

BRITISH COLUMBIA REPORTING REGULATION METHODOLOGY MANUAL

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INTRODUCTION

The Reporting Regulation (B.C. Reg. 272/2009) of the *Greenhouse Gas Reduction (Cap and Trade) Act* (GGRTA) requires the use of specified methodologies for quantifying emissions from source types listed in Tables 1 and 2 of Schedule A of the regulation.

This methodology manual provides a compilation of:

- 1) Each methodology that is incorporated by reference from the *Final Essential Requirements for Mandatory Reporting* published by the Western Climate Initiative (WCI) on July 15, 2009 (see links under: www.westernclimateinitiative.org) and listed in column 5 of a table in Schedule A of the Reporting Regulation; and
- 2) A methodology for each source type listed in column 5 of a table in Schedule A of the Reporting Regulation that states “Refer to Methodology Manual.”

The latter are emissions quantification methodologies for source types specified in the Reporting Regulation that have not yet been published by WCI. The methodologies contained in this manual for these source types are adopted from established approaches or based on WCI methodologies that are under development.

Under the Reporting Regulation operators are required legally to comply with methodologies that are published by the WCI (see references available from the WCI website described under point 1 above). Emissions quantification methodologies for these source categories are provided in this manual for ease of reference and information purposes only.

For source categories for which WCI methodologies have not been published (i.e., those described under point 2 above), operators are required to comply with the emissions quantification methodologies described in this methodology manual.

Emissions quantification methodologies will be reviewed and revised as appropriate. Published WCI methodologies will be incorporated in revisions to the methodology manual as they become available.

This methodology manual has been prepared by the Ministry of Environment. If you have any questions regarding the contents, please contact the ministry at: ghgreporting@gov.bc.ca.

1. GENERAL STATIONARY COMBUSTION

WCI.020 General Stationary Combustion

WCI.021 Source category definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

WCI.022 Greenhouse gas reporting requirements

The emissions data report shall include the following information at the facility level:

- (a) Annual greenhouse gas emissions in metric tons, reported as follows:
 - (1) Total CO₂ emissions for fossil and biomass fuels, reported by fuel type.
 - (2) Total CH₄ emissions, reported by fuel type.
 - (3) Total N₂O emissions, reported by fuel type.
- (b) Annual fuel consumption:
 - (1) For gases, report in units of standard cubic meters.
 - (2) For liquids, report in units of kiloliters.
 - (3) For non-biomass solids, report in units of metric tons.
 - (4) For biomass solid fuels, report in units of bone dry metric tons.
- (c) Average carbon content of each fuel, if used to compute CO₂ emissions.
- (d) Average high heat value of each fuel, if used to compute CO₂ emissions.
- (e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste.

WCI.023 Calculation of CO₂ emissions

For each fuel, calculate CO₂ mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in WCI.23(e).

- (a) Calculation Methodology 1. Calculate the annual CO₂ mass emissions by substituting a fuel-specific default CO₂ emission factor, a default high heat value, and the annual fuel consumption into the Equation 20-1.

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$

Equation 20-1

Where:

- CO₂ = Annual CO₂ mass emissions for the specific fuel type (metric tons).
- Fuel = Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
- HHV = Default high heat value of the fuel, from Table 20-1 (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
- EF = Fuel-specific default CO₂ emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO₂/GJ).
- 0.001 = Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO₂ mass emissions using a default fuel-specific CO₂ emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

- (1) For any type of fuel for which an emission factor is provided in Tables 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2.

$$CO_2 = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.001 \quad \text{Equation 20-2}$$

Where:

- CO₂ = Annual CO₂ mass emissions for a specific fuel type (metric tons).
- n = Number of required heat content measurements for the year as specified in WCI.25.
- Fuel_p = Mass or volume of the fuel combusted during the measurement period “p” (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
- HHV_p = High heat value of the fuel for the measurement period (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
- EF = Fuel-specific default CO₂ emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO₂/GJ).
- 0.01 = Conversion factor from kilograms to metric tons.

- (2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3.

$$CO_2 = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-3}$$

Where:

- CO₂ = Annual CO₂ mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
- Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
- B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
- EF = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO₂/GJ).
- 0.001 = Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO₂ mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section.

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times 3.664 \quad \text{Equation 20-4}$$

Where:

- CO₂ = Annual CO₂ mass emissions from the combustion of the specific solid fuel (metric tons).
- n = Number of carbon content determinations for the year.
- Fuel_i = Mass of the solid fuel combusted in measurement period “i” (metric tons).
- CC_i = Carbon content of the solid fuel, from the fuel analysis results for measurement period “i” (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5.

$$CO_2 = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-5}$$

Where:

- CO₂ = Annual CO₂ mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
- Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
- B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).

EF = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO₂/GJ), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).

0.01 = Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section.

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \quad \text{Equation 20-6}$$

Where:

CO₂ = Annual CO₂ mass emissions from the combustion of the specific liquid fuel (metric tons).

n = Number of required carbon content determinations for the year, as specified in WCI.25.

Fuel_i = Volume of the liquid fuel combusted in measurement period “i” (kiloliters).

CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement period “i” (metric ton C per kiloliter of fuel).

3.664 = Ratio of molecular weights, CO₂ to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section.

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001 \quad \text{Equation 20-7}$$

Where:

CO₂ = Annual CO₂ mass emissions from combustion of the specific gaseous fuel (metric tons).

n = Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.

Fuel_i = Volume of the gaseous fuel combusted in period “i” (a day or month, as applicable) (scm).

CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the period “i” (day or month, as applicable) (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).

MVC = Molar volume conversion factor (24.1 scm per kg-mole for STP of 20°C and 1 atmosphere or 23.7 scm per kg-mole for STP of 60°F, and 1 atmosphere).

3.664 = Ratio of molecular weights, CO₂ to carbon.

0.001 = Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO₂ mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

- (1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, use CO₂ or O₂ concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.
 - (A) The operator shall report CO₂ emissions for the reporting year in metric tons based on the sum of hourly CO₂ mass emissions over the year, converted to metric tons.
 - (B) If the operator of a facility that combusts biomass fuels uses O₂ concentrations to calculate CO₂ concentrations, annual source testing must demonstrate that calculated CO₂ concentrations when compared to measured CO₂ concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.
- (2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations use CO₂ concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.
 - (A) Annual CO₂ emissions shall be reported in metric tons based on the sum of hourly CO₂ mass emissions over the year.
 - (B) Emissions calculations shall not be based on O₂ concentrations.
- (3) The operator of a facility that combusts waste-derived fuels and calculates CO₂ emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass using the method provided in WCI.23(f).
- (4) An operator who uses CEMS data to report CO₂ emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass shall determine the portion of total CO₂ emissions separately assigned to the fossil fuel and the biomass using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO₂ emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO₂ emissions determined using the CEMS based methodology.
- (5) For any units for which CO₂ emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.
- (6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO₂ concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the

facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

- (7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO₂ concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75 or equivalent requirements as applicable in Canada.
 - (A) The operator shall use CO₂ concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in 40 CFR Part 75, Appendix F or equivalent requirements as applicable in Canada.
 - (B) The operator shall report CO₂ emissions for the report year in metric tons based on the sum of hourly CO₂ mass emissions over the year, converted to metric tons.
 - (C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.
- (e) Use of the Four CO₂ Calculation Methodologies. Use of the four CO₂ emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:
 - (1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO₂ emission factor (Tables 20-2, 20-3, 20-5, or 20-7, as applicable) and a default high heat value for the fuel (Table 20-1) is specified.
 - (2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO₂ emission factor for the fuel is specified in Tables 20-2, 20-3, 20-5, or 20-7, as applicable.
 - (3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.
 - (4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO₂ concentration monitor.
- (f) Mixtures of biomass or biomass fuel and fossil fuel.
 - (1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a) through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

- (2) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO₂ emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO₂ emissions.
- (A) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.
- (B) The operator shall divide total CO₂ emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.
- (C) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

WCI.024 Calculation of CH₄ and N₂O emissions

Calculate the annual CH₄ and N₂O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

- (a) If the heat content of the fuel is not measured for CO₂ estimation, calculate CH₄ and N₂O emissions using Equation 20-8 for all fuels except coal. For coal, use Equation 20-9.

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.000001 \quad \text{Equation 20-8}$$

$$CH_4 \text{ or } N_2O = Fuel \times EF_c \times 0.000001 \quad \text{Equation 20-9}$$

Where:

- CH₄ or N₂O = Combustion emissions from specific fuel type, metric tons CH₄ or N₂O per year.
- Fuel = Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
- HHV_D = Default high heat value specified by fuel type provided in Table 20-1, (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
- EF = Default CH₄ or N₂O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH₄ or N₂O per GJ.
- EF_c = Default CH₄ or N₂O emission factor for coal provided in Table 20-6 (grams CH₄ or N₂O per metric ton of coal)
- 0.000001 = Factor to convert grams to metric tons.

- (b) If the heat content of the fuel is measured or provided by the fuel supplier for CO₂ estimation, calculate CH₄ and N₂O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11.

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.000001 \quad \text{Equation 20-10}$$

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n Fuel_p \times EF_c \times 0.000001 \quad \text{Equation 20-11}$$

Where:

- CH₄ or N₂O = CH₄ or N₂O emissions from a specific fuel type, metric tons CH₄ or N₂O per year.
- Fuel_p = Mass or volume of the fuel combusted during the measurement period “p” (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
- HHV_p = High heat value measured directly or provided by the fuel supplier for the measurement period, p, specified by fuel type (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
- EF = Default CH₄ or N₂O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH₄ or N₂O per GJ.
- EF_c = CH₄ or N₂O emission factor for coal, either measured directly or provided by the fuel supplier, grams CH₄ or N₂O per metric ton of coal
- 0.000001 = Factor to convert grams to metric tons.

- (c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH₄ and N₂O emissions.

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001 \quad \text{Equation 20-10}$$

Where:

- CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a municipal solid waste (metric tons).
- Steam = Total mass of steam generated by municipal solid waste combustion during the reporting year (metric tons steam).
- B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output (GJ/metric ton steam).
- EF = Fuel-specific emission factor for CH₄ or N₂O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH₄ or N₂O per GJ).
- 0.000001 = Conversion factor from grams to metric tons.

- (d) The operator may elect to calculate CH₄ or N₂O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of B.C. Ministry of Environment. Upon approval of a source test plan, the source test procedures in

that plan shall be repeated in each future year to update the source specific emission factors annually.

- (e) Use of the Four CO₂ Calculation Methodologies. Use of the four CH₄ and N₂O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:
- (1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH₄ or N₂O emission factor (Tables 20-2, 20-4 or 20-6) and a default higher heat value (Table 20-3) is specified.
 - (2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.
 - (3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.
 - (4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

WCI.025 Sampling, analysis, and measurement requirements

- (a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.
- (1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).
 - (2) Monthly for natural gas, associated gas, and mixtures of low MJ gas.
 - (3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
 - (4) Monthly for solid fuels, as specified below:
 - (A) The monthly solid fuel sample shall be a composite sample of weekly samples.
 - (B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
 - (C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
 - (D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
 - (E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

- (F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.
- (5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):
 - (A) If CO₂ emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by B.C. Ministry of Environment, the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.
 - (B) If CO₂ emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO₂/MJ not less frequently than every third year, through a stack test measurement of CO₂ and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.
- (b) Fuel Consumption Monitoring Requirements.
 - (1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, liters, million standard cubic meters, metric tons or bone dry metric tons) using the following equation:
Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End
 - (2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.
 - (3) All 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 an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.
 - (4) For fuel oil, tank drop measurements may also be used.
- (c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.
 - (1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.” The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the value to high heat value as follows.

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture high heat value (MJ/scm).

LHV = fuel or fuel mixture low heat value (MJ/scm).

CF = conversion factor.

- (1) For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:
 - (A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
 - (B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.
 - (2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).
 - (3) For solid biomass-derived fuels, use ASTM D5865-07a.
 - (4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO₂ emissions using the method specified in section WCI.23(f), if applicable.
- (d) Fuel Carbon Content Monitoring Requirements. 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 or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.
- (1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.
 - (2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “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 D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).
 - (3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.
- (e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.23 through WCI.24 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

- (1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.
 - (2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.23 through WCI.24, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.
- (f) Procedure for Interim Fuel Analytical Data Collection.
- (1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.23 through WCI.24, B.C. Ministry of Environment may authorize an operator to use an interim data collection procedure if B.C. Ministry of Environment determines that the operator has satisfactorily demonstrated that:
 - (A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;
 - (B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;
 - (C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and
 - (D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.
 - (2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to B.C. Ministry of Environment that includes all of the following:
 - (A) The proposed start date and end date of the interim procedure;
 - (B) A detailed description of what data are affected by the breakdown;
 - (C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;
 - (D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and
 - (E) A demonstration that the proposed interim procedure meets the criteria specified in section WCI.25(f)(1).
 - (3) B.C. Ministry of Environment may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.25(f)(1) are met.

- (4) When approving an interim data collection procedure, B.C. Ministry of Environment shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(o).

Table 20-1: Default Carbon Content and High Heat Value by Fuel Type

Liquid Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/kl)
Asphalt & Road Oil	19.8	44.46
Aviation Gasoline	19.25	33.52
Diesel	19.06	38.3
Aviation Turbo Fuel	18.67	37.4
Kerosene	18.53	37.68
Propane	16.35	25.31
Ethane	15.61	17.22
Butane	16.67	28.44
Lubricants	19.66	39.16
Motor Gasoline - Off-Road	18.02	35
Light Fuel Oil	19.35	38.8
Residual Fuel Oil (#5 & 6)	20.07	42.5
Crude Oil	19.8	38.32
Naphtha	19.33	35.17
Petrochemical Feedstocks	19.33	35.17
Petroleum Coke - Refinery Use	22.71	46.35
Petroleum Coke - Upgrader Use	22.71	40.57
Solid Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/metric ton)
Anthracite Coal	23.74	27.7
Bituminous Coal	20.97	26.33
Foreign Bituminous Coal	21.79	29.82
Sub-Bituminous Coal	25.05	19.15
Lignite	29.97	15
Coal Coke	23.69	28.83
Solid Wood Waste	28.41	18
Spent Puling Liquor	N/A	14
Gaseous Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/m3)
Natural Gas	14.12	0.03832
Coke Oven Gas	23.03	0.01914
Still Gas - Refineries	13.34	0.03608
Still Gas - Upgraders	13.34	0.04324
Landfill Gas	14.97	0.0359

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada.

