizable component k in reactor feed gas.
ρ _{CO2}	=	1.8613 kg/m ³ at standard conditions (where ρ _{CO2} is determined by the molecular weight of CO ₂ divided by the molar volume of ideal gas at standard conditions as defined by Appendix C).

(3) Data requirements

- The volume, temperature, pressure and composition of the reactor feed gas must be measured in accordance with Chapter 17.
- The volume of the reactor feed gas must be adjusted to the volume at standard conditions as defined in Appendix C.

8.2.3 CO₂ Mass balance method

(1) Introduction

The CO₂ Mass Balance Method is typically used in hydrogen production situations where there is a PSA unit that purifies a raw hydrogen stream by removing all non-hydrogen contaminants produced in the SMR and shift reactions or where partial oxidation is used for hydrogen generation. The PSA Purge Gas stream containing CO₂, CO, CH₄, C₂H₆, and some waste H₂ is typically recovered and used as a low-HHV fuel gas in the combustion side of the Reformer Furnace. The method recognizes the following assumptions:

- CO₂ contained in reaction or imported feed is not counted in the IP CO₂ calculation.

(2) Equations

For each hydrogen production unit, calculate IP CO₂ emissions using Equation 8-2:

$$CO_2 = CO_2 \text{ in Raw Unpurified } H_2 \text{ stream} - CO_2 \text{ in feed}$$

$$CO_{2,p} = \left[\sum_{i=1}^N (v_{RawU H_2,i} \times MF_{CO_2,RawU H_2,i} - v_{Feed,i} \times MF_{CO_2,Feed,i}) \times \rho_{CO_2} \right] \times 0.001 \quad \text{Equation 8-2}$$

Where:

CO _{2,p}	=	IP CO ₂ mass emissions in the reporting period, p (tonnes CO ₂).
i	=	Measurement period for IP CO ₂ .
N	=	Number of IP CO ₂ measurement periods i in the reporting period.
v _{RawU H₂,i}	=	Volume of raw unpurified H ₂ stream in measurement period i (sm ³).
v _{Feed,i}	=	Volume of reactor feed gas in measurement period i (sm ³).
MF _{CO₂,Feed,i}	=	CO ₂ mole fraction in reactor feed gas (kmol _{CO₂} /kmol _{Feed}).
MF _{CO₂,RawU H₂,i}	=	CO ₂ mole fraction in raw unpurified hydrogen stream (kmol _{CO₂} /kmol _{RawH₂}).
ρ _{CO2}	=	1.8613 kg/m ³ at standard conditions as defined in Appendix C.
0.001	=	Mass conversion factor (t/kg).

(3) Data requirements

- The volume, temperature, pressure and composition of the reactor feed gas must be measured in accordance with Chapter 17.
- The volume, temperature, pressure and composition of the raw unpurified hydrogen streams (i.e. before PSA) must be measured in the same frequency as the reactor feed gas.
- The volume of the reactor feed gas and raw unpurified hydrogen stream must be adjusted to the volume at standard conditions as defined in Appendix C.

8.2.4 Hydrogen feed calculation method

(1) Introduction

The Hydrogen Feed Calculation Method is an alternative method that back-calculates the quantity of eligible gas feed based on the measured mass of hydrogen generated. This method eliminates the need to measure intermediate, recycled, and wasted streams and their composition by focusing on the stoichiometric feed-to-hydrogen molar ratios for each oxidizable component of the feed gas. The method recognizes the following assumptions:

- CO₂ contained in reaction feed is not counted in the IP CO₂ calculation; and
- All hydrogen is generated through full oxidation of carbon contained in hydrocarbons.

(2) Equations

For each hydrogen production unit, calculate IP CO₂ emissions using the following equation:

$$CO_{2,p} = \sum_{i=1}^N \left(\frac{v_{H2,i}}{\sum_{k=1}^K (SR_{H2/CO2,k} \times MF_{k,i})} \right) \times \rho_{CO2} \times 0.001 \quad \text{Equation 8-3}$$

Where:

CO _{2,p}	=	IP CO ₂ mass emissions in the reporting period, <i>p</i> (tonnes CO ₂).
<i>i</i>	=	Measurement period for reactor feed gas analysis.
<i>N</i>	=	Number of reactor feed gas analysis measurement periods <i>i</i> in reporting period.
<i>k</i>	=	Carbon-based oxidizable components.
<i>K</i>	=	Number of carbon-based oxidizable components.
v _{H2,i}	=	Volume of hydrogen produced in measurement period <i>i</i> (sm ³) at standard conditions as defined in Appendix C.
SR _{H2/CO2,k}	=	Stoichiometric hydrogen-to-CO ₂ molar ratio for carbon-based oxidizable component <i>k</i> (CO, CH ₄ , C ₂ H ₆ , etc.) in reactor feed gas, as listed in Table 8-1;
MF _{k,i}	=	Mole fraction of carbon-based oxidizable component <i>k</i> (e.g. CO, hydrocarbons) in the reactor feed gas in measurement period <i>i</i> . Note: CO ₂ and other inert components contained in the reactor feed gas are not included.
ρ _{CO2}	=	1.8613 kg/m ³ at standard conditions as defined in Appendix C.
0.001	=	Mass conversion factor (t/kg).

Table 8-1 Stoichiometric Molar Ratios of Hydrogen to CO₂

Feed Component	Overall Reaction Equation	SR: H ₂ /CO ₂ Molar Ratio (mol H ₂ /mol CO ₂)
Methane	CH ₄ + 2H ₂ O → CO ₂ + 4H ₂	4/1 = 4.000
Ethylene	C ₂ H ₄ + 4H ₂ O → 2CO ₂ + 6H ₂	6/2 = 3.000
Ethane	C ₂ H ₆ + 4H ₂ O → 2CO ₂ + 7H ₂	7/2 = 3.500
Propylene	C ₃ H ₆ + 6H ₂ O → 3CO ₂ + 9H ₂	9/3 = 3.000
Propane	C ₃ H ₈ + 6H ₂ O → 3CO ₂ + 10H ₂	10/3 = 3.333
Butylenes	C ₄ H ₈ + 8H ₂ O → 4CO ₂ + 12H ₂	12/4 = 3.000
Butanes	C ₄ H ₁₀ + 8H ₂ O → 4CO ₂ + 13H ₂	13/4 = 3.250
Pentenes	C ₅ H ₁₀ + 10H ₂ O → 5CO ₂ + 15H ₂	15/5 = 3.000
Pentanes	C ₅ H ₁₂ + 10H ₂ O → 5CO ₂ + 16H ₂	16/5 = 3.200
Hexanes	C ₆ H ₁₄ + 12H ₂ O → 6CO ₂ + 19H ₂	19/6 = 3.167
Heptanes	C ₇ H ₁₆ + 14H ₂ O → 7CO ₂ + 22H ₂	22/7 = 3.143
Carbon Monoxide	CO + H ₂ O → CO ₂ + H ₂	1/1 = 1.000

(3) Data requirements

- The composition of the reactor feed gas must be measured in accordance with Chapter 17 and Appendix C.
- The volume, temperature, pressure and composition of the hydrogen product stream must be measured in the same frequency as the reactor feed gas.
- The volume of the hydrogen product stream must be adjusted to the volume at standard conditions as defined in Appendix C.

8.2.5 IP CO₂ Emissions from Mass Balance**(1) Introduction**

Industrial process CO₂ emissions from hydrogen production can be determined by a mass balance approach if the facility's fuel and feed metering system is integrated and the total fuel and feed consumption can be accurately determined (e.g., third party custody meter). Provided that the facility uses the required methodologies prescribed in Chapter 1 Stationary Fuel Combustion to quantify the CO₂ emissions from fuel combustion, a mass balance approach can be used to quantify the IP CO₂ emissions, which assumes that all carbon that is not combusted would be emitted as IP CO₂. Similar to above methods, CO₂ entrained in the fuel or feed is not included in the IP CO₂ emissions.

(2) Equations

For gaseous fuels and feedstocks, where fuel consumption is measured in units of volume (m³), use Equation 8-4a:

$$CO_{2,p} = (v_{total,p} - v_{SFC,p}) \times CC_{gas,p} \times 3.664 \times 0.001 \quad \text{Equation 8-4a}$$

For gaseous fuels and feedstocks, where fuel consumption is measured in units of energy (GJ), use Equation 8-4b:

$$CO_{2,p} = \frac{ENE_{total,p} - ENE_{SFC,p}}{HHV} \times CC_{gas,p} \times 3.664 \times 0.001 \quad \text{Equation 8-4b}$$

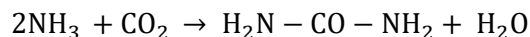
Where:

$CO_{2,p}$	=	IP CO_2 mass emissions in the reporting period, p (tonnes CO_2).
$V_{total,p}$	=	Total volume of feed and fuel supplied to the facility in the reporting period, p (sm^3) calculated in accordance with Chapter 17 and Appendix C.
$V_{SFC,p}$	=	Total volume of fuel that is combusted by the facility in the reporting period, p (sm^3) calculated in accordance with Chapter 17 and Appendix C.
$CC_{gas,p}$	=	Weighted average carbon content of the gaseous fuel during the reporting period, p , calculated in accordance with Chapter 17 and Appendix C; however CO_2 contained in the feed gas is not included. CC_p is in the units of kilogram of carbon per standard cubic metre of gaseous fuel ($kg\ C/m^3$).
$ENE_{total,p}$	=	Total energy of the total fuel and feed (GJ) supplied to the facility at standard conditions combusted during reporting period, p , calculated in accordance with Chapter 17 and Appendix C.
$ENE_{SFC,p}$	=	Total energy of the fuel combusted (GJ) by the facility at standard conditions combusted during reporting period, p , calculated in accordance with Chapter 17 and Appendix C.
HHV	=	Weighted average higher heating value of fuel (GJ/m^3) at standard conditions as defined in Appendix C.
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Mass conversion factor (t/kg).

8.2.6 CO_2 Consumption in urea production

(1) Introduction

Urea production is often performed in conjunction with ammonia production in fertilizer plants and a methodology is included here though this is not necessarily an IP quantity. While steam methane reforming is required and generates CO_2 as IP emissions when producing ammonia, CO_2 is consumed in the urea production process as shown in the following chemical reaction:



(2) Equations

The CO_2 emissions consumed in the urea production process must be included in the total regulated emissions reported under the Carbon Competitiveness Incentive Regulation in accordance with Equation 8-5:

$$CO_{2,Urea,p} = m_{Urea} \times \frac{MW_{CO_2}}{MW_{Urea}} \times 0.001 \quad \text{Equation 8-5}$$

Where:

$CO_{2, Urea,p}$	=	CO_2 consumed in urea production in reporting period, p (tonnes CO_2).
m_{Urea}	=	Mass of urea produced during reporting period (kg).
MW_{Urea}	=	Molecular weight of urea (kg/kmol) (60.06 kg/kmol).
MW_{CO_2}	=	Molecular weight of CO_2 (kg/kmol) (44.01 kg/kmol).
0.001	=	Mass conversion factor (t/kg).

(3) Data requirements

- Urea production must be measured based on measurement systems used for accounting purposes.

8.2.7 Reporting of waste hydrogen

(1) Introduction

Generated hydrogen that is not used or exported is considered to be waste hydrogen. Waste hydrogen may be vented, flared, or combusted. The method described below is an optional method for calculating waste hydrogen. Other site specific methods of estimating waste hydrogen are also acceptable.

(2) Equations

The equation used to calculate the waste hydrogen is provided by Equation 8-6.

$$H_{2,Waste,p} = \sum_{i=1}^N [(m_{H_2,Gen,i} + m_{H_2,Imp,i}) - (m_{H_2,Exp,i} + m_{H_2,Use,i})] \quad \text{Equation 8-6}$$

Where:

$H_{2,Waste,p}$	=	Waste H_2 generated in the reporting period, p (tonnes H_2).
i	=	Measurement period for H_2 .
N	=	Number of H_2 measurement periods, i , in the reporting period.
$m_{H_2,Gen,i}$	=	Mass of H_2 generated during period i (tonnes).
$m_{H_2,Imp,i}$	=	Mass of H_2 imported during period i (tonnes).
$m_{H_2,Exp,i}$	=	Mass of H_2 exported during period i (tonnes).
$m_{H_2,Use,i}$	=	Mass of H_2 used during period i (tonnes).

A waste hydrogen stream may contain other components such as hydrocarbons and inerts. For the purpose of reporting, only the mass of the hydrogen component is reported. For each of the hydrogen streams (i.e. imported, exported, generated, used, and waste), the mass of the hydrogen component is calculated in accordance with Equation 8-7.

$$H_{2,j} = \sum_{i=1}^N [v_{H_2,j} \times MF_{H_2,j} \times \rho_{H_2}] \times 0.001 \quad \text{Equation 8-7}$$

Where:

$H_{2,j}$	=	Hydrogen mass for hydrogen stream j in the reporting period (tonnes H ₂).
j	=	Hydrogen stream.
i	=	Measurement period for hydrogen.
N	=	Number of H ₂ measurement periods, i, in the reporting period.
$V_{H_2,j}$	=	Volume of hydrogen stream j (sm ³ at standard conditions as defined in Appendix C).
$MF_{H_2,j}$	=	Mole fraction of hydrogen in stream j (kmolH ₂ /kmol).
ρ_{H_2}	=	0.08526 kg/m ³ , standard density of hydrogen at standard conditions as defined in Appendix C (kg/sm ³).
0.001	=	Mass conversion factor (t/kg).

(3) Data requirements

There are no additional data requirements needed.

8.3 CO₂ from calcining carbonates (minerals)

(1) Introduction

Calcining of carbonates into oxides occurs at high temperatures in cement, lime (CaO), and magnesia (MgO) kilns. The most common carbonate feeds used in these facilities are calcium carbonate (CaCO₃; Limestone) and magnesium carbonate (MgCO₃). Lime kilns can operate at merchant lime facilities and Kraft pulp mills. The primary reaction equations for calcining of carbonates are:



This section is adapted from the guidance provided by the World Business Council for Sustainable Development (WBCSD) Cement CO₂ Protocol (2001) and the Western Climate Initiative (WCI). One generic method is provided to cover cement, lime, and magnesia kilns. The contribution from each type of carbonate is accounted for by a composite CO₂ emission factor. The IP CO₂ emissions from calcination include only the CO₂ generated in the calcining reaction. Any CO₂ generated through the combustion of organic carbon contained in kiln feed materials creates useful energy and must be calculated using Equation 8-9 and reported under the Stationary Fuel Combustion source category.

