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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 SGR 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 ($\text{CO}_2$), methane ($\text{CH}_4$), nitrous oxide ($\text{N}_2\text{O}$), sulphur hexafluoride ($\text{SF}_6$), nitrogen trifluoride ($\text{NF}_3$), 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 ($\text{CO}_2\text{e}$). 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
The chapters below provide guidance for reporters:

Chapter 17: Measuring, Sampling, Analysis and Data Management

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.


“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 direct 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 ±2 %.


σ means the standard deviation.
1.0 Quantification Methods for Stationary Fuel Combustion

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 (CO$_2$) emissions from biomass combustion are provided in Chapter 14, while methods for methane (CH$_4$) and nitrous oxide (N$_2$O) 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 CO$_2$ emissions from fuel combustion for the reporting period, using one of the four quantification methodologies specified in this section.

1.2.2 Tier 1 - A fuel-specific default CO$_2$ emission factor for non-variable fuels

(1) Introduction

This method is used for fuels that are non-variable in composition based on a default CO$_2$ emission factor and the quantity of fuel consumed. 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 CO$_2$ 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 CO$_2$ 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 HHV of the fuel. Table 1-1 provides the emission factors for these fuels in mass of CO$_2$ emitted per GJ or kilolitres.

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 CO$_2$ mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-1a can be used directly to calculate the CO$_2$ 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 CO$_2$ mass emissions.

(2) Equations

For a liquid or gaseous fuel, use Equation 1-1 or Equation 1-1a to calculate the CO$_2$ mass emissions for the reporting period.
\[ CO_{2,p} = v_{fuel,p} \times HHV \times EF_{ene} \]  
Equation 1-1

\[ CO_{2,p} = v_{fuel,p} \times EF_{vol} \text{ or } ENE_{fuel,p} \times EF_{ene} \]  
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, \( p \).

\[ ENE_{fuel,p} \] = 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 (kilolitres) 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 Tier 2 - CO₂ emissions from combustion of natural gas

(1) Introduction

This method is adapted from ECCC’s Canada’s Greenhouse Gas Quantification Requirements [3] for calculating CO₂ mass emissions from natural gas combustion based on the measured HHV.

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:

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

Where:

\[ CO_{2,p} \] = CO₂ mass emissions for the marketable natural gas combusted during the reporting period, \( p \) (tonnes CO₂).

\[ v_{fuel,p} \] = Volume of fuel (m³) at standard conditions combusted during reporting period, \( p \), calculated in accordance with Chapter 17 and Appendix C.

\[ HHV \] = Weighted average measured higher heating value of fuel (MJ/m³) at standard conditions as defined in Appendix C.

\[ (60.554 \times HHV_p - 404.15) \] = Empirical equation adapted from ECCC [3] (grams of CO₂ per cubic meter of natural gas) representing relationship between CO₂ and volume of natural gas determined through higher
heating value using a discreet set of data collected by ECCC.

\[10^{-6} = \text{Mass conversion factor (t/g)}\]

(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 Tier 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 balanced approach using the measured fuel carbon content. Variable fuels are those that have varying composition and require testing for carbon content. For facilities subject to CCIR, CO₂ emissions from combustion of non-variable fuels may apply Tier 1 methodology. All fuels not listed as 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:

\[
CO_{2,p} = v_{fuel\,(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001
\]

Equation 1-3a

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

\[
CO_{2,p} = \frac{ENE_{fuel\,(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV}
\]

Equation 1-3b

**Where:**

- \(CO_{2,p}\) = CO₂ mass emissions for the gaseous fuel 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 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:

$$\text{CO}_2 p = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664$$

Where:

$\text{CO}_2 p$ = 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:

$$\text{CO}_2 p = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664$$

Where:

$\text{CO}_2 p$ = 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 Tier 4 - Continuous emissions monitoring systems

(1) **Generality**

Calculate the CO\textsubscript{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\textsubscript{2} monitor (or O\textsubscript{2} monitor) and a flow monitoring subsystem, except as otherwise provided in paragraph (c). CEMS shall use methodologies provided in [8] or by another 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 CO\textsubscript{2} or O\textsubscript{2} concentrations and flue gas flow measurements to determine hourly CO\textsubscript{2} mass emissions using methodologies required by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) or provided in [8].

(b) Report CO\textsubscript{2} emissions for the reporting year in tonnes based on the sum of hourly CO\textsubscript{2} mass emissions over the year, converted to tonnes.

(c) An O\textsubscript{2} concentration monitor may be used in lieu of a CO\textsubscript{2} concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO\textsubscript{2} concentrations. This may be used if the effluent gas stream monitored by the CEMS consists of combustion products (i.e., no process CO\textsubscript{2} emissions or CO\textsubscript{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\textsubscript{2} concentrations.

   (2) If the operator of a facility that combats biomass fuels uses O\textsubscript{2} concentrations to calculate CO\textsubscript{2} concentrations, annual source testing must demonstrate that the calculated CO\textsubscript{2} concentrations, when compared to measured CO\textsubscript{2} concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in [8] 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 CO\textsubscript{2} mass emissions separately, as described in Chapter 7.

(e) For any units using CEMS data, industrial process and stationary combustion CO\textsubscript{2} 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 CO\textsubscript{2} concentrations or flue gas flow, select and operate the added devices using appropriate requirements [8] for the facility, as applicable in Alberta under the Alberta CEMS Code or in Canada.

(g) If a facility does not have a CEMS and chooses to add one in order to measure CO\textsubscript{2} concentrations, select and operate the CEMS using the appropriate requirements [8] or equivalent requirements as applicable in Canada.

(2) **Data requirements**

No additional data requirements are needed.
1.3  Methane and Nitrous Oxide

1.3.1 Introduction

Calculate the CH\textsubscript{4} and N\textsubscript{2}O 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.

1.3.2 Tiers 1, 2, and 3 - Default CH\textsubscript{4} and N\textsubscript{2}O emission factor

(1) Introduction

Tiers 1, 2, and 3 are currently the same quantification methodology. Distinctions between these tier classifications may be prescribed in future revisions to the standard quantification methodologies. This method calculates the CH\textsubscript{4} and N\textsubscript{2}O mass emissions based on default emission factors that are based in energy or physical units. CH\textsubscript{4} and N\textsubscript{2}O 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, and 1-3 provide the emission factors for these fuels in mass of CH\textsubscript{4} and N\textsubscript{2}O emitted per GJ, kilolitres, cubic metres, or tonnes of fuel.

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, or 1-3 to calculate the CH\textsubscript{4} and N\textsubscript{2}O mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-4a can be used directly to calculate the CH\textsubscript{4} and N\textsubscript{2}O mass emissions based on the appropriate energy based emission factor from Tables 1-1, 1-2, and 1-3.

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, or 1-3 to calculated the CH\textsubscript{4} and N\textsubscript{2}O mass emissions.

(2) Equations

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

\[
CH_4_{p} or N_2O_{p} = Fuel_{p} \times HHV \times EF_{ene} \tag{Equation 1-4}
\]

\[
CH_4_{p} or N_2O_{p} = Fuel_{p} \times EF_{vol} or EF_{ene} \tag{Equation 1-4a}
\]

Where:

\[
CH_4_{p} or N_2O_{p} = \text{CH}_4 \text{ or } N_2O \text{ mass emissions for the specific fuel type for the reporting period, } p, \text{ (tonnes CH}_4 \text{ or N}_2O).
\]

\[
Fuel_{p} = \text{For Equation 1-4, the quantity of fuel combusted in kilolitres, cubic metres, or tonnes (kl, m}^3 \text{, tonnes) combusted during reporting period, } p. \text{ For Equation 1-4a, energy of fuel in gigajoules or quantity of fuel in kilolitres, cubic metres, or tonnes (GJ, kl, m}^3 \text{, or tonnes) combusted during reporting period, } p. \text{ Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.}
\]

\[
HHV = \text{Measured or supplied higher heating value in gigajoules per kilolitres, cubic metres, or tonnes (GJ/kl, GJ/m}^3 \text{, or GJ/tonne).}
\]
EF\textsubscript{vol}, EF\textsubscript{ene} = Fuel-specific default emission factor, from Tables 1-1, 1-2, or 1-3 in tonnes of CH\textsubscript{4} or N\textsubscript{2}O 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:

\[
CH\textsubscript{4p} \text{ or } N\textsubscript{2}O\textsubscript{p} = \text{Steam} \times B \times EF
\]

Equation 1-5

Where:

\( CH\textsubscript{4p} \text{ or } N\textsubscript{2}O\textsubscript{p} \) = CH\textsubscript{4} and N\textsubscript{2}O mass emissions for the specific fuel type for the reporting period, \( p \) (tonnes CH\textsubscript{4} or N\textsubscript{2}O).

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\textsubscript{4} and N\textsubscript{2}O emission factor, from Table 1-3, in tonnes of CH\textsubscript{4} and N\textsubscript{2}O per GJ.

(3) Data requirements

- There is no differentiation between Tiers 1-3 for the quantification of CH\textsubscript{4} and N\textsubscript{2}O, with the exception of facilities that generate steam from biomass fuels. For these facilities, the boiler efficiency calculation are differentiated by tiers and are provided in Chapter 17 and Appendix C.
- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Facilities that are in the conventional oil and gas sector (NAICS code: 211113) are required to use equipment specific emission factors to calculate the CH\textsubscript{4} and N\textsubscript{2}O emissions from their facilities.
- Facilities that use internal combustion engines are required to use the emission factors for internal combustion engines to calculate the CH\textsubscript{4} and N\textsubscript{2}O emissions from those equipment.

1.3.3 Tier 4 – Continuous emissions monitoring systems

(1) Introduction

The CH\textsubscript{4} or N\textsubscript{2}O 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\textsubscript{4} or N\textsubscript{2}O concentration monitor, in accordance with [9] 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

<table>
<thead>
<tr>
<th>Non-Variable Fuels¹</th>
<th>HHV (GJ/kl)²</th>
<th>CO₂ Emission Factor⁴ (tonne/kl)</th>
<th>CH₄ Emission Factor⁴ (tonne/kl)</th>
<th>N₂O Emission Factor⁴ (tonne/kl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel¹</td>
<td>38.35</td>
<td>2.681</td>
<td>0.0699</td>
<td>-</td>
</tr>
<tr>
<td>&lt;19kW</td>
<td>-</td>
<td>-</td>
<td>7.30E-05</td>
<td>1.90E-06</td>
</tr>
<tr>
<td>&lt;=19kW, Tier 1-3</td>
<td>-</td>
<td>-</td>
<td>7.30E-05</td>
<td>1.90E-06</td>
</tr>
<tr>
<td>&gt;=19kW, Tier 4</td>
<td>-</td>
<td>-</td>
<td>7.30E-05</td>
<td>1.90E-06</td>
</tr>
<tr>
<td>Diesel in Alberta³</td>
<td>37.83</td>
<td>2.610</td>
<td>0.06953</td>
<td>see note 6</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>37.83</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Gasoline</td>
<td>33.43</td>
<td>2.307</td>
<td>0.06900</td>
<td>-</td>
</tr>
<tr>
<td>2-stroke</td>
<td>-</td>
<td>-</td>
<td>1.06E-02</td>
<td>3.00E-04</td>
</tr>
<tr>
<td>4-stroke</td>
<td>-</td>
<td>-</td>
<td>5.80E-03</td>
<td>1.50E-04</td>
</tr>
<tr>
<td>Gasoline in Alberta⁴</td>
<td>33.24</td>
<td>2.174</td>
<td>0.06540</td>
<td>see note 7</td>
</tr>
<tr>
<td>Butane</td>
<td>28.45</td>
<td>1.747</td>
<td>0.06140</td>
<td>2.40E-05</td>
</tr>
<tr>
<td>Ethane</td>
<td>17.21</td>
<td>0.986</td>
<td>0.05730</td>
<td>2.40E-05</td>
</tr>
<tr>
<td>Propane</td>
<td>25.29</td>
<td>1.515</td>
<td>0.05990</td>
<td>2.40E-05</td>
</tr>
</tbody>
</table>

¹Fuels listed in this table are for stationary combustion sources only. Diesel and gasoline that is used for on-site transportation is covered in a separate chapter.
²For facilities that are unable to obtain the HHV of their fuel, this column presents the default HHV for the non-variable fuels.
³Tiers adapted from USEPA.
⁴Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content.
⁵Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements [3].
⁶Diesel CH₄ and N₂O emission factors are used.
⁷Gasoline CH₄ and N₂O emission factors are used.