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO ₂ Emission Factor (kg /L)	CO ₂ Emission Factor (kg /GJ)	CH ₄ Emission Factor (g/L)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/L)	N ₂ O Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline - Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569

Biomass and Other Solid Fuels	CO₂ Emission Factor (kg /kg)	CO₂ Emission Factor (kg /GJ)	CH₄ Emission Factor (g/kg)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/kg)	N₂O Emission Factor (g/GJ)
Landfill Gas	29.89	833	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada) ¹	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA) ²	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor (Env.Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	CO₂ Emission Factor (kg /m3)	CO₂ Emission Factor (kg /GJ)	CH₄ Emission Factor (g/m3)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/m3)	N₂O Emission Factor (g/GJ)
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas - Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas - Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

¹ Assumes 50% moisture content of wood waste

² Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH₄ (g/m3)	CH₄ (g/GJ)	N₂O (g/m3)	N₂O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg/kg)	Emission Factor (kg/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH ₄ Emission Factor (g/kg)	N ₂ O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO ₂ Emission Factor (kg/GJ)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/GJ)
Municipal Solid Waste	91.7	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, unless otherwise stated

The WCI notes the significant difference in both the black liquor and the solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.

2. FUEL COMBUSTION BY MOBILE EQUIPMENT AT A SINGLE FACILITY OPERATION

BC.280 Mobile Equipment at Facilities

BC.281 Source category definition

The mobile equipment at facilities category includes:

- (a) Mobile equipment used for the on-site transportation or movement of substances, materials or products, and
- (b) Other mobile equipment such as tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers and other industrial equipment,
but does not include an on road vehicle, an aircraft or a marine vessel.

For clarity, an on-road vehicle means a motor vehicle that:

- (a) Can exceed a speed of 40 kilometers per hour on a level paved surface, and
- (b) Has features customarily associated with safe and practical highway use such as a reverse ear (unless the vehicle is a motorcycle), a differential and safety features required by federal or provincial laws,
but does not include a vehicle that exhibits features that render its use on a highway unsafe, impractical or highly unlikely, such as tracked road contact or inordinate size.

Mobile equipment that is part of normal facility operations that are operated by contractors is also included as it is managed or controlled by the facility.

BC.282 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

- (a) Total emissions of CO₂, CO₂ from biomass, CH₄, and N₂O at the facility level by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (metric tons).
- (b) Annual and quarterly quantities of fuel used by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (litres) from the sum of mobile equipment at the facility.

BC.283 Calculation of CO₂ emissions

- (a) CO₂ Emissions Calculation Methodology for Fossil Fuels. Calculate total CO₂ emissions using Equation 280-1.

$$E_{i,CO_2} = Q_i \times EF_i \quad \text{Equation 280-1}$$

Where:

- E_{i,CO_2} = CO₂ emissions from mobile equipment for fuel *i* (metric tons);
 Q_i = Quantity of fuel *i* used in mobile equipment (litres);
 EF_i = Emission factor for the fuel (metric tons CO₂e/litre, required emission factors provided in the Annex to the methodology manual);

(b) CO₂ Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass CO₂ emissions as specified in paragraph (1) of this section.

- (1) The owner or operator that combusts fuels or fuel mixtures where there is a mixture of biofuel (i.e. biodiesel and ethanol) and other fuels shall determine the portion of the biofuel used by broad fuel category (i.e. gasoline and diesel) and use the appropriate emission factors for each of the biofuel and the conventional fuel. When reporting emissions, CO₂ from the biomass component of biofuels shall be reported separately from CO₂ from fossil fuels.

BC.284 Calculation of CH₄ and N₂O emissions

(a) CH₄ Emissions Calculation Methodology. Calculate total CH₄ emissions from mobile equipment at facilities as specified in paragraph (1) of this section.

- (1) Calculate CH₄ emissions from mobile equipment at facilities using Equation 280-3 and the emission factors provided in the Annex to the methodology manual.

$$E_{i,CH_4} = Q_i \times EF_{i,CH_4} \times \left(\frac{1}{10^6} \right) \quad \text{Equation 280-3}$$

Where:

- E_{i,CH_4} = Quarterly CH₄ emissions from mobile equipment for fuel *i* (metric tons);
 Q_i = Quarterly quantity of fuel *i* (litres);
 EF_{i,CH_4} = CH₄ mobile equipment emission factor fuel *i* (grams/litre) (required emission factors provided in the Annex to the methodology manual);
 $(1/10^6)$ = Conversion factor from grams to metric tons.

(b) N₂O Emissions Calculation Methodology. Calculate total N₂O emissions from mobile equipment at facilities as specified using paragraph (1) of this section.

- (1) Calculate N₂O emissions from mobile equipment at facilities using Equation 280-5 and the emission factors provided in the Annex to the methodology manual.

$$E_{i,N_2O} = Q_i \times EF_{i,N_2O} \times \left(\frac{1}{10^6} \right) \quad \text{Equation 280-5}$$

Where:

- E_{i,N_2O} = Quarterly N_2O emissions from mobile equipment for fuel i (metric tons);
- Q_i = Quarterly quantity of fuel i (litres);
- EF_{i,N_2O} = N_2O mobile equipment emission factor fuel i (grams/litre) (required emission factors provided in the Annex to the methodology manual);
- $(1/10^6)$ = Conversion factor from grams to metric tons.

- (c) Annual Emissions Calculation Methodology. Annual emissions for each fuel type and GHG are calculated as the sum of the quarterly emissions. Annual emissions are reported by fuel and by GHG.

BC.285 Sampling, analysis, and measurement requirements

Fuel use and emission factors shall be determined as specified under paragraphs (a),(b) and (c) of this section.

- (a) For biofuels, the portion(s) of ethanol or biodiesel from vendor specifications.
- (b) For conventional fuels and biofuels, required emission factors listed in the Annex to this methodology manual.
- (c) Fuel volumes used shall be determined by vendor receipts, dipstick measurement or other appropriate means on a quarterly basis, starting on January 1 of the calendar year.

3. ALUMINUM OR ALUMINA PRODUCTION

WCI.070 Primary Aluminum Production

WCI.071 Source category definition

A primary aluminum production process converts alumina mineral to aluminum metal using electrolysis.

WCI.072 Greenhouse gas reporting requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

- (a) CO₂ emissions from anode consumption from prebaked and Söderberg electrolysis cells.
- (b) CO₂ emissions from anode and cathode baking.
- (c) CF₄ and C₂F₆ emissions for anode effects.
- (d) CO₂ emissions from green coke calcination.
- (e) SF₆ emissions from cover gas consumption.
- (f) CO₂, N₂O, and CH₄ emissions from stationary combustion units as specified in WCI.020.
- (g) Annual aluminum production.

WCI.073 Calculation of GHG emissions

- (a) Calculate CO₂ emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.
 - (1) For Prebaked Anodes.

$$E_{CO_2} = \sum_{i=1}^{12} [NCC \times MP \times \frac{(100 - S_a - Ash_a - Imp_a)}{100} \times 3.664]_i \quad \text{Equation 70-1}$$

Where:

- E_{CO_2} = Annual CO₂ emissions (metric tons).
- NCC = Net anode consumption per metric ton of aluminum for month i (metric ton/ metric ton aluminum).
- MP = Aluminum production for month i (metric ton).
- S_a = Sulfur content in baked anodes for month i (wt %).
- Ash_a = Ash content in baked anodes for month i (wt %).
- Imp_a = Content of fluorine and other impurities in baked anodes for month i (wt %).
- 3.664 = Conversion factor from carbon to CO₂.

(2) Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[\left(PC \times MP \right) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100} \right) \right) \right] \times 3.664 \quad \text{Equation 70-2}$$

$$- \left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100} \right)$$

Where:

- E_{CO_2} = Annual CO₂ emissions (metric tons).
- PC = Paste consumption for month i (metric tons paste/metric ton aluminum).
- MP = Aluminum production for month i (metric tons).
- BSM = Emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum).
- BC = Average binder (pitch) content in paste for month i (wt %).
- S_p = Sulfur content in pitch for month i (wt %).
- Ash_p = Ash content in pitch (wt %).
- H_p = Hydrogen content in pitch (wt %).
- S_c = Sulfur content in calcinated coke (wt %).
- Ash_c = Ash content in calcinated coke (wt %).
- 3.664 = Conversion factor from carbon to CO₂.

(b) If anode or cathode baking is performed onsite, calculate CO₂ emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO₂ emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc} - Imp}{100} \right) \times 3.664 \quad \text{Equation 70-3}$$

Where:

- EC_{CO_2} = Annual CO₂ emissions (metric tons pre year).
- PCC = Packing coke consumption per metric ton of baked anode for month i (metric tons coke/metric ton anodes).
- BAP = Baked anode production for month i (metric tons).
- Ash_{pc} = Ash content in packing coke for month i (wt %).
- S_{pc} = Sulfur content in packing coke for month i (wt %).
- Imp = Content of other impurities for month i (wt %).
- 3.664 = Conversion factor from carbon to CO₂.

(2) Calculate CO₂ emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664 \quad \text{Equation 70-4}$$

Where:

- EP_{CO2} = CO₂ emissions (metric tons pre year).
- GAW = Green anode consumption for month i (metric tons).
- BAP = Baked anode production for month i (metric tons).
- H_p = Hydrogen content in pitch for month i (wt %).
- PC = Pitch content in green anode for month i (wt %).
- RT = Recovered tar for month i (metric tons).
- 3.664 = Conversion factor from carbon to CO₂.

- (3) Calculate total CO₂ emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO_2} + EP_{CO_2} \quad \text{Equation 70-5}$$

Where:

- E_{anodebaking} = Total annual CO₂ emissions from anode baking (metric tons).
- EC_{CO2} = Annual CO₂ emissions from packing coke (metric tons).
- EP_{CO2} = Annual CO₂ emissions from pitch coking (metric tons).

- (c) Calculate CF₄ and C₂F₆ emissions from anode effects for each pot line using either the Slope Method in paragraph (c)(1) or the Pechiney Method in paragraph (c)(2).

- (1) Slope Method: Calculate the CF₄ and C₂F₆ emissions using Equation 70-6.

$$E_{CF_4, C_2F_6} = \sum_{i=1}^n [slope_{CF_4, C_2F_6} \times AEF \times AED \times MP]_i \quad \text{Equation 70-6}$$

Where:

- E_{CF4, C2F6} = Annual emissions of CF₄ or C₂F₆ (metric tons/yr).
- slope_{CF4, C2F6} = Measured slope coefficient ([Metric tons of CF₄ or C₂F₆ /metric ton Aluminum]/[anode effect minutes/pot-days]).
- AEF = Anode effect frequency (number of anode effects per pot per day).
- AED = Anode effect duration (minutes per anode effect).
- MP = Aluminum production per day (metric tons).
- n = Number of operating days per year.

- (2) Pechiney Method: Calculate the CF₄ and C₂F₆ emissions using Equation 70-7.

$$E_{CF_4, C_2F_6} = \sum_{i=1}^n [Over - voltage \ coefficient_{CF_4, C_2F_6} \times \frac{AEO}{CE} \times MP]_i \quad \text{Equation 70-8}$$

Where:

- Emission_{CF₄, C₂F₆} = Emissions of CF₄ or C₂F₆ (metric tons/yr).
- Over-voltage coefficient_{CF₄, C₂F₆} = Experimentally measured ([Metric tons of CF₄ or C₂F₆ /metric ton Aluminum]/mV).
- AEO = Anode effect over-voltage (millivolts per pot per day).
- CE = Current efficiency of aluminum production process, expressed as a fraction.
- MP = Aluminum production per day (metric tons).
- n = Number of operating days per year.

(d) Calculate CO₂ emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12} \left[\left[GC \times \frac{(100 - H_2O_{gc} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100} \right] \times 3.664 \right]_i \quad \text{Equation 70-9}$$

$$+ \left[GC \times 0.035 \times \frac{44}{16} \right]_i$$

Where:

- E_{CO₂} = CO₂ emissions (metric tons pre year).
- GC = Green coke feed for month i (metric tons).
- H₂O_{gc} = Humidity in green coke feed for month i (wt %).
- V_{gc} = Volatiles in green coke feed for month i (wt %).
- S_{gc} = Sulfur content in green coke feed in month i (wt %).
- S_{cc} = Sulfur content in calcinated coke in month i (wt %).
- CC = Calcinated coke produced in month i (metric tons).
- UCC = Under-calcinated coke produced in month i (metric tons).
- DE = Coke dust emissions for month i (metric tons).
- 3.664 = Conversion factor from carbon to CO₂
- 0.035 = Assumed CH₄ and tar content in coke volatiles, contributing to CO₂ emissions.
- 44/16 = Conversion factor from methane to CO₂.

(e) Calculate SF₆ emissions from cover gas consumption using one of the following methods.

(1) Calculate the annual SF₆ emissions using inventory records and Equation 70-10.

$$E_{SF_6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped} \quad \text{Equation 70-10}$$

Where:

- E_{SF_6} = SF₆ emissions from cover gas (metric tons).
- $S_{Purchased}$ = Quantity of SF₆ purchased (metric tons).
- $S_{Shipped}$ = Quantity of SF₆ shipped offsite (metric tons).
- $S_{Inv-Begin}$ = Quantity of SF₆ in storage at the beginning of the year, (metric tons).
- $S_{Inv-End}$ = Quantity of SF₆ in storage at the end of the year (metric tons).