The IP CO₂ emissions are calculated as the sum of CO₂ emitted from calcination producing the primary product, P, and the CO₂ emitted from calcination producing any waste product from the kiln. The primary product, P, may be clinker for cement production, quicklime for lime production, or magnesia for magnesia production. If multiple product grades are produced in one kiln, they must be weight-averaged into one primary product or their CO₂ calculated separately. The waste product, W, may be cement kiln dust (CKD) for cement production, lime kiln dust (LKD) for lime production, or magnesia kiln dust (MKD) for magnesia production. The waste product, W, is a final product from the kiln that is not recycled back to the feed. If multiple waste products are produced, they must be weight-averaged into one waste product or their CO₂ calculated separately.

(2) Equations

For each kiln, calculate IP CO₂ emissions from calcination using the following equation:

$$CO_{2-IP,p} = \sum_{i=1}^I (m_{P,i} \times EF_{P,i}) + \sum_{j=1}^N (m_{W,j} \times EF_{W,j}) \quad \text{Equation 8-8}$$

Where:

$CO_{2-IP,p}$	=	IP CO ₂ mass emissions from calcination of carbonates in reporting period, p (tonnes CO ₂).
i	=	Measurement period i for CaO and MgO in primary product.
I	=	Number of periods per reporting period for which measurement is required of CaO and MgO in primary product.
j	=	Measurement period j for CaO and MgO in waste product.
N	=	Number of periods per reporting period for which measurement is required of CaO and MgO in waste product.
P	=	Primary kiln product.
W	=	Waste kiln material.
$m_{P,i}$	=	Mass of primary kiln product P in measurement period i (tonnes).
$EF_{P,i}$	=	CO ₂ emission factor for primary kiln product P in measurement period i (tonnes CO ₂ per tonne P), as defined in Equation 8-8a.
$m_{W,j}$	=	Mass of waste kiln material W in measurement period j .
$EF_{W,j}$	=	CO ₂ emission factor for waste kiln material W in measurement period j (tonnes CO ₂ per tonne W), as defined in Equation 8-8b.

The kiln-specific CO₂ emission factors ($EF_{P,i}$, $EF_{W,j}$) are calculated based on the total oxide content (e.g. CaO, MgO) of the product or waste, less any oxide in that product or waste that would have been originally present in the feed materials before calcination. These latter oxides are called “non-calcined” oxides and may be present in fly ash or alternative fuels or raw materials (AFR).

$$EF_{P,i} = (CaO_{P,i} - CaO_{FP,i}) \times 0.785 + (MgO_{P,i} - MgO_{FP,i}) \times 1.092 \quad \text{Equation 8-8a}$$

Where:

$EF_{P,i}$	=	CO ₂ emission factor for primary kiln product P in measurement period i (tonnes CO ₂ per tonne P).
$CaO_{P,i}$	=	Total calcium oxide content of primary product P in measurement period i (tonnes CaO per tonne P).
$CaO_{FP,i}$	=	Non-calcined calcium oxide content of primary product P in measurement period i (tonnes CaO per tonne P), calculated as: fraction of feed calcium oxide mass allocated to P /mass of P ;
$MgO_{P,i}$	=	Total magnesium oxide content of primary product P in measurement period i (tonnes MgO per tonne P).
$MgO_{FP,i}$	=	Non-calcined magnesium oxide content of primary product P in measurement period i (tonnes MgO per tonne P), calculated as: fraction of feed magnesium oxide mass allocated to P /mass of P ;
0.785	=	Ratio of molecular weight of CO ₂ to CaO (44.0/56.1).
1.092	=	Ratio of molecular weights of CO ₂ to MgO (44.0/40.3).

$$EF_{W,j} = (CaO_{W,j} - CaO_{FW,j}) \times 0.785 + (MgO_{W,j} - MgO_{FW,j}) \times 1.09 \quad \text{Equation 8-8b}$$

Where:

$EF_{W,j}$	=	CO ₂ emission factor for waste kiln material W in measurement period j (tonnes CO ₂ per tonne W).
$CaO_{W,j}$	=	Total calcium oxide content of waste kiln material W in measurement period j (tonnes CaO per tonne W).
$CaO_{FW,j}$	=	Non-calcined calcium oxide content of waste kiln material W in measurement period j (tonnes CaO per tonne W), calculated as: fraction of feed calcium oxide mass allocated to W/mass of W.
$MgO_{W,j}$	=	Total magnesium oxide content of waste kiln material W in measurement period j (tonnes MgO per tonne W).
$MgO_{FW,j}$	=	Non-calcined magnesium oxide content of waste kiln material W in measurement period j (tonnes MgO per tonne W), calculated as: fraction of feed magnesium oxide mass allocated to W/mass of W; magnesium oxide mass allocated to P/mass of P;
0.785	=	Ratio of molecular weight of CO ₂ to CaO (44.0/56.1).
1.092	=	Ratio of molecular weights of CO ₂ to MgO (44.0/40.3).

The CO₂ emissions from oxidation of total organic carbon in feed are calculated based on the carbon content of the feed.

$$CO_{2,p} = m \times TOC \times 3.664 \quad \text{Equation 8-9}$$

Where:

$CO_{2,p}$	=	Fuel combustion CO ₂ mass emissions from oxidation of feed organic carbon in the reporting period, <i>p</i> (tonnes CO ₂).
<i>m</i>	=	Mass of kiln feed materials (tonnes) in reporting period.
TOC	=	Total organic carbon content in kiln feed materials (mass fraction); Default TOC = 0.002 (0.2%);
3.664	=	Ratio of molecular weights, CO ₂ to carbon.

(3) Data requirements

- The mass of all feeds and products must be determined monthly from measurement systems used for accounting purposes for each lime type and each calcined by products/waste type.
- Chemical composition of CaO and MgO contents of each lime type and each calcined byproduct/waste type must be determined during the same month as the production data.
- The CaO and MgO content of feed and products must be determined once per month based on composite samples.
- The CaO and MgO content of waste materials must be determined once per quarter.
- The CaO and MgO content of any material must be determined using: ASTM C25 - Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime; or the most appropriate industry standard method published by a consensus-based standards organization to determine CaO and MgO content. The reporter should explain the method used while reporting.
- The Total Organic Carbon contained in kiln feeds (TOCF) that is oxidized to CO₂ should be measured once per year, using ASTM C114 or an industry standard method. However, a default TOCF factor of 0.002 (0.2%) can be used.

8.4 CO₂ from use of carbonates

8.4.1 Introduction

CO₂ can be generated when carbonates participate in some chemical reactions. Flue gas desulphurization, pH control of wastewater, acid leaching of ores containing carbonates, and use of carbonates in metal fluxing are some examples of CO₂ generated from carbonate reactions.

8.4.2 Tier 1 - Carbonate consumption method

(1) Introduction

This simplified method measures carbonate consumption and uses default carbonate CO₂ emission factors. The method assumes a default fraction of carbonate reacted of 1.0 (complete reaction). Measurement of fraction reacted by carbonated analysis is optional.

(2) Equations

For any carbonate used, calculate IP CO₂ emissions using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (m_i \times EF_i \times F_i) \quad \text{Equation 8-10}$$

Where:

- CO_{2,p} = IP CO₂ mass emissions from consumption of carbonates in the reporting period, *p* (tonnes CO₂).
- i* = Carbonate types.
- N* = Number of carbonate types.
- m_i* = Mass of carbonate type *i* consumed (tonnes) in the reporting period.
- EF_{*i*} = Emission factor for carbonate type *i* (tonne CO₂/tonne carbonate consumed), from Table 8-2. If an emission factor is not available in Table 8-2 for a carbonate that is used at the facility, the facility may develop an emission factor based on stoichiometry for the specific carbonate.
- F_i* = Fraction reacted for each carbonate type *i* (mass fraction). A default value of 1.0 (complete reaction) is assumed. Alternatively, fraction reacted can be determined by analyzing input and output materials.

(3) Data requirements

The mass of carbonate consumed shall be determined for the reporting period using the same plant processes used for accounting purposes including purchase records, adjusted for inventory, or direct measurements.

8.4.3 Tier 2 - Place marker

8.4.4 Tier 3 - Carbonate mass balance method

(1) Introduction

The carbonate mass balance method requires the measurement of the carbonate content in both the input material reacted and the output material produced by reaction.

(2) Equations

For any carbonate used, calculate IP CO₂ emissions for the reporting period using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (m_{in} - m_{out}) \times EF_i \quad \text{Equation 8-11}$$

Where:

- $CO_{2,p}$ = IP CO₂ mass emissions from consumption of carbonates (tonnes CO₂) in reporting period, p (tonnes CO₂).
 i = Carbonate type.
 N = Number of input carbonate types.
 m_{in} = Mass of input carbonate type i (tonnes) in the reporting period.
 EF_i = Emission factor for carbonate type i (tonnes CO₂/tonne carbonate), from Table 8-2.
 m_{out} = Mass of output carbonate type i (tonnes) in the reporting period.

(3) Data requirements

The mass of carbonate inputs and outputs must be determined for the reporting period from measurements using the same plant processes used for accounting purposes including purchase records, adjusted for inventory, or direct measurements.

Table 8-2 Default Carbonate CO₂ Emission Factors

Mineral Name	Formula	CO ₂ Emission Factor (tonnes CO ₂ /tonnes Carbonate)
Limestone	CaCO ₃	0.43971
Magnesite	MgCO ₃	0.52197
Dolomite	CaMg(CO ₃) ₂	0.47732
Siderite	FeCO ₃	0.37987
Ankerite	Ca(Fe,Mg,Mn)(CO ₃) ₂	0.47572
Rhodochrosite	MnCO ₃	0.38286
Sodium Carbonate/Soda Ash	Na ₂ CO ₃	0.41492
Others		Facility specific emission factor to be determined through analysis or supplier information.

8.4.5 Tier 4- Measured CO₂ emission factor method

(1) Introduction

CO₂ from use of carbonates can be estimated based on a facility-specific CO₂ emission factor measured by an annual stack gas test. This method is only applicable when no other sources of CO₂ contribute to the CO₂ in the stack gas from the reaction. CO₂ emissions in the reporting period are calculated by multiplying the activity level of the CO₂ generation process in the reporting period by the measured CO₂ emission factor. Activity level data may be based on:

- Mass of carbonates consumed; or
- Any applicable substance participating in the reaction where CO₂ is released.

One example application of this method is the calculation of CO₂ emissions from the acid leaching of different types of ore containing carbonates.

(2) Equations

For an eligible source of CO₂ from use of carbonates, calculate IP CO₂ emissions in the reporting period using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (m_i \times EF_i) \quad \text{Equation 8-12}$$

Where:

CO _{2,p}	=	CO ₂ mass emissions from consumption of carbonates in the reporting period, <i>p</i> (tonnes CO ₂).
<i>i</i>	=	Carbonate-containing material.
<i>N</i>	=	Number of different carbonate-containing materials.
<i>m_i</i>	=	Mass of carbonate-containing material of type <i>i</i> consumed (tonnes carbonate) in reporting period.
EF _{<i>i</i>}	=	CO ₂ emission factor for carbonate-containing material of type <i>i</i> (tonnes CO ₂ /tonne carbonate), as determined by Equation 8-133.

$$EF_i = \frac{ME_{CO_2}}{AL} \quad \text{Equation 8-13}$$

Where:

ME _{CO₂}	=	CO ₂ mass emission rate (tonnes CO ₂ /hour), where this value is determined from stack testing;
AL	=	Activity level mass rate of carbonate-containing material of type <i>i</i> (tonnes carbonate/hour) during stack test.

(3) Data requirements

- The activity level used in Equation 8-133 must be determined from measurement systems used for accounting purposes for the period that the stack tests are conducted.
- Stack tests to determine EF_{*j*} must be conducted at least once per year for each different type of carbonate used or ore treated. A minimum of three test runs for each stack test and hourly measurement of activity level are required during the stack test and the results averaged. CO₂ concentrations must be measured by one of the following tests:
 - U.S. EPA Method 320 (40 CFR Part 63, Appendix A), U.S. EPA Method 3A, or any method equivalent to these;
 - ASTM D6348;
 - Any equivalent method published by Environment and Climate Change Canada or Provinces.
- Stack test report containing the measurements used to determine the concentration and mass emission rate of the CO₂ is required to be submitted.

8.5 CO₂ from ethylene oxide production

(1) Introduction

Ethylene oxide (“EO”, C₂H₄O) is a reactive chemical that is used mostly as a chemical intermediate to make ethylene glycol (EG) at integrated facilities. Ethylene glycol (“EG”, C₂H₄(OH)₂) is an organic

chemical widely used as an automotive antifreeze and a precursor to polymers such as polyester (for fabrics) and polyethylene terephthalate (PET, for plastic bottles). Ethylene oxide is made by the catalytic “partial” oxidation of ethylene with air or pure oxygen. CO₂ and water are formed as by-products since a fraction of the ethylene is completely oxidized in the reaction process. Approximately 80% of ethylene feed is converted to ethylene oxide and 20% to carbon dioxide and water in two parallel reactions. The by-product CO₂ generated is separated and vented, if not captured for use. All by-product CO₂ is considered as an IP emission.