### Table 1-2  Default CH₄ and N₂O emission factors for natural gas

<table>
<thead>
<tr>
<th>Natural Gas¹</th>
<th>CH₄ Emission Factor⁴ (tonne/m³)</th>
<th>N₂O Emission Factor⁴ (tonne/m³)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Utilities</td>
<td>4.90E-07</td>
<td>4.90E-08</td>
<td>4</td>
</tr>
<tr>
<td>Industrial</td>
<td>3.70E-08</td>
<td>3.30E-08</td>
<td>4</td>
</tr>
<tr>
<td>Pipelines</td>
<td>1.90E-06</td>
<td>5.00E-05</td>
<td>4</td>
</tr>
<tr>
<td>Cement</td>
<td>3.70E-08</td>
<td>3.40E-08</td>
<td>4</td>
</tr>
<tr>
<td>Manufacturing Industries</td>
<td>3.70E-08</td>
<td>3.30E-08</td>
<td>4</td>
</tr>
<tr>
<td>Residential, Construction, Commercial/Institutional, Agriculture/Other</td>
<td>3.70E-08</td>
<td>3.50E-08</td>
<td>4</td>
</tr>
</tbody>
</table>

¹Emission factors by sector:

<table>
<thead>
<tr>
<th>Natural Gas¹</th>
<th>CH₄ Emission Factor⁴ (tonne/m³)</th>
<th>N₂O Emission Factor⁴ (tonne/m³)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipelines</td>
<td>1.90E-06</td>
<td>5.00E-05</td>
<td>4</td>
</tr>
<tr>
<td>Cement</td>
<td>3.70E-08</td>
<td>3.40E-08</td>
<td>4</td>
</tr>
<tr>
<td>Manufacturing Industries</td>
<td>3.70E-08</td>
<td>3.30E-08</td>
<td>4</td>
</tr>
<tr>
<td>Residential, Construction, Commercial/Institutional, Agriculture/Other</td>
<td>3.70E-08</td>
<td>3.50E-08</td>
<td>4</td>
</tr>
</tbody>
</table>

Emission factor by technology², ⁵:

<table>
<thead>
<tr>
<th>Natural Gas¹</th>
<th>CH₄ Emission Factor⁴ (tonne/m³)</th>
<th>N₂O Emission Factor⁴ (tonne/m³)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine</td>
<td>1.405E-07</td>
<td>4.902E-08</td>
<td>AP-42 Table 3.1-2a</td>
</tr>
<tr>
<td>2 cycle lean</td>
<td>2.369E-05</td>
<td>6.234E-04</td>
<td>AP-42 Table 3.2-1</td>
</tr>
<tr>
<td>NOx 90-105% Load</td>
<td>-</td>
<td>7.769E-07</td>
<td>AP-42 Table 3.2-1</td>
</tr>
<tr>
<td>NOx &lt; 90% Load</td>
<td>-</td>
<td>4.755E-07</td>
<td>AP-42 Table 3.2-1</td>
</tr>
<tr>
<td>4 cycle lean</td>
<td>2.042E-05</td>
<td>5.374E-04</td>
<td>AP-42 Table 3.2-2</td>
</tr>
</tbody>
</table>
### Table 1-3  Default \( \text{CH}_4 \) and \( \text{N}_2\text{O} \) emission factors by fuel type

<table>
<thead>
<tr>
<th>Liquid Fuels(^3)</th>
<th>( \text{CH}_4 ) Emission Factor</th>
<th>( \text{N}_2\text{O} ) Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tonne/kl</td>
<td>tonne/GJ</td>
</tr>
<tr>
<td></td>
<td>tonne/m(^3)</td>
<td>tonne/m(^3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>tonne/GJ</td>
</tr>
<tr>
<td>Kerosene</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity Utilities</td>
<td>6.00E-06</td>
<td>2.00E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>8.30E-07</td>
</tr>
<tr>
<td>Industrial</td>
<td>6.00E-06</td>
<td>2.00E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>8.30E-07</td>
</tr>
<tr>
<td>Producer Consumption(^4)</td>
<td>6.00E-06</td>
<td>1.59E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>8.230E-07</td>
</tr>
<tr>
<td>Forestry, Construction and Commercial/Institution</td>
<td>2.60E-05</td>
<td>7.0E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>8.00E-07</td>
</tr>
<tr>
<td>Light Fuel Oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Utilities(^4)</td>
<td>1.80E-04</td>
<td>4.639E-06</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>7.99E-07</td>
</tr>
<tr>
<td>Industrial</td>
<td>6.00E-06</td>
<td>2.00E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>8.00E-07</td>
</tr>
<tr>
<td>Producer Consumption(^4)</td>
<td>6.00E-06</td>
<td>1.550E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>7.990E-07</td>
</tr>
<tr>
<td>Forestry, Construction and Commercial/Institution</td>
<td>2.60E-05</td>
<td>6.700E-07</td>
</tr>
<tr>
<td></td>
<td>3.10E-05</td>
<td>8.00E-07</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Utilities</td>
<td>3.40E-05</td>
<td>8.00E-07</td>
</tr>
<tr>
<td></td>
<td>6.40E-05</td>
<td>1.506E-06</td>
</tr>
<tr>
<td>Industrial</td>
<td>1.20E-04</td>
<td>2.824E-06</td>
</tr>
<tr>
<td></td>
<td>6.40E-05</td>
<td>1.506E-06</td>
</tr>
<tr>
<td>Producer Consumption(^5)</td>
<td>1.20E-04</td>
<td>2.824E-06</td>
</tr>
<tr>
<td></td>
<td>6.40E-05</td>
<td>1.506E-06</td>
</tr>
<tr>
<td>Forestry, Construction and Commercial/Institution</td>
<td>2.60E-05</td>
<td>7.00E-07</td>
</tr>
<tr>
<td></td>
<td>3.00E-05</td>
<td>8.30E-07</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>( \text{CH}_4 ) Emission Factor</th>
<th>( \text{N}_2\text{O} ) Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tonne/m(^3)</td>
<td>tonne/GJ</td>
</tr>
<tr>
<td>Petroleum Coke - Refinery Use</td>
<td>1.20E-04</td>
<td>2.80E-05</td>
</tr>
<tr>
<td></td>
<td>5.90E-07</td>
<td></td>
</tr>
<tr>
<td>Petroleum Coke - Upgrader Use</td>
<td>1.20E-04</td>
<td>2.40E-05</td>
</tr>
<tr>
<td></td>
<td>5.9E-07</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Solid Fuels(^3)</th>
<th>( \text{CH}_4 ) Emission Factor</th>
<th>( \text{N}_2\text{O} ) Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tonne/tonne</td>
<td>tonne/GJ</td>
</tr>
<tr>
<td></td>
<td>tonne/m(^3)</td>
<td>tonne/m(^3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>tonne/GJ</td>
</tr>
<tr>
<td>Coal</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Marketable gas is considered to be gas that is saleable for consumption.
\(^2\) Facilities in the Oil and Gas Sector (NAICS code: 211113) are required to utilize equipment specific emission factors to calculation emissions from natural gas combustion.
\(^3\) A facility is required to use technology based emission factors instead of the sector based emission factors if the facility is using internal combustion engines as stationary equipment.
\(^4\) Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements [3].
\(^5\) For emission factors adapted from USEPA AP-42, the default emission factor is based on 1,020 British thermal units per standard cubic feet (Btu/scf).
<table>
<thead>
<tr>
<th>Industry and Heat and Steam Plants</th>
<th>Anthracite</th>
<th>Canadian Bituminous</th>
<th>Foreign Bituminous</th>
<th>Lignite</th>
<th>Sub-bituminous</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emission Factor</td>
<td>tonne/tonne</td>
<td>tonne/GJ</td>
<td>tonne/tonne</td>
<td>tonne/GJ</td>
<td>tonne/tonne</td>
</tr>
<tr>
<td>Anthracite</td>
<td>3.0E-05</td>
<td>1.0E-06</td>
<td>2.0E-05</td>
<td>1.0E-06</td>
<td></td>
</tr>
<tr>
<td>Canadian Bituminous</td>
<td>3.0E-05</td>
<td>1.0E-06</td>
<td>2.0E-05</td>
<td>1.0E-06</td>
<td></td>
</tr>
<tr>
<td>Foreign Bituminous</td>
<td>3.0E-05</td>
<td>1.0E-06</td>
<td>2.0E-05</td>
<td>1.0E-06</td>
<td></td>
</tr>
<tr>
<td>Lignite</td>
<td>3.0E-05</td>
<td>2.0E-06</td>
<td>2.0E-05</td>
<td>1.0E-06</td>
<td></td>
</tr>
<tr>
<td>Sub-bituminous</td>
<td>3.0E-05</td>
<td>2.0E-06</td>
<td>2.0E-05</td>
<td>1.0E-06</td>
<td></td>
</tr>
</tbody>
</table>

| 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   | 1.04E-06            | 2.0E-05           | 7.0E-07|

<table>
<thead>
<tr>
<th>Biomass Fuels(^3)</th>
<th>CH(_4) Emission Factor</th>
<th>N(_2)O Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tonne/tonne</td>
<td>tonne/GJ</td>
</tr>
<tr>
<td>Wood Waste</td>
<td>9.0E-05</td>
<td>5.0E-06</td>
</tr>
<tr>
<td>Spent Pulping Liquor</td>
<td>2.0E-05</td>
<td>1.0E-06</td>
</tr>
<tr>
<td>Peat(^1)</td>
<td>NA</td>
<td>1.00E-06</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Gaseous Fuels(^3)</th>
<th>CH(_4) Emission Factor</th>
<th>N(_2)O Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tonne/m(^3)</td>
<td>tonne/GJ</td>
</tr>
<tr>
<td>Coke Oven Gas</td>
<td>4.0E-08</td>
<td>2.0E-06</td>
</tr>
<tr>
<td>Still Gas(^4)</td>
<td>3.1E-08</td>
<td>9.1E-07</td>
</tr>
</tbody>
</table>

\(^1\)WCI Table 20-2 or 20-7.
\(^2\)Ontario Table 20-2.
\(^3\)Unless specified otherwise, emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements [3].
\(^4\)Adapted from IPCC (2006) and CIEEDAC (2014).
\(^5\)SGA (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:

- CO\(_2\) from Hydrogen Production;
- CO\(_2\) from Calcining Mineral Carbonates;
- CO\(_2\) from Carbonate Use;
- CO\(_2\) from Ethylene Oxide Production;
- CO\(_2\) from Thermal Carbon Black Production;
- CO\(_2\) from Carbon Consumption; and
- N\(_2\)O 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 for reporters under the CCIR.