- (2) Calculate the annual SF₆ emissions using Equation 70-11 and direct measurement of the SF₆ input to electrolysis cells and the SF₆ waste gases collected and transferred off-site.

$$E_{SF_6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \quad \text{Equation 70-11}$$

Where:

- E_{SF_6} = SF₆ emissions from cover gas (metric tons).
- Q_{input} = Quantity of SF₆ input to the electrolysis cell for month i (metric tons).
- C_{Input} = Concentration of SF₆ input to the electrolysis cell for month i (metric tons).
- Q_{Output} = Quantity of SF₆ gas collected during month i (if applicable) (metric tons).
- C_{Output} = Concentration of SF₆ gas collected and sent off-site during month i (metric tons).

WCI.074 Monitoring requirements

- (1) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly.
- (2) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production, U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeat whenever:
 - (1) Thirty-six months have passed since the last measurements;
 - (2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or
 - (3) Changes occur in the distribution or duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.
- (3) If using the direct measurement approach in WCI.073(e)(2) to calculate SF₆ emissions from cover gas consumption, you must measure the quantity of SF₆ gas input to the electrolysis cell month and the quantity and SF₆ concentration of any waste gas collected and sent off-site.

4. AMMONIA PRODUCTION

BC.80 Ammonia Production

BC.81 Source category definition

An ammonia production process produces ammonia either by steam reforming of a hydrocarbon or the gasification of solid raw material.

BC.82 Greenhouse gas reporting requirements

For each facility, the annual emissions report must contain the following information:

- (a) Process CO₂ Emissions. Report CO₂ process emissions from the ammonia production process.
- (b) Stationary Combustion Units. Report CO₂, N₂O, and CH₄ emissions as specified in WCI.23.
- (c) Feedstock Consumption. Report annual feedstock consumption by feedstock type reported in units of million standard cubic feet for gases, gallons for liquids, short tons for solid fuels.
- (d) Production. Report annual ammonia produced.

BC.83 Calculation of GHG emissions

The operator shall calculate and report CO₂ process emissions that result from the conversion of hydrocarbon feedstocks into CO₂ and H₂ using the methods in paragraphs (a) or (b) of this section.

- (a) Continuous Emission Monitoring Systems. The operator may measure CO₂ emissions using CEMS. The operator must comply with the requirements in section WCI.23(d).
- (b) Feedstock Material Balance. The operator may calculate CO₂ process emissions using the measured carbon content and feedstock input and Equation 80-1.

$$CO_2(\text{Feedstock}) = [(FS \times CC \times 3.664) - U] \times 0.001 \quad \text{Equation 80-1}$$

Where:

CO ₂ (Feedstock)	=	Carbon dioxide emitted from feedstock (metric tons/year).
FS	=	Quantity of feedstock consumed
CC	=	Carbon content of feedstock (kg C/m ³ feedstock)
U	=	Carbon dioxide converted to urea or methanol (kg CO ₂)
3.664	=	ratio of molecular weights, CO ₂ to carbon.
0.001	=	conversion factor – kg to metric tons.

BC.84 Monitoring requirements

- (a) Operators using CEMS to estimate CO₂ emissions shall comply with the monitoring requirements in section WCI.23(d).

- (b) Operators using the mass balance method shall perform the following monitoring:
- (1) The operator shall measure the feedstock consumption rate daily using methods that comply with the measurement accuracy provisions in the Reporting Regulation.
 - (2) The operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed on that day in the ammonia production process.
 - (3) Operators shall measure the CO₂ collected and used for urea and/or methanol production daily.

5. CEMENT PRODUCTION

WCI.090 Cement Manufacturing

WCI.091 Source category definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

WCI.092 Greenhouse gas reporting requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

- (a) Total emissions of CO₂, CH₄, and N₂O in metric tons.
- (b) CO₂ process emissions from calcination (metric tons) and the following information:
 - (1) Plant specific clinker emission factor (kg CO₂/metric ton clinker).
 - (A) Quantity of clinker produced (metric tons).
 - (B) Total lime (CaO) content of clinker (wt. fraction).
 - (C) Total magnesium Oxide (MgO) content of clinker (wt. fraction).
 - (D) Total carbonate (CO₂) content of clinker (wt. fraction).
 - (2) Cement kiln dust (CKD) emission factor (kg CO₂/metric ton CKD discarded).
 - (A) Plant specific CKD calcination rate (unitless ratio).
 - (B) Quantity of CKD discarded (metric tons).
- (c) CO₂ process emissions from organic carbon oxidation (metric tons) and the following information:
 - (1) Amount of raw material consumed in the report year (metric tons).
 - (2) Organic carbon content of raw material (wt. fraction).
- (d) CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).
- (e) CO₂, CH₄, and N₂O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.020 (metric tons).
- (f) If a continuous emissions monitor is used to measure CO₂ emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO₂. Cement plants that measure CO₂ emissions using CEMS shall report fuel usage by fuel type for kilns.
- (g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:
 - (1) Coal fuel storage as specified in WCI.100.
 - (2) Electricity generating as specified in WCI.040.

- (3) Cogeneration systems as specified in WCI.50.

WCI.093 Calculation of greenhouse gas emissions from kilns

- (a) Determine CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
- (1) Use a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).
 - (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- (b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$\text{CO}_2 \text{ process} = \text{CO}_2 \text{ calcination} + \text{CO}_2 \text{ raw material} \quad \text{Equation 90-0}$$

- (1) Calcination Emissions. Calculate CO₂ process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$\text{CO}_2 - c = \sum_{i=1}^{12} [(Cl_i) \times (EF_{Cl_i})] + [(Q_{CKD}) \times (EF_{CKD})] \quad \text{Equation 90-1}$$

Where:

- CO_{2-c} = CO₂ emissions from calcination, metric tones.
- Cl_i = Monthly quantity of clinker produced, metric tons.
- EF_{Cl_i} = Monthly clinker emission factor, metric tons CO₂/metric ton clinker computed as specified in paragraph (b)(1)(A) of this section.
- Q_{CKD} = Monthly quantity CKD discarded (i.e., not recycled to the kiln), metric tons.
- EF_{CKD} = Monthly CKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

- (A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cl_i}) for each report year based on monthly measurements of the weight fraction of CaO, MgO and CO₂ (carbonate) content in the clinker and using Equation 90-2, which assumes all carbonate remaining in the clinker is associated with the calcium.

$$EF_{Cl_i} = [(CaO \text{ content} - \frac{CO_2 \text{ Content}}{\text{Molecular ratio } CO_2/CaO}) \times \text{Molecular ratio of } CO_2/CaO] + [(MgO \text{ Content}) \times \text{Molecular ratio of } CO_2/MgO] \quad \text{Equation 90-2}$$

Where:

CaO Content (by weight) = Total CaO content of Clinker (including calcined and uncalcined) (wt. fraction).

CO₂ Content (by weight) = Total CO₂ content of Clinker (wt. fraction).

Molecular ratio of CO₂/CaO = 0.785.

MgO Content (by weight) = Total MgO content of Clinker (including calcined and uncalcined) (wt. fraction).

Molecular ratio of CO₂/MgO = 1.092.

- (B) CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a plant-specific CKD emission factor based on monthly sampling. The CKD emission factor shall be calculated using Equation 90-3 and a plant-specific CKD calcination rate as specified in Equation 90-4.

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \left(\frac{EF_{Cli}}{1 + EF_{Cli}} \times d \right)} \quad \text{Equation 90-3}$$

Where:

EF_{CKD} = Monthly CKD emission factor, kg CO₂/metric ton CKD discarded.

EF_{Cli} = Clinker emission factor, determined according to Equation 90-2.

d = CKD calcination rate, determined according to Equation 90-4.

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}} \quad \text{Equation 90-4}$$

Where:

d = CKD calcination rate (unitless ratio).

fCO_{2CKD} = Weight fraction of carbonate CO₂ in the CKD.

fCO_{2RM} = Weight fraction of carbonate CO₂ in the raw material.

- (2) Organic Carbon Oxidation Emissions. Calculate CO₂ process emissions from the total organic content in raw materials by using Equation 90-5.

$$CO_{2-RM} = TOC_{RM} \times RM \times 3.664 \quad \text{Equation 90-5}$$

Where:

CO_{2-RM} = CO₂ emissions from raw material oxidation, metric tons.

TOC_{RM} = Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(c) or using a default of 0.002 (0.2%).

RM = Amount of raw material consumed (metric tons/yr).
3.664 = The CO₂ to carbon molar ratio.

- (c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O emissions from stationary fuel combustion following the calculation methods specified in WCI.020. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO₂ emissions from fossil fuels using the emission factor methodology in WCI.23(a). “Pure” means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

WCI.094 Sampling, analysis, and measurement requirements

- (a) Determine the plant-specific weight fractions of total CaO, total MgO, total carbonate CO₂ in clinker using ASTM C114-07. Determine the weight fraction of carbonate CO₂ in the CKD and the weight fraction of carbonate CO₂ in the raw material using ASTM C114-07. The monitoring must be conducted monthly from clinker and CKD samples drawn from bulk storage.
- (b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually using ASTM Method C114-07. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.
- (c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- (d) The quantity of CKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- (e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

6. COAL MINING FROM UNDERGROUND MINES

BC.250 Coal Mining

BC.251 Source category definition

As part of the geological processes of coal formation, CO₂ and CH₄ may also be produced and trapped in the coal seam until the coal is exposed and broken during mining. In general, CH₄ is the predominant greenhouse gas emitted from coal mines. The following processes are potential source categories for fugitive emissions associated with both underground and surface coal mines:

- (a) Mining (emissions from the breakage of coal and associated strata, including ventilation air and degasification systems for underground mines);
- (b) Low temperature oxidation (oxidation of coal when exposed to oxygen in air);
- (c) Uncontrolled combustion (active fire caused by trapped heat and increased temperature from low temperature oxidation); and
- (d) Abandoned mines.

BC.252 Greenhouse gas reporting requirements

The emissions data report shall include the following information at the facility level:

- (a) Annual CH₄ emissions from each specific mine.
- (b) Depth of mine.

BC.253 Calculation of GHG emissions

- (a) Calculate CH₄ emissions from underground mines using Equations 251 and 252.

$$E_{\text{Underground-CH}_4} = E_{\text{Mining-CH}_4} - R_{\text{CH}_4} \quad \text{Equation 251}$$

where:

- $E_{\text{Underground-CH}_4}$ = Total CH₄ emissions from underground coal mining (metric tons);
- $E_{\text{Mining-CH}_4}$ = CH₄ emissions from underground coal mining operations (metric tons);
- R_{CH_4} = CH₄ recovered and utilized for energy production or flared.

$$E_{\text{Mining-CH}_4} = P_{\text{Underground}} \times EF_{\text{Underground-CH}_4} \times 0.00067 \quad \text{Equation 252}$$

where:

- $E_{\text{Mining-CH}_4}$ = CH₄ emissions from underground coal mining operations (metric tons);
- $P_{\text{Underground}}$ = Underground coal production (metric tons);
- $EF_{\text{Underground-CH}_4}$ = CH₄ emission factor (m³ CH₄/metric ton coal), equal to 10 m³/metric ton for mine depths less than 200m, 18 m³/metric ton for mine depths between 200 m and 400 m, and 25 m³/metric ton for mine depths greater than 400m
- 0.00067 = Conversion factor from volume of CH₄ to mass of CH₄ (metric ton/m³).

BC.254 Monitoring requirements

Not applicable

7. COAL STORAGE AT FACILITIES THAT COMBUST COAL

WCI.100 Coal Storage

WCI.101 Source category definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH₄ emissions. Within natural coal deposits, CH₄ is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH₄ to the atmosphere; adsorbed CH₄ is also released until the CH₄ in the coal reaches equilibrium with the surrounding atmospheric conditions.

WCI.102 Greenhouse gas reporting requirements

The emissions data report shall include the following information at the facility level:

- (a) Annual greenhouse gas emissions in metric tons, reported as follows:
 - (1) Total CH₄ emissions.
- (b) Annual coal purchases (tons for U.S.; metric tons for Canada).
- (c) Source of coal purchases:
 - (1) Coal basin.
 - (2) State/province.
 - (3) Coal mine type (surface or underground).

WCI.103 Calculation of CH₄ emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations – including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach utilized by the California Climate Action Registry – attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility.

Calculate fugitive CH₄ emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

- (a) For coal purchased from U.S. sources, calculate fugitive CH₄ emissions using Equation 100-1 (English) and Table 100-1, or Equation 100-1 (Metric) and Table 100-2.
- (b) For coal purchased from Canadian sources, calculate fugitive CH₄ emissions using Equation 100-1 (Metric) and Table 100-3.
- (c) For coal purchased from non-U.S. and non-Canadian sources, owners or operators should use either WCI.103(a) or WCI.103(b), whichever is the most applicable. This chosen approach is subject to approval by B.C. Ministry of Environment.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.04228 / 2,204.6 \quad \text{Equation 100-1 (English Units)}$$

Where:

- CH₄ = Fugitive emissions from coal storage piles for each coal category *i* (metric tons CH₄ per year);
- PC_{*i*} = Purchased coal for each coal category *i* (tons per year);
- EF_{*i*} = Default CH₄ emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1 (scf CH₄ per ton of coal);
- 0.04228 = Methane conversion factor to convert scf to lbs;
- 2,204.6 = Factor to convert lbs to metric tons.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 / 1,000 \quad \text{Equation 100-1 (Metric Units)}$$

Where:

- CH₄ = Fugitive emissions from coal storage piles for each coal category *i*, (metric tons CH₄ per year);
- PC_{*i*} = Purchased coal for each coal category *i* (metric tons per year);
- EF_{*i*} = Default CH₄ emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-2 or Table 100-3 (m³ CH₄ per metric ton of coal);
- 0.6772 = Methane conversion factor to convert m³ to kg;
- 1,000 = Factor to convert kg to metric tons.

WCI.104 Sampling, analysis, and measurement requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ ft³ per Short Ton)

Coal Origin		Coal Mine Type	
Coal Basin	States	Surface Post-Mining Factors	Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005*

April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH₄ Emission Factors (ft³ per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per Metric Ton)

Coal Origin		Coal Mine Type	
Coal Basin	States	Surface Post-Mining Factors	Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005*
 April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH₄ Emission Factors (ft³ per Short Ton; converted to m³ per metric ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-3. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per Metric Ton)

Coal Origin		Coal Mine Type	
Province	Coalfield	Surface Post-Mining Factors	Underground Post-Mining Factors
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options*. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Dartmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).