Ethylene Oxide Production: $C_2H_4 + \frac{1}{2}O_2 \rightarrow C_2H_4O + \text{heat}$ (~80% C₂H₄ converted)

Ethylene Full Oxidation: $C_2H_4 + 3O_2 \rightarrow 2CO_2 + 2H_2O + \text{heat}$ (~20% C₂H₄ converted)

(2) Equations

For each ethylene oxide production train, calculate IP CO₂ emissions using the following equation

$$CO_{2,p} = \left(\sum_{i=1}^N \left[m_{C_2H_4 \text{ feed},i} - m_{C_2H_4 \text{ loss},i} - \left(m_{EO,i} \times \frac{28.05}{44.05} \right) \right] / 28.05 \right) \times 2 \times 44.01 \quad \text{Equation 8-14}$$

Where:

- CO_{2,p} = CO₂ mass emissions from ethylene full oxidation in reporting period, *p* (tonnes CO₂).
- i* = Measurement period.
- N* = Number of measurement periods in reporting period.
- m*_{C₂H₄ feed,*i*} = Mass of ethylene (C₂H₄) feed for reaction in measurement period *i* (tonne).
- m*_{C₂H₄ loss,*i*} = Mass of ethylene (C₂H₄) carried out in the waste gas in measurement period *i* (tonnes); calculated by Equation 8-14a.
- m*_{EO,*i*} = Mass EO produced in period *i* (tonne), calculated from production of monoethylene glycol (MEG), diethylene glycol (DEG), and/or triethylene glycol (TEG), heavy glycols and glycol water in equation 8-14b or other equations depending on the available sampled parameters and concentrations.
- 2 = Number of moles of carbon in C₂H₄.
- 44.01 = Molecular weight of CO₂ (kg/kmol).
- 28.05 = Molecular weight of C₂H₄ (kg/kmol).
- 44.05 = Molecular weight of ethylene oxide (C₂H₄O) (kg/kmol).

$$m_{C_2H_4,loss} = Q_{vent} \times C_{C_2H_4} / 1000 \quad \text{Equation 8-14a}$$

Where:

- Q*_{vent} = Vent gas flow rate in the reporting period (m³).
- C*_{C₂H₄ loss,*i*} = Concentration of the ethylene (kg/m³) in the vent gas based on measurements.

$$m_{EO,p,i} = m_{MEG} \times 0.710 + m_{DEG} \times 0.830 + m_{TEG} \times 0.880 + m_{HG} \times a + m_{GW} \times b \quad \text{Equation 8-14b}$$

Where:

- m*_{MEG} = Mass of monoethylene glycol production.
- 0.710 = Ethylene oxide equivalency of monoethylene glycol production.
- m*_{DEG} = Mass of diethylene glycol production.
- 0.830 = Ethylene oxide equivalency of diethylene glycol production.

m_{TEG}	=	Mass of triethylene glycol production.
0.880	=	Ethylene oxide equivalency of triethylene glycol production.
m_{HG}	=	Mass of heavy glycol if applicable.
a	=	Ethylene oxide equivalency of heavy glycol based on site specific heavy glycol composition.
m_{GW}	=	Mass of glycol water if applicable.
b	=	Ethylene oxide equivalency of heavy glycol based on site specific glycol water composition of glycol water.

(3) Data requirements

- The mass of ethylene reacted, mass of ethylene loss and ethylene oxide production are required for the calculation.
- The monthly mass of ethylene oxide should be calculated from the monthly production of all the products: MEG, DEG, TEG, heavy glycol and glycol water, if applicable.
- The quantities of monthly ethylene feed must be based on monthly purchase and accounting records or direct measurements.
- Ethylene content in waste or vent stream should be measured and recorded monthly at minimum.

8.6 CO₂ from use of carbon as reductant

(1) Introduction

CO₂ can be generated when carbon is used directly as a chemical reductant to reduce oxide ores to metals in smelting operations. The consumption of carbon electrodes is a special example of carbon used for metals production.

(2) Equation

For any carbon used in a chemical reaction, calculate IP CO₂ emissions using the following equation:

$$CO_{2,p} = m_c \times 3.664 \quad \text{Equation 8-15}$$

Where:

$CO_{2,p}$	=	CO ₂ mass emissions from consumption of carbon in reporting period, p (tonnes CO ₂).
m_c	=	Mass of carbon consumed (tonnes) in the reporting period. For impure forms of carbon, this quantity is calculated as material mass times carbon content (e.g. 1,000 tonnes x 98.6% C = 986 tonnes C).
3.664	=	Ratio of molecular weights, CO ₂ to carbon.

(3) Data requirements

- The mass of carbon used is quantified monthly from purchase records, adjusted for inventory, or direct measurement.
- The carbon content of material consumed monthly is based on sampling and chemical analysis using a suitable industry standard method.

8.7 N₂O from nitric acid production

8.7.1 Introduction

Nitric acid (HNO₃; NA) is produced by the oxidation of anhydrous ammonia (NH₃) followed by the absorption of nitrogen oxides (NO, NO₂, N₂O) by water (H₂O). Nitric acid is produced as a 60% solution from the absorber tower. The NO_x absorber tail gas contains unabsorbed nitrogen oxides (NO, NO₂, N₂O), which must be controlled prior to release. NO_x abatement systems, such as Non-Selective Catalytic Reduction (NSCR) systems, are used to reduce NO, NO₂, and N₂O emissions from NO_x absorber tail gas. Nitrous oxide (N₂O) is present in very small concentrations as a by-product of the oxidation reaction and some of this N₂O is emitted in the absorber tail gas as an IP emission.

8.7.2 Tier 1 - Method 1: N₂O Emission factor method for systems with abatement downtime

(1) Introduction

The N₂O Emission Factor Method is used for nitric acid trains that do **not** measure N₂O emissions directly using a CEMS and had abatement downtime when the NO_x abatement system was bypassed for a certain period of time during the reporting period. This method requires an annual measurement of N₂O concentration in the NO_x Absorber tail gas stream (before the NO_x abatement system) and N₂O concentration in the final stack gas stream (after the NO_x abatement system).

(2) Equations

For each nitric acid train, calculate IP N₂O emissions using the following equation:

$$N_2O_p = m_{PNA} \times EF_{N2O,NAO} \times (1 - (DF_{N2O} \times AF_{N2O})) \times 0.001 \quad \text{Equation 8-16}$$

Where:

N ₂ O _p	=	N ₂ O mass emissions from nitric acid production in reporting period, <i>p</i> (tonnes N ₂ O).
m _{PNA}	=	Production mass of nitric acid (100% basis), (tonnes nitric acid product) in reporting period.
DF _{N₂O}	=	Average destruction efficiency of NO _x abatement system (%), determined by either: 1) Manufacturer's specifications; 2) Documented engineering estimates based on process knowledge; or 3) Calculated using the direct measurement as shown in Equation 8-16a if the test personal can safely access the upstream of the NO _x abatement system.
EF _{N₂O,NAO}	=	Average N ₂ O emission factor for NO _x Absorber Outlet (NAO) (kg N ₂ O per tonne nitric acid), as defined in Equation 8-16b.
AF _{N₂O}	=	NO _x abatement system operating fraction (%) in the reporting period, as defined in Equation 8-16c.
0.001	=	Mass conversion factor (t/kg).

The average destruction efficiency can be calculated using the following equation:

$$DF_{N2O} = \frac{(C_{N2O,NAO} \times Q_{N2O,NAO} - C_{N2O,NAS} \times Q_{N2O,NAS})}{C_{N2O,NAO} \times Q_{N2O,NAO}} \times 100\% \quad \text{Equation 8-16a}$$

Where:

DF_{N_2O}	=	Average abatement system destruction efficiency (%) in reporting period.
$C_{N_2O,NAO}$	=	N_2O concentration (ppmv) from the NO_x Absorber Outlet (NAO).
$Q_{N_2O,NAO}$	=	Flow rates (m^3/h) from the NO_x Absorber Outlet (NAO).
$C_{N_2O,NAS}$	=	N_2O concentration (ppmv) from the Nitric Acid Stack (NAS).
$Q_{N_2O,NAS}$	=	Flow rates (m^3/h) from the Nitric Acid Stack (NAS).

The train-specific average N_2O emission factor is calculated based on direct measurement of N_2O concentration in the NO_x Absorber outlet (NAO).

$$EF_{N_2O,NAO} = \frac{\sum_{i=1}^N \frac{Q_{NAO,i} \times C_{N_2O,NAO,i}}{PR_{NA,i}} \times 1.861 \times 10^{-6}}{N}$$

Equation 8-16b

Where:

$EF_{N_2O,NAO}$	=	Average N_2O emission factor for NO_x Absorber Outlet (kg N_2O per tonne nitric acid).
i	=	Test runs.
N	=	Number of N_2O measurement test runs during stack test.
$Q_{NAO,i}$	=	Volumetric flow rate of effluent gas at NO_x Absorber Outlet during test run i (sm^3/h) at $15^\circ C$ & 1 atm.
$C_{N_2O,NAO,i}$	=	Measured N_2O concentration at NO_x Absorber Outlet in test run i (ppmv N_2O);
$PR_{NA,i}$	=	Measured nitric acid production rate during test run i (tonnes nitric acid per hour).
1.861×10^{-6}	=	N_2O Density conversion factor ($kg/sm^3 \cdot ppmv^{-1}$; at $15^\circ C$ & 1 atm).

The NO_x abatement operating fraction (AF_{N_2O}) is a measure of the fraction of total nitric acid production where N_2O emissions are controlled by an operating NO_x abatement system. This factor corrects the N_2O equation for any periods during the year when the N_2O destruction by the NO_x abatement system is not applied. For operations having 100% NO_x abatement uptime, the default $AF_{N_2O} = 1.0$.

$$AF_{N_2O} = \frac{PR_{NA,Abate}}{PR_{NA,Total}}$$

Equation 8-16c

Where:

AF_{N_2O}	=	NO_x abatement system operating fraction (%) in the reporting period.
$PR_{NA,Abate}$	=	Nitric acid production when NO_x abatement system is operating (tonnes nitric acid) in the reporting period.
$PR_{NA,Total}$	=	Total nitric acid production (tonnes nitric acid) in the reporting period.

(3) Data requirements

- The nitric acid production for the reporting period and the monthly nitric acid production when the N_2O abatement system is operating must be determined from measurement systems used for accounting purposes.
- Stack tests to determine $EF_{N_2O,NAO}$ must be conducted at least once per year. A minimum of three test runs for each stack test and hourly measurement of nitric acid production are required during the

stack test and the results averaged. N₂O concentrations must be measured by one of the following tests:

- U.S. EPA Method 320 (40 CFR Part 63, Appendix A) or any method equivalent to this;
- ASTM D6348;
- Any equivalent method published by Environment and Climate Change Canada or Provinces.
- Conduct the performance tests for determining the EF_{N₂O,NAO} when nitric acid production process has changed or abatement equipment is installed.
- The NO_x abatement system destruction efficiency is determined by direct measurement, tests must occur at least once every three years, using the same N₂O concentration methods outlined above.
- For the calculation of AF_{N₂O}, the operating time of the NO_x abatement system during the reporting period must be determined hourly.

8.7.3 Tier 2 - Method 2: N₂O emission factor method for direct stack test

(1) Introduction

The N₂O Emission Factor Method is used for nitric acid production where NO_x abatement systems are integrated within the operating process and cannot be bypassed. A site specific emission factor is developed based on N₂O emissions by stack testing on the final Nitric Acid Stack (NAS) and production rate during the stack test.

(2) Equations

$$N_2O_p = m_{PNA} \times EF_{N_2O,NAS} \times 0.001 \quad \text{Equation 8-17}$$

Where:

- N₂O_p = N₂O mass emissions from nitric acid production in the reporting period, *p* (tonnes N₂O).
- m_{PNA} = Production mass of nitric acid (100% basis) (tonnes nitric acid product) in reporting period.
- EF_{N₂O,NAO} = Average N₂O emission factor (kg N₂O per tonne nitric acid) for the final Nitric Acid Stack (NAS) based on the direct stack testing of the final N₂O emission stack and calculated in Equation 8-17a.
- 0.001 = Mass conversion factor: tonnes per kg.

$$EF_{N_2O,NAS} = \frac{\sum_{i=1}^N \frac{Q_{NAS,i} \times C_{N_2O,NAS,i}}{PR_{NA,i}} \times 1.861 \times 10^{-6}}{N} \quad \text{Equation 8-17a}$$

Where:

- EF_{N₂O,NAO} = Average N₂O emission factor based on final Nitric Acid Stack (NAS) (kg N₂O per tonne nitric acid) in the reporting period.
- i* = Test runs.
- N* = Number of N₂O measurement test runs during stack test;
- Q_{NAS,*i*} = Volumetric flow rate of effluent gas at final NAS during test run *i* (sm³/h) at 15°C & 1 atm.
- C_{N₂O,NAO,*i*} = Measured N₂O concentration at NAS in test run *i* (ppmv N₂O);

$PR_{NA,i}$ = Measured nitric acid production rate during test run i (tonnes nitric acid per hour).
 1.861×10^{-6} = N_2O Density conversion factor ($kg/sm^3 \cdot ppmv^{-1}$; at $15^\circ C$ & 1 atm).

(3) Data requirements

- The nitric acid production for reporting period and the monthly nitric acid production when the N_2O abatement system is operating must be determined from measurement systems used for accounting purposes.
- Stack tests to determine $EF_{N_2O,NAS}$ must be conducted at least once per year. A minimum of three test runs for each stack test and hourly measurement of nitric acid production are required during the stack test and the results averaged.
- The performance test for determining the $EF_{N_2O,NAS}$ must be conducted when nitric acid production process has changed including abatement equipment installation.

8.7.4 Tier 3 - CEMS Method

(1) Introduction

The CEMS Method is a continuous direct measurement of stack flow and N_2O concentrations, which is used to determine the mass flow of N_2O emissions in the stack.

(2) Equation

For each nitric acid production train, calculate N_2O emissions from a CEMS in the reporting period using the following equation. Add N_2O emissions calculated from each train to calculate the total N_2O emissions.

$$N_2O_p = \sum_{t=1}^T \left[vel_{s,t} \times Area_s \times C_{N_2O,t} \times \left(\frac{P_{act,t} \times 288.15}{101.325 \times T_{act,t}} \right) \right] \times \frac{MW_{N_2O}}{23.645} \times 0.001 \quad \text{Equation 8-18}$$

Where:

N_2O_p = N_2O mass emissions from nitric acid production in reporting period, p (tonnes N_2O).
 t = CEMS data reporting interval (hour).
 T = Number of CEMS data reporting intervals in reporting period ($T = 8,760$ hours for a non-leap year annual reporting period).
 vel_s = Stack gas velocity (m/h), measured by continuous ultrasonic flow meter.
 $Area_s$ = Stack cross-sectional area (m^2).
 $C_{N_2O,t}$ = N_2O concentration (wet basis) of stack gas ($kmol_{N_2O}/kmol_{GAS}$), measured by in-situ gas analyzer; (If analyzer provides N_2O concentration in ppmv, then $C_{N_2O,t} = ppmv \times 10^{-6}$).
 MW_{N_2O} = Molecular weight of $N_2O = 44.01$ kg/kmol.
 P_{act} = Measured actual pressure of stack gas volume (kPa).
 T_{act} = Measured actual temperature of stack gas volume (K).
 288.15 = Standard temperature (K).
 101.325 = Standard pressure (kPa).
 23.645 = Standard molar volume at standard conditions as defined in Appendix C.
 0.001 = Mass conversion factor: tonnes per kg.