8.2 CO\(_2\) 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, followed by shift reactions. The primary and secondary reforming reactions produce carbon monoxide (CO) and hydrogen (H\(_2\)). Subsequent shift reactions convert CO to CO\(_2\) to produce additional hydrogen. Carbon dioxide (CO\(_2\)) is a by-product of the net reaction:

- **Steam Methane Reforming:** CH\(_4\) + H\(_2\)O \rightarrow CO + 3H\(_2\)
- **Shift Reaction:** CO + H\(_2\)O \rightarrow CO\(_2\) + H\(_2\)
- **Overall Reaction:** CH\(_4\) + 2H\(_2\)O \rightarrow CO\(_2\) + 4H\(_2\)

Any CO\(_2\) generated as a by-product of the above reaction is considered an IP emission. The CO\(_2\) 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 H\(_2\)). This process can occur as shown in the first equation above (steam-methane reforming) or the same reaction with pure oxygen added, as follows:

- **Partial Oxidation Reaction:** HCs + H\(_2\)O + O\(_2\) \rightarrow xCO + yH\(_2\) + CO\(_2\)(trace)

As above, any CO\(_2\) generated as a by-product of the above reaction can be considered an IP emission. Syngas can be combusted as a fuel but the CO\(_2\) generated from syngas combustion are considered Stationary Fuel Combustion emissions and must be reported under that source category.
Three methods are provided in the guidance below.

### 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:

\[
CO_{2,p} = \sum_{i=1}^{N} (v_{Feed,i} \times EF_{CO2,i}) \times 0.001 \tag{Equation 8-1}
\]

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).

\[
EF_{CO2,i} = \sum_{k=1}^{K} (MF_{k,i} \times NC_k) \times \rho_{CO2} \tag{Equation 8-1a}
\]

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, CS₂) having non-zero molar fractions in feed gas. Note: CO₂ contained in 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 CO₂ contained in the feed gas is not included.
- \(NC_k\) = Number of carbons contained in carbon-based oxidizable component \(k\) in reactor feed gas.
\( \rho_{\text{CO}_2} = 1.8613 \text{ kg/m}^3 \) at standard conditions (where \( \rho_{\text{CO}_2} \) is determined by the molecular weight of \( \text{CO}_2 \) 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 to standard conditions as defined in Appendix C.

8.2.3 \( \text{CO}_2 \) Mass balance method

(1) Introduction

The \( \text{CO}_2 \) 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 \( \text{CO}_2, \text{CO}, \text{CH}_4, \text{C}_2\text{H}_6 \), and some waste \( \text{H}_2 \) 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:

- \( \text{CO}_2 \) contained in reaction or imported feed is not counted in the IP \( \text{CO}_2 \) calculation.

(2) Equations

For each hydrogen production unit, calculate IP \( \text{CO}_2 \) emissions using either Equation 8-2:

\[
\text{CO}_2 = \text{CO}_2 \text{ in Raw Unpurified H}_2 \text{ stream} - \text{CO}_2 \text{ in feed}
\]

\[
\text{CO}_2,p = \left[ \sum_{i=1}^{N} \left( V_{\text{RawU H}_2,i} \times MF_{\text{CO}_2,\text{RawU H}_2,i} - V_{\text{Feed,i}} \times MF_{\text{CO}_2,\text{Feed,i}} \right) \right] \times 0.001
\]

Equation 8-2

Where:

- \( \text{CO}_2,p \) = IP \( \text{CO}_2 \) mass emissions in the reporting period, \( p \) (tonnes \( \text{CO}_2 \)).
- \( i \) = Measurement period for IP \( \text{CO}_2 \).
- \( N \) = Number of IP \( \text{CO}_2 \) measurement periods \( i \) in the reporting period.
- \( V_{\text{RawU H}_2,i} \) = Volume of raw unpurified \( \text{H}_2 \) stream in measurement period \( i \) (sm\(^3\)).
- \( V_{\text{Feed,i}} \) = Volume of reactor feed gas in measurement period \( i \) (sm\(^3\)).
- \( MF_{\text{CO}_2,\text{Feed,i}} \) = \( \text{CO}_2 \) mole fraction in reactor feed gas (kmol\( \text{CO}_2 \)/kmol\( \text{Feed} \)).
- \( MF_{\text{CO}_2,\text{RawU H}_2,i} \) = \( \text{CO}_2 \) mole fraction in raw unpurified hydrogen stream (kmol\( \text{CO}_2 \)/kmol\( \text{RawH}_2 \)).
- \( \rho_{\text{CO}_2} \) = 1.8613 \text{ 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:

\[ \text{CO}_2,p = \sum_{i=1}^{N} \left( \frac{\nu_{H2,i}}{\sum_{k=1}^{K} (\text{SR}_{H2/CO2,k} \times \text{MF}_{k,i})} \right) \times \rho_{CO2} \times 0.001 \]  

Equation 8-3

Where:

- \( \text{CO}_2,p \) = 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.
- \( k \) = Carbon-based oxidizable components.
- \( K \) = Number of carbon-based oxidizable components.
- \( \nu_{H2,i} \) = Volume of hydrogen produced in measurement period \( i \) (sm³) at standard conditions as defined in Appendix C.
- \( \text{SR}_{H2/CO2,k} \) = Stoichiometric hydrogen-to-CO₂ molar ratio for carbon-based oxidizable component \( k \) (CO, CH₄, C₂H₆, etc.) in reactor feed gas, as listed in Table 8-1;
- \( \text{MF}_{k,i} \) = Mole fraction of carbon-based oxidizable component \( k \) (e.g. CO, hydrocarbons) in reactor feed gas in measurement period \( i \). Note: CO₂ and other inert components contained in the reactor feed gas are not included.
- \( \rho_{CO2} \) = 1.8613 kg/m³ 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

<table>
<thead>
<tr>
<th>Feed Component</th>
<th>Overall Reaction Equation</th>
<th>SR: H₂/CO₂ Molar Ratio (mol H₂/mol CO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>CH₄ + 2H₂O → CO₂ + 4H₂</td>
<td>4/1 = 4.000</td>
</tr>
<tr>
<td>Ethylene</td>
<td>C₂H₄ + 4H₂O → 2CO₂ + 6H₂</td>
<td>6/2 = 3.000</td>
</tr>
<tr>
<td>Feed Component</td>
<td>Overall Reaction Equation</td>
<td>SR: $H_2/CO_2$ Molar Ratio (mol $H_2$/mol $CO_2$)</td>
</tr>
<tr>
<td>----------------</td>
<td>---------------------------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td>Ethane</td>
<td>$C_2H_6 + 4H_2O \rightarrow 2CO_2 + 7H_2$</td>
<td>$7/2 = 3.500$</td>
</tr>
<tr>
<td>Propylene</td>
<td>$C_3H_6 + 6H_2O \rightarrow 3CO_2 + 9H_2$</td>
<td>$9/3 = 3.000$</td>
</tr>
<tr>
<td>Propane</td>
<td>$C_3H_8 + 6H_2O \rightarrow 3CO_2 + 10H_2$</td>
<td>$10/3 = 3.333$</td>
</tr>
<tr>
<td>Butylenes</td>
<td>$C_4H_8 + 8H_2O \rightarrow 4CO_2 + 12H_2$</td>
<td>$12/4 = 3.000$</td>
</tr>
<tr>
<td>Butanes</td>
<td>$C_4H_{10} + 8H_2O \rightarrow 4CO_2 + 13H_2$</td>
<td>$13/4 = 3.250$</td>
</tr>
<tr>
<td>Pentenes</td>
<td>$C_5H_{10} + 10H_2O \rightarrow 5CO_2 + 15H_2$</td>
<td>$15/5 = 3.000$</td>
</tr>
<tr>
<td>Pentanes</td>
<td>$C_5H_{12} + 10H_2O \rightarrow 5CO_2 + 16H_2$</td>
<td>$16/5 = 3.200$</td>
</tr>
<tr>
<td>Hexanes</td>
<td>$C_6H_{14} + 12H_2O \rightarrow 6CO_2 + 19H_2$</td>
<td>$19/6 = 3.167$</td>
</tr>
<tr>
<td>Heptanes</td>
<td>$C_7H_{16} + 14H_2O \rightarrow 7CO_2 + 22H_2$</td>
<td>$22/7 = 3.143$</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>$CO + H_2O \rightarrow CO_2 + H_2$</td>
<td>$1/1 = 1.000$</td>
</tr>
</tbody>
</table>

(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 $CO_2$ 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:

$$2NH_3 + CO_2 \rightarrow H_2N - CO - NH_2 + H_2O$$

(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 8-4:

$$CO_{2, urea,p} = m_{urea} \times \frac{MW_{CO_2}}{MW_{urea}} \times 0.001$$  

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_{CO2} = 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.

8.2.6 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 8-5.

\[ H_{2\text{,Waste},p} = \sum_{i=1}^{N} \left[ (m_{H2\text{,Gen},i} + m_{H2\text{,Imp},i}) - (m_{H2\text{,Exp},i} + m_{H2\text{,Use},i}) \right] \]  

Equation 8-5

Where:
- \( H_{2\text{,Waste},p} \) = 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.
- \( m_{H2\text{,Gen},i} \) = Mass of H$_2$ generated during period \( i \) (tonnes).
- \( m_{H2\text{,Imp},i} \) = Mass of H$_2$ imported during period \( i \) (tonnes).
- \( m_{H2\text{,Exp},i} \) = Mass of H$_2$ exported during period \( i \) (tonnes).
- \( m_{H2\text{,Use},i} \) = 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 8-6.

\[ H_{2\text{,j}} = \sum_{i=1}^{N} [V_{H2\text{,j}} \times MF_{H2\text{,j}} \times \rho_{H2}] \times 0.001 \]  

Equation 8-6

Where:
- \( H_{2\text{,j}} \) = 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.
- \( V_{H2\text{,j}} \) = Volume of hydrogen stream \( j \) (sm$^3$ at standard conditions as defined in Appendix C).
MF_{H2,j} = \text{Mole fraction of hydrogen in stream } j \text{ (kmol}H_2/\text{kmol}).
\rho_{H2} = 0.08526 \text{ kg/m}^3, \text{ standard density of hydrogen at standard conditions as defined in Appendix C (kg/sm}^3).\nonumber
0.001 = \text{Mass conversion factor (t/kg}).

(3) Data requirements
There are no additional data requirements needed.

8.3 CO\textsubscript{2} 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 (CaCO}_3; Limestone) and magnesium carbonate (MgCO}_3). Lime kilns can operate at merchant lime facilities and Kraft pulp mills. The primary reaction equations for calcining of carbonates are:

\text{Calcium Carbonate: } CaCO}_3 + \text{ heat } \rightarrow CaO + CO\textsubscript{2}
\text{Magnesium Carbonate: } MgCO}_3 + \text{ heat } \rightarrow MgO + CO\textsubscript{2}

This section is adapted from the guidance provided by the World Business Council for Sustainable Development (WBCSD) Cement CO\textsubscript{2} 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 CO\textsubscript{2} emission factor. The IP CO\textsubscript{2} emissions from calcination include only the CO\textsubscript{2} generated in the calcining reaction. Any CO\textsubscript{2} generated through the combustion of organic carbon contained in kiln feed materials creates useful energy and must be calculated using Equation 8-8 and reported under the Stationary Fuel Combustion source category.

The IP CO\textsubscript{2} emissions are calculated as the sum of CO\textsubscript{2} emitted from calcination producing the primary product, P, and the CO\textsubscript{2} 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 CO\textsubscript{2} 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 CO\textsubscript{2} calculated separately.

(2) Equations
For each kiln, calculate IP CO\textsubscript{2} emissions from calcination using the following equation:

\[ CO_2-IP_p = \sum_{i=1}^{I}(m_{P,i} \times EF_{P,i}) + \sum_{j=1}^{N}(m_{W,j} \times EF_{W,j}) \]  \hspace{1cm} \text{Equation 8-7} \nonumber

Where:

\( CO_2-IP_p \) = IP CO\textsubscript{2} mass emissions from calcination of carbonates in reporting period, \( p \text{ (tonnes CO}_2). \)
\( i \) = 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 8-7a.