8. COPPER OR NICKEL SMELTING OR REFINING

BC.260 Nickel and Copper Metal Production

BC.261 Source category definition

The nickel and copper metal production category includes process-related sources at nickel and copper metal smelting and refining facilities. Metals addressed in other categories (i.e., iron and steel, ferroalloys, aluminum, magnesium, lead, and zinc) are not included in this category.

The nickel and copper metal production category includes three main processes that produce CO₂ emissions: removal of impurities from nickel or copper ore concentrate using carbonate flux reagents (i.e., limestone [CaCO₃] or dolomite [CaCO₃·MgCO₃]), the use of other reducing agents to extract metals from their oxides (e.g., metallurgical coke, coal, natural gas, etc.), the use of material (e.g., coke) for slag cleaning and the consumption of graphite or carbon electrodes in electric arc furnaces. It is important to distinguish between fuels used for combustion and fuels used as reducing agents; only fuels used as reducing agents should be included in the base metal production category. Fuels used for combustion are reported in WCI.020.

BC.262 Greenhouse gas reporting requirements

In addition to the information required by the Reporting Regulation, the annual emissions data report shall contain the following information:

- Annual emissions of CO₂ at the facility level (metric tons).
- Annual quantities of each carbonate flux reagent used (metric tons).
- Fractional purity of each carbonate flux reagent used (metric tons carbonate/metric tons raw material).
- Annual quantities of other reducing agents used (metric tons).
- Carbon content of other reducing agent used or material used for slag cleaning (metric tons C/metric ton reducing agent or material for slag cleaning).
- Annual quantity of ore processed (metric tons).
- Carbon content of ore processed (metric tons C/metric ton ore).

BC.263 Calculation of CO₂ emissions

Calculate total CO₂ emissions as specified under paragraph (a), (b), and (c) of this section.

- Calculate CO₂ emissions from carbonate flux reagents using Equation 260-1.

$$E_{cf} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100} \right) + Q_d \times f_d \times \left(\frac{88}{184} \right) \quad \text{Equation 260-1}$$

Where:

- E_{cf} = Annual CO₂ emissions from carbonate flux reagents (metric tons);
- Q_{ls} = Annual quantity of limestone consumed (metric tons);

- f_s = Fractional purity of limestone (metric tons CaCO_3 /metric tons of raw material);
 $44/100$ = Stoichiometric conversion factor from CaCO_3 to CO_2 ;
 Q_d = Annual quantity of dolomite consumed (metric tons);
 f_d = Fractional purity of dolomite (metric tons $\text{CaCO}_3 \cdot \text{MgCO}_3$ /metric tons of raw material);
 $88/184$ = Stoichiometric conversion factor from $\text{CaCO}_3 \cdot \text{MgCO}_3$ to CO_2 .

- (b) Calculate CO_2 emissions from other reducing agents or material used in slag cleaning using Equation 260-2.

$$E_{ra} = Q_a \times C_a \times 3.664 \quad \text{Equation 260-2}$$

Where:

- E_{ra} = Annual CO_2 emissions from other reducing agents or slag cleaning (metric tons);
 Q_a = Annual quantity of other reducing agent or material used for slag cleaning (metric tons);
 C_a = Carbon content of other reducing agent or material used for slag cleaning (metric tons C/metric ton of reducing agent or material used for slag cleaning);
 3.664 = Stoichiometric conversion factor from C to CO_2 .

- (c) Calculate CO_2 emissions from release of carbon from metal ores using Equation 260-3.

$$Q_{ore} \times C_{ore} \times 3.664 \quad \text{Equation 260-3}$$

Where:

- Q_{ore} = Annual quantity of nickel or copper metal ore consumed (metric tons);
 C_{ore} = Carbon content of base metal ore (metric tons C/metric ton of base metal ore);
 3.664 = Stoichiometric conversion factor from C to CO_2 .

- (d) Calculate CO_2 emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 260-4.

$$E_{ce} = Q_{ce} \times C_{ce} \times 3.664 \quad \text{Equation 260-4}$$

Where:

- E_{ce} = Annual CO_2 emissions from carbon electrode consumption in EAFs (metric tons);
 Q_{ce} = Quantity of carbon electrodes consumed (metric tons);
 C_{ce} = Carbon content of carbon electrodes (metric tons C/metric ton carbon electrodes);
 3.664 = Stoichiometric conversion factor from C to CO_2 .

BC.264 Sampling, analysis, and measurement requirements

Reducing agent carbon content shall be determined as specified under paragraph (a), (b), or (c) of this section.

- (a) Carbon contents from reducing agents or material for slag cleaning should be determined in the following manner:
 - (1) For coal and coke, use ASTM D5373-02 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke”.
 - (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “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 D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).
- (b) Carbon contents of carbon electrodes should be obtained from the electrode vendor or supplier.
- (c) Carbon contents from carbonate flux reagents (i.e., limestone and dolomite) should be determined using ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.

9. ELECTRICITY GENERATION

WCI.040 Electricity Generation (Metric Units)

WCI.041 Source category definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units.

Note: For SF₆ quantification methods, reporters should refer to the section of the methodology manual addressing “Electricity Transmission (and Emissions from Electrical Equipment in Electricity Generation)” (section 0).

WCI.042 Greenhouse gas reporting requirements

For each electricity generating unit, the emissions data report shall include the following information:

- (a) Annual greenhouse gas emissions in metric tons, reported as follows:
 - (1) Total CO₂ emissions for fossil fuels, reported by fuel type.
 - (2) Total CO₂ emissions for all biomass fuels combined.
 - (3) Total CH₄ emissions for fuels combined.
 - (4) Total N₂O emissions for all fuels combined.
- (b) Annual fuel consumption:
 - (1) For gases, report in units of standard cubic meters.
 - (2) For liquids, report in units of kiloliters.
 - (3) For non-biomass solids, report in units of metric tons.
 - (4) For biomass-derived solid fuels, report in units of bone dry metric tons.
- (c) Average carbon content of each fuel, if used to compute CO₂ emissions as specified in WCI.43.
- (d) Average high heating value of each fuel, if used to compute CO₂ emissions as specified WCI.43.
- (e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.
- (f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).
- (g) Process CO₂ emissions from acid gas scrubbers and acid gas reagent.

- (h) Fugitive emissions of HFC from cooling units that support power generation.
- (i) Fugitive CO₂ emissions from geothermal facilities.
- (j) Fugitive CO₂ emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

WCI.043 Calculation of greenhouse gas emissions

- (a) Calculation of CO₂ Emissions. Operators shall use CEMS to measure CO₂ emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO₂ emissions shall comply with the provisions in section WCI.23(d).
 - (1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:
 - (A) If the high heat value is greater than or equal to 36.3 and less than or equal to 40.98 MJ/scm use either:
 - (i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or
 - (ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.
 - (B) If the high heat value is less than 36.3 or greater than 40.98 MJ/scm, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).
 - (2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

 - (A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or
 - (B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.
 - (3) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.030.

- (4) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:
 - (A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
 - (B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.
- (5) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in WCI.020 Table 20-7, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO₂ emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO₂ emission factor according to the provisions of WCI.23(c)(2).
- (6) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO₂ emissions from fossil fuel combustion using one of the following methods:
 - (A) The default emission factors from Tables 20-2, 20-3, 20-5 or 20-7, as applicable, and calculation methodology 1 provided in section WCI.23(a);
 - (B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);
 - (C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or
 - (D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.030.
- (7) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO₂ emissions as follows:
 - (A) For co-fired electricity generators that burn only fossil fuels, CO₂ emissions shall be determined using one of the following methods:
 - (i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.
 - (ii) For units not equipped with a continuous emission system, calculate the CO₂ emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.
 - (B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO₂ emissions shall be determined using one of the following methods:
 - (i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall

determine the portion of the total CO₂ emissions attributable to the biomass-derived fuel and portion of the total CO₂ emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

- (ii) For units not equipped with a continuous emission system, calculate the CO₂ emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.
- (C) Calculation of CH₄ and N₂O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH₄ and N₂O emissions. For coal combustion, use the default CH₄ emission factor(s) in Table 20-6.
- (D) Calculation of CO₂ Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO₂ emissions from these processes using Equation 40-1 if these emissions are not already captured in CO₂ emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times (CO_{2\text{MW}} / Sorbent_{\text{MW}}) \quad \text{Equation 40-1}$$

Where:

- CO₂ = CO₂ emitted from sorbent for the report year, metric tons;
- S = Limestone or other sorbent used in the report year, metric tons;
- R = Ratio of moles of CO₂ released upon capture of one mole of acid gas;
- CO₂_{MW} = Molecular weight of carbon dioxide (44);
- Sorbent_{MW} = Molecular weight of sorbent (if calcium carbonate, 100).

- (E) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

- (i) Use Equation 40-2 to calculate annual HFC emissions.

$$HFC = HFC_{\text{inventory}} + HFC_{\text{purchases / acquisitions}} - HFC_{\text{sales / disbursements}} + HFC_{\Delta\text{capacity}} \quad \text{Equation 40-2}$$

Where:

- HFC = Annual fugitive HFC emission, metric tons;
- HFC_{inventory} = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in

operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.

- $HFC_{\text{purchases/acquisitions}}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
- $HFC_{\text{sales/disbursements}}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.
- $HFC_{\Delta\text{capacity}}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

- (ii) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{\text{Install}} = R_{\text{new}} - C_{\text{new}}$$

$$HFC_{\text{Service}} = R_{\text{recharge}} - R_{\text{Recover}}$$

$$HFC_{\text{Retire}} = C_{\text{retire}} - R_{\text{retire}}$$

Where:

- HFC_{Install} = HFC emitted during initial charging/installation of the unit, kilograms;
- HFC_{Service} = HFC emitted during use and servicing of the unit for the report year, kilograms;
- HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
- R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
- C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
- R_{recharge} = HFC used to recharge the unit during maintenance and service, kilograms;
- R_{recover} = HFC recovered from the unit during maintenance and service, kilograms;
- C_{retire} = Nameplate capacity of the retired unit, kilograms; and
- R_{retire} = HFC recovered from the retired unit, kilograms.

- (F) Fugitive CO₂ Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO₂ emissions using one of the following methods:

- (i) Calculate the fugitive CO₂ emissions using Equation 40-3.

$$CO_2 = 7.14 \times Heat \times 0.001 \quad \text{Equation 40-3}$$

Where:

- CO₂ = CO₂ emissions, metric tons per year;
7.14 = Default fugitive CO₂ emission factor for geothermal facilities, kg per GJ; and
Heat = Heat taken from geothermal steam and/or fluid, GJ/yr.

- (ii) Calculate CO₂ emissions using B.C. Ministry of Environment approved source specific emission factor.

WCI.044 Sampling, analysis, and measurement requirements

- (a) CO₂, CH₄ and N₂O Emissions from Fuel Combustion. Operators using CEMS to estimate CO₂ emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.
- (b) CO₂ Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.
- (c) CO₂ Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO₂ emission rate using a method approved by B.C. Ministry of Environment. The operator shall submit a test plan to the B.C. Ministry of Environment for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the B.C. Ministry of Environment.

10. ELECTRONICS MANUFACTURING

BC.110 Electronics Manufacturing

BC.111 Source category definition

A large number of fluorinated compounds are used in the manufacture of semiconductors. These compounds include sulfur hexafluoride (SF₆), nitrogen trifluoride (NF₃), and various perfluorocarbons (PFCs) and hydrofluorocarbons (HFCs). Many of these fluorinated compounds are greenhouse gases; the remaining fluorinated compounds may potentially generate greenhouse gases as by-products of various manufacturing processes. Nitrogen trifluoride (NF₃) is currently not included in British Columbia's reporting requirements. However, the WCI is considering requiring reporting of NF₃ due to its very high GWP and it used by the industry as a substitute for PFCs. Therefore, reporting of NF₃ emissions is solely for information purposes and is not included in GHG totals for a facility.

Within the electronics industry, these fluorinated compounds are used in two critical manufacturing processes: cleaning of chemical vapor deposition (CVD) chambers and plasma/dry etching processes. In addition to direct use of fluorinated compounds in these two manufacturing processes, fluorinated compounds may also be generated as chemical by-products.

BC.112 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information at the facility level:

- Total SF₆ emissions (metric tons).
- Total PFC species emissions (metric tons).
- Total HFC species emissions (metric tons).
- Total NF₃ emissions (metric tons).

BC.113 Calculation of SF₆, PFC species, HFC species, and NF₃

Calculate the annual SF₆, PFC species, HFC species, and NF₃ emissions using the mass balance approach specified in paragraphs (a) through (f) of this section.

- Calculate the cleaning or etching emissions using Equation 110-1.

$$E_i = (1 - h) \times \sum_p \left[FC_{i,p} \times (1 - U_{i,p}) \times (1 - a_{i,p} \times d_{i,p}) \right] \quad \text{Equation 110-1}$$

Where:

- E_i = Emissions of gas i (kilogram);
- h = Fraction of gas remaining in shipping container (heel) after use;
- p = Process (cleaning or etching);
- $FC_{i,p}$ = Mass of gas i fed into process p (kilogram);

- $U_{i,p}$ = Use rate of each gas i and process p (fraction destroyed or transformed);
 $a_{i,p}$ = Fraction of gas i volume fed into process p with emission control technologies;
 $d_{i,p}$ = Fraction of gas i destroyed by the emission control technology used in process p (If more than one emission control technology is used in process p , this is the average of the fraction destroyed by those emission control technologies, where each fraction is weighted by the quantity of gas fed into tools using that technology).