(3) Data requirements

- Measure N₂O concentration continuously using an in-situ gas analyzer, based on one of the following test methods:
 - U.S. EPA Method 320 (40 CFR Part 63, Appendix A) or any method equivalent to this using Fourier Transform Infrared (FTIR) Spectroscopy;
 - ASTM D6348;
 - Any equivalent method published by Environment and Climate Change Canada or Provinces.
- Measure stack gas temperature and pressure continuously using stack instruments.

8.8 CO₂ from thermal carbon black production

(1) Introduction

The production of thermal carbon black is resulted from the thermal cracking of natural gas based on the following theoretical chemical reaction, where the natural gas is assumed to be primarily methane:

Theoretical Chemical Reaction: $CH_4 = 2H_2 + C$

The off-gas that is generated from this process typically consists of hydrogen, uncracked hydrocarbons, and other smaller constituents. This off-gas may be captured and used as a supplemental fuel to generate energy for the thermal cracking process. The CO₂ emissions generated from the combustion of the off-gas are considered to be stationary fuel combustion emissions. The calculation methodologies for these emissions are prescribed in Chapter 1 of the Quantification Methodologies document.

In addition to offgas combustion, there is combustion of residual carbon that remains in the reactor that can not be extracted as product. The emissions from the combustion of the residual carbon is considered to be IP as the combustion is unavoidable in the chemical production of carbon black.

(2) Equations

The CO₂ emissions from the combustion of the residual carbon are determined using Equation 8-19. Equation 8-19a provides the equation to calculate the mass of carbon in the gaseous feedstock and offgas.

$$CO_{2,p} = (m_{C,Feed,p} - m_{C,Product,p} - m_{C,Offgas,p}) \times 3.664 \quad \text{Equation 8-19}$$

where:

CO _{2,p}	=	CO ₂ mass emissions from the combustion of residual carbon in the thermal carbon black production process during the reporting period, <i>p</i> (tonnes CO ₂).
m _{C, Feed, p}	=	Mass of carbon in the feedstock consumed in the reporting period, <i>p</i> (tonnes C).
m _{C, Product,p}	=	Mass of carbon in the product produced in the reporting period, <i>p</i> (tonnes C).
m _{C, Offgas,p}	=	Mass of carbon in the offgas consumed in the reporting period, <i>p</i> (tonnes C).
3.664	=	Ratio of molecular weights, CO ₂ to carbon.

$$m_{C,Feed,p} \text{ or } m_{C,Offgas,p} = v_{fuel(gas)} \times CC_{gas,p} \times 0.001 \quad \text{Equation 8-19a}$$

Where:

m _{C,Feed,p} or m _{C,Offgas,p}	=	Mass of carbon in the gaseous feedstock or offgas used during the reporting period, <i>p</i> (tonnes C).
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$V_{\text{fuel (gas),p}}$	=	Volume of the gaseous feedstock or offgas (m^3) during the reporting period, p , at standard conditions as defined in Appendix C.
$CC_{\text{gas,p}}$	=	Weighted average carbon content of the gaseous feedstock or offgas during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of kilogram of carbon per standard cubic metre of gaseous fuel ($\text{kg C}/\text{m}^3$).
0.001	=	Mass conversion factor (t/kg).

(3) Data requirements

- Facilities must ensure that the proper units of feedstock and offgas consumption and carbon content are applied in Equation 8-19a.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.
- Mass of carbon in the product must be based on the facility's production accounting methods used for the sale of product.

Superseded

12.0 Quantification of Imports

12.1 Introduction

Imports are considered to be useful thermal energy, electricity and/or hydrogen that are brought into the facility from another facility for consumption in production activities and/or facility operations. Imports do not include quantities of thermal energy, electricity, and/or hydrogen that are generated and consumed within the facility boundaries. Generation and export of these parameters are quantified in a similar manner but are reported as a product, as described in Chapter 13.

There is considerable variation in the consumption of imported and onsite generated electricity, heat, and hydrogen in Alberta facilities, leading to variation in their direct emissions despite otherwise comparable activity. Data on these imports allows these differences to be taken into account when facility performance is compared over time, and across facilities. While other imports also play a role in facility emissions variations, electricity, heat, and hydrogen imports explain many significant emissions performance differences observed. The quantification of these imports should be supported by documents such as invoices or third party documentation, whenever possible, because they represent the shared position of both parties (producer and importer) involved in these imports.

The reporting of imported quantities should be consistent with the overall facility boundaries used for emissions and production reporting. For example, the inclusion of camps, roads, and construction equipment must be consistent with facility boundary definitions.

12.2 Imported Useful Thermal Energy

Imported useful thermal energy refers to energy in any form transferred from a facility producing industrial heat to another facility or residual thermal energy returning to a facility producing industrial heat from a regulated facility or registered offset project, including heat transfer fluids, steam, and hot water. Imported useful thermal energy is to be reported based on third party invoices of total heat imported, if available. If third party invoices of total heat imported are not available then total heat imported is to be calculated in accordance to Chapter 13.9.

The total heat imported is to be reported as follows:

$\text{Heat}_{\text{imported}}$ = Amount of useful thermal energy imported to the facility, reported in GJ.

12.3 Imported Electricity

Imported electricity refers to electricity generated outside the facility and delivered to the facility from the grid or directly from electricity suppliers. Imported electricity is to be reported based on third party invoices of total imported electricity if available. If third party invoices of imported electricity are not available then total imported electricity is to be calculated in accordance to Chapter 13.6.

The total electricity imported is to be reported as follows:

E_{imported} = Amount of electricity imported to the facility in MWh.

12.4 Imported Hydrogen

Imported hydrogen refers to hydrogen manufactured outside the facility and delivered to the facility. Imported hydrogen is to be reported where hydrogen is greater than 5% of the gas stream by volume. Imported hydrogen is to be reported based on third party invoices of total imported hydrogen if available. If third party invoices of imported hydrogen are not available then total imported hydrogen is to be calculated in accordance to Chapter 13.8.

The hydrogen imported is to be reported as follows:

H_{imported} = Amount of imported hydrogen in tonnes.

As the imported hydrogen stream may contain other constituents (i.e. hydrocarbons, etc.), only the mass of the hydrogen component is reported.

Superseded

13.0 Quantification of Production

13.1 Introduction

Product data quantification and reporting procedures differ by product. For most product data, reporting is based on production quantities of the finished products. Reporters may use two methodologies for reporting production quantities of finished product data: i) production data and ii) sales data with an inventory adjustment. These two methodologies are considered equivalent. The following table provides the production units that must be reported for each sector.

The quantification of the reported production must be based on direct measurements or a method that is used for accounting records and/or sales records with third parties, except when the production is based on specific references or approaches (e.g. refining, in-situ, and mining oil sands sectors).

Specific products covered in this chapter are those for which established benchmarks have been developed under the *Carbon Competitiveness Incentive Regulation* (CCIR). Definitions of these products are provided in Schedule 2 of the CCIR. This section covers the quantification of production where the definition of what qualifies as a product is covered in the CCIR.

Table 13-1 Products and Production Units

Product	Description/Unit
Ammonia	Tonnes of ammonia (tonnes)
Ammonium Nitrate	Tonnes of ammonium nitrate (tonnes)
Bituminous Coal	Tonnes of clean coal (tonnes)
Cement	Tonnes of clinker, mineral additives (gypsum and limestone) and Supplementary Cementitious Materials added to the clinker produced (tonnes)
Electricity	Megawatt hours (MWh)
Ethylene Glycol	Tonnes of ethylene glycol (tonnes)
Hardwood Kraft Pulp	Air Dried Metric tonnes (ADMt)
High Value Chemicals (HVC)	Tonnes of HVC (tonnes)
Hydrogen	Tonnes of hydrogen (tonnes)
Industrial Heat	Gigajoules (GJ)
Oil Sands In Situ Oil Bitumen	Cubic meter of bitumen (m ³)
Oil Sands Mining Bitumen	Cubic meter of bitumen (m ³)
Refining	Alberta Complexity-Weighted Barrel Thousands of barrels (thousand bbl)
Softwood Kraft Pulp	Air Dried Metric tonnes (ADMt)

13.2 Ammonia

Ammonia means a compound that is composed of nitrogen and hydrogen with a chemical formula of NH_3 that is typically produced by steam hydrocarbon reforming.

Ammonia production should be reported in tonnes of ammonia. The purity grade of the reported amount should be at least a 99% of ammonia by mass. Production should be measured by mass or by volume at standard conditions as defined in Appendix C.

13.3 Ammonium Nitrate

Ammonium Nitrate is a soluble crystalline solid that can be sold in solid or liquid form, composed of nitrogen and hydrogen with a chemical formula of NH_4NO_3 that is typically produced by the reaction of ammonia with nitric acid.

Ammonium Nitrate production should be measured and reported in tonnes of ammonium nitrate. The purity grade of the reported amount should be at least a 99% of Ammonium Nitrate.

13.4 Bituminous Coal

Bituminous Coal is a moist, mineral-matter free coal which is recovered or obtained from a coal mine located in the Mountain or Foothills regions of Alberta.

Clean Coal means coal which is processed to give a clean, uniform product for sale. In general, a clean coal product would meet product specifications with negotiated maximum and minimum values for ash, volatiles, fixed carbon, sulphur, total moisture, and free swelling index.

Bituminous coal production is to be reported in tonnes of clean coal as delivered.

13.5 Cement

Cement is a fine powered material that consists of a mixture of clinker, gypsum, limestone, and supplementary cementitious materials.

Cement production shall be measured and reported in tonnes after final blending. Cement production is the total mass of clinker produced in tonnes, including mineral and other additives (gypsum, limestone and supplementary cementitious materials).

13.6 Electricity

Electricity means electricity that is exported from the facility. Report electricity production as the total electricity either sold to the end user directly or transmitted to the Alberta Electric System Operator (AESO) controlled grid or an Industrial System (ISD). Electricity transactions (the purchase, sale, import or export of electric power) must be quantified in accordance with the AESO ISO definition for “metered energy” (ISO rule (2010-07-23)). Metered energy means the quantity of electric energy transferred to a point of delivery or from a point of supply, in MWh, reflected by the relevant metering equipment during a particular period of time.

13.7 Ethylene Glycol

As defined by CCIR.

13.8 Hardwood Kraft Pulp

Hardwood Kraft Pulp means wood pulp processed from hardwood species (typically Aspen, Balsam Poplar, or White Birch) by a sulphate chemical process using cooking liquor. Annual Hardwood Kraft Pulp production should be reported in ADMt (Air Dry Metric Tonnes - 10% moisture by mass). Actual mass and moisture content should be measured by bale with measured mass corrected back to a 10% moisture basis.

13.9 High Value Chemicals

As defined by CCIR.

13.10 Hydrogen

Hydrogen is a colorless elemental gas represented by the chemical formula H₂ and is typically produced by, steam methane reforming or hydrocarbon fractionation. Annual production of hydrogen is based on direct measurements, accounting records or sales records with third parties. As the hydrogen product stream may contain other constituents (i.e. hydrocarbons, etc.), only the mass of the hydrogen component is reported.

13.11 Industrial Heat

Industrial heat is quantified as the total heat sold to a third party. Returned boiler feed water or low pressure steam energy is not subtracted as this is to be separately reported as imported heat. Annual production of Industrial Heat is based on sales records with third parties, or calculated in accordance with Chapter 17, Tier 3 and Appendix C.

13.12 Oil Sands In Situ Bitumen

Oil sands in situ bitumen shall be reported consistent with the methodology required by Directive 042: Measurement, Accounting, and Reporting Plan (MARP) Requirement for Thermal Bitumen Schemes and used for the Statistical Report 53 (ST-53) published by the Alberta Energy Regulator in cubic meters.

13.13 Oil Sand Mining Bitumen

Oil sands mining bitumen shall be reported as the total mined crude bitumen production corrected for inventory changes consistent with the methodology used for the Statistical Report 39 (ST-39) published by the Alberta Energy Regulator in cubic meters.

13.14 Refining

13.14.1 Introduction

Refining means any manufacturing or industrial process that occurs at a refinery at which crude oil or bitumen is processed or refined into a transportation fuel.

Complexity Weighted Barrel or CWB is a metric created by Solomon Associates to evaluate the greenhouse gas efficiency of petroleum refineries and related processes. The Canadian version of the methodology (CAN-CWB) is outlined in *The CAN-CWB Methodology for Regulatory Support: Public Report, January 2014* (CAN-CWB Methodology).

Alberta has adapted the CAN-CWB to the regulatory and technical requirements in the province introducing the Alberta Complexity Weighed Barrel (AB-CWB) for use as production metric for the refining sector in the province.

13.14.2 Calculations

The AB-CWB methodology is based on three components from the CAN-CWB: the Process CWB, the CWB credit for off-sites and non-energy utilities and the CWB credit for non-crude sensible heat. The CWB adjustments for sales and exports of steam and electricity are not applied in the AB-CWB calculation, since this is already addressed in the CCIR framework which provides allocations for these exports.