\( m_{W,j} \) = 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 8-7b.

The kiln-specific CO\(_2\) 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).

\[
EF_{P,i} = \left( CaO_{P,i} - CaO_{FP,i} \right) \times 0.785 + \left( MgO_{P,i} - MgO_{FP,i} \right) \times 1.092 \quad \text{Equation 8-7a}
\]

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).

\[
EF_{W,j} = \left( CaO_{W,j} - CaO_{FW,j} \right) \times 0.785 + \left( MgO_{W,j} - MgO_{FW,j} \right) \times 1.09 \quad \text{Equation 8-7b}
\]

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} = \text{Total magnesium oxide content of waste kiln material W in measurement period j (tonnes MgO per tonne W)}.

MgO_{FW,j} = \text{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 = \text{Ratio of molecular weight of CO}_2\text{ to CaO (44.0/56.1).}

1.092 = \text{Ratio of molecular weights of CO}_2\text{ to MgO (44.0/40.3).}

The CO$_2$ emissions from oxidation of total organic carbon in feed are calculated based on the carbon content of the feed.

\[ CO_{2,p} = m \times TOC \times 3.664 \]  

Equation 8-8

Where:

CO$_{2,p}$ = \text{Fuel combustion CO$_2$ mass emissions from oxidation of feed organic carbon in the reporting period, p (tonnes CO$_2$).}

m = \text{Mass of kiln feed materials (tonnes) in reporting period.}

TOC = \text{Total organic carbon content in kiln feed materials (mass fraction); Default TOC = 0.002 (0.2%).}

3.664 = \text{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 CO$_2$ 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 CO$_2$ from use of carbonates

8.4.1 Introduction

CO$_2$ 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 CO$_2$ 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:

\[
CO_{2,p} = \sum_{i=1}^{N} (m_i \times EF_i \times F_i)
\]

Equation 8-9

Where:
- \(CO_{2,p}\) = IP CO₂ mass emissions from consumption of carbonates in the reporting period, \(p\) (tonnes CO₂).
- \(m_i\) = 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:

\[
CO_{2,p} = \sum_{i=1}^{N} (m_{in} - m_{out}) \times EF_i
\]

Equation 8-10
Where:

\[ CO_{2,p} = IP \text{ CO}_2 \text{ mass emissions from consumption of carbonates (tonnes CO}_2\text{) in reporting period, } p \text{ (tonnes CO}_2\text{).} \]

\[ i = \text{Carbonate type.} \]

\[ N = \text{Number of input carbonate types.} \]

\[ m_{in} = \text{Mass of input carbonate type } i \text{ (tonnes) in the reporting period.} \]

\[ EF_{i} = \text{Emission factor for carbonate type } i \text{ (tonnes CO}_2\text{/tonne carbonate), from Table 8-2.} \]

\[ m_{out} = \text{Mass of output carbonate type } i \text{ (tonnes) in the reporting period.} \]

(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 CO\(_2\) Emission Factors

<table>
<thead>
<tr>
<th>Mineral Name</th>
<th>Formula</th>
<th>CO(_2) Emission Factor (tonnes CO(_2)/tonnes Carbonate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Limestone</td>
<td>CaCO(_3)</td>
<td>0.43971</td>
</tr>
<tr>
<td>Magnesite</td>
<td>MgCO(_3)</td>
<td>0.52197</td>
</tr>
<tr>
<td>Dolomite</td>
<td>CaMg(CO(_3))(_2)</td>
<td>0.47732</td>
</tr>
<tr>
<td>Siderite</td>
<td>FeCO(_3)</td>
<td>0.37987</td>
</tr>
<tr>
<td>Ankerite</td>
<td>Ca(Fe,Mg,Mn)(CO(_3))(_2)</td>
<td>0.47572</td>
</tr>
<tr>
<td>Rhodochrosite</td>
<td>MnCO(_3)</td>
<td>0.38286</td>
</tr>
<tr>
<td>Sodium Carbonate/Soda Ash</td>
<td>Na(_2)CO(_3)</td>
<td>0.41492</td>
</tr>
<tr>
<td>Others</td>
<td>Facility specific emission factor to be determined through analysis or supplier information.</td>
<td></td>
</tr>
</tbody>
</table>

8.4.5 Tier 4- Measured CO\(_2\) emission factor method

(1) Introduction

CO\(_2\) from use of carbonates can be estimated based on a facility-specific CO\(_2\) emission factor measured by an annual stack gas test. This method is only applicable when no other sources of CO\(_2\) contribute to the CO\(_2\) in the stack gas from the reaction. CO\(_2\) emissions in the reporting period are calculated by multiplying the activity level of the CO\(_2\) generation process in the reporting period by the measured CO\(_2\) emission factor. Activity level data may be based on:

- Mass of carbonates consumed; or
- Any applicable substance participating in the reaction where CO\(_2\) is released.

One example application of this method is the calculation of CO\(_2\) 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:

\[
\text{CO}_2^{p} = \sum_{i=1}^{N} (m_i \times EF_i)
\]

Equation 8-11

Where:

- \( \text{CO}_2^{p} \) = CO₂ mass emissions from consumption of carbonates in the reporting period, \( p \) (tonnes CO₂).
- \( i \) = Carbonate-containing material.
- \( N \) = Number of different carbonate-containing materials.
- \( m_i \) = Mass of carbonate-containing material of type \( i \) consumed (tonnes carbonate) in reporting period.
- \( EF_i \) = CO₂ emission factor for carbonate-containing material of type \( i \) (tonnes CO₂/tonne carbonate), as determined by Equation 8-12.

Equation 8-12

Where:

\[
EF_i = \frac{ME_{CO2}}{AL}
\]

Where:

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

(3) Data requirements

- The activity level used in Equation 8-12 must be determined from measurement systems used for accounting purposes for the period that the stack tests are conducted.
- Stack tests to determine \( EF_i \) 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”, \( \text{C}_2\text{H}_4\text{O} \)) is a reactive chemical that is used mostly as a chemical intermediate to make ethylene glycol (EG) at integrated facilities. Ethylene glycol (“EG”, \( \text{C}_2\text{H}_4(\text{OH})_2 \)) 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:** \( \text{C}_2\text{H}_4 + \frac{1}{2}\text{O}_2 \rightarrow \text{C}_2\text{H}_4\text{O} + \text{heat} \) (~80% \( \text{C}_2\text{H}_4 \) converted)

**Ethylene Full Oxidation:** \( \text{C}_2\text{H}_4 + 3\text{O}_2 \rightarrow 2\text{CO}_2 + 2\text{H}_2\text{O} + \text{heat} \) (~20% \( \text{C}_2\text{H}_4 \) converted)

\[(2) \text{ Equations} \]

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

\[
\text{CO}_2,p = \left( \sum_{i=1}^{N} \left[ m_{\text{C}_2\text{H}_4\text{feed},i} - m_{\text{C}_2\text{H}_4\text{loss},i} - \left( m_{\text{EO},i} \times \frac{28.05}{44.05} \right) \right] \right) / 2 \times 44.01 \]

Equation 8-13

Where:

- \( \text{CO}_2,p \): CO₂ mass emissions from ethylene full oxidation in reporting period, \( p \) (tonnes CO₂).
- \( i \): Measurement period.
- \( N \): Number of measurement periods in reporting period.
- \( m_{\text{C}_2\text{H}_4\text{feed},i} \): Mass of ethylene (\( \text{C}_2\text{H}_4 \)) feed for reaction in measurement period \( i \) (tonne).
- \( m_{\text{C}_2\text{H}_4\text{loss},i} \): Mass of ethylene (\( \text{C}_2\text{H}_4 \)) carried out in the waste gas in measurement period \( i \) (tonnes); calculated by Equation 8-13a.
- \( m_{\text{EO},i} \): 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 8-13b or other equations depending on the available sampled parameters and concentrations.
- \( 2 \): Number of moles of carbon in \( \text{C}_2\text{H}_4 \).
- \( 44.01 \): Molecular weight of CO₂ (kg/kmol).
- \( 28.05 \): Molecular weight of \( \text{C}_2\text{H}_4 \) (kg/kmol).
- \( 44.05 \): Molecular weight of ethylene oxide (\( \text{C}_2\text{H}_4\text{O} \)) (kg/kmol).

\[
m_{\text{C}_2\text{H}_4\text{loss}} = Q_{\text{vent}} \times C_{\text{C}_2\text{H}_4}/1000 \]

Equation 8-13a

Where:

- \( Q_{\text{vent}} \): Vent gas flow rate in the reporting period (m³).
- \( C_{\text{C}_2\text{H}_4\text{loss},i} \): Concentration of the ethylene (kg/m³) in the vent gas based on measurements.

\[
m_{\text{EO},p,i} = m_{\text{MEG}} \times 0.710 + m_{\text{DEG}} \times 0.830 + m_{\text{TEG}} \times 0.880 + m_{\text{HG}} \times a + m_{\text{GW}} \times b \]

Equation 8-13b

Where:

- \( m_{\text{MEG}} \): Mass of monoethylene glycol production.
- \( 0.710 \): Ethylene oxide equivalency of monoethylene glycol production.
- \( m_{\text{DEG}} \): Mass of diethylene glycol production.
- \( 0.830 \): Ethylene oxide equivalency of diethylene glycol production.
m_{\text{TEG}} = \text{Mass of triethylene glycol production.}
0.880 = \text{Ethylene oxide equivalency of triethylene glycol production.}
m_{\text{HG}} = \text{Mass of heavy glycol if applicable.}
a = \text{Ethylene oxide equivalency of heavy glycol based on site specific heavy glycol composition.}
m_{\text{GW}} = \text{Mass of glycol water if applicable.}
b = \text{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 CO$_2$ from use of carbon as reductant

(1) Introduction

CO$_2$ 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 CO$_2$ emissions using the following equation:

\[ CO_{2,p} = m_c \times 3.664 \]  

Equation 8-14

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 NOx absorber tail gas contains unabsorbed nitrogen oxides (NO, NO₂, N₂O), which must be controlled prior to release. NOx abatement systems, such as Non-Selective Catalytic Reduction (NSCR) systems, are used to reduce NO, NO₂, and N₂O emissions from NOx 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 NOx 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 NOx Absorber tail gas stream (before the NOx abatement system) and N₂O concentration in the final stack gas stream (after the NOx abatement system).

(2) Equations

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

\[
N_{2O_p} = m_{PNA} \times EF_{N2O,NAO} \times \left(1 - (DF_{N2O} \times AF_{N2O})\right) \times 0.001
\]

Where:

- \(N_{2O_p}\) = N₂O mass emissions from nitric acid production in reporting period, \(p\) (tonnes N₂O).
- \(m_{PNA}\) = Production mass of nitric acid (100% basis), (tonnes nitric acid product) in reporting period.
- \(DF_{N2O}\) = Average destruction efficiency of NOx 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 8-15a if the test personal can safely access the upstream of the NOx abatement system.
- \(EF_{N2O,NAO}\) = Average N₂O emission factor for NOx Absorber Outlet (NAO) (kg N₂O per tonne nitric acid), as defined in Equation 8-15b.
- \(AF_{N2O}\) = NOx abatement system operating fraction (%) in the reporting period, as defined in Equation 8-15c.
- 0.001 = Mass conversion factor (t/kg).