- (b) Calculate the by-product emissions of CF₄ using Equation 110-2.

$$BPE_{CF_4,i} = (1 - h) \times \sum_p \left[B_{CF_4,i,p} \times FC_{i,p} \times (1 - a_{i,p} \times d_{CF_4,p}) \right] \quad \text{Equation 110-2}$$

Where:

- $BPE_{CF_4,i}$ = By-product emissions of CF₄ converted from the gas i used (kilogram);
 h = Fraction of gas remaining in shipping container (heel) after use;
 p = Process;
 $B_{CF_4,i,p}$ = Emission factor for by-product emissions of CF₄ converted from gas i in process p (kilogram CF₄ created/kilogram gas i used);
 $FC_{i,p}$ = Mass of gas i fed into process p (kilogram);
 $a_{i,p}$ = Fraction of gas i volume fed into process p with emission control technologies;
 $d_{CF_4,p}$ = Fraction of CF₄ by-product destroyed by the emission control technology used in process p .

- (c) Calculate the by-product emissions of C₂F₆ using Equation 110-3.

$$BPE_{C_2F_6,i} = (1 - h) \times \sum_p \left[B_{C_2F_6,i,p} \times FC_{i,p} \times (1 - a_{i,p} \times d_{C_2F_6,p}) \right] \quad \text{Equation 110-3}$$

Where:

- $BPE_{C_2F_6,i}$ = By-product emissions of C₂F₆ converted from the gas i used (kilogram);
 h = Fraction of gas remaining in shipping container (heel) after use;
 p = Process;
 $B_{C_2F_6,i,p}$ = Emission factor for by-product emissions of C₂F₆ converted from gas i in process p (kilogram C₂F₆ created/kilogram gas i used);
 $FC_{i,p}$ = Mass of gas i fed into process p (kilogram);
 $a_{i,p}$ = Fraction of gas i volume fed into process p with emission control technologies;
 $d_{C_2F_6,p}$ = Fraction of C₂F₆ by-product destroyed by the emission control technology used in process p .

- (d) Calculate the by-product emissions of CHF₃ using Equation 110-4.

$$BPE_{CHF_3,i} = (1 - h) \times \sum_p \left[B_{CHF_3,i,p} \times FC_{i,p} \times (1 - a_{i,p} \times d_{CHF_3,p}) \right] \quad \text{Equation 110-4}$$

Where:

- $BPE_{CHF_3,i}$ = By-product emissions of CHF_3 converted from the gas i used (kilogram);
- h = Fraction of gas remaining in shipping container (heel) after use;
- p = Process;
- $B_{CHF_3,i,p}$ = Emission factor for by-product emissions of CHF_3 converted from gas i in process p (kilogram CHF_3 created/kilogram gas i used);
- $FC_{i,p}$ = Mass of gas i fed into process p (kilogram);
- $a_{i,p}$ = Fraction of gas i volume fed into process p with emission control technologies;
- $d_{CHF_3,p}$ = Fraction of CHF_3 by-product destroyed by the emission control technology used in process p .

(e) Calculate the by-product emissions of C_3F_8 using Equation 110-5.

$$BPE_{C_3F_8,i} = (1 - h) \times \sum_p \left[B_{C_3F_8,i,p} \times FC_{i,p} \times (1 - a_{i,p} \times d_{C_3F_8,p}) \right] \quad \text{Equation 110-5}$$

Where:

- $BPE_{C_3F_8,i}$ = By-product emissions of C_3F_8 converted from the gas i used (kilogram);
- h = Fraction of gas remaining in shipping container (heel) after use;
- p = Process;
- $B_{C_3F_8,i,p}$ = Emission factor for by-product emissions of C_3F_8 converted from gas i in process p (kilogram C_3F_8 created/kilogram gas i used);
- $FC_{i,p}$ = Mass of gas i fed into process p (kilogram);
- $a_{i,p}$ = Fraction of gas i volume fed into process p with emission control technologies;
- $d_{C_3F_8,p}$ = Fraction of C_3F_8 by-product destroyed by the emission control technology used in process p .

(f) Calculate the total emissions of gas i Equation 110-6.

$$TE_i = (E_i + BPE_{CF_4,i} + BPE_{C_2F_6,i} + BPE_{CHF_3,i} + BPE_{C_3F_8,i}) / 1,000 \quad \text{Equation 110-6}$$

Where:

- TE_i = Total emissions of gas i (kilogram);
- E_i = Process (CVD chamber cleaning or plasma etching) emissions of gas i , (kilogram);
- $BPE_{CF_4,i}$ = By-product emissions of CF_4 converted from the gas i used (kilogram);
- $BPE_{C_2F_6,i}$ = By-product emissions of C_2F_6 converted from the gas i used (kilogram);
- $BPE_{CHF_3,i}$ = By-product emissions of CHF_3 converted from the gas i used (kilogram);
- $BPE_{C_3F_8,i}$ = By-product emissions of C_3F_8 converted from the gas i used (kilogram);
- 1,000 = Factor to convert kilograms to metric tons.

BC.114 Monitoring requirements

Parameters included in the BC.113 mass balance approach shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Measure process-specific use rates and by-product emission factors using the International SEMATECH Manufacturing Initiative’s “Guideline for Environmental Characterization of Semiconductor Process Equipment”.
- (b) Use the following default parameters specified in paragraph (i), (ii), or (iii).
 - (1) Fraction of gas remaining in shipping container after use (i.e., heel) – 0.10.
 - (2) Use rates and by-product emission factors – see Table 110-1.
 - (3) Destruction fraction – see Table 110-2.

(1)
(2)
(3)
(4)
(5)
(6)
(7)
(8)
(9)
(10)

Table 110-1. Tier 2 Default Emission Factors for FC Emissions from Semiconductor Manufacturing

Process Gas (i)	Greenhouse Gases with TAR GWP										Greenhouse Gases without TAR GWP				Non-GHGs Producing FC By-products [‡]	
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	e-C ₄ F ₈	NF ₃ Remote	NF ₃	SF ₆	C ₄ F ₆	C ₃ F ₈	C ₄ F ₈ O	F ₂	COF ₂		
Tier 2a																
1-Ui	0.9	0.6	0.4	0.1	0.4	0.1	0.02	0.2	0.2	0.1	0.1	0.1	0.1	NA	NA	
B _{CF4}	NA	0.2	0.07	0.08	0.1	0.1	0.02 [†]	0.09	NA	0.3	0.1	0.1	0.02 [†]	0.02 [†]	0.02 [†]	
B _{CF6}	NA	NA	NA	NA	NA	0.1	NA	NA	NA	0.2	0.04	NA	NA	NA	NA	
B _{CF8}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.04	0.04	NA	NA	NA	
Tier 2b																
Etch 1-Ui	0.7 [*]	0.4 [*]	0.4 [*]	0.06 [*]	NA	0.2 [*]	NA	0.2	0.2	0.1	0.2	NA	NA	NA	NA	
CVD 1-Ui	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1	NA	NA	NA	
Etch B _{CF4}	NA	0.4 [*]	0.07 [*]	0.08 [*]	NA	0.2	NA	NA	NA	0.3 [*]	0.2	NA	NA	NA	NA	
Etch B _{CF6}	NA	NA	NA	NA	NA	0.2	NA	NA	NA	0.2 [*]	0.2	NA	NA	NA	NA	
CVD B _{CF4}	NA	0.1	NA	NA	0.1	0.1	0.02 [†]	0.1 [†]	NA	NA	0.1	0.1	0.02 [†]	0.02 [†]	0.02 [†]	
CVD B _{CF6}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
CVD B _{CF8}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.04	NA	NA	NA	

Notes: NA denotes not applicable based on currently available information

[†] The default emission factors for F₂ and COF₂ may be applied to cleaning low-k CVD reactors with ClF₃.

^{*} Estimate includes multi-gas etch processes

[‡] Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing FC additive

Table 110-2. Tier 2a & 2b Default Efficiency Parameters for electronics Industry FC Emission Reduction Technologies^{a, b, e}

Emission Control Technology	CF ₄	C ₂ F ₆	CHF ₃	C ₃ F ₈	c-C ₄ F ₈	NF ₃ ^f	SF ₆
Destruction ^c	0.9	0.9	0.9	0.9	0.9	0.95	0.9
Capture/Recovery ^d	0.75	0.9	0.9	NT	NT	NT	0.9

^a Values are simple (unweighted) averages of destruction efficiencies for all abatement technologies. Emission factors do not apply to emission control technologies which cannot abate CF₄ at destruction or removal efficiency (DRE) ≥ 85 percent when CF₄ is present as an input gas or by-product and all other FC gases at DRE ≥ 90 percent. If manufacturers use any other type of emission control technology, its destruction efficiency is 0 percent when using the Tier 2 methods.

^b Tier 2 emission control technology factors are applicable only to electrically heated, fuelled-combustion, plasma, and catalytic devices that

- are specifically designed to abate FCs.
- are used within the manufacturer's specified process window and in accordance with specified maintenance schedules and
- have been measured and has been confirmed under actual process conditions, using a technically sound protocol, which accounts for known measurement errors including, for example, CF₄ by-product formation during C₂F₆ as well as the effect of dilution, the use of oxygen or both in combustion abatement systems

^c Average values for fuelled combustion, plasma, and catalytic abatement technologies.

^d Average values for cryogenic and membrane capture and recovery technologies.

^e Vendor data verified by semiconductor manufacturers. Factors should only be used when an emission control technology is being utilised and maintained in accordance with abatement manufacturer specifications.

^f Use of NF₃ in the etch process is typically small compared to CVD. The aggregate emissions of NF₃ from etch and CVD under Tier 2b will usually not be greater than estimates made with Tier 2a or Tier 1 methods.

NT = not tested.

11. FERROALLOY PRODUCTION

BC.270 Ferroalloy Production

BC.271 Source category description

Ferroalloys include concentrated alloys of iron and one or more metals (e.g., silicon, manganese, chromium, molybdenum, vanadium, tungsten, etc.). The production of ferroalloys is based upon metallurgical reduction, which produces significant CO₂ emissions. Silicon metal production is also often included in ferroalloy production because the silicon metal production process is similar to the ferrosilicon production process. After production of the concentrated ferroalloy compounds, these compounds are delivered to steel production plants to be incorporated in alloy steels. Silicon metal is used in aluminum alloys and silicones.

The reduction process combines raw ore, carbon materials (i.e., typically coal and coke, but also possibly charcoal and wood), and slag-forming materials that are heated to a high temperature for reduction and smelting. Electric submerged arc furnaces (either open, semi-covered, or covered) are used with either graphite or consumable Soderberg electrodes to produce heat. As the carbon materials and the carbon-containing electrodes are consumed, the ores are reduced to molten base metals, which then combine in solution. In addition, the calcination of limestone or dolomite fluxes used in slag formation will also produce greenhouse gases.

BC.272 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

- Annual emissions of CO₂ at the facility level (metric tons).
- Annual quantities of each reducing agent used (metric tons).
- Fractional purity of each reducing agent used (metric tons carbonate/metric tons reducing agent).
- Annual quantity of ore processed (metric tons).
- Carbon content of ore processed (metric tons C/metric ton ore).

BC.272 Calculation of CO₂ emissions

Calculate CO₂ emissions from reducing agent consumption using Equation 270-1

$$E = \left[\sum_i (RA_i \times CC_{RA,i}) + \sum_h (Ore_h \times CC_{Ore,h}) + \sum_j (SF_j \times CC_{SF,j}) - \sum_k (P_k \times CC_{P,k}) - \sum_n (NP_n \times CC_{NP,n}) \right] \times \left(\frac{44}{12} \right)$$

Equation 270-1

where:

- E = CO₂ emissions from ferroalloy production (metric tons);
- RA_i = Quantity of reducing agent *i* (metric tons);

$CC_{RA,i}$	= Carbon content of reducing agent i (metric tons C/metric tons reducing agent);
Ore_h	= Quantity of ore h (metric tons);
$CC_{Ore,h}$	= Carbon content of ore h (metric tons C/metric tons ore);
SF_j	= Quantity of slag-forming material j (metric tons);
$CC_{SF,j}$	= Carbon content of slag-forming material j (metric tons C/metric tons slag-forming material);
P_k	= Quantity of product k (metric tons);
$CC_{P,k}$	= Carbon content of product k (metric tons C/metric tons product);
NP_n	= Quantity of non-product outgoing stream n (metric tons);
$CC_{NP,n}$	= Carbon content of non-product outgoing stream n (metric tons C/metric tons non-product outgoing stream).

BC.274 Monitoring requirements

Measurements of carbon contents of the material balance input, output, and by-product materials should be conducted as described in paragraphs (a) through (f), below:

- (a) Reducing Agent Carbon Content Monitoring Requirements. Fuel carbon contents for coal, coke, solid biomass-derived fuels, and waste-derived fuels should be monitored using ASTM 5373-02 (Reapproved 2007).
- (b) Ore Carbon Content Monitoring Requirements. Carbon contents of ore used in ferroalloy production should be monitored using ASTM E1941-04.
- (c) Slag-Forming Carbon Content Monitoring Requirements. Carbon contents of slag-forming materials (e.g., limestone or dolomite fluxes) used in ferroalloy production should be monitored using ASTM C25-06.
- (d) Finished Product Carbon Content Monitoring Requirements. Carbon contents of finished ferroalloy product should be monitored using ASTM E1941-04.
- (e) Non-Product Outgoing Stream Carbon Content Monitoring Requirements. Carbon contents of non-product outgoing stream materials should be monitored using either ASTM 5373-02, ASTM E1941-04 or ASTM C25-06, as appropriate.
- (f) Quantity Measurement Monitoring Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:
 - (1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
 - (2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.
 - (3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

12. GLASS MANUFACTURING

BC.140 Glass Manufacturing

BC.141 Source category definition

The glass manufacturing source category consists of all glass manufacturing facilities that manufacture container, flat, fiber, and specialty glass by melting a mixture of carbonate minerals using a melting furnace.

BC.142 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions report must contain the following information:

- (a) Annual CO₂ process emissions from the glass melting furnaces, as specified in BC.143 (metric tons).
- (b) CO₂, N₂O, and CH₄ emissions from stationary combustion units, as specified in WCI.23 (metric tons).
- (c) Annual consumption of each type of carbonate used (metric tons).