The steps for determining the refining production in units of AB-CWB are described below:

13.14.3 Alberta Process CWB

The calculation of the CWB process component is defined as per CAN-CWB methodology and is provided as Equation 13.14-17, with the following two exceptions:

- The CWB Factor for all types of hydrogen production is set to 5.7, independent of the technology and/or feedstock used for hydrogen production.
- The fluid catalytic cracking (FCC) Coke on Catalyst (vol. %) factor is estimated based on the Grace-Davison method described below through equations 13.14 to 13.14-16. The FCC coke on Catalyst (vol. %) factor is then used to calculate the process CWB factor for the FCC unit per CAN-CWB Methodology.

$$FCC\ Coke\ on\ Catalyst\ vol\% \ factor_y = Coke\ Yield_y \times \frac{350}{342.17} \times Specific\ Gravity \quad \text{Equation 13.14-1}$$

Where:

FCC Coke on Catalyst vol% factor_y = Required input parameter in process CWB
 y = Reporting period
 Coke Yield = Weight percent of Fresh Feed as calculated below (unitless)
 Specific Gravity = As calculated below (unitless)
 350/342.17 = Solomon conversion (lb/bbl over lb/bbl)

$$Specific\ Gravity = \frac{141.5}{API\ Gravity + 131.5} \quad \text{Equation 13.14-2}$$

Where:

API Gravity = As measured for combined FCC feed or aggregate of all equivalent FCC feed streams

$$Coke\ Yield = 100 \times \frac{Total\ Coke}{FF\ Rate} \quad \text{Equation 13.14-3}$$

Where:

Total Coke = As calculated below (lb/hr)
 FF Rate = Fresh feed rate as calculated below (lb/hr)

$$\text{Total Coke} = \text{Carbon Regen Burn Rate} + \text{Hydrogen Regen Burn Rate} + \text{Sulphur Regen Burn Rate} + \text{Nitrogen Regen Burn Rate} \quad \text{Equation 13.14-4}$$

Where:

Carbon Regen Burn Rate = As calculated below (lb/hr)
 Hydrogen Regen Burn Rate = As calculated below (lb/hr)
 Sulphur Regen Burn Rate = As calculated below (lb/hr)
 Nitrogen Regen Burn Rate = As calculated below (lb/hr)

$$\text{Carbon Regen Burn Rate} = \text{Molecular Wt C} * (\text{CO rate in flue gas} + \text{CO}_2 \text{ rate in flue gas}) \quad \text{Equation 13.14-5}$$

Where:

Molecular Wt C = 12.0107
 CO rate in flue gas = As calculated below as component rate (lb/hr)
 CO₂ rate in flue gas = As calculated below as component rate (lb/hr)

$$\text{Hydrogen Regen Burn Rate} = \text{Molecular Wt H}_2 * \text{H}_2\text{O rate in flue gas} \quad \text{Equation 13.14-6}$$

Where:

Molecular Wt H₂ = 2.01588
 H₂O rate in flue gas = As calculated below (lb-mole/hr)

$$\text{Sulphur Regen Burn Rate} = \text{Molecular Wt S} * (\text{SO}_2 \text{ rate in flue gas} + \text{SO}_3 \text{ rate in flue gas}) \quad \text{Equation 13.14-7}$$

Where:

Molecular Wt S = 32.065
 SO₂ rate in flue gas = As calculated below as component rate (lb-mole/hr)
 SO₃ rate in flue gas = As calculated below as component rate (lb-mole/hr)

$$\text{Nitrogen Regen Burn Rate} = \text{Molecular Wt N} * (\text{NO rate in flue gas} + \text{NO}_2 \text{ rate in flue gas}) \quad \text{Equation 13.14-8}$$

Where:

Molecular Wt N = 14.0067
 NO rate in flue gas = As calculated below as component rate (lb-mole/hr)
 NO₂ rate in flue gas = As calculated below as component rate (lb-mole/hr)

$$\text{Component Mol Rate in Flue Gas} = \text{Component mole \%} \times \text{Dry Flue Gas Mol Rate}/100 \quad \text{Equation 13.14-9}$$

Where:

Component Rate in Flue Gas = Applies to CO, CO₂, SO₂, SO₃, NO, NO₂, O₂

Component mole % = Measured mole % of component in flue gas (unitless)
 Dry Flue Gas Mol Rate = As calculated below (lb-mole/hr)

$$H_2O \text{ mol rate in flue gas} = \frac{2 \text{ mole } H_2}{\text{mole } O_2} \times [0.20947 \times \text{dry air mol rate} + O_2 \text{ purity} \times O_2 \text{ mol rate enriched} - 0.5 \times CO \text{ mol rate in flue gas} - CO_2 \text{ mol rate in flue gas} - SO_2 \text{ mol rate in flue gas} - 1.5 \times SO_3 \text{ mol rate in flue gas} - 0.5 \times NO \text{ mol rate in flue gas} - NO_2 \text{ mol rate in flue gas} - O_2 \text{ mol rate in flue gas}] \quad \text{Equation 13.14-10}$$

Where:

0.20947 = Fraction of O₂ in air (unitless)
 Blower Dry Rate = As calculated below (lb-mole/hr)
 O₂ purity = Mole fraction O₂ in O₂ enriched gas (unitless)
 O₂ mol rate enriched = Rate of enriched gas use as calculated below (lb-mole/hr)
 CO mol rate in flue gas = As calculated above as component rate (lb-mole/hr)
 CO₂ mol rate in flue gas = As calculated above as component rate (lb-mole/hr)
 SO₂ mol rate in flue gas = As calculated above as component rate (lb-mole/hr)
 SO₃ mol rate in flue gas = As calculated above as component rate (lb-mole/hr)
 NO mol rate in flue gas = As calculated above as component rate (lb-mole/hr)
 NO₂ mol rate in flue gas = As calculated above as component rate (lb-mole/hr)
 O₂ mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

$$\text{Blower Dry Rate} = \text{Dry Air Rate} \times \frac{60}{379.482} \quad \text{Equation 13.14-11}$$

Where:

60 = (minutes/hour)
 Blower Dry Volume = As calculated below (SCF/minute)
 379.482 = Molar volume ideal gas at 1 atm, 60 deg F (SCF/lb-mole)

$$\text{Dry Flue Gas Rate} = \frac{(0.78084 + 0.00934) \times \text{Dry air mol rate} + O_2 \text{ Purity} \times O_2 \text{ Mol rate enriched}}{\text{Regen Flue Gas } N_2 + AR \text{ mol rate}} \quad \text{Equation 13.14-12}$$

Where:

0.78984 = Mole fraction Nitrogen in air (unitless)
 0.00934 = Mole fraction Argon in Air (unitless)
 Dry air mol rate = As calculated below (lb-mole/hr)
 O₂ Purity = Mole fraction O₂ in O₂ enriched gas (unitless)
 O₂ mol rate enriched = As calculated below (lb-mole/hr)
 Regen Flue Gas N₂+AR mol rate = 1 – sum of mole fraction of CO, CO₂, SO₂, SO₃, NO, NO₂, O₂ in flue gas (unitless)

$$O_2 \text{ mol rate enriched} = O_2 \text{ volume enriched rate} \times \frac{60}{379.482} \quad \text{Equation 13.14-13}$$

Where:

60 = (minutes/hour)

O2 volume enriched rate = As measured (SCF/minute)
 379.482 = Molar volume ideal gas at 1 atm, 60 deg F (SCF/lb-mole)

$$\text{Dry Air Rate} = \text{Blower Wet Rate} \times (1 - \text{Water content in air}) \quad \text{Equation 13.14-14}$$

Where:

Wet Air Rate = Measured volume (SCF/minute). This may represent each source of air. Total air input must be captured if resulted from multiple blowers.

Water content in air = As calculated below

$$\begin{aligned} \text{Water content in Air} &= \frac{\text{Saturated Water Vapour Pressure}}{\text{Atmospheric Pressure}} \times \frac{\text{Relative Humidity}}{100} \\ &= \frac{6.1121 \times e^{(17.67 \times T / (243.5 + T))}}{\text{Atmospheric Pressure}} \times \frac{\text{Relative Humidity}}{100} \end{aligned} \quad \text{Equation 13.14-15}$$

Where:

Saturated Water Vapour Pressure = Based on Bolton Equation (mbar)
 T = Measured ambient temperature (deg C)
 Atmospheric Pressure = Measured (mbar)
 Relative Humidity = Measured (unitless)

$$\text{FF Rate} = \text{FF Volume} \times \frac{349.776}{24} \times \frac{141.5}{131.5 + \text{API Gravity}} \quad \text{Equation 13.14-16}$$

Where:

FF Volume = Measured fresh feed volume (B/D)
 349.776 = Water density at 60 F and 1 atm (lb/B)
 API Gravity = Measured API Gravity of fresh feed (unitless)
 24 = time conversion (hr/D)

$$\text{CWB}_{pro} = \sum_{u=1}^U \text{Daily Throughput Barrel}_u \times \text{CWB Factor}_u \quad \text{Equation 13.14-17}$$

Where:

CWB_{pro} [bbl/cd] = Alberta Process CWB as per CAN-CWB and section 13.14.3
 u = Units in the refinery boundaries as per CAN-CWB
 U = Total number of units in the refinery boundaries as per CAN-CWB
 Daily Throughput Barrel_u [bbl/cd] = Throughput for unit u as defined in CAN-CWB in bbl/cd
 CWB Factor_u = CWB factor for unit u as defined in CAN-CWB except for Hydrogen Production Unit.

13.14.4 Offsites and non-energy utilities CWB

The CWB credit for offsites and non-energy utilities (CWB_{off}) is calculated based on Process CWB and Total Input Barrels. Total Input Barrels are defined as all raw material inputs to the refinery less transfers of raw materials from the refinery. As per Solomon Associates raw materials include:

- Crude oil to be distilled and otherwise processed by the refinery.
- Natural gas liquids and intermediate hydrocarbon materials that are processed by the refinery, typically downstream from atmospheric crude distillation.
- Blending components and additives that are blended by the refinery into its final products.

In determining Total Input Barrels all liquids should be measured in barrels at 60 F and 1 atm while gasses including hydrogen, natural gas, fuel gas, ethane, ethylene, and coke should be expressed in Fuel Oil Equivalent Barrels where one Fuel Oil Equivalent Barrel is 6.05 million Btu based on lower heating value.

13.14.5 Non-crude input barrels

The CWB credit for non-crude sensible heat (CWB_{non}) is calculated based on the non-crude input barrels. Non-crude input barrels includes the total input raw material processed by the refinery other than crude or other materials entering the atmospheric distillation unit. As per Solomon Associates they potentially include:

- Hydrogen and hydrogen-rich gas
- Natural gas for hydrogen plant feed
- Butane, isobutane, and mixed butanes
- Natural gas liquids
- Naphtha
- Toluene
- Light cycle oil
- Sour kerosene
- Sour diesel
- Slop oil
- Atmospheric gas oil
- Coker gas oil
- Heavy/vacuum gas oil
- Vacuum residuum
- Residual fuel oil
- Atmospheric reduced crude oil and similar raw materials

All liquids should be measured in barrels at 60 F and 1 atm while gasses including hydrogen, natural gas, fuel gas, ethane, ethylene and coke should be expressed in Fuel Oil Equivalent Barrels where one Fuel Oil Equivalent Barrel is 6.05 million Btu based on lower heating value.

Blending raw materials which are not processed at the refinery are also not included. As per Solomon Associates these may include the following types of material:

- Product additives

- Motor gasoline products and blendstocks, including but not limited to the following:
 - Ethanol, ETBE, MTBE, and other oxygenates
 - Butanes, pentanes, hexanes, isooctane, isooctane, mixed aromatics, benzene, toluene, mixed xylenes, in addition to other specific hydrocarbons and hydrocarbon mixtures that are suitable for gasoline blending
 - Alkylate, cat poly gasoline, coker gasoline, and reformat
 - Motor gasoline product that is purchased for blending by the refinery
- Kerosene products and blendstocks
- Diesel products and blendstocks including, but not limited to, the following:
 - Vegetable oil
 - Biodiesel
 - Diesel product for blending that is purchased for blending by the refinery

13.14.6 Refinery production measured in units of AB-CWB

The refinery production, measured in units of AB-CWB (AB-CWB in thousands of barrels per calendar year) is calculated using equation 13.14-18 below:

$$\text{Refinery Production}_y = \frac{(CWB_{pro} + CWB_{off} + CWB_{non}) \times Days}{1000} \quad \text{Equation 13.14-18}$$

Where:

Refinery Production _y	=	AB-CWB Production of the refinery for year y, in thousand bbl/y
y	=	Reporting year
CWB _{pro} [bbl/cd]	=	As per equation 13.14-17 for the reporting year
CWB _{off} [bbl/cd]	=	0.327 × Total Input Barrels + 0.0085 × CWB _{pro}
CWB _{non} [bbl/cd]	=	0.44 × Non-Crude Input Barrels
Days	=	Days in the reporting year

The equation above includes the conversion from barrels per calendar day (as defined in the CAN-CWB method) to thousands of barrels per calendar year, which is the unit used in the AB-CWB.

13.15 Softwood Kraft Pulp

Softwood Kraft Pulp means wood pulp processed from softwood species (typically White Spruce, Black Spruce, or Lodgepole Pine) by a sulphate chemical process using cooking liquor. Annual Softwood Kraft Pulp production should be reported in ADMt (Air Dry Metric Tonnes - 10% moisture by mass). Actual mass and moisture content should be measured by bale with measured mass corrected back to a 10% moisture basis.

14.0 Quantification Methods for Carbon Dioxide from Combustion of Biomass

14.1 Introduction

This chapter presents the methodologies for CO₂ emissions from the combustion of biomass, while CH₄ and N₂O emissions from the combustion of biomass are considered to be stationary fuel combustion and are covered in Chapter 1.

14.2 Tier 1 - A fuel-specific default CO₂ emission factor

(1) Introduction

This method is used for biomass fuels based on a default CO₂ emission factor and the quantity of fuel consumed. The quantity of biomass consumed may be in energy or physical unit basis, which is measured by the facility using the methods prescribed in Chapter 17 and Appendix C. Biomass consumption measured or provided in units of energy must be based on the HHV of the fuel. Table 14-1 provides the emission factors for biomass fuels in mass of CO₂ emitted per gigajoules (GJ), tonnes or kilolitres (kl).

For facilities that have the HHV of the fuel, measured or supplied by the third party supplier, Equation 14-1 is used to convert the volume or mass of the fuel to the energy of the fuel based on the HHV and then multiplied by the appropriate energy based emission factor from Table 14-1 to calculate the CO₂ mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 14-1a can be used directly to calculate the CO₂ mass emissions based on the appropriate energy based emission factor from Table 14-1.

Facilities must use measured or supplied HHVs to determine the fuel consumption if this data is available; however in cases where a facility is unable to obtain this information, a facility may apply Equation 14-1a using the fuel quantity in mass/volume basis with the appropriate mass/volume based emission factor from Table 14-1 to calculate the CO₂ mass emissions.

Calculate the CO₂ mass emissions for the reporting period for each type of biomass by substituting a fuel-specific default CO₂ emission, a measured or supplied HHV and the fuel consumption for the reporting period into Equation 14-1 or Equation 14-1a.

(2) Equations

For a biomass fuel, use Equation 14-1 or Equation 14-1a to calculate the CO₂ mass emissions for the reporting period.

$$CO_{2,p} = Fuel_p \times HHV \times EF_{ene} \quad \text{Equation 14-1}$$

$$CO_{2,p} = Fuel_p \times EF_{vol} \text{ or } EF_{ene} \quad \text{Equation 14-1a}$$

Where:

CO_{2,p} = CO₂ mass emissions for the biomass fuel for the reporting period, *p* (tonnes CO₂).
Fuel_{*p*} = For Equation 14-1, the mass/volume of fuel combusted in tonnes or kilolitres (tonnes or kl). For Equation 14-1a, energy units of fuel in gigajoules or physical units of fuel in tonnes or kilolitres (GJ, tonnes, or kl). Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.