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

\[
DF_{N2O} = \frac{\left(C_{N2O,NAO} \times Q_{N2O,NAO} - C_{N2O,NAO} \times Q_{N2O,NAO}\right)}{C_{N2O,NAO} \times Q_{N2O,NAO}} \times 100\%
\]

Where:
DF\textsubscript{N\textsubscript{2}O} = Average abatement system destruction efficiency (%) in reporting period.
\begin{align*}
C\textsubscript{N\textsubscript{2}O,NAO} &= \text{ N}_{2}O concentration (ppmv) from the NOx Absorber Outlet (NAO).
Q\textsubscript{N\textsubscript{2}O,NAO} &= \text{ Flow rates (m}^3/\text{h}) from the NOx Absorber Outlet (NAO).
C\textsubscript{N\textsubscript{2}O,NAS} &= \text{ N}_{2}O concentration (ppmv) from the Nitric Acid Stack (NAS).
Q\textsubscript{N\textsubscript{2}O,NAS} &= \text{ Flow rates (m}^3/\text{h}) from the Nitric Acid Stack (NAS).
\end{align*}

The train-specific average N\textsubscript{2}O emission factor is calculated based on direct measurement of N\textsubscript{2}O concentration in the NOx Absorber outlet (NAO).

\[
EF_{N\textsubscript{2}O,NAO} = \frac{\sum_{i=1}^{N} Q_{NAO,i} \times C_{N\textsubscript{2}O,NAO,i}}{PR_{NA,i} \times 1.861 \times 10^{-6}}
\]

Equation 8-15b

Where:
\[
\begin{align*}
EF_{N\textsubscript{2}O,NAO} &= \text{ Average N}_{2}O emission factor for NOx Absorber Outlet (kg N}_{2}O per tonne nitric acid).

i &= \text{ Test runs.}

N &= \text{ Number of N}_{2}O measurement test runs during stack test.}

Q_{NAO,i} &= \text{ Volumetric flow rate of effluent gas at NOx Absorber Outlet during test run i (sm}^3/\text{h}) at 15\textdegree C & 1 \text{ atm.}

C_{N\textsubscript{2}O,NAO,i} &= \text{ Measured N}_{2}O concentration at NOx Absorber Outlet in test run i (ppmv N}_{2}O);

PR_{NA,i} &= \text{ Measured nitric acid production rate during test run i (tonnes nitric acid per hour).}

1.861 \times 10^{-6} &= \text{ N}_{2}O Density conversion factor (kg/sm}^3 \cdot \text{ppmv}^{-1}; \text{ at 15\textdegree C & 1 atm).}
\end{align*}
\]

The NOx abatement operating fraction (AF\textsubscript{N\textsubscript{2}O}) is a measure of the fraction of total nitric acid production where N\textsubscript{2}O emissions are controlled by an operating NOx abatement system. This factor corrects the N\textsubscript{2}O equation for any periods during the year when the N\textsubscript{2}O destruction by the NOx abatement system is not applied. For operations having 100% NOx abatement uptime, the default AF\textsubscript{N\textsubscript{2}O} = 1.0.

\[
AF_{N\textsubscript{2}O} = \frac{PR_{NA,Abate}}{PR_{NA,Total}}
\]

Equation 8-15c

Where:
\[
\begin{align*}
AF_{N\textsubscript{2}O} &= \text{ NOx abatement system operating fraction (%) in the reporting period.}

PR_{NA,Abate} &= \text{ Nitric acid production when NOx abatement system is operating (tonnes nitric acid) in the reporting period.}

PR_{NA,Total} &= \text{ Total nitric acid production (tonnes nitric acid) in the reporting period.}
\end{align*}
\]

(3) **Data requirements**

- The nitric acid production for the reporting period and the monthly nitric acid production when the N\textsubscript{2}O abatement system is operating must be determined from measurement systems used for accounting purposes.
- Stack tests to determine EF\textsubscript{N\textsubscript{2}O,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<sub>N₂O,NAO</sub> when nitric acid production process has changed or abatement equipment is installed.
- The NOx 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<sub>N₂O</sub>, the operating time of the NOx abatement system during the reporting period must be determined hourly.

### 8.7.3 Tier 1 Method 2: N₂O emission factor method for direct stack test

**(1) Introduction**

The N₂O Emission Factor Method is used for nitric acid production where NOx 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**

\[
N_2O_p = m_{PNA} \times EF_{N2O,NAS} \times 0.001 
\]

*Equation 8-16*

Where:

- \( N_2O_p \) = 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.
- \( EF_{N2O,NAS} \) = 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 8-16a.
- 0.001 = Mass conversion factor: tonnes per kg.

\[
EF_{N2O,NAS} = \frac{\sum_{i=1}^{N} \frac{Q_{NAS,i} \times C_{N2O,NAS,i}}{PR_{NAS,i}} \times 1.86 \times 10^{-6}}{N} 
\]

*Equation 8-16a*

Where:

- \( EF_{N2O,NAS} \) = 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.
\[ C_{N2O-NAS,i} = \text{Measured N}_2\text{O concentration at NAS in test run i (ppmv N}_2\text{O);} \]

\[ PR_{NA,i} = \text{Measured nitric acid production rate during test run i (tonnes nitric acid per hour).} \]

\[ 1.861 \times 10^{-6} = \text{N}_2\text{O Density conversion factor (kg/sm}^3\text{ppmv}^{-1}; \text{at 15°C & 1 atm).} \]

### (3) Data requirements

- The nitric acid production for reporting period and the monthly nitric acid production when the N\textsubscript{2}O abatement system is operating must be determined from measurement systems used for accounting purposes.
- Stack tests to determine EF\textsubscript{N2O,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\textsubscript{N2O,NAS} must be conducted when nitric acid production process has changed including abatement equipment installation.

### 8.7.4 Tier 2 - CEMS Method

#### (1) Introduction

The CEMS Method is a continuous direct measurement of stack flow and N\textsubscript{2}O concentrations, which is used to determine the mass flow of N\textsubscript{2}O emissions in the stack.

#### (2) Equation

For each nitric acid production train, calculate N\textsubscript{2}O emissions from a CEMS in the reporting period using the following equation. Add N\textsubscript{2}O emissions calculated from each train to calculate the total N\textsubscript{2}O emissions.

\[
N_2O_p = \sum_{t=1}^{T} \left[ Vel_{s,t} \times Area_s \times C_{N2O,t} \times \left( \frac{P_{act} \times 288.15}{101.325 \times T_{act}} \right) \right] \times \frac{MW_{N2O}}{23.645} \times 0.001 \quad \text{Equation 8-17}
\]

Where:

- \( N_2O_p \) = N\textsubscript{2}O mass emissions from nitric acid production in reporting period, \( p \) (tonnes N\textsubscript{2}O).
- \( T \) = 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).
- \( Vel_{s,t} \) = Stack gas velocity (m/h), measured by continuous ultrasonic flow meter.
- \( Area_s \) = Stack cross-sectional area (m\(^2\)).
- \( C_{N2O,t} \) = N\textsubscript{2}O concentration (wet basis) of stack gas (kmol\textsubscript{N2O}/kmol\textsubscript{GAS}), measured by in-situ gas analyzer; (If analyzer provides N\textsubscript{2}O concentration in ppmv, then \( C_{N2O,t} = \text{ppmv} \times 10^6 \)).
- \( MW_{N2O} \) = Molecular weight of N\textsubscript{2}O = 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

- The NOx CEMS must comply with all requirements of the Alberta N₂O Meter (CEMS) Code.¹
- 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 8-18. Equation 8-18a provides the equation to calculate the mass of carbon in the gaseous feedstock and offgas.

\[
CO_{2,p} = (m_{C, Feed,p} - m_{C, Product,p} - m_{C, Off gas,p}) \times 3.664
\]

Equation 8-18

where:

- \( CO_{2,p} \) = CO₂ mass emissions from the combustion of residual carbon in the thermal carbon black production process during the reporting period, \( p \) (tonnes CO₂).
- \( m_{C, Feed,p} \) = Mass of carbon in the feedstock consumed in the reporting period, \( p \) (tonnes C).
- \( m_{C, Product,p} \) = Mass of carbon in the product produced in the reporting period, \( p \) (tonnes C).
- \( m_{C, Off gas,p} \) = Mass of carbon in the offgas consumed in the reporting period, \( p \) (tonnes C).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

\[
m_{C, Feed,p} \text{ or } m_{C, Off gas,p} = v_{fuel(gas)} \times CC_{gas,p} \times 0.001
\]

Equation 8-18a

Where:

\[ m_{C,\text{Feed},p} \text{ or } m_{C,\text{Offgas},p} = \text{Mass of carbon in the gaseous feedstock or offgas used during the reporting period, } p \text{ (tonnes C).} \]

\[ V_{\text{fuel (gas)},p} = \text{Volume of the gaseous feedstock or offgas (m}^3\text{) during the reporting period, } p, \text{ at standard conditions as defined in Appendix C.} \]

\[ CC_{\text{gas},p} = \text{Weighted average carbon content of the gaseous feedstock or offgas during the reporting period } p, \text{ calculated in accordance with Chapter 17 and Appendix C. } CC_p \text{ is in units of } \text{ kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m}^3\text{).} \]

\[ 0.001 = \text{Mass conversion factor (t/kg).} \]


(3) Data requirements

- Facilities must ensure that the proper units of feedstock and offgas consumption and carbon content are applied in Equation 8-18a.
- 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.
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:

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

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:

$$\text{E}_{\text{imported}} = \text{Amount of electricity imported to the facility in MWh}.$$  

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:
\( H_{\text{imported}} \) = 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.
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

<table>
<thead>
<tr>
<th>Product</th>
<th>Description/Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ammonia</td>
<td>Tonnes of ammonia (tonnes)</td>
</tr>
<tr>
<td>Ammonium Nitrate</td>
<td>Tonnes of ammonium nitrate (tonnes)</td>
</tr>
<tr>
<td>Bituminous Coal</td>
<td>Tonnes of clean coal (tonnes)</td>
</tr>
<tr>
<td>Cement</td>
<td>Tonnes of clinker, mineral additives (gypsum and limestone) and Supplementary Cementitious Materials added to the clinker produced (tonnes)</td>
</tr>
<tr>
<td>Electricity</td>
<td>Megawatt hours (MWh)</td>
</tr>
<tr>
<td>Hardwood Kraft Pulp</td>
<td>Air Dried Metric tonnes (ADMt)</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>Tonnes of hydrogen (tonnes)</td>
</tr>
<tr>
<td>Industrial Heat</td>
<td>Gigajoules (GJ)</td>
</tr>
<tr>
<td>Oil Sands In Situ Oil Bitumen</td>
<td>Cubic meter of bitumen (m³)</td>
</tr>
<tr>
<td>Oil Sands Mining Bitumen</td>
<td>Cubic meter of bitumen (m³)</td>
</tr>
<tr>
<td>Refining</td>
<td>Alberta Complexity-Weighted Barrel Thousand of barrels (thousand bbl)</td>
</tr>
<tr>
<td>Softwood Kraft Pulp</td>
<td>Air Dried Metric tonnes (ADMt)</td>
</tr>
</tbody>
</table>

13.2 Ammonia

Ammonia means a compound that is composed of nitrogen and hydrogen with a chemical formula of \( \text{NH}_3 \) 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 $\text{NH}_4\text{NO}_3$ 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 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.
13.8 Hydrogen

Hydrogen is a colorless elemental gas represented by the chemical formula $\text{H}_2$ 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.

13.9 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.

13.10 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.

13.11 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.

13.12 Refining

13.12.1 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.


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.