BC.143 Calculation of GHG emissions

- (a) Calculate CO₂ emissions using the methods in either paragraphs (1) or (2) of this section.
 - (1) Continuous Emission Monitoring Systems. The owner or operator may measure CO₂ emissions using CEMS, as specified WCI.23(d).
 - (2) Feedstock Material Balance. The owner or operator may calculate CO₂ process emissions using Equation 140-1, the measured input of each carbonate mineral consumed, and the appropriate emission factor from Table 140-1.

$$CO_2 = \sum_{i=1}^n (M_i \times EF_i) \quad \text{Equation 140-1}$$

Where:

- CO₂ = process CO₂ emitted from glass furnaces (metric tons/year).
- M_i = weight of carbonate i consumed (metric tons/year).
- EF_i = emission factor for the carbonate i from Table 140-1 (metric tons CO₂/metric ton of carbonate).
- n = total number of carbonates.

BC.144 Monitoring requirements

Owners and operators using Equation 140-1 to calculate CO₂ emissions must measure the quantity of carbonate minerals consumed each year by direct measurement, using the same instruments used for accounting purposes.

Table 140-1: Formulae, Formula Weights, and Carbon Dioxide Emission Factors for Common Carbonate Species.

Carbonate	Mineral Name	Formula Weight	Emission Factor (metric tons CO ₂ /metric ton Carbonate)
CaCO ₃	Calcite	100.1	0.4397
CaMg(CO ₃) ₂	Dolomite	184.4	0.4773
Na ₂ CO ₃	Soda ash (sodium carbonate)	106.0	0.4149
BaCO ₃	Barium carbonate	197.3	0.22302
K ₂ CO ₃	Potassium carbonate	138.2	0.31844
CaO ₂ P ₂ O ₅ ·CaCO ₃ ·MgCO ₃	Bone ash	2110.3	0.0417
SrCO ₃	Strontium carbonate	147.6	0.29811

13. HYDROGEN PRODUCTION

WCI.130 Hydrogen Production

WCI.131 Source category definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

WCI.132 Greenhouse gas reporting requirements

For each facility, the annual emissions report must contain the following information:

- (a) Process CO₂ Emissions. The CO₂ process emissions from the hydrogen produced process.
- (b) Feedstock Consumption (if estimating emissions using mass balance approach in WCI.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.
- (c) Production. Annual hydrogen produced.
- (d) Stationary Combustion Units. Report CO₂, N₂O, and CH₄ emissions as specified in WCI.020.

WCI.133 Calculation of greenhouse gas emissions

The owner or operator shall calculate and report CO₂ process emissions using the methods in paragraphs (a) or (b) of this section.

- (a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO₂ process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.020.
- (b) Feedstock Material Balance. The owner or operator may calculate CO₂ process emissions using the following method. The factor S shall be used only for CO₂ and/or CH₄ emissions that are calculated and reported using applicable methods specified in this regulation. For example, carbon species in uncovered feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO₂ and/or CH₄ emissions are reported using other methods in this regulation.

$$CO_2(\text{Feedstock}) = \sum_{i=1}^n \sum_{j=1}^y [(FS_j * CF_j) - S_j] * 3.664 * 0.001 \quad \text{Equation 130-1 (English Units)}$$

Where:

CO₂(Feedstock) = CO₂ emitted from feedstock (metric tons/year).

n = Days of operation per year.

FS_j = Feedstock b consumption rate (scf/day).

CF_j	=	Carbon content of feedstock j (kg C/scf feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO ₂ to carbon
0.001	=	conversion factor – kg to metric tons

$$CO_2(\text{Feedstock}) = \sum_{i=1}^n \sum_{j=1}^y [(FS_j * CF_j) - S_j] * 3.664 * 0.001 \quad \text{Equation 130-1 (Metric Units)}$$

Where:

$CO_2(\text{Feedstock})$	=	CO ₂ emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (m ³ /day).
CF_j	=	Carbon content of feedstock j (kg C/m ³ feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO ₂ to carbon
0.001	=	conversion factor – kg to metric tons

WCI.134 Sampling, analysis, and measurement requirements

- (a) Owners or operators using CEMS to estimate CO₂ emissions shall comply with the monitoring requirements in section WCI.020.
- (b) Owners or operators using the method in section WCI.133 (b) shall perform the following monitoring:
 - (1) The owner or operator shall measure the feedstock consumption rate daily.
 - (2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.
 - (3) Owners or operators shall measure the hydrogen produced daily.
 - (4) Owners or operators shall measure the CO₂ and CO collected daily.

14. INDUSTRIAL WASTEWATER PROCESSING

WCI.200 Section 203 (g)

(a) Wastewater Treatment.

- (1) The operator shall calculate CH₄ emissions from wastewater treatment using Equation 200-14.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001 \quad \text{Equation 200-14}$$

Where:

- CH₄ = emission of methane (tons/yr)
 Q = volume of wastewater treated (m³/yr)
 COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m³)
 S = organic component removed as sludge (kg COD/yr)
 B = methane generation capacity (B = 0.25 kg CH₄/kg COD)
 MCF = methane correction factor for anaerobic decay (0-1.0) from Table 200-2
 0.001 = conversion factor – kg to metric tons

- (2) The operator shall calculate N₂O emissions from wastewater treatment using Equation 200-15.

$$N_2O = Q \times N_{qave} \times EF_{N_2O} \times 1.571 \times 0.001 \quad \text{Equation 200-15}$$

Where:

- N₂O = emissions of N₂O (metric tons/yr)
 Q = volume of wastewater treated (m³/yr)
 N_{qave} = average of quarterly determinations of N in effluent (kg N/m³)
 EF_{N₂O} = emission factor for N₂O from discharged wastewater (0.005 kg N₂O-N/kg N)
 1.571 = conversion factor – kg N₂O-N to kg N₂O
 0.001 = conversion factor – kg to metric tons

15. LEAD PRODUCTION

BC.160 Lead Production

BC.161 Source category definition

The lead production category includes two primary production processes used to produce lead from lead concentrates (i.e., the sintering/smelting process and the direct smelting process). In addition, secondary production or recycling of lead (primarily from scrapped lead acid batteries) is included in the category.

BC.162 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

- (a) Annual emissions of CO₂ from the use of reducing agents at the facility level (metric tons).
- (b) Annual quantities of each reducing agent used (metric tons).
- (c) Carbon content of each reducing agent used (metric tons C/metric ton reducing agent).

BC.163 Calculation of CO₂ emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- (a) Determine facility CO₂ emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
- (b) Calculate total CO₂ emissions using Equation 160-1.

$$E_{pb} = \sum_x (RA_x \times C_x) \times 3.664 \quad \text{Equation 160-1}$$

Where:

- E_{pb} = Annual CO₂ emissions from lead production (metric tons);
- RA_x = Annual quantity of reducing agent x used (metric tons);
- C_x = Carbon content of reducing agent x (metric tons C/metric tons of x);
- 3.664 = Conversion factor from metric tons of C to metric tons of CO₂.

BC.164 Sampling, analysis, and measurement requirements

Reducing agent carbon content shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Carbon contents from reducing agents that are fuels should be determined from at least three representative samples of the material per year in the following manner:

- (1) For coal and coke, use ASTM D5373-02 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke”.
 - (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “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 D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).
- (b) Carbon contents from reducing agents that are not fuels should be determined as specified under paragraph (1) or (2) of this section:
- (1) Obtain carbon content from material vendor or supplier.
 - (2) Obtain default carbon content from Table 160-1.

Table 160-1. Material-Specific Carbon Content for Lead Production (kg C/kg material)^a

Process Material	Carbon Content
Blast Furnace Gas	0.17
Charcoal	0.91
Coal ^b	0.67
Coal Tar	0.62
Coke	0.83
Coke Oven Gas	0.47
Coking Coal	0.73
EAF (Electric Arc Furnace) Carbon Electrodes ^c	0.82
EAF Charge Carbon ^d	0.83
Fuel Oil ^e	0.86
Gas Coke	0.83
Natural Gas	0.73
Petroleum Coke	0.87

^a Carbon contents obtained from IPCC Volume 3, Chapter 4, Table 4.22.

^b Assumed other bituminous coal.

^c Assumed 80 percent petroleum coke and 20 percent coal tar.

^d Assumed coke oven coke.

^e Assumed gas/diesel fuel.

16. LIME MANUFACTURING

WCI.170 Lime Manufacturing

WCI.171 Source category definition

Lime manufacturing is comprised of all processes that are used to manufacture quick lime (i.e. calcium oxide or calcium-magnesium oxide). Lime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

WCI.172 Greenhouse gas reporting requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

- (a) Total emissions of CO₂, CH₄, and N₂O in metric tons.
- (b) CO₂ process emissions from quick lime production (metric tons) and the following information:
 - (1) For lime production:
 - (A) The emission factor (kg CO₂/metric ton) for each lime type for each month.
 - (B) The quantity of lime produced (metric tons) each month.
 - (C) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.
 - (D) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.
 - (2) For the production of calcined byproducts and wastes:
 - (A) The emission factor (kg CO₂/metric ton) for each calcined byproduct/waste type for each month.
 - (B) The quantity of each type of calcined byproduct/waste type produced each month.
 - (C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each month.
 - (D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each month.
- (c) CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).
- (d) CO₂, CH₄, and N₂O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.020 (metric tons).
- (e) If a continuous emissions monitor is used to measure CO₂ emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO₂.

- (f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:
- (1) Coal fuel storage as specified in WCI.100.
 - (2) Electricity generating as specified in WCI.040.
 - (3) Cogeneration systems as specified in WCI.42(f).

WCI.173 Calculation of greenhouse gas emissions from kilns

- (a) Determine process CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
- (1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
 - (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- (b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from quick lime production, using the method specified in paragraph (b)(1) of this section.
- (1) CO₂ Process Emissions. Calculate CO₂ emissions from quick lime production from each kiln using Equation 170-1 and a plant-specific quick lime emission factor and a plant-specific lime kiln dust (LKD) emission factor as specified in this section.

$$CO_2 = \sum_i^{12} \sum_j^y [QL_{ij} \times EF_{QL_{ij}}] + \sum_k^4 \sum_l^z [LKD_{kl} \times EF_{LKD_{kl}}] \quad \text{Equation 170-1}$$

Where:

- CO₂ = CO₂ emissions in metric tons/yr.
- QL = Monthly Quantity of quick lime produced, metric tons.
- EF_{QL} = Monthly Quick lime emission factor, metric tons CO₂/metric ton quick lime computed as specified in paragraph (b)(2) of this section.
- LKD = Quarterly Quantity of calcined byproduct/waste, including LKD, scrubber sludge and other calcined wastes, produced annually, metric tons.
- EF_{LKD} = Quarterly calcined byproduct/waste emission factor, computed as specified in paragraph (b)(3) of this section.
- i = Month.
- j = Lime type.
- k = Quarter.
- l = Calcined byproduct/waste type.
- y = Total number of lime types.
- z = Total number of calcined byproduct/waste types.

- (2) Monthly Quick Lime Emission Factor. Calculate a plant-specific quick lime emission factor (EF_{QL}) for each kiln and month based on the percent of measured CaO and MgO content in quick lime and using Equation 170-2.

$$EF_{QL} = (CaO \text{ content} \times \text{Molecular ratio of } CO_2 / CaO) + (MgO \text{ content} \times \text{Molecular ratio } CO_2 / MgO) \quad \text{Equation 170-2}$$

Where:

- CaO Content (by weight) = Total CaO content of Quick Lime.
 Molecular ratio of CO₂/CaO = 0.785.
 MgO Content (by weight) = Total MgO content of Quick Lime.
 Molecular ratio of CO₂/MgO = 1.092.

- (3) Monthly LKD Emission Factor. If LKD is generated and not recycled back to the kiln, then calculate a plant-specific LKD emission factor for each kiln and month. The LKD emission factor shall be calculated using Equation 170-3.

$$EF_{LKD} = [(CaO \text{ content} - \text{uncalcined } CaO) \times \text{Molecular ratio of } CO_2 / CaO] + [(MgO \text{ Content} - \text{uncalcined } MgO) \times \text{Molecular ratio of } CO_2 / MgO] \quad \text{Equation 170-3}$$

Where:

- EF_{LKD} = LKD emission factor.
 CaO Content (by weight) = Total CaO content of LKD, including calcined and uncalcined (weight fraction).
 Uncalcined CaO (by weight) = Uncalcined CaO content of LKD (weight fraction).
 Molecular ratio of CO₂/CaO = 0.785.
 MgO Content (by weight) = Total MgO content of LKD, including calcined and uncalcined (weight fraction).
 Uncalcined MgO = Uncalcined MgO content of LKD (weight fraction).
 Molecular ratio of CO₂/MgO = 1.092.

- (c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.020. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO₂ emissions from fossil fuels using the emission factor methodology in WCI.23(a). “Pure” means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

WCI.174 Sampling, analysis, and measurement requirements

Determine the chemical composition (percent total CaO and percent total MgO) of each lime type and each calcined byproduct/waste type by laboratory analysis on a monthly basis for each lime type, and a quarterly basis for each calcined byproduct/waste type. This determination must be performed according to ASTM Methods C25, C1301 or C1271. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced during the quarter.

- (a) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.
- (b) The quantity of calcined byproduct/waste sold is to be estimated quarterly using direct measurements (such as rail and truck scales) of byproduct/waste sales for each byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than quarterly for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).

17. MAGNESIUM PRODUCTION

BC.290 Magnesium Production

BC.291 Source category definition

The magnesium production source category consists of primary magnesium metal production facilities that produce magnesium metal from dolomite ($Mg \cdot Ca(CO_3)_2$) and magnesite ($MgCO_3$), secondary magnesium production facilities that recover or recycle magnesium, and magnesium casting facilities that use molten magnesium in alloying, casting, drawing, extruding, forming, or rolling operations.