- HHV = Measured or supplied higher heating value in gigajoules per tonne or kilolitres (GJ/tonne or GJ/kl).
- EF_{vol}, EF_{ene} = Fuel-specific default CO₂ emission factor, from Table 14-1 in tonnes of CO₂ per energy units (GJ) or physical units (tonnes or kl).

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.

14.3 Tier 2 - Place marker.

14.4 Tier 3 - Measurement of fuel carbon content

(1) Introduction

Calculate the CO₂ mass emissions from biomass combustion by using the measured fuel carbon content using Equation 14-3a, Equation 14-3b, Equation 14-3c, or Equation 14-3d. For steam generation from biomass combustion, CO₂ mass emissions may be calculated using Equation 14-3e.

(2) Equations

For gaseous biofuels, where fuel consumption is measured in units of volume (m³), use Equation 14-3a:

$$CO_{2,p} = v_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001 \quad \text{Equation 14-3a}$$

For gaseous biofuels, where fuel consumption is measured in units of energy (GJ), use Equation 14-3b:

$$CO_{2,p} = \frac{ENE_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV} \quad \text{Equation 14-3b}$$

Where:

- CO_{2,p} = CO₂ mass emissions for the gaseous biofuel combusted during the reporting period, *p* (tonnes CO₂).
- v_{fuel(gas),p} = Volume of fuel (m³) at standard conditions combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.
- ENE_{fuel(gas),p} = Energy of fuel (GJ) at standard conditions combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.
- HHV = Weighted average higher heating value of biofuel (GJ/m³).
- CC_{gas,p} = Weighted average carbon content of the gaseous biofuel during the reporting period *p*, calculated in accordance with Chapter 17 and Appendix C. CC_{*p*} is expressed in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m³).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Mass conversion factor (t/kg).

For liquid biofuels, where fuel consumption is measured in units of volume (kl), use Equation 14-3c:

$$CO_{2,p} = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664 \quad \text{Equation 14-3c}$$

Where:

- $CO_{2,p}$ = CO₂ mass emissions for the liquid biofuels during the report period, p (tonnes CO₂).
- $v_{fuel(liq),p}$ = Volume of liquid biofuel combusted during the reporting period p , calculated in accordance with Chapter 17 and Appendix C (kl).
- $CC_{liq,p}$ = Weighted average carbon content of the liquid biofuel during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. CC_p is expressed in units of tonnes of carbon per kilolitres of liquid biofuel (tonnes C/kl).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

For solid biomass fuels, where fuel consumption is measured in units of mass (tonnes), use Equation 14-3d:

$$CO_{2,p} = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664 \quad \text{Equation 14-3d}$$

Where:

- $CO_{2,p}$ = CO₂ mass emissions for the biomass fuel during the report period, p (tonnes CO₂)
- $m_{fuel(sol),p}$ = Mass of biomass fuel combusted during the reporting period p , calculated in accordance with Chapter 17 and Appendix C (tonnes).
- $CC_{sol,p}$ = Weighted average carbon content of the fuel during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. CC_p is expressed in units of tonnes of carbon per tonnes of solid fuel (tonnes C/tonnes).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

For biomass combustion used to generate steam, use Equation 14-3e:

$$CO_{2,p} = \text{Steam} \times B \times EF \quad \text{Equation 14-3e}$$

Where:

- $CO_{2,p}$ = CO₂ mass emissions for the biomass fuel for the reporting period, p , (tonnes CO₂).
- Steam = Total steam generated by biomass fuel or biomass combustion during the reporting year (tonnes steam), in GJ and calculated in accordance with Chapter 17 and Appendix C.
- B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity in GJ per GJ provided by the manufacturer or calculated in accordance with Chapter 17 and Appendix C.
- EF = Measured emission factor for biomass solid fuel from a methodology approved by the director, in tonnes of CO₂ per GJ.

(3) Data requirements

No additional requirements are needed.

14.5 Tier 4 Continuous emissions monitoring systems

(1) Generality

Calculate the CO₂ mass emissions for the reporting period from all fuels combusted in a unit, by using data from CEMS as specified in (a) through (g). This methodology requires a CO₂ monitor and a flow monitoring subsystem, except as otherwise provided in paragraph (c). CEMS shall use methodologies in accordance with reference [8] in Appendix A or by other document that supersedes it.

- (a) For a facility that operates CEMS in response to federal, provincial or local regulation (i.e. required by the facility's Alberta Energy Regulator (AER) or Environmental Protection and Enhancement Act (EPEA) approval), use CO₂ or oxygen (O₂) concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) or in accordance with reference [8] in Appendix A.
- (b) Report CO₂ emissions for the reporting period in tonnes based on the sum of hourly CO₂ mass emissions over the reporting period.
- (c) An O₂ concentration monitor may be used in lieu of a CO₂ concentration monitor in a CEMS install before January 1, 2012, to determine the hourly CO₂ concentrations, if the effluent gas stream monitored by the CEMS consists of combustion products, and if only the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.
- (3) If the operator of a facility that combusts biomass fuels uses O₂ concentrations to calculate CO₂ concentrations, annual source testing must demonstrate that the calculated CO₂ concentrations, when compared to measured CO₂ concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in reference [8] in Appendix A or Alberta CEMS Code.
- (d) If both biomass and fossil fuels (including fuels that are partially biomass) are combusted during the reporting period, determine the biogenic CO₂ mass emissions separately, as described in Section 14.4 (2).
- (e) For any units using CEMS data, industrial process and stationary combustion CO₂ emissions must be provided separately. Determine the quantities of each type of fossil fuel and biomass consumed during the reporting period, using the fuel sampling approach in Table 17.3 of Chapter 17.
- (f) If a facility subject to requirements for continuous monitoring of gaseous emissions chooses to add devices to an existing CEMS for the purpose of measuring CO₂ concentrations or flue gas flow, select and operate the added devices using appropriate requirements in accordance with reference [8] in Appendix A for the facility, as applicable in Alberta under the Alberta CEMS Code.
- (g) If a facility does not have a CEMS and chooses to add one in order to measure CO₂ concentrations, select and operate the CEMS using the appropriate requirements in accordance with reference [8] in Appendix A or equivalent requirements as applicable in Alberta under the Alberta CEMS Code.

(2) CO₂ emissions from combustion of mixture of biomass, or biomass fuels and fossil fuels

Use the procedures in this section to estimate biogenic CO₂ emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels that are partially biomass.

- (a) If a CEMS is not used to measure CO₂ and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Tier 1, 2 or 3, as applicable, to calculate the biogenic CO₂ mass emissions for the reporting period from the combustion of biomass

- fuels. Determine the mass of biomass combusted using either company records or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use the best available information to determine the mass of biomass fuels and document the procedure.
- (b) If a CEMS is used to measure CO₂ (or O₂ as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels, use Tier 1, 2 or 3, as appropriate in Chapter 1, to calculate the CO₂ mass emissions for the reporting period from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO₂ emissions determined from the CEMS based methodology.
- (c) If combusted fuels or fuel mixtures contain a biomass fraction that is unknown or cannot be documented (e.g., wood waste and tire-derived fuel, etc.), or biomass fuels with no CO₂ emission factor provided in Table 14-1 use the following to estimate biogenic CO₂ emissions:
- (1) Tier 1, 2, 3 or 4 to calculate the total CO₂ mass emissions for the reporting period, as applicable.
 - (2) Determine the biogenic portion of the CO₂ emissions using ASTM D6866-16 “Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis”. This procedure is not required for fuels containing less than 5% biomass by weight or for waste-derived fuels that are less than 30% by weight of total fuels combusted in the year for which emissions are being reported, except, if a facility wishes to report a biomass fuel fraction of CO₂ emissions.
 - (3) Conduct analysis of representative fuel or exhaust gas samples at least every three months, using ASTM D6866-16. Collect the exhaust gas samples over a minimum of 24 consecutive hours following the standard practice specified by ASTM D7459-08(2016) “Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.”
 - (4) Allocate total CO₂ emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed annually for which emissions are being reported.
 - (5) If there is a common fuel source for multiple units at the facility, ASTM D6866-16 analysis may be conducted for only one of the unit sharing the common fuel source.
- (d) If Equation 14-1 or 14-1a is selected to calculate the biogenic mass emissions for the reporting period for wood, wood waste, or other solid biomass-derived fuel, Equation 14-4 may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified according to Chapter 17 and Appendix C. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$Fuel_i = \frac{[H \times Steam] - (HI)_{nb} \times (Eff)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}} \quad \text{Equation 14-4}$$

Where:

- Fuel_i = Quantity of biomass consumed during the measurement period i (tonnes/year or tonnes/month, as applicable) calculated in accordance with Section 17.
- H = Average enthalpy increase of the boiler steam through the boiler for the measurement period (GJ/tonne) calculated in accordance with Chapter 17.
- Steam = Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable) calculated in accordance with Chapter 17.

- (HI)_{nb} = Heat input from co-fired fossil fuel and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable) calculated in accordance with Chapter 17.
- (HHV)_{bio} = Default or measured higher heating value of the biomass fuel (GJ/tonne) calculated in accordance with Chapter 17.
- (Eff)_{bio} = Efficiency of biomass-to-energy conversion for boiler, expressed as a decimal fraction and calculated in accordance with Chapter 17.
- (Eff)_{nb} = Efficiency of fossil fuel and non-biomass derived fuel to energy conversion for boiler, expressed as a decimal fraction.

(3) Data requirements

No additional data requirement are needed.

14.6 Emission Factors

Table 14-1 Default emission factors for biomass fuels

Biomass Fuel	HHV (GJ/kl)	CO ₂ Emission Factor tonne/kl	tonne/GJ	Reference
Ethanol	23.42	1.508	0.0644	ECCC Table 2-2
Biodiesel	35.16	2.472	0.0703	ECCC Table 2-2
	HHV (GJ/tonne)	tonne/tonne	tonne/GJ	Reference
Wood Fuel / Wood Waste	18.0	0.840	0.0467	ECCC Table 2-3
Spent Pulping Liquor	14.0	0.891	0.0636	ECCC Table 2-3

17.0 Measurement, Sampling, Analysis and Data Management Requirements

17.1 Introduction

The methodologies prescribed in this chapter are intended to be aligned with methods that are prescribed under Environment and Climate Change Canada (ECCC) and other jurisdictions that regulate greenhouse gas emissions such as British Columbia, Ontario, Quebec, and California. Further, methodologies from organizations such as the Western Climate Initiative, Inc. (WCI), United States Environmental Protection Agency (USEPA), and the Intergovernmental Panel on Climate Change (IPCC) are referenced or adopted as appropriate for various activity types and modified to meet the needs of Alberta sectors.

17.2 Measurement requirements

17.2.1 Fuel consumption monitoring

- (a) Facilities may determine fuel consumption on the basis of direct measurement, fuel purchase records, or sales invoices measuring any stock change. Equation 17-1 is used to quantify fuel consumption.

$$Fuel = Fuel_p - Fuel_s + Fuel_{ii} - Fuel_{ei} \quad \text{Equation 17-1}$$

Where:

<i>Fuel</i>	=	amount of fuel used by the facility in the reporting year
<i>Fuel_p</i>	=	amount of fuel purchased and produced in the reporting year
<i>Fuel_s</i>	=	amount of fuel sold in the reporting year
<i>Fuel_{ii}</i>	=	initial amount of fuel in the inventories
<i>Fuel_{ei}</i>	=	ending amount of fuel in the inventories

Facilities may quantify liquid fuels consumed at the facility based on third party invoices for the reporting period without accounting for the initial and ending fuel quantities in the inventories for the reporting period provided that:

- (i) the liquid fuels are stored in a storage tank with a volume of 120,000 litres or less; and
 - (ii) the method to calculate these emissions are consistent from year to year.
- (b) Fuel consumption may be estimated per the following:
- (i) For Tier 1 classification, facilities may estimate fuel consumption from combustion equipment or mobile equipment based on the methodology outlined in Section C.6 of Appendix C.
 - (ii) For Tiers 2 and 3, Section C.6 of Appendix C can be used to estimate fuel use from negligible sources; otherwise Equation 17-1 must be used.
 - (iii) For Tiers 2 and 3, Section C.7 of Appendix C can be used to allocate fuel use for individual equipment if the total fuel use can be measured or quantified, but the fuel use for individual equipment cannot.
- (c) For liquid fuels, tank drop measurement can be used.
- (d) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.", or an alternative

method that is appropriate based on a method published by a consensus-based standards organization.

- (e) Fuel that is used as feed in industrial processes involving chemical or physical reactions other than combustion may utilize the same monitoring requirements as for fuel combustion. This includes gaseous fuels (i.e. natural gas) that are used in steam methane reforming processes.
- (f) Fuels that are self produced must be accurately measured over the reporting period. This may include mass flow meters that totalize the flow of consumed fuel over a specific period or fuel consumption based on Equation 17-1.

17.2.2 Calibration

All fuel oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated once every three years, upon replacement of a previously calibrated meter or at the minimum frequency specified by the manufacturer. For orifice, nozzle, and venturi flow meters, the calibration shall consist of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. For flow meters used for natural gas, the facility may follow the requirements prescribed by Alberta Energy Regulator, Measurement Canada, or other regulations or standards for electricity and gas, as applicable for the facility.

17.2.3 Fuel properties

(1) Density

- (a) Facilities using Tiers 1 or 2 for CO₂ emissions may use the default density values for fuel oil provided in Table B-3 in Appendix B, in lieu of using the ASTM method in paragraph (d) of Section 17.2.1.
- (b) For Tier 3, direct measurements of the density are required in accordance Section 17.3.

(2) Fuel heat content measurement requirement

Fuel heat content sampling and analysis shall be as follows:

- (a) For fuel heat content monitoring of natural gas, the facilities may
 - (i) Follow the requirements prescribed by Alberta Energy Regulator, Measurement Canada, or other regulations or standards for electricity and gas, as applicable for the facility;
 - (ii) Use on-line instrumentation that determines heating value accurate to within ±0.5 per cent and if such instrumentation provides only low heat value, the facility shall convert the value to HHV using Equation 17-2 in accordance with the following:
 - 1. The conversion factor (CF) for LHV to HHV, shall be determined as a fuel-specific average CF using the following:
 - (a) Concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the monthly carbon content determination; or
 - (b) The HHV/LHV ratio obtained from the laboratory analysis of the monthly samples

$$HHV = LHV \times CF \quad \text{Equation 17-2}$$

Where:

HHV = Fuel or fuel mixture higher heat value

LHV = Fuel or fuel mixture lower heat value
 CF = Conversion factor

- (b) For gases, use the most appropriate method published by a consensus-based standards organization, if such a method exists or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM D1826 "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter", ASTM D3588 "Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels", or ASTM D4891-, GPA Standard 2261 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography."
- (c) For middle distillates and oil, or liquid waste-derived fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM D240 "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter" or ASTM D4809 "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (d) For solid biomass-derived fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM D5865 "Standard Test Method for Gross Calorific Value of Coal and Coke." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (e) For waste-derived fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM D5865 and ASTM D5468 "Standard Test Method for Gross Calorific and Ash Value of Waste Materials."