13.12.2 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:

### 13.12.3 Alberta Process CWB

The calculation of the CWB process component is defined as per CAN-CWB methodology and is provided as Equation 13.12-17, 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 13.12 to 13.12-16. The FCC Coke on Catalyst (vol. %) factor is then used to calculate the process CWB factor for the FCC unit per CAN-CWB Methodology.

\[
\text{FCC Coke on Catalyst vol\% factor}_y = \text{Coke Yield}_y \times \frac{350}{342.17} \times \text{Specific Gravity}
\]

Where:

- **FCC Coke on Catalyst vol\% factor** = 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)

\[
\text{Specific Gravity} = \frac{141.5}{\text{API Gravity} + 131.5}
\]

Where:

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

\[
\text{Coke Yield} = 100 \times \frac{\text{Total Coke}}{\text{FF Rate}}
\]

Where:

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

\[
\text{Total Coke} = \text{Carbon Regen Burn Rate} + \text{Hydrogen Regen Burn Rate} + \text{Sulphur Regen Burn Rate} + \text{Nitrogen Regen Burn Rate}
\]

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)
**Carbon Regen Burn Rate** = \( \text{Molecular Wt C} \times (\text{CO rate in flue gas} + \text{CO2 rate in flue gas}) \) \hspace{1cm} \text{Equation 13.12-5}

Where:

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

**Hydrogen Regen Burn Rate** = \( \text{Molecular Wt H2} \times \text{H2O rate in flue gas} \) \hspace{1cm} \text{Equation 13.12-6}

Where:

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

**Sulphur Regen Burn Rate** = \( \text{Molecular Wt S} \times (\text{SO2 rate in flue gas} + \text{SO3 rate in flue gas}) \) \hspace{1cm} \text{Equation 13.12-7}

Where:

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

**Nitrogen Regen Burn Rate** = \( \text{Molecular Wt S} \times (\text{NO rate in flue gas} + \text{NO2 rate in flue gas}) \) \hspace{1cm} \text{Equation 13.12-8}

Where:

- Molecular Wt S \( = 14.0067 \)
- NO rate in flue gas \( = \text{As calculated below as component rate (lb-mole/hr)} \)
- NO2 rate in flue gas \( = \text{As calculated below as component rate (lb-mole/hr)} \)

**Component Mol Rate in Flue Gas** = Component mole \% \times \text{Dry Flue Gas Mol Rate/100} \hspace{1cm} \text{Equation 13.12-9}

Where:

- Component Rate in Flue Gas \( = \text{Applies to CO, CO2, SO2, SO3, NO, NO2, O2} \)
- Component mole \% \( = \text{Measured mole \% of component in flue gas (unitless)} \)
- Dry Flue Gas Mol Rate \( = \text{As calculated below (lb-mole/hr)} \)

\( \text{H2O mol rate in flue gas} = \frac{2 \times \text{mole H2}}{\text{mole O2}} \times [0.20947 \times \text{dry air mol rate} + \text{O2 purity} \times \text{O2 mol rate enriched} - 0.5 \times \text{CO mol rate in flue gas} - \text{CO2 mol rate in flue gas} - \text{SO2 mol rate in flue gas} - 1.5 \times \text{SO3 mol rate in flue gas} - 0.5 \times \text{NO mol rate in flue gas} - \text{NO2 mol rate in flue gas} - \text{O2 mol rate in flue gas}] \) \hspace{1cm} \text{Equation 13.12-10}

Where:

- 0.20947 \( = \text{Fraction of O2 in air (unitless)} \)
- Blower Dry Rate \( = \text{As calculated below (lb-mole/hr)} \)
- O2 purity \( = \text{Mole fraction O2 in O2 enriched gas (unitless)} \)
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)

Blower Dry Rate = Dry Air Rate \times \frac{60}{379.482} \hspace{1cm} \text{Equation 13.12-11}

\text{Where:}

60 = (minutes/hour)

\text{Blower Dry Volume} = \text{As calculated below (SCF/minute)}

379.482 = \text{Molar volume ideal gas at 1 atm, 60 deg F (SCF/lb-mole)}

Dry Flue Gas Rate = \frac{(0.78984 + 0.00934) \times \text{Dry air mol rate} + O₂ Purity \times O₂ mol rate enriched}{\text{Regen Flue Gas N2+AR mol rate}} \hspace{1cm} \text{Equation 13.12-12}

\text{Where:}

0.78984 = \text{Mole fraction Nitrogen in air (unitless)}

0.00934 = \text{Mole fraction Argon in Air (unitless)}

\text{Dry air mol rate} = \text{As calculated below (lb-mole/hr)}

O₂ Purity = \text{Mole fraction O₂ in O₂ enriched gas (unitless)}

O₂ mol rate enriched = \text{As calculated below (lb-mole/hr)}

\text{Regen Flue Gas N2+AR mol rate} = 1 – \text{sum of mole fraction of CO, CO₂, SO₂, SO₃, NO, NO₂, O₂ in flue gas (unitless)}

O₂ mol rate enriched = O₂ \text{ volume enriched rate} \times \frac{60}{379.482} \hspace{1cm} \text{Equation 13.12-13}

\text{Where:}

60 = (minutes/hour)

O₂ \text{ volume enriched rate} = \text{As measured (SCF/minute)}

379.482 = \text{Molar volume ideal gas at 1 atm, 60 deg F (SCF/lb-mole)}

Dry Air Rate = \text{Blower Wet Rate} \times (1 – \text{Water content in air}) \hspace{1cm} \text{Equation 13.12-14}

\text{Where:}

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

\text{Water content in air} = \text{As calculated below}
\[
\text{Water content in Air} = \frac{\text{Saturated Water Vapour Pressure}}{\text{Atmospheric Pressure}} \times \frac{\text{Relative Humidity}}{100}
\]

\[
= 6.1121 \times e^{\frac{7.67T}{(24.5+T)}} \times \frac{\text{Relative Humidity}}{100}
\]

Equation 13.12-15

Where:

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

\[
\text{FF Rate} = \text{FF Volume} \times \frac{349.776}{24} \times \frac{141.5}{131.5+\text{API Gravity}}
\]

Equation 13.12-16

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)

\[
\text{CWB}_{\text{pro}} = \sum_{u=1}^{U} \text{Daily Throughput Barrel}_u \times \text{CWB Factor}_u
\]

Equation 13.12-17

Where:

- \( \text{CWB}_{\text{pro}} \) [bbl/cd] = Alberta Process CWB as per CAN-CWB and section 13.12.3
- \( u \) = Units in the refinery boundaries as per CAN-CWB
- \( U \) = Total number of units in the refinery boundaries as per CAN-CWB
- \( \text{Daily Throughput Barrel}_u \) [bbl/cd] = Throughput for unit \( u \) as defined in CAN-CWB in bbl/cd
- \( \text{CWB Factor}_u \) = CWB factor for unit \( u \) as defined in CAN-CWB except for Hydrogen Production Unit.

### 13.12.4 Offsites and non-energy utilities CWB

The CWB credit for offsites and non-energy utilities (\( \text{CWB}_{\text{off}} \)) 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

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Oil Equivalent Barrels where one Fuel Oil Equivalent Barrel is 6.05 million Btu based on lower heating value.

### 13.12.5 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, isoctane, isoctane, 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 reformate
  - 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
13.12.6 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 13.12-18 below:

\[
Refinery\ Production_y = \frac{(CWB_{pro} + CWB_{off} + CWB_{non}) \times Days}{1000}
\]

Equation 13.12-18

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 13.12-17 for the reporting year
- CWB\(_{off}\) [bbl/cd] = 0.327 \times Total\ Input\ Barrels + 0.0085 \times CWB\(_{pro}\)
- CWB\(_{non}\) [bbl/cd] = 0.44 \times 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.

13.13 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 covered in Chapter 1 Stationary Fuel Combustion.

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 GJ or tonnes or kilolitres.

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 the 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 calculated 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.

\[
\text{CO}_2,p = \text{Fuel}_p \times \text{HHV} \times EF_{ene} \quad \text{Equation 14-1}
\]

\[
\text{CO}_2,p = \text{Fuel}_p \times EF_{vol or ene} \quad \text{Equation 14-1a}
\]

Where:

\[
\text{CO}_2,p = \text{CO}_2 \text{ mass emissions for the biomass fuel for the reporting period, } p \text{ (tonnes CO}_2). \\
\text{Fuel}_p = \text{For Equation 14-1, the mass/volume of fuel combusted in tonnes or kilolitres (tonnes or kl). For Equation 14-1a, energy units of fuel in gigajoules or physical units of fuel in tonnes or kilolitres (GJ, tonnes, or kl). Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.}
\]
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 CO$_2$ emission factor, from Table 14-1- in tonnes of CO$_2$ per energy units (GJ) or physical units (tonnes or kilolitres).

(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 CO$_2$ 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, CO$_2$ mass emissions may be calculated using Equation 14-3e.

#### (2) Equations

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

$$ CO_{2,p} = V_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001 $$

Equation 14-3a

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

$$ CO_{2,p} = \frac{ENE_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV} $$

Equation 14-3b

Where:

- $CO_{2,p}$ = CO$_2$ mass emissions for the gaseous biofuel 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 biofuel (GJ/m$^3$).
- $CC_{gas,p}$ = 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/m$^3$).
- 3.664 = Ratio of molecular weights, CO$_2$ to carbon.
- 0.001 = Mass conversion factor (t/kg).
For a liquid biofuels, where fuel consumption is measured in units of volume (kilolitres), use Equation 14-3c:

\[
CO_2,p = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664 \tag{Equation 14-3c}
\]

Where:
- \(CO_2,p\) = \(CO_2\) mass emissions for the liquid biofuels during the report period, \(p\) (tonnes CO\(_2\)).
- \(v_{fuel(liq),p}\) = Volume of liquid biofuel 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 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, \(CO_2\) to carbon.

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

\[
CO_2,p = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664 \tag{Equation 14-3d}
\]

Where:
- \(CO_2,p\) = \(CO_2\) mass emissions for the biomass fuel during the report period, \(p\) (tonnes CO\(_2\)).
- \(m_{fuel(sol),p}\) = 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, \(CO_2\) to carbon.

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

\[
CO_2,p = Steam \times B \times EF \tag{Equation 14-3e}
\]

Where:
- \(CO_2,p\) = \(CO_2\) mass emissions for the biomass fuel for the reporting period, \(p\), (tonnes CO\(_2\)).
- \(Steam\) = 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 CO\(_2\) per GJ.

### (3) Data requirements

No additional requirements are needed.
14.5 Tier 4 Continuous emissions monitoring systems

(1) Generality

Calculate the CO$_2$ mass emissions for the reporting period from all fuels combusted in a unit, by using data from CEMS as specified in (a) though (g). This methodology requires a CO$_2$ monitor and a flow monitoring subsystem, except as otherwise provided in paragraph (c). CEMS shall use methodologies provided in [8] or by other document that supersedes it.

(a) For a facility that operates CEMS in response to federal, state, 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 provided by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) or provided in [8].

(b) Report CO$_2$ emissions for the reporting year in tonnes based on the sum of hourly CO$_2$ mass emissions over the year.

(c) An oxygen (O$_2$) concentration monitor may be used in lieu of a CO$_2$ concentration monitor in a CEMS install before January 1, 2012, to determine the hourly CO$_2$ 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 combuts 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 [8] 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 CO$_2$ mass emissions separately, as described in Section 14.4 (2).

(e) For any units using CEMS data, industrial process and stationary combustion CO$_2$ 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 Section 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 CO$_2$ concentrations or flue gas flow, select and operate the added devices using appropriate requirements [8] for the facility, as applicable in Alberta under the Alberta CEMS Code or in Canada.

(g) If a facility does not have a CEMS and chooses to add one in order to measure CO$_2$ concentrations, select and operate the CEMS using the appropriate requirements [8] or equivalent requirements as applicable in Canada.