BC.292 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions report must contain the following information:

- (a) Annual CO_2 process emissions from primary magnesium production.
- (b) Annual emissions of CO_2 used as cover gas or carrier gas in magnesium production and/or processing, as specified in BC.293 (metric tons).
- (c) Annual emissions of SF_6 used as cover gas or carrier gas in magnesium production and/or processing, as specified in BC.293 (metric tons).
- (d) Annual emissions of HFC-134a used as cover gas or carrier gas in magnesium production and/or processing, as specified in BC.293 (metric tons).
- (e) Annual emissions of fluorinated ketone, FK 5-1-12, used as cover gas or carrier gas in magnesium production and/or processing, as specified in BC.293 (metric tons).
- (f) Annual emissions of other fluorinated GHGs used as cover gases or carrier gases in magnesium production and/or processing, as specified in BC.293 (metric tons).
- (g) CO_2 , N_2O , and CH_4 emissions from stationary combustion units, as specified in WCI.23 (metric tons).

BC.293 Calculation of GHG emissions

- (a) Calculate CO_2 emissions from primary magnesium production facilities using the methods in either paragraphs (1) or (2) of this section.
 - (1) Continuous Emission Monitoring Systems. The owner or operator may measure CO_2 emissions using CEMS, as specified WCI.23(d).
 - (2) Feedstock Material Balance. The owner or operator may estimate CO_2 process emissions using Equation 290-1 and the measured carbon content and feedstock input of the raw material.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Mi_j)] \quad \text{Equation 290-1}$$

Where:

- CO₂ = CO₂ process emissions from primary magnesium production (metric tons/year).
 C_i = Carbon content of feedstock j input (percent by weight, expressed as a decimal fraction).
 M_i = Weight of feedstock j input (metric tons/month).
 3.664 = Ratio of molecular weights, CO₂ to carbon.

- (b) Estimate emissions of CO₂, SF₆, FK 5-1-12, HFC-134a and any other fluorinated GHGs used as cover gases or carrier gases using Equation 290-2.

$$E_i = B_i - E_i + A_i - D_i \quad \text{Equation 290-2}$$

Where:

- E_i = Annual emissions of GHG i used as cover gas or carrier gas (metric tons/year).
 B_i = Inventory of cover gas or carrier gas i stored onsite at the beginning of the reporting period (metric tons).
 E_i = Inventory of cover gas or carrier gas i stored onsite at the end of the reporting period (metric tons).
 A_i = Acquisitions of cover gas or carrier gas i during the reporting year (metric tons).
 D_i = Transfer of cover gas or carrier gas i offsite (including heels in cylinders or other containers returned to the gas distributor) (metric tons).

BC.294 Monitoring requirements

- (a) Owners and operators using the mass balance method to calculate CO₂ emissions from primary magnesium production must:
- (1) Measure the quantity of raw material input by direct measurement using the same instruments used for accounting purposes.
 - (2) Collect monthly samples of raw material and analyze each sample for carbon content using method ASTM E359-00(2005).
- (b) Owners and operators using cover gases and/or carrier gases in magnesium production and/or processing must maintain records of the following:
- (1) Inventory data from beginning and end of each reporting year;
 - (2) Measurements of gas returned to suppliers (e.g., as heels in cylinders); and
 - (3) Invoices for gas purchases and sales.

18. NITRIC ACID MANUFACTURING

BC.310 Nitric Acid Production

BC.311 Source category definition

The nitric acid production source category consists of facilities that produce a weak nitric acid (30 to 70 percent in strength) from ammonia using high temperature catalytic oxidation, condensation, and absorption.

BC.312 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions report must contain the following information:

- (a) Annual N₂O process emissions from all nitric acid production lines, as specified in BC.313 (metric tons).
- (b) CO₂, N₂O, and CH₄ emissions from stationary combustion units, as specified in WCI.23 (metric tons).
- (c) Annual nitric acid production for each production line (metric tons).
- (d) The site-specific emission factor for each production line (lb or kg N₂O/ton of acid produced), for owners and operators using the method in BC.313(b).

BC.313 Calculation of GHG emissions

- (a) You must calculate N₂O emissions using the methods in either paragraphs (a)(1) or (a)(2) of this section.
 - (1) Continuous Emission Monitoring Systems. The owner or operator may measure N₂O emissions using CEMS.
 - (2) Site-Specific Emission Factor. The owner or operator may calculate N₂O process emissions using Equation 310-1 and the results from a monthly performance test, measured carbon content and feedstock input of the trona ore or carbonate-rich brine.

$$N_2O = \sum_{j=1}^{12} \frac{EF_j \times P_j}{c} \quad \text{Equation 310-1}$$

Where:

- N₂O = Annual N₂O process emissions from nitric acid production (metric tons/year).
- EF_j = Site-specific N₂O emission factor for month j (in lbs N₂O/ton of acid produced, 100 percent acid basis).
- P_j = Nitric acid produced in month j (tons of acid produced, 100 percent basis).
- c = conversion factor (2205 lb/metric ton or 1,000 kg/metric ton).

BC.314 Monitoring requirements

Owners and operators using the site-specific emission factor method must comply with the following monitoring requirements:

- (a) Measure the quantity and concentration of nitric acid produced each month by direct measurement using the same instruments used for accounting purposes.
- (b) Determine the site-specific emission factor monthly by conducting a performance test in accordance with EPA Method 320 in 40 CFR part 63, Appendix A or ASTM D6348-03.

19. PETROCHEMICAL PRODUCTION

WCI.300 Petrochemical Manufacturing

WCI.301 Source category definition

The petrochemical manufacturing source category consists of any facility that manufactures petrochemicals, including acrylonitrile, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

WCI.302 Greenhouse gas reporting requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

- (a) CO₂, N₂O, and CH₄ emissions from combustion of fuels in the stationary combustion unit in metric tons, as specified in WCI.020.
- (b) CO₂, N₂O, and CH₄ emissions from flares and other oxidizers in metric tons, as specified in WCI.303(a).
- (c) CO₂, N₂O, and CH₄ emissions from process vents in metric tons, as specified in WCI.303(b).
- (d) CH₄ emissions tons from equipment leaks in metric, as specified in WCI.303I.
- (e) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.303 Calculation of GHG emissions

- (a) Flares and Other Oxidizers. You must calculate GHG emissions from flares and oxidation control devices as follows:
 - (1) Calculate CO₂, CH₄ and N₂O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in WCI.20.
 - (2) Calculate CO₂ emissions for each gas destroyed in a flare or other oxidation control device using Equation 300-1.

$$CO_2 = \sum_{i=1}^n GV_i \times CC_i \times MW_i / MVC \times 3.664 \times 0.001 \quad \text{Equation 300-1}$$

Where:

- CO₂ = CO₂ emissions (metric tons/year).
- GV_{*i*} = Volume of gas *I* destroyed annually (scf/year).
- CC_{*i*} = Average annual carbon content of gas *I* (kg C/kg fuel).
- MW_{*i*} = Average annual molecular weight of gas *i*.

MVC = Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere).

3.664 = Ratio of molecular weights, CO₂ to carbon.

0.001 = Conversion factor, kg to metric tons.

N = Number of gases destroyed.

(b) Process Vents. Except for process emissions calculated pursuant to WCI.303(a) or (c), you must calculate process emissions of CO₂, CH₄, and N₂O from process vents using Equation 300-2.

$$E_x = \sum_{i=1}^n VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \quad \text{Equation 300-2}$$

Where:

E_x = Emissions of x (metric tons/yr), where x = CO₂, N₂O, or CH₄.

VR_i = Vent rate for venting event I (scf/unit time).

F_{xi} = Molar fraction of x in vent gas stream during event i.

MW_x = Molecular weight of x (kg/kg-mole).

MVC = Molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere).

VT_i = Time duration of venting event I (same units of time used for VR_i).

n = Number of venting events.

0.001 = Conversion factor, kg to metric tons.

(c) Equipment Leaks. You must calculate CH₄ emissions for each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems as follows:

(1) Identify and screen each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems using the monitoring method in WCI.304. Components identified as “other” components include instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

(2) Use the results of the component screening and the following equations to calculate VOC emissions:

(A) For components where the measured screening value is equal to zero when corrected for background, calculate VOC emissions using Equation 300-3 and the appropriate default emission factors from Table 300-1.

$$E_{VOC-0} = \sum_{i=1}^6 CC_i \times ZF_{i0} \times t \quad \text{Equation 300-3}$$

Where:

- E_{VOC-0} = Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).
- I = Component type (valve, pump seal, other, connector, flange, open-ended line).
- CC_i = Number of I components where the screening value is 0.
- ZF_{i0} = Default zero factor for component I from Table 300-1 (kg/hr).
- t = Time since last screening (hours/screening period).

- (B) For components where the measured screening value, corrected for background, is between 0 and 10,000 ppmv, calculate VOC emissions using Equation 300-4 and the appropriate default factors from Table 300-1.

$$E_{VOCL-C} = \sum_{i=1}^6 \sum_{n=1}^n (\sigma_i \times SV_n^{\beta_i}) \times t \quad \text{Equation 300-4}$$

Where:

- E_{VOCL-C} = Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).
- I = Component type (valve, pump seal, others, connector, flange, open ended-line).
- N = Number of I components.
- Σ_i = Correlation equation coefficient for component type I from Table 300-1.
- SV_n = Screening value for component n .
- β_i = Correlation equation exponent for component type I from Table 300-1.
- T = Time component has been leaking (default value is time from last screening) (hours/screening period).

- (C) For components where the screening value, corrected for background, is greater than or equal to 10,000 ppmv, calculate VOC emissions using Equation 300-5 and the appropriate default factors from Table 300-1.

$$E_{VOCP} = \sum_{i=1}^6 CC_i \times PF_{ip} \times t \quad \text{Equation 300-5}$$

Where:

- E_{VOCP} = Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).
- I = Component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line).
- CC_i = Number of I components with screening values greater than 9,999 ppmv.
- PF_{ip} = VOC emission factor for component type I pegged over 9,999 ppmv from Table 300-1 (kg/hr).

t = Time component has been leaking (default value is time since last screening) (hours/screening period).

- (3) Calculate CH₄ emissions using Equation 300-6 and either a default factor of 0.6 for CFVOC or a site-specific conversion factor calculated from the composition and methane content of the gas.

$$CH_4 = \sum_1^n (E_{VOC-0} + E_{VOC-LC} + E_{VOC-P})_n \times CF_{VOC} \times 0.001 \quad \text{Equation 300-6}$$

Where:

CH₄ = CH₄ emissions (metric tons/year).

N = Number of screenings/year.

E_{VOC-0} = Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).

E_{VOC-LC} = Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).

E_{VOC-P} = Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).

CF_{VOC} = VOC to CH₄ conversion factor (default $CF_{VOC} = 0.6$).

0.001 = Conversion factor (kg to metric tons).

WCI.304 Monitoring requirements

- (a) Flares and Other Oxidizers. You must measure:
- (1) The volume of each gas destroyed annually determined to an accuracy of ± 5 percent.
 - (2) The carbon content and molecular weight of each gas quarterly using the methods specified in WCI.25 and calculate the annual average values for carbon content and molecular weight for each gas destroyed.
- (b) Process Vents. You must measure the following parameters for each process vent:
- (1) The gas flow rate for each venting event.
 - (2) The molar fraction of CO₂, N₂O, and CH₄ in the vent gas stream during each venting event.
 - (3) The duration of each venting event.
- (c) Equipment Leaks. You must screen each valve, pump seal, connector, flange, and open-ended line used in natural gas, fuel gas, and off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Screenings must be performed at the frequency interval required by B.C. Ministry of Environment. The instrumentation used for screening must be capable of detecting methane.

- (d) Feedstock Consumption. You must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 300-1. Fugitive Emissions from Gas Service Components

Component Type / Service Type	Default Zero Factor (kg/hr)	Correlation Equation (kg/hr)	Pegged Factor (kg/hr)
	(SV = 0) $Z_{f_{i0}}$	(SV > 0 and < 10,000) σ_i and β_i	(SV ≥ 10,000) PF_{iP-10}
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others ^a	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

^a The “other” component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The “other” component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

20. PETROLEUM REFINING

WCI.200 Petroleum Refineries

WCI.201 Source category definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

WCI.202 Greenhouse gas reporting requirements

The annual emissions report must contain the following information reported at the facility level:

- (a) Catalyst Regeneration. Report CO₂ emissions.
- (b) Process Vents. Report CO₂, N₂O, and CH₄ emissions.
- (c) Asphalt Production. Report CO₂ and CH₄ emissions.
- (d) Sulfur Recovery. Report CO₂ emissions.
- (e) Stationary Combustion Units Other than Flares and Control Devices. Report CO₂, N₂O, and CH₄ emissions as specified in WCI.23.
- (f) Flares and Other Control Devices. Report CO₂, N₂O, and CH₄ emissions.
- (g) Above-Ground Storage Tanks. Report CH₄ emissions.
- (h) Wastewater Treatment. Report CH₄ and N₂O emissions.
- (i) Oil-Water Separators. Report CH₄ emissions.
- (j) Equipment Leaks. Report CH₄ emissions.
- (k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.
- (l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of greenhouse gas emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

- (a) Catalyst Regeneration. For units equipped with CEMS, operators shall calculate CO₂ process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

- (1) The operator shall calculate process CO₂ emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^n CR_d \times CF \times 3.664 \times 0.001 \quad \text{Equation 200-1}$$

Where:

- CO₂ = CO₂ emissions (metric tons/yr)
 n = number of days of operation in the report year
 CR_d = daily average coke burn rate (kg/day)
 CF = carbon fraction in coke burned
 3.664 = ratio of molecular weights, CO₂ to carbon
 0.001 = conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^n [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO / 2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{xy})]_i \right] / n \quad \text{Equation 200-2}$$

Where:

- CR_d = daily average coke burn rate (kg/day or lb/day)
 K₁, K₂, K₃ = material balance and conversion factors (K₁, K₂, and K₃ from Table 200-1)
 n = number of hours per day
 Q_r = volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)
 Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
 %CO₂ = CO₂ concentration in regenerator exhaust, percent by volume – dry basis
 %CO = CO concentration in regenerator exhaust, percent by volume – dry basis
 %O₂ = O₂ concentration in regenerator exhaust, percent by volume – dry basis
 Q_{oxy} = volumetric flow rate of O₂ enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
 %O_{xy} = O₂ concentration in O₂ enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \%O_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2) \quad \text{Equation 200-3}$$