17.2.4 Fuel carbon content monitoring requirements

The determination of fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier, online calibrated analyzers or determined by the operator, using an applicable analytical method listed below. For carbon content monitoring of natural gas, the facility may follow the requirements prescribed by Alberta Energy Regulator, Measurement Canada or other regulations or standards for electricity and gas, as applicable for the facility.

Appendix B: Fuel Properties and Appendix C: General Calculation Instructions provide guidance for the use of fuel properties and calculation of carbon content and carbon content uncertainties.

(1) Solid fuel

For coal and coke, solid biomass fuels, and waste-derived fuels, and any other solid fuel use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM 5373 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal". If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used. Operators of coal fired electricity generators are expected to apply additional quality control procedures to ensure accuracy of measured fuel carbon content.

(2) Liquid fuel

For liquid fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on ASTM D3238, and either ASTM D2502 "Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements" or ASTM D2503 "Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(3) Gaseous fuel

For gaseous fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM D1945 "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" or ASTM D1946 "Standard Practice for Analysis of Reformed Gas by Gas Chromatography." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

17.2.5 Releases

17.2.6 Venting

17.2.7 Fugitives

17.3 Equipment, fuel and properties sampling frequency

17.3.1 Introduction

The facility is required to obtain fuel samples pursuant to this standard quantification method by conducting fuel sampling or obtaining fuel sampling results from the fuel supplier in accordance with the following rules:

- (a) Fuel samples shall be taken at a location in the fuel handling system that provides a representative sample of the fuel combusted or consumed.
- (b) Fuel samples shall be obtained and analysis performed at the minimum frequencies prescribed in Table 17-3.
- (c) In the event that more than one sampling frequency criteria is applicable to a fuel type, the higher sampling frequency shall be applied.
- (d) If a facility is sampling at a higher frequency than prescribed in Table 17.3, the facility must ensure that the analysis used is representative and unbiased.
- (e) Facilities must be able to quantify the fuel consumed at the frequencies/intervals prescribed in Table 17-3, where the data is used to calculate the weighted average carbon content.
- (f) Samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

Table 17-3 Summary of Minimum Required Sampling/Monitoring Frequency

Type of Fuel	Tier 1	Tier 2	Tier 3
Purchased gasoline, and diesel,	No sampling required	No sampling required	No sampling required
Ethane, propane, and butane	No sampling required	No sampling required	No sampling required
Fuel received by batches	No sampling required	Six times a year	By shipment
Marketable natural gas	No sampling required	Six times a year	Monthly
Non-marketable liquid or gaseous fuels co-produced at an oil and gas production facility.	No sampling required	Quarterly	Monthly
Gases derived from biomass and biogas	No sampling required	Quarterly	Quarterly
Gaseous fuels, including refinery fuel gas and fuels used in industrial processes other than for combustion. This excludes marketable natural gas.	No sampling required	Every two weeks	Hourly (online instrumentation in place) Weekly (online instrumentation not in place)
Coal / Coke	No Sampling required	Monthly	Weekly
Solid fuels other than coal and coke	No sampling required	No sampling required	Monthly
Heat/Steam including industrial heat exported as a product (steam flow rate, steam discharge temperature and pressure)	Weekly	Daily	Hourly
Boiler efficiency (by fuel)	Manufacturer Specification	Every three years based on manufacturer specification	Every two years or during boiler planned maintenance based on manufacturer specification, whichever is lower

Weekly/monthly samples means the composition of several samples uniformly distributed over the period of the reported time.

17.3.2 Tier 1

- (a) Weekly samples and calculation of steam variables and properties, which includes steam flow, steam discharge temperature and pressure.
- (b) Manufacturer specification of boiler efficiency for each fuel used.

17.3.3 Tier 2

- (a) At least six times a year with a minimum period of 45 days between samples for shipment or delivery fuels received by batches, or the shipment/delivery if this occurs at lower frequency.
- (b) At least six times a year with a minimum period of 45 days between samples for marketable natural gas and fuels not received in batches.
- (c) Quarterly for non-marketable liquid or gaseous fuels co-produced at an oil and gas production facility.
- (d) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
- (e) Every two weeks for gaseous fuels including refinery fuel gas and fuels used in industrial processes other than for combustion. This excludes marketable natural gas.
- (f) Monthly composite samples of coke and/or coal.
- (g) Daily samples and calculations of steam variables and properties, which includes steam flow, steam discharge temperature and pressure.
- (h) Every three years for boiler efficiency testing for each used fuel, following manufacturer's specifications.

17.3.4 Tier 3

- (a) Once for each shipment or delivery fuels received by batches.
- (b) Monthly for natural gas and fuels not received in batches.
- (c) Monthly for liquid fuels or gaseous fuels produced at an oil and gas production facility.
- (d) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
- (e) Hourly for gaseous fuels other than marketable natural gas if the necessary equipment is in place to make these measurements.
- (f) Weekly for gaseous fuels other than marketable natural gas where the necessary equipment is not in place to make hourly measurements.
- (g) Weekly composite samples for coal and coke fuels.
- (h) Monthly composite samples of solid fuels other than coal and coke
- (i) Hourly samples and calculation of steam variables and properties, which includes steam flow, steam discharge temperature and pressure.
- (j) Every two years for boiler efficiency testing for each used fuel or during planned maintenance, whichever is lower, following manufacturer's specifications.

17.4 Data analysis and data management

17.4.1 Fuel reconciliation

When the fuel usage for the reporting of emissions is taken from an internal meter, reconciliations should be developed, where applicable, to ensure that internal meters are accurate. If reconciliation is performed, the reconciliation should be conducted at least once per reporting period. It is noted that facilities can only

conduct a reconciliation process if there are reference meters that can be used. For example, a facility may measure fuel consumption based on internal metering and also receives third party documentation for the amount of fuel consumed, which would allow a facility to conduct a reconciliation process.

$$\text{Reconciled Fuel}_{i,j} = \text{Non Adjusted Fuel}_{i,j} \times \left(1 + \frac{\Delta}{\text{Non-Adjusted Fuel}_i}\right) \quad \text{Equation 17-3}$$

$$\Delta = \text{Reference Fuel}_i - \text{Non Adjusted Fuel}_i \quad \text{Equation 17-4}$$

$$\text{Non Adjusted Fuel}_i = \sum_{j=1}^n \text{Non Adjusted Fuel}_{i,j} \quad \text{Equation 17-5}$$

Where:

Reconciled Fuel _{i,j}	=	Amount of reconciled stream j for the fuel i at standard conditions as defined in Appendix C.
Non-Adjusted Fuel _i These are	=	Amount of unreconciled fuel i at standard conditions. fuels that are quantified by the facility that have not been adjusted by a reconciliation process.
Non-Adjusted Fuel _{i,j} standard	=	Amount of unreconciled stream j for the fuel i in conditions as defined in Appendix C.
Reference Fuel _i	=	Reference amount of fuel i used for reconciliation of the several j streams, at standard conditions. For example, a reference fuel measurement may be fuel quantities measured by alternative metering used by the facility or fuel quantities provided by a third party fuel supplier.
Δ	=	Amount of fuel to be adjusted.

17.4.2 Procedures for estimating missing data

The following method for estimating missing data was adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements, December 2017.

Whenever a quality-assured value of a required parameter for emissions calculations is unavailable (e.g., if a CEMS malfunctions or fuel meter during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

- (a) Whenever analytical data relating to sampling is unavailable, the facility shall, using the methods prescribed in Section 17.3, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period; if this is not physically possible, the operator should follow the missing data approach.
- (b) Whenever sampling and measurement data required by Tier 1, 2, 3 or 4 for the calculation of emissions is missing the facility shall ensure that the data is replaced using the following missing data procedures:
 - (i) When the missing data concerns high heat value, carbon content, molecular mass, CO₂ concentration, water content or any other data sampled, the facility shall:
 1. Determine the sampling or measurement rate using Equation 17-6:

$$R = \frac{Q_{S\ Ac}}{Q_{S\ Required}}$$

Equation 17-6

Where:

- R = Sampling or measurement rate that was used, expressed as a percentage
 $Q_{S\ Ac}$ = Quantity of actual samples or measurements obtained by the facility
 $Q_{S\ Required}$ = Quantity of samples or measurements required under Section 17.3

2. Replace the missing data as follows:
 - a. If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the facility shall use the first available data from after the missing data period.
 - b. If $0.75 \leq R < 0.9$ and data directly effects estimated emissions: replace the missing data by the highest data value sampled or analyzed during the calendar year for which the calculation is made.
 - c. If $0.75 \leq R < 0.9$ and data inversely effects estimated emissions: replace the missing data by the lowest data value sampled or analyzed during the calendar year for which the calculation is made.
 - d. If $R < 0.75$ and data directly effects estimated emissions: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years or the maximum number of years of operation (if less than 3 years).
 - e. If $R < 0.75$ and data inversely effects estimated emissions: replace the missing data by the lowest data value sampled or analyzed during the 3 preceding years or the maximum number of years of operation (if less than 3 years).
- (ii) When the missing data concerns stack gas flow rate, fuel consumption or the quantity of sorbent used, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (c) A facility that uses CEMS shall determine the replacement data using the procedure in accordance with reference [8] in Appendix A or the following method:
 - (i) When the missing data is data measured by the CEMS:
 1. Determine the sampling or measurement rate using Equation 17-6
 2. Replace the missing data as follows:
 - a. If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the facility shall use the first available data from after the missing data period.
 - b. If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the calendar year for which the calculation is made.
 - c. If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years or the maximum number of years of operation (if less than 3 years).
 - (d) For missing data associated with the quantification of production items, the facility must utilized the best available data to assess the quantities during the missing period. This may include the use of engineering estimates (i.e. operating hours and equipment specifications). For further guidance, facilities may contact the director.

APPENDIX A: References

- [1] The CAN-CWB Methodology for Regulatory Support: Public Report. January 2014. Prepared by Solomon Associates for the Canadian Fuels Association
- [2] “2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines”: 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Intergovernmental Panel on Climate Change National Greenhouse Gas Inventories Program. Available online at: <http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html>
- [3] Canada’s Greenhouse Gas Quantification Requirements, Environment and Climate Change Canada, December 2017
- [4] National Inventory Report. 1990-2014. Greenhouse Gas Sources and Sinks in Canada.
- [5] Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions. Ministry of the Environment and Climate Change. Effective January 2017.
- [6] Final Essential Requirements of Mandatory Reporting. 2011 Amendments for Harmonization of Reporting in Canada Jurisdictions, December 21, 2011 with WCI Quantification Method 2013 Addendum to Canadian Harmonization Version.
- [7] AP 42 Compilation of Air Pollutant Emission Factors, Volume 1, Fifth Edition.
- [8] Environment and Climate Change Canada’s Reference Method for Source Testing: Quantification of Carbon dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation (June 2012, Cat. No.: En14-46/1-2012E-PDF)
- [9] EPS 1/PG/7 protocol “Protocols and performance specifications for continuous monitoring of gaseous emissions from thermal power generation”, November 2005.
- [10] API Manual Of Petroleum Measurement Standards. Chapter 14
- [11] API Manual Of Petroleum Measurement Standards. Chapter 8
- [12] API Technical Report. Carbon Content, Sampling, & Calculation. Final Draft, August 27, 2012
- [13] CAPP A Recommended Approach to Completing the National Pollutant Release Inventory (NPRI) for the Upstream Oil and Gas Industry. October 2014
- [14] A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H₂S) Emissions by the Upstream Oil and Gas Industry. Volume 3, Methodology for Greenhouse Gases. September 2004.
- [15] A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H₂S) Emissions by the Upstream Oil and Gas Industry. Volume 5, Compendium of Terminology, Information Sources, Emission Factors, Equipment Sched’s and Uncertainty Data. September 2004.

APPENDIX B: Fuel Properties

Table B-1. Table of physical properties for hydrocarbons and other compounds¹

Component	Chemical Formula	HHV [GJ/e ³ m ³]	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 ₂ S	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 ₂ H ₆	66.065	2	30.0690
Propane	C ₃ H ₈	93.936	3	44.0956
Isobutane	C ₄ H ₁₀	121.406	4	58.1222
n-Butane	C ₄ H ₁₀	121.794	4	58.1222
Isopentane	C ₅ H ₁₂	149.363	5	72.1488
n-Pentane	C ₅ H ₁₂	149.656	5	72.1488
Hexane	C ₆ H ₁₄	177.550	6	86.1754
Heptane	C ₇ H ₁₆	205.424	7	100.2019
Octane	C ₈ H ₁₈	233.284	8	114.2285
Nonane	C ₉ H ₂₀	261.191	9	128.2551
Decane	C ₁₀ H ₂₂	289.067	10	142.2817
Acetylene	C ₂ H ₂	55.038	2	26.0373
Ethylene	C ₂ H ₄	59.724	2	28.0532
Propylene	C ₃ H ₆	86.099	3	42.0797
Hexene	C ₆ H ₁₂	174.068	6	84.1595
Benzene	C ₆ H ₆	139.689	6	78.1118
Toluene	C ₇ H ₈	167.056	7	92.1384
Heptane	C ₇ H ₁₆	205.424	7	95.00
o-Xylene	C ₈ H ₁₀	194.484	8	106.1650
m-Xylene	C ₈ H ₁₀	194.413	8	106.1650
p-Xylene	C ₈ H ₁₀	194.444	8	106.1650

¹ GPSA Engineering Handbook Section 23 - Physical Properties

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

Table B-3. Fuel oil default density value

Fuel Oil	No. 1	No. 2	No.3
Density (kg/L)	0.81	0.86	0.97

Superseded

APPENDIX C: General Calculation Instructions

C.1 Weighted average carbon content

Use Equation C.1-1 to calculate the weighted average carbon content of the fuel, if the measured carbon content is used to calculate CO₂ emissions. The units of measure for carbon content for gaseous, liquid, and solid fuels are as follows:

Carbon Content Units of Measure:

Gaseous Fuels: kilograms of carbon per cubic metre of fuel (kg C/m³)

Liquid Fuels: tonnes of carbon per kilolitre of fuel (tonnes C/kl)

Solid Fuels: tonnes of carbon per tonne of fuel

To apply the carbon content in the equations outlined for various quantification methods, the facility must ensure that the correct units are applied in the equation. Equation C.1-1a provides a common conversion from mole fraction to mass fraction for gaseous fuels.

$$CC_p = \frac{\sum_{i=1}^N CC_i \times Fuel_i}{\sum_{i=1}^N Fuel_i} \quad \text{Equation C.1-1}$$

Where:

CC _p	=	Weighted average carbon content of the fuel during the reporting period, p.
CC _i	=	Carbon content of the fuel for sampling period i.
Fuel _i	=	Quantity of fuel combusted during sampling period i, in accordance with Chapter 17.
		Cubic metres (m ³) for gaseous fuels.
		Kilolitres (kl) for liquid fuels.
		Tonnes for solid fuels.
N	=	Number of measurement periods in the reporting period, in accordance with Chapter 17.