(2) CO$_2$ emissions from combustion of mixture of biomass, or biomass fuels and fossil fuels

Use the procedures in this section to estimate biogenic CO$_2$ 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 CO$_2$ and the facility combuts 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 CO$_2$ 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 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.

\[ \text{Fuel}_{i} = \frac{[H \times \text{Steam}] - (H \times \text{Eff})_{nb} \times (\text{Eff})_{nb}}{(H \times \text{HHV})_{bio} \times (\text{Eff})_{bio}} \]  
Equation 14-4

Where:

- **Fuel** = 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.
\((HI)_{ab}\) = 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

<table>
<thead>
<tr>
<th>Biomass Fuel</th>
<th>HHV (\text{GJ/kl})</th>
<th>(\text{CO}_2) Emission Factor (\text{tonne/kl})</th>
<th>(\text{tonne/GJ})</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethanol</td>
<td>23.42</td>
<td>1.508</td>
<td>0.0644</td>
<td>ECCC Table 2-2</td>
</tr>
<tr>
<td>Biodiesel</td>
<td>35.16</td>
<td>2.472</td>
<td>0.0703</td>
<td>ECCC Table 2-2</td>
</tr>
<tr>
<td>Wood Fuel / Wood Waste</td>
<td>17.99</td>
<td>0.840</td>
<td>0.0467</td>
<td>ECCC Table 2-3</td>
</tr>
<tr>
<td>Spent Pulping Liquor</td>
<td>14.00</td>
<td>0.891</td>
<td>0.0636</td>
<td>ECCC Table 2-3</td>
</tr>
</tbody>
</table>
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 in a cap and trade system 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.

\[
Fuel = Fuel_p - Fuel_s + Fuel_{ii} - Fuel_{ei}
\]

Equation 17-1

Where:

- \(Fuel\) = amount of fuel used by the facility in the reporting year
- \(Fuel_p\) = amount of fuel purchased in the reporting year
- \(Fuel_s\) = amount of fuel sold in the reporting year
- \(Fuel_{ii}\) = initial amount of fuel in the inventories
- \(Fuel_{ei}\) = 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 equipment consumption 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.

(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 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.

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 facilities may follow the requirements under the laws and regulation of Alberta Energy Regulator or Measurement Canada for electricity and gas, as applicable for the facility.

17.2.3 Fuel properties

(1) Density

(a) Facilities using Tiers 1 or 2 for CO\textsubscript{2} 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 under the laws and regulation of Alberta Energy Regulator and/or Measurement Canada for electricity and gas, as appropriate; (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

      \[ HHV = LHV \times CF \]  
      \[ \text{Equation 17-2} \]

      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 that may be required to be used 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 that may be required to use 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 that may be required to use 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 that may be required to use 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 facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.

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 that may be required 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 that may be
required to use 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 that may be required to used include use 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.

(b) Fuel samples shall be obtained and analysis performed at the minimum frequencies 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) Facilities must apply the sampling frequencies prescribed in Table 17-3 for the quantification of the fuel consumed where applicable.

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

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

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.

### 17.3.2 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 other than natural gas, gases derived from biomass, and biogas in order to determine the carbon content and molecular weight of the fuel.

(f) Daily samples and calculation of steam variables and properties, which includes steam flow, steam discharge temperature and pressure.

(g) Every three years for boiler efficiency testing for each used fuel, following manufacturer's specifications.

(h) Monthly composite samples of coke and/or coal.

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) Every two months for liquid fuels or gaseous fuels produced at the facility.

(d) Every two months 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, gases derived from biomass, and biogas in order to determine the carbon content and molecular weight of the fuel if the necessary equipment is in place to make these measurements.

(f) Weekly for gaseous fuels other than marketable natural gas, gases derived from biomass, and biogas, where the necessary equipment is not in place to make daily measurements.

(g) Hourly samples and calculation of steam variables and properties, which includes steam flow, steam discharge temperature and pressure.

(h) Every two years for boiler efficiency testing for each used fuel or during planned maintenance, whichever is lower, following manufacturer's specifications.

(i) Weekly composite samples for coal and coke fuels.

(j) Monthly composite samples of solid fuels other than coal and waste-derived fuels shall be taken in accordance with the following:

   (i) The sample shall be a composite sample of weekly samples of equal mass taken during the month.

   (ii) Sampling shall be done at a location after all fuel treatment operations but before fuel combustion.

   (iii) Samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

   (iv) Sub-samples shall be collected at a day and time when the fuel consumption rate is representative and unbiased.

   (v) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(vi) One in every twelve composite samples shall be randomly selected for additional analysis of its discrete samples.

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 before emission calculations. The frequency required for reconciliation should follow the same frequencies prescribed in Table 17-3. 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.

\[
\text{Reconciled Fuel}_{ij} = \text{Non Adjusted Fuel}_{ij} \times \left(1 + \frac{\Delta}{\text{Non-Adjusted Fuel}_{i}}\right)
\]

Equation 17-3

\[
\Delta = \text{Reference Fuel}_i - \text{Non Adjusted Fuel}_i
\]

Equation 17-4

\[
\text{Non Adjusted Fuel}_i = \sum_{j=1}^{n} \text{Non Adjusted Fuel}_{ij}
\]

Equation 17-5

Where:

- Reconciled Fuel\(_{ij}\) = Amount of reconciled stream \(j\) for the fuel \(i\) at standard conditions as defined in Appendix C.
- Non-Adjusted Fuel\(_i\) = Amount of unreconciled fuel \(i\) at standard conditions. These are fuels that are quantified by the facility that have not been adjusted by a reconciliation process.
- Non-Adjusted Fuel\(_{ij}\) = Amount of unreconciled stream \(j\) for the fuel \(i\) in standard 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.
- \(\Delta\) = 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, CO$_2$ concentration, water content or any other data sampled, the facility shall:

1. Determine the sampling or measurement rate using Equation 17-6:

$$ R = \frac{Q_{SAc}}{Q_{s \text{ Required}}} $$

Equation 17-6

Where:

- $R$ = Sampling or measurement rate that was used, expressed as a percentage
- $Q_{SAc}$ = Quantity of actual samples or measurements obtained by the facility
- $Q_{s \text{ Required}}$ = 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 [8] 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 utilize the best available data to assess the quantities during the missing period. This may include the use of engineer estimates (i.e. operating hours and equipment specifications). For further guidance, facilities may contact the Director for guidance.
APPENDIX A: References


[13] CAPP A Recommended Approach to Completing the National Pollutant Release Inventory (NPRI) for the Upstream Oil and Gas Industry. October 2014


## APPENDIX B: Fuel Properties

Table B-1. Table of physical properties for hydrocarbons and other compounds\(^1\)

<table>
<thead>
<tr>
<th>Component</th>
<th>Chemical Formula</th>
<th>HHV [GJ/m(^3)]</th>
<th>Carbon [atoms]</th>
<th>Molar Mass [t/t-mol]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen</td>
<td>H(_2)</td>
<td>12.102</td>
<td>0</td>
<td>2.0159</td>
</tr>
<tr>
<td>Oxygen</td>
<td>O(_2)</td>
<td>0.000</td>
<td>0</td>
<td>31.9988</td>
</tr>
<tr>
<td>Helium</td>
<td>He</td>
<td>0.000</td>
<td>0</td>
<td>4.0026</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>N(_2)</td>
<td>0.000</td>
<td>0</td>
<td>28.0134</td>
</tr>
<tr>
<td>Hydrogen Sulphide</td>
<td>H(_2)S</td>
<td>23.738</td>
<td>0</td>
<td>34.0809</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>CO(_2)</td>
<td>0.000</td>
<td>1</td>
<td>44.0095</td>
</tr>
<tr>
<td>Carbon monoxide</td>
<td>CO</td>
<td>12.035</td>
<td>1</td>
<td>28.0100</td>
</tr>
<tr>
<td>Methane</td>
<td>CH(_4)</td>
<td>37.632</td>
<td>1</td>
<td>16.0425</td>
</tr>
<tr>
<td>Ethane</td>
<td>C(_2)H(_6)</td>
<td>65.937</td>
<td>2</td>
<td>30.0690</td>
</tr>
<tr>
<td>Propane</td>
<td>C(_3)H(_8)</td>
<td>93.747</td>
<td>3</td>
<td>44.0956</td>
</tr>
<tr>
<td>Isobutane</td>
<td>C(_4)H(_10)</td>
<td>121.162</td>
<td>4</td>
<td>58.1222</td>
</tr>
<tr>
<td>n-Butane</td>
<td>C(_4)H(_10)</td>
<td>121.550</td>
<td>4</td>
<td>58.1222</td>
</tr>
<tr>
<td>Isopentane</td>
<td>C(_5)H(_12)</td>
<td>149.069</td>
<td>5</td>
<td>72.1488</td>
</tr>
<tr>
<td>n-Pentane</td>
<td>C(_5)H(_12)</td>
<td>149.360</td>
<td>5</td>
<td>72.1488</td>
</tr>
<tr>
<td>Hexane</td>
<td>C(_6)H(_14)</td>
<td>177.200</td>
<td>6</td>
<td>86.1754</td>
</tr>
<tr>
<td>Heptane</td>
<td>C(_7)H(_16)</td>
<td>205.021</td>
<td>7</td>
<td>100.2019</td>
</tr>
<tr>
<td>Octane</td>
<td>C(_8)H(_18)</td>
<td>232.831</td>
<td>8</td>
<td>114.2285</td>
</tr>
<tr>
<td>Nonane</td>
<td>C(_9)H(_20)</td>
<td>260.675</td>
<td>9</td>
<td>128.2551</td>
</tr>
<tr>
<td>Decane+</td>
<td>C(<em>{10})H(</em>{22})+</td>
<td>288.492</td>
<td>10</td>
<td>142.2817</td>
</tr>
<tr>
<td>Acetylene</td>
<td>C(_2)H(_2)</td>
<td>55.872</td>
<td>2</td>
<td>26.0373</td>
</tr>
<tr>
<td>Ethylene</td>
<td>C(_2)H(_4)</td>
<td>59.603</td>
<td>2</td>
<td>28.0532</td>
</tr>
<tr>
<td>Propylene</td>
<td>C(_3)H(_6)</td>
<td>86.925</td>
<td>3</td>
<td>42.0797</td>
</tr>
<tr>
<td>Hexene</td>
<td>C(_6)H(_12)</td>
<td>174.068</td>
<td>6</td>
<td>84.1595</td>
</tr>
<tr>
<td>Benzene</td>
<td>C(_6)H(_6)</td>
<td>139.531</td>
<td>6</td>
<td>78.1118</td>
</tr>
<tr>
<td>Toluene</td>
<td>C(_8)H(_8)</td>
<td>164.408</td>
<td>7</td>
<td>92.1384</td>
</tr>
<tr>
<td>Heptanes Plus</td>
<td>C(<em>7)H(</em>{14})</td>
<td>195</td>
<td>7</td>
<td>95.00</td>
</tr>
<tr>
<td>Xylene</td>
<td>C(_8)H(_10)</td>
<td>192.270</td>
<td>8</td>
<td>106.1650</td>
</tr>
</tbody>
</table>

\(^1\) Note that physical properties of all hydrocarbons and other compounds are not listed above. For those compounds not listed, the GPSA Engineering Handbook Section 23 - Physical Properties shall be referred to.
### Table B-2. Table of properties of gases

<table>
<thead>
<tr>
<th>Component</th>
<th>Description</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>MVC</td>
<td>Standard Molar Volume for a gas at standard conditions (as defined in Appendix C)</td>
<td>23.645</td>
<td>m³/kmol</td>
</tr>
<tr>
<td>MWC</td>
<td>Molecular Weight of Carbon</td>
<td>12.01</td>
<td>t/t-mol</td>
</tr>
</tbody>
</table>