Where:

- Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
- Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)
- $\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
- Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
- $\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
- $\%CO$ = CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume $\%CO$ to be zero
- $\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

- (2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^n CRR \times (CF_{spent} - CF_{regen})_i \times 3.664 \times 0.001 \quad \text{Equation 200-4}$$

Where:

- CO_2 = CO_2 emissions (metric tons/yr)
- CRR = mass of catalyst regenerated (mass/regeneration cycle)
- CF_{spent} = weight fraction carbon on spent catalyst
- CF_{regen} = weight fraction carbon on regenerated catalyst (default = 0)
- n = number of regeneration cycles
- 3.664 = ratio of molecular weights, CO_2 to carbon
- 0.001 = conversion factor – kg to metric tons

- (3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664 \quad \text{Equation 200-5}$$

Where:

- CO_2 = CO_2 emissions (metric tons/yr)
- CC_{irc} = average catalyst regeneration rate (metric tons/hr)
- CF_{spent} = weight carbon fraction on spent catalyst
- CF_{regen} = weight carbon fraction on regenerated catalyst (default = 0)

H = hours regenerator was operational (hr/yr)
 3.664 = ratio of molecular weights, CO₂ to carbon

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO₂, CH₄, and N₂O from process vents using Equation 200-6.

$$E_x = \sum_{i=1}^n VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \quad \text{Equation 200-6}$$

Where:

E_x = emissions of x (metric tons/yr), where x = CO₂, N₂O, or CH₄
 VR_i = vent rate for venting event i (scf/unit time or m³/unit time)
 F_{xi} = molar fraction of x in vent gas stream during event i
 MW_x = molecular weight of x (kg/kg-mole)
 MVC = molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere)
 VT_i = time duration of venting event i
 n = number of venting events
 0.001 = conversion factor – kg to metric tons

(c) Asphalt Production. The operator shall calculate CO₂ and CH₄ process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

$$CH_4 = (M_A \times EF \times MW_{CH_4} / MVC) \times (1 - DE) \times 0.001 \quad \text{Equation 200-7}$$

Where:

CH₄ = CH₄ emissions (metric tons/yr)
 M_A = mass of asphalt blown (10³ bbl/yr)
 EF = emission factor (EF = 2,555 scf CH₄/10³ bbl or 72.35 m³ CH₄/10³ bbl)
 MW_{CH₄} = CH₄ molecular weight (16.04 kg/kg-mole)
 MVC = molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere or 24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere)
 DE = control measure destruction efficiency (DE = 98% expressed as 0.98)
 0.001 = conversion factor – kg to metric tons

$$CO_2 = (M_A \times EF \times MW_{CH_4} / MVC) \times DE \times 2.743 \times 0.001 \quad \text{Equation 200-8}$$

Where:

- CO₂ = CO₂ emissions (metric tons/yr)
 M_A = mass of asphalt blown (10³ bbl/yr)
 EF = emission factor (EF = 2,555 scf CH₄/10³ bbl or 72.35 m³ CH₄/10³ bbl)
 MW_{CH₄} = CH₄ molecular weight (16.04 kg/kg-mole)
 MVC = molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere or 24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere)
 DE = control measure destruction efficiency (DE = 98% expressed as 0.98)
 2.743 = CH₄ to CO₂ conversion factor
 0.001 = conversion factor – kg to metric tons

- (d) Sulfur Recovery. The operator shall calculate CO₂ process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO₂ in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by B.C. Ministry of Environment and derived from source tests conducted at least once per calendar year under the supervision of B.C. Ministry of Environment.

$$CO_2 = FR \times MW_{CO_2} / MVC \times MF \times 0.001 \quad \text{Equation 200-9}$$

Where:

- CO₂ = emissions of CO₂ (metric tons/yr)
 FR = volumetric flow rate of acid gas to SRU (scf/year or m³/year)
 MW_{CO₂} = molecular weight of CO₂ (44 kg/kg-mole)
 MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere or 24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere)
 MF = molecular fraction (%) of CO₂ in sour gas (default MF = 20% expressed as 0.20)
 0.001 = conversion factor – kg to metric tons

- (e) Flares and Other Control Devices.

- (1) The operator shall calculate and report CO₂, CH₄ and N₂O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.
- (2) The operator shall calculate and report CO₂ emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:
 - (A) Use Equation 200-10 if the flare is equipped with a continuous flow and high heat value monitors.

$$CO_2 = Flare_N \times HHV \times (0.001 \times EmF) \quad \text{Equation 200-10}$$

Where:

- CO₂ = CO₂ emissions (metric tons/year)
 Flare_N = volume of flare gas (m³/yr)
 HHV = High heat value for refinery fuel or flare gas (MMBtu/MMscf or J/m³)
 0.001 = conversion factor – kg to metric tons
 EmF = default CO₂ emission factor (60 kg CO₂/MMBtu or 5.7 kg/kJ)

- (B) Use Equation 200-11 if the flare is equipped with a continuous flow and carbon content monitors.

$$CO_2 = Flare_N \times CC_N \times (MW_n / MVC) \times 3.664 \times 0.001 \quad \text{Equation 200-11}$$

Where:

- CO₂ = CO₂ emissions (metric tons/year)
 Flare_N = volume of flare gas (m³/yr)
 CC_N = carbon content of flare gas (kg of carbon/kg of fuel)
 MW_N = molecular weight of flare gas
 MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere)
 3.664 = ratio of molecular weights, CO₂ to carbon
 0.001 = conversion factor – kg to metric tons

- (C) Use Equation 200-12 if the flare is not equipped with a continuous flow monitor and HHV or carbon content monitor.

$$CO_2 = RFT \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001 \quad \text{Equation 200-12}$$

Where:

- CO₂ = CO₂ emissions (metric tons/year)
 RFT = refinery feed input (m³/yr)
 EF_{NMHC} = non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m³ throughput)
 CF_{NMHC} = conversion factor – NMHC to carbon (CF_{NMHC} = 0.6)
 3.664 = ratio of molecular weights, CO₂ to carbon
 0.001 = conversion factor – kg to metric tons

- (3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas,

gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO₂ emissions using Equation 200-13. The operator shall determine CCA and MWA quarterly using methods specified in section WCI.20 and use the annual average values of CCA and MWA to calculate CO₂ emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001 \quad \text{Equation 200-13}$$

Where:

- CO₂ = CO₂ emissions (metric tons/year)
- GV_A = volume of gas A destroyed annually (scf/year or m³/year)
- CC_A = carbon content of gas A (kg C/kg fuel)
- MW_A = molecular weight of gas A
- MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere)
- 3.664 = ratio of molecular weights, CO₂ to carbon
- 0.001 = conversion factor – kg to metric tons

(f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH₄ emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

- (1) A default conversion factor of 0.6 (CH₄ = 0.6 * VOC); or
- (2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by B.C. Ministry of Environment.

(g) Wastewater Treatment.

- (1) The operator shall calculate CH₄ emissions from wastewater treatment using Equation 200-14.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001 \quad \text{Equation 200-14}$$

Where:

- CH₄ = emission of methane (tons/yr)
- Q = volume of wastewater treated (m³/yr)
- COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m³)

- S = organic component removed as sludge (kg COD/yr)
 B = methane generation capacity (B = 0.25 kg CH₄/kg COD)
 MCF = methane correction factor for anaerobic decay (0-1.0) from Table 200-2
 0.001 = conversion factor – kg to metric tons

- (2) The operator shall calculate N₂O emissions from wastewater treatment using Equation 200-15.

$$N_2O = Q \times N_{qave} \times EF_{N_2O} \times 1.571 \times 0.001 \quad \text{Equation 200-15}$$

Where:

- N₂O = emissions of N₂O (metric tons/yr)
 Q = volume of wastewater treated (m³/yr)
 N_{qave} = average of quarterly determinations of N in effluent (kg N/m³)
 EF_{N₂O} = emission factor for N₂O from discharged wastewater (0.005 kg N₂O-N/kg N)
 1.571 = conversion factor – kg N₂O-N to kg N₂O
 0.001 = conversion factor – kg to metric tons

- (h) Oil-Water Separators. The operator shall calculate CH₄ emissions from oil-water separators using Equation 200-16. For the CF_{NMHC} conversion factor, operators shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using a sampling and analysis methodology approved by B.C. Ministry of Environment.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \quad \text{Equation 200-16}$$

Where:

- CH₄ = emission of methane (tons/yr)
 EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m³) from Table 200-3.
 V_{water} = volume of waste water treated by the separator (m³/yr)
 CF_{NMHC} = NMHC to CH₄ conversion factor
 0.001 = conversion factor – kg to metric tons

- (i) Equipment leaks. The operator shall calculate CH₄ emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:
- (1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999) [for the method in CCME EPC-73E for Canadian jurisdictions], which are incorporated by reference in WCI.6. Operators shall conduct screenings at the

frequency interval required by B.C. Ministry of Environment. Operators shall measure and record emissions using instrumentation capable of detecting methane.

(2) The VOC emissions shall be calculated using the following methods:

(A) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-17.

$$E_{VOC-0} = \sum_{i=1}^6 CC_i \times ZF_{i0} \times t \quad \text{Equation 200-17}$$

Where:

- E_{VOC-0} = zero component VOC emission (kg/screening period)
 i = component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
 CC_i = number of i components where $SV = 0$
 ZF_{i0} = zero VOC emission factor (kg/hr) for component i from Table 200-5
 t = time (hours) since last screening

(B) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-18.

$$E_{VOCL-C} = \sum_{i=1}^6 \sum_{n=1}^n (\sigma_i \times SV_n^{\beta_i}) \times t \quad \text{Equation 200-18}$$

Where:

- E_{VOCL-C} = leaking components VOC emissions (kg/screening period)
 i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
 n = number of i components
 σ_i = correlation equation coefficient for component type i from Table 200-5
 SV_n = screening value for component n
 β_i = correlation equation exponent for component type i from Table 200-5
 t = time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-19.

$$E_{VOCP} = \sum_{i=1}^6 CC_i \times PF_{iP} \times t \quad \text{Equation 200-19}$$

Where:

- E_{VOCP} = VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)

- i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
- CC_i = number of i components pegged over 9,999 ppmv
- PF_{ip} = VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
- t = time component has been leaking (hours) – default value is time since last screening

- (C) The operator shall calculate CH₄ emissions using Equation 200-20. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a CFVOC value. The sampling and analysis methodology must be approved by B.C. Ministry of Environment. When representative data is not available, operators shall use the default value of 0.6 for CFVOC.

$$CH_4 = \sum_1^n (E_{VOC-0} + E_{VOC-LC} + E_{VOC-P})_n \times CF_{VOC} \times 0.001 \quad \text{Equation 200-20}$$

Where:

- CH₄ = methane emissions (metric tons/year)
- n = number of screenings/year
- E_{VOC-0} = zero component VOC emissions (kg/screening period)
- E_{VOC-LC} = leaking component VOC emissions (kg/screening period)
- E_{VOC-P} = VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
- CF_{VOC} = VOC to CH₄ conversion factor (default CF_{VOC}=0.6)
- 0.001 = conversion factor – kg to metric tons

WCI.204 Sampling, analysis, and measurement requirements

- (a) Catalyst Regeneration.
- (1) For FCCUs and fluid coking units, the operators shall measure the following parameters:
- (A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
- (B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
- (C) Continuous or weekly periodic measurements of the CO₂, CO and O₂ concentrations in the regenerator exhaust gas, to be determined by individual jurisdictions.
- (D) Daily determinations of the carbon content of the coke burned.
- (E) The number of days of operation.

- (2) For periodic catalyst regeneration, the operators shall measure the following parameters.
 - (A) The mass of catalyst regenerated in each regeneration cycle.
 - (B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
- (3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters.
 - (A) The hourly catalyst regeneration rate.
 - (B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
 - (C) The number of hours of operation.
- (b) Process vents. Operators shall measure the following parameters for each process vent.
 - (1) The vent flow rate for each venting event.
 - (2) The molar fraction of CO₂, N₂O, and CH₄ in the vent gas stream during each venting event.
 - (3) The duration of each venting event.
- (c) Asphalt Production. Operators shall measure the mass of asphalt blown.
- (d) Sulfur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molecular fraction value instead of the default factor, the operator shall conduct an annual test of the CO₂ content using methods approved by B.C. Ministry of Environment. The operator shall submit a test plan to the B.C. Ministry of Environment for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the B.C. Ministry of Environment.
- (e) Flares and Other Control Devices. The operator shall measure the following:
 - (1) If using the method specified in WCI.203(e)(2)(a), monitor the flow rate and high heat value of the flare gas using continuous monitors.
 - (2) If using the method specified in WCI.203(e)(2)(b), monitor the flow rate and carbon content of the flare gas using continuous monitors.
 - (3) If using the method specified in WCI.203(e)(3), monitor the volume of gas destroyed annually (determined to accuracy of $\pm 7.5\%$) and the carbon content.
- (f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters.
- (g) Wastewater Treatment. Operators shall measure the following parameters.
 - (1) The daily volume of waste water treated.
 - (2) The quarterly chemical oxygen demand of the wastewater.
 - (3) The amount of sludge removed and the organic content of the sludge.
 - (4) The quarterly nitrogen content of the wastewater.

- (h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(d).
- (i) Equipment Leaks. Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method [or the method in CCME EPC-73E for Canadian jurisdictions] and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by B.C. Ministry of Environment.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K ₁	0.2982	0.0186
K ₂	2.0880	0.1303
K ₃	0.0994	0.0062

Table 200-2. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH ₄ may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0
For CH ₄ generation capacity (B) in kg CH ₄ /kg COD, use default factor of 0.25 kg CH ₄ /kg COD. The emission factor for N ₂ O from discharged wastewater (EF _{N₂O}) is 0.005 kg N ₂ O-N/kg-N. MCF = methane conversion factor (the fraction of waste treated anaerobically). COD = chemical oxygen demand (kg COD/m ³).			

Table 200-3. Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF _{sep}