For gaseous fuels, where carbon content is measured in mole fraction, Equation C.1-1a is used to convert the mole fraction to kilogram of carbon per cubic metre of fuel:

$$CC_i = \sum_{j=1}^c (MF_j \times NC_j) \times \frac{12.01}{MVC} \quad \text{Equation C.1-1a}$$

Where:

CC _i	=	Carbon content of the gaseous fuel (kg of C/m ³).
MF _i	=	Normalized mole fraction of component j, where, in cases the sum of the mole fractions of components may not add up to 1 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.
NC _j	=	Number of carbons in component j.
c	=	Number of components.
MVC	=	Standard molar volume conversion at standard molar volume as defined in Appendix B, Table B-2 (23.645 m ³ /kmol).

12.01 = Molecular weight of carbon (kg/kmol).

C.2 Average carbon content expanded uncertainty (95% confidence level)

The 95 % confidence level carbon content uncertainty for the period that the average sample data is used can be calculated from the following Equation C.2-1

$$\text{Period } CC_{95\% \text{ Uncertainty}} = \pm \frac{k_{95\%} \times \sigma}{\sqrt{n}} \quad \text{Equation C.2-1}$$

Where:

Period $CC_{95\% \text{ Uncertainty}}$ = Period carbon content 95% confidence uncertainty.

$k_{95\%}$ = 95% confidence coverage factor; for the purpose of this assessment is taken as 2.00 (normal distribution with infinite degrees of freedom).

σ = Carbon content standard deviation of the samples.

n = Number of samples.

This calculation instruction is to be used if the Director requests the calculation and reporting of the carbon content uncertainty.

C.3 Fuel gas molecular weight estimation

If the molecular weight (MW) of the fuel gas is not measured, the molecular weight of the fuel gas should be calculated by the summation of the mole fraction of each fuel gas component multiplied by its respective molecular weight, as shown in the following equation.

$$MW = \sum x_i MW_i \quad \text{Equation C.3-1}$$

Where:

MW = Molecular weight of fuel gas (kg/kmol)

x_i = Normalized mole fraction of component i, where, in cases the sum of the mole fractions of components may not add up to 1 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.

MW_i = Molecular weight of component (kg/kmol), using Table B-1, Appendix B.

C.4 Standard temperature and pressure or standard conditions

In the document, standard conditions for pressure and temperature is 101.325 kPa (1 atm) and 15°C (288.15K), respectively. If the gas volume is metered or recorded at different conditions, the following equation should be used to convert gas volumes to standard gas volumes.

$$v_s = 2.8438 \times \frac{P \times v}{T} \quad \text{Equation C.4-1}$$

Where:

v_s	=	Gas volume at standard conditions.
P	=	Pressure under which the gas volume is metered or recorded (kPa).
T	=	Temperature under which the gas volume is metered or recorded, in Kelvin degrees.
v	=	Gas volume at the metered or recorded conditions.
2.8438	=	Constant for converting gas volumes to the standard condition (K/kPa).

C.5 Heating value

The heating value of a fuel is the amount of heat produced by the complete combustion of a unit quantity of fuel. The higher heating value of the fuel gas are calculated by summing the products of the mole fraction and the heating value of each fuel gas component, as shown in the following equations:

$$HHV = \sum_i^N x_i HHV_i \quad \text{Equation C.5-1}$$

Where:

HHV	=	Higher heating value of fuel gas (GJ/m ³).
x_i	=	Normalized mole fraction of component i, where, in cases the sum of the mole fractions of components may not add up to 1 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. The mole fractions of the gas components should be obtained from gas analyses of the fuel stream.
HHV _i	=	Higher heating value of component, using Table B-1, Appendix B.

The weighted average higher heating value of the fuel shall be calculated using Equation C.5-2.

$$HHV_p = \frac{\sum_{i=1}^N HHV_i \times Fuel_i}{\sum_{i=1}^N Fuel_i} \quad \text{Equation C.5-2}$$

Where:

HHV _p	=	Weighted average higher heating value of the fuel for the reporting period.
Fuel _i	=	Mass or volume of the fuel combusted during measurement period i, in accordance with Chapter 17.
N	=	Number of measurement periods in the period, in accordance with Chapter 17.
HHV _i	=	Higher heating value of the fuel, for measurement period i, in accordance with Chapter 17.

C.6 Fuel consumption estimation

Facilities may estimate fuel consumption for combustion equipment based on equipment specifications and operating hours using Equation C.6-1 or C.6-2.

$$v_{fuel,j,p} = \sum_{j=1}^N \frac{P_{ratedj}}{n_j} \times \frac{LF_j}{HHV_j} \times OH_j \times 0.0036 \quad \text{Equation C.6-1}$$

$$v_{fuel,j,p} = \sum_{j=1}^N (OH_j \times HP_j \times LF_j \times BSFC_j) \times 10^{-3} \quad \text{Equation C.6-2}$$

Where:

$V_{fuel,j,p}$	=	Estimated fuel consumption from combustion equipment for a specific fuel type for the reporting period, p (m^3).
j	=	Equipment type.
$P_{rated,j}$	=	Maximum rated power for equipment j (kW).
LF_j	=	Load factor for each type of equipment j (dimensionless; ranges between 0 and 1).
OH_j	=	Operating hours for equipment j (hours/reporting period).
η_j	=	Thermal efficiency for equipment j .
HHV_j	=	Higher heating value of the fuel combusted by equipment j (GJ/m^3).
N	=	Number of equipment types using the same fuel.
HP_j	=	Rated horsepower for equipment j (horsepower).
$BSFC_j$	=	Brake-specific fuel consumption for equipment j in litres per horsepower-hour (l/hp-h).
0.0036	=	Conversion factor for kWh to GJ.
10^{-3}	=	Conversion factor for litres to cubic metres.

Table C-1. 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 [13].

Source Type	Maximum Rated Power Output (kW)	Maximum Rated Power Output (HP)	Input Heat Rate (kJ/kWh)	Thermal Efficiency (percent)
Reciprocating Engines	<325	<435	12 857	28
	325 to 600	435 to 805	11 250	32
	600 to 2250	805 to 3017	10 000	35
	>2250	>3017	9 474	38
Turbine Engines	All	All	10 909	33
Industrial and Commercial Heaters and Boilers	<375 (Natural Draft)	<503 (Natural Draft)	4 736	76
	<375 (Forced Draft)	<503 (Natural Draft)	4 500	80
	≥ 375	≥ 503	4 500	80
Residential Water Heaters	All	All	7 500	48
Residential Furnaces	All	All	5 143	70
Catalytic Heaters	Vented Outdoors	Vented Outdoors	4 500	80
	Vented Indoors	Vented Indoors	3 600	100
Thermoelectric Generators	All	All	100 000	3.6

Table C-2. Estimated load factors for combustion devices during actual running/firing periods

Source Type	Load Factor (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

C.7 Proration of total measured fuel usage to individual devices

In a situation that a site has only one fuel meter, and 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.

$$fuel_{actual,i} = fuel_{theoretical,i} \times \frac{(fuel_{measurement} - \sum fuel_{theoretical,non-com})}{\sum fuel_{theoretical,com}} \quad \text{Equation C.7-1}$$

Where:

$fuel_{actual,i}$	=	Actual volume of fuel combusted for equipment i in a certain time period.
$fuel_{theoretical,i}$	=	Theoretical volume of fuel combusted for equipment i (calculated using C.6) in a certain time period
$fuel_{measurement}$	=	Total volume of fuel consumption metered in a certain time period for all combustion and non-combustion devices.
$\sum fuel_{theoretical,non-com}$	=	Calculated/theoretical fuel gas consumption by all non-combustion devices at the site in a certain time period.
$\sum fuel_{theoretical,com}$	=	Sum of the calculated/theoretical fuel gas usage by each combustion device at the site in a certain time period

C.8 Quantification of fuel consumption based on carbon mass balance

A facility may use a mass balance approach to determine the amount of fuel consumed or combusted for a source such as stationary fuel combustion, flaring or industrial process emissions if the total facility consumption of a fuel can be accurately determined by a custody meter (e.g. third party meter) and the fuel consumption of all other sources are quantified and reported. For example, if a facility consumes natural gas for combustion and as feed for an industrial process, the facility may use a mass balance approach to calculate the natural gas consumed for stationary fuel combustion or feed if the total facility fuel consumption and fuel quantity for one of these sources are known. The mass balance approach may only be used if there is only one source with an unknown fuel quantity. The facility may not use this methodology to calculate emissions for venting or fugitive sources.

$$Fuel_{source} = Fuel_{facility\ total} - \sum_i^N Fuel_{known\ source,i} \quad \text{Equation C.8-1}$$

Where:

$Fuel_{source}$	=	Fuel quantity determined for the source of interest (GJ or m ³).
$Fuel_{facility\ total}$	=	Total fuel consumed by the facility (GJ or m ³).
$Fuel_{known\ source,i}$	=	Fuel consumed by a source that is quantified and reported (GJ or m ³).
N	=	Number of sources.

C.9 Variables

When a variable is used in a calculation, fuel weighted averages should be calculated as per Equation C.9-1.

$$\text{Variable}_p = \frac{\sum_{i=1}^N \text{Fuel}_i \times \text{Variable}_i}{\sum_{i=1}^N \text{Fuel}_i} \quad \text{Equation C.9-1}$$

Where:

Variable _p	=	Weighted value of any variable for a reporting period.
Variable _i	=	Value of any variable in a measurement period i.
Fuel _i	=	Value of the fuel used in a measurement period i.
i	=	A measurement period where the variables are collected.
N	=	Number of measurement periods in a reporting period.

C.10 Allocation of electricity generated from multiple energy suppliers

Use Equation C.10-1 to calculate the allocation of electricity from different suppliers.

$$\text{Electricity}_i = \text{Produced Electricity} \times \frac{\text{Heat}_i}{\sum_{j=1}^N \text{Heat}_j} \quad \text{Equation C.10-1}$$

Where:

Electricity _i	=	Electricity allocated to supplier i
Produced Electricity	=	net electricity produced
Heat _i	=	net heat provided by supplier i
j	=	each supplier
N	=	amount of suppliers

C.11 Oxidation factor

As recommended by the Intergovernmental Panel on Climate Change (IPCC), the oxidation factor in the combustion of any fuel including flared fuels, but excluding coal used for electricity generation assumes 100% combustion (i.e. 100% conversion of carbon to carbon dioxide). The methane emissions from fuel combustion assumes a fraction of the fuel that is not combusted. These emissions are conservatively included in the total emissions generated from fuel combustion. For coal combustion used for electricity generation, an oxidation factor of 99.48% is applied. This oxidation factor was derived from a study conducted by ECCC on oxidation factors for coal combustion in Canada.

C.12 Rounding of final reported values

Final reported values should be rounded to the significant digits required in the compliance or reporting form. Rounding of data and intermediate values used in the calculations should be avoided.

APPENDIX D: Conversion Factors

Table D-1. Prefixes

Metric	Meaning
pico (p)	10 ⁻¹²
angstrom (A)	10 ⁻¹⁰
nano (n)	10 ⁻⁹
micro (μ)	10 ⁻⁶
mili (m)	10 ⁻³
deca (da)	10 ¹
kilo (k)	10 ³
mega (M)	10 ⁶
giga (G)	10 ⁹
tetra (T)	10 ¹²
peta (P)	10 ¹⁵
exa (E)	10 ¹⁸
zetta (Z)	10 ²¹

Table D-2. Mass Conversion

Source unit	Factor	Final Unit
1 kg	2.205	lb
1 lb	453.6	g
1 lb	16	oz
1 metric tonne	2,205	lb
1 US short ton	2,000	lb
1 UK long ton	2,239	lb

Table D-3. Volume Conversion

Source unit	Factor	Final Unit
1 l	0.264	gal
1 gal	3.785	l
1 m ³	35.3	ft ³
1 ft ³	28.32	l
1 ft ³	7.482	gal
1 bbl	42	gal
1 bbl	158.9	l
1 bbl	5.6	ft ³

Table D-4. Temperature Conversion

Source unit	Factor
°F	$9 / 5 * ^\circ\text{C} + 32$
°C	$(^\circ\text{F} - 32) * 5 / 9$
°K	$^\circ\text{C} + 273.15$
°R	$^\circ\text{F} + 459.67$

Table D-5. Pressure Conversion

Source unit	Factor	Final Unit
1 MPa	0.1	bar
1 MPa	9.87	atm
1 MPa	145	psi
1 atm	1.0132	bar
1 atm	780	mmHg
1 atm	14.696	psi

Table D-6. Distance Conversion

Source unit	factor	Final Unit
1 cm	0.3937	in
1 m	3.281	ft
1 m	1.094	yd
1 km	0.62137	mi
1 mi	1.609	km

Table D-7. Energy Conversion

Source unit	factor	Final Unit
1 J	1	Nm
1 J	0.2391	cal
1 J	0.74	ft-lb
1 J	0.0009478	Btu
1 Cal	1	kcal
1 Cal	1 4.187	kJ
1 Cal	3.968	Btu
1 Btu	1,055.056	J
1 Btu	0.2521	kcal
1 kWh	3.6	MJ
1 kWh	3,412	Btu
1 mmBtu	1.055	GJ