### Table B-3. Fuel oil default density value

<table>
<thead>
<tr>
<th>Fuel Oil</th>
<th>No. 1</th>
<th>No. 2</th>
<th>No.3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (kg/L)</td>
<td>0.81</td>
<td>0.86</td>
<td>0.97</td>
</tr>
</tbody>
</table>
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 CO$_2$ 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/m$^3$)
- **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 measurement period i.
- $Fuel_i$ = Quantity of fuel combusted during measurement 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:

\[
CC_i = \sum_{j=1}^{c} (MF_j \times NC_j) \times \frac{1201}{MVC} \quad \text{Equation C.1-1a}
\]

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

\[
\text{Period CC}_{95\% \text{ Uncertainty}} = \pm k_{95\%} \times \frac{\sigma}{\sqrt{n}}
\]

Equation C.2-1

Where:
- Period CC_{95\% 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)
- \(\sigma\) = 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.

\[
\text{MW} = \sum x_i M_{W_i}
\]

Equation C.3-1

Where:
- \(\text{MW}\) = 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.
- \(M_{W_i}\) = 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.

\[
V_s = 2.8438 \times \frac{P_x v}{T}
\]

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:

\[
HHV = \sum_{i}^{N} x_i HHV_i
\]

Equation C.5-1

Where:

- \( HHV \) = Higher heating value of fuel gas (GJ/m³)
- \( x_i \) = 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.

\[
HHV_p = \frac{\sum_{i=1}^{N} HHV_i \times Fuel_i}{\sum_{i=1}^{N} Fuel_i}
\]

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 determine fuel equipment consumption based on Section C.6 on the basis of direct measurement.

\[
v = \sum_{j=1}^{N} \left( \frac{P_{rated}}{n_j} \right) \times \frac{LD_j}{HHV_j} \times OH_j \times 0.0036
\]

Equation C.6-1

Where:

- \( Fuel \) = Theoretical volume of fuel combusted by fired equipment \( j \)
\( P_{\text{rated } j} \) = Maximum rated power for fired equipment \( j \) (kW).
\( LD_j \) = Load for fired equipment \( j \) (load factor).
\( OH_j \) = Operating hours for fired equipment \( j \) (hours/reporting period).
\( n_j \) = Thermal efficiency for fired equipment \( j \).
\( HHV_j \) = Higher heating value of the fuel combusted by fired equipment \( j \) (GJ/m^3).
\( N \) = quantity of fired equipment units,
0.0036 = conversion factor between kWh and GJ.
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].

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

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

<table>
<thead>
<tr>
<th>Source Type</th>
<th>Load Factor (Fraction of Maximum Rated Power Output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reciprocating Engines</td>
<td>0.75</td>
</tr>
<tr>
<td>Turbine Engines</td>
<td>0.90</td>
</tr>
<tr>
<td>Industrial and Commercial Heaters and Boilers</td>
<td>1.0</td>
</tr>
<tr>
<td>Residential Water Heaters</td>
<td>1.0</td>
</tr>
<tr>
<td>Residential Furnaces</td>
<td>1.0</td>
</tr>
<tr>
<td>Catalytic Heaters</td>
<td>1.0</td>
</tr>
<tr>
<td>Thermoelectric Generators</td>
<td>1.0</td>
</tr>
</tbody>
</table>

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.

\[
\text{fuel}_{\text{actual}, i} = \text{fuel}_{\text{theoretical}, i} \times \frac{(\text{fuel}_{\text{measurement}} - \sum \text{fuel}_{\text{theoretical, non-com}})}{\sum \text{fuel}_{\text{theoretical, com}}} \\
\]

Equation C.7-1

Where:
- \(\text{fuel}_{\text{actual}, i}\) = Actual volume of fuel combusted for equipment \(i\) in a certain time period.
- \(\text{fuel}_{\text{theoretical}, i}\) = Theoretical volume of fuel combusted for equipment \(i\) (calculated using C.6) in a certain time period.
\[ \text{fuel}_{\text{measurement}} = \text{Total volume of fuel consumption metered in a certain time period for all combustion and non-combustion devices.} \]

\[ \sum_{\text{fuel, theoretical, non-com}} = \text{Calculated/theoretical fuel gas consumption by all non-combustion devices at the site in a certain time period.} \]

\[ \sum_{\text{fuel, theoretical, com}} = \text{Sum of the calculated/theoretical fuel gas usage by each combustion device at the site in a certain time period.} \]

**C.8 Variables**

When a variable is used in a calculation, fuel weighted averages should be calculated as per Equation C.8-1.

\[
\text{Variable}_p = \frac{\sum_{i=1}^{N} \text{Fuel}_i \times \text{Variable}_i}{\sum_{i=1}^{N} \text{Fuel}_i} \quad \text{Equation C.8-1}
\]

Where:

- \( \text{Variable}_p \) = Weighted value of any variable for a reporting period.
- \( \text{Variable}_i \) = Value of any variable in a measurement period \( i \).
- \( \text{Fuel}_i \) = 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.9 Allocation of electricity generated from multiple energy suppliers**

Use Equation C.9-1 to calculate the allocation of electricity from different suppliers.

\[
\text{Electricity}_i = \text{Produced Electricity} \times \frac{\text{Heat}_i}{\sum_{j=1}^{N} \text{Heat}_j} \quad \text{Equation C.9-1}
\]

Where:

- \( \text{Electricity}_i \) = Electricity allocated to supplier \( i \)
- \( \text{Produced Electricity} \) = net electricity produced
- \( \text{Heat}_i \) = net heat provided by supplier \( i \)
- \( j \) = each supplier
- \( N \) = amount of suppliers

**C.10 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.11 Rounding of final reported values

Final reported values should be rounded to the significant digits required in the compliance or reporting form. Data and intermediate values used in the calculations shall not be rounded.
## APPENDIX D: Conversion Factors

### Table D-1. Prefixes

<table>
<thead>
<tr>
<th>Metric</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>pico (p)</td>
<td>$10^{-12}$</td>
</tr>
<tr>
<td>angstrom (Å)</td>
<td>$10^{-10}$</td>
</tr>
<tr>
<td>nano (n)</td>
<td>$10^{-9}$</td>
</tr>
<tr>
<td>micro (µ)</td>
<td>$10^{-6}$</td>
</tr>
<tr>
<td>mili (m)</td>
<td>$10^{-3}$</td>
</tr>
<tr>
<td>deca (da)</td>
<td>$10^{1}$</td>
</tr>
<tr>
<td>kilo (k)</td>
<td>$10^{3}$</td>
</tr>
<tr>
<td>mega (M)</td>
<td>$10^{6}$</td>
</tr>
<tr>
<td>giga (G)</td>
<td>$10^{9}$</td>
</tr>
<tr>
<td>tetra (T)</td>
<td>$10^{12}$</td>
</tr>
<tr>
<td>peta (P)</td>
<td>$10^{15}$</td>
</tr>
<tr>
<td>exa (E)</td>
<td>$10^{18}$</td>
</tr>
<tr>
<td>zetta (Z)</td>
<td>$10^{21}$</td>
</tr>
</tbody>
</table>

### Table D-2. Mass Conversion

<table>
<thead>
<tr>
<th>Source unit</th>
<th>Factor</th>
<th>Final Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 kg</td>
<td>2.205 lb</td>
<td></td>
</tr>
<tr>
<td>1 lb</td>
<td>453.6 g</td>
<td></td>
</tr>
<tr>
<td>1 lb</td>
<td>16 oz</td>
<td></td>
</tr>
<tr>
<td>1 metric tonne</td>
<td>2,205 lb</td>
<td></td>
</tr>
<tr>
<td>1 US short ton</td>
<td>2,000 lb</td>
<td></td>
</tr>
<tr>
<td>1 Uk long ton</td>
<td>2,239 lb</td>
<td></td>
</tr>
</tbody>
</table>

### Table D-3. Volume Conversion

<table>
<thead>
<tr>
<th>Source unit</th>
<th>Factor</th>
<th>Final Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 l</td>
<td>0.264 gal</td>
<td></td>
</tr>
<tr>
<td>1 gal</td>
<td>3.785 l</td>
<td></td>
</tr>
<tr>
<td>1 m³</td>
<td>35.3 ft³</td>
<td></td>
</tr>
<tr>
<td>1 ft³</td>
<td>28.32 l</td>
<td></td>
</tr>
<tr>
<td>1 gal</td>
<td>7.482 gal</td>
<td></td>
</tr>
<tr>
<td>1 bbl</td>
<td>42 gal</td>
<td></td>
</tr>
<tr>
<td>1 bbl</td>
<td>158.9 l</td>
<td></td>
</tr>
<tr>
<td>1 bbl</td>
<td>5.6 ft³</td>
<td></td>
</tr>
</tbody>
</table>
Table D-4. Temperature Conversion

<table>
<thead>
<tr>
<th>Source unit</th>
<th>Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>°F</td>
<td>9 / 5 * °C +32</td>
</tr>
<tr>
<td>°C</td>
<td>(°F – 32) * 5 / 9</td>
</tr>
<tr>
<td>°K</td>
<td>°C + 273.15</td>
</tr>
<tr>
<td>°R</td>
<td>°F + 459.67</td>
</tr>
</tbody>
</table>

Table D-5. Pressure Conversion

<table>
<thead>
<tr>
<th>Source unit</th>
<th>Factor</th>
<th>Final Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 MPa</td>
<td>0.1</td>
<td>bar</td>
</tr>
<tr>
<td>1 MPa</td>
<td>9.87</td>
<td>atm</td>
</tr>
<tr>
<td>1 MPa</td>
<td>145</td>
<td>psi</td>
</tr>
<tr>
<td>1 atm</td>
<td>1.0132</td>
<td>bar</td>
</tr>
<tr>
<td>1 atm</td>
<td>780</td>
<td>mmHg</td>
</tr>
<tr>
<td>1 atm</td>
<td>14.696</td>
<td>psi</td>
</tr>
</tbody>
</table>

Table D-6. Distance Conversion

<table>
<thead>
<tr>
<th>Source unit</th>
<th>Factor</th>
<th>Final Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 cm</td>
<td>0.3937</td>
<td>in</td>
</tr>
<tr>
<td>1 m</td>
<td>3.281</td>
<td>ft</td>
</tr>
<tr>
<td>1 m</td>
<td>1.094</td>
<td>yd</td>
</tr>
<tr>
<td>1 km</td>
<td>0.62137</td>
<td>mi</td>
</tr>
<tr>
<td>1 mi</td>
<td>1.609</td>
<td>km</td>
</tr>
</tbody>
</table>

Table D-7. Energy Conversion

<table>
<thead>
<tr>
<th>Source unit</th>
<th>Factor</th>
<th>Final Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 J</td>
<td>1</td>
<td>Nm</td>
</tr>
<tr>
<td>1 J</td>
<td>0.2391</td>
<td>cal</td>
</tr>
<tr>
<td>1 J</td>
<td>0.74</td>
<td>ft-lb</td>
</tr>
<tr>
<td>1 J</td>
<td>0.0009478</td>
<td>Btu</td>
</tr>
<tr>
<td>1 Cal</td>
<td>1</td>
<td>kcal</td>
</tr>
<tr>
<td>1 Cal</td>
<td>1.4187</td>
<td>kJ</td>
</tr>
<tr>
<td>1 Cal</td>
<td>3.968</td>
<td>Btu</td>
</tr>
<tr>
<td>1 Btu</td>
<td>1.055056</td>
<td>J</td>
</tr>
<tr>
<td>1 Btu</td>
<td>0.2521</td>
<td>kcal</td>
</tr>
<tr>
<td>1 kWh</td>
<td>3.6</td>
<td>MJ</td>
</tr>
<tr>
<td>1 kWh</td>
<td>3.412</td>
<td>Btu</td>
</tr>
<tr>
<td>1 mmBtu</td>
<td>1.055</td>
<td>GJ</td>
</tr>
</tbody>
</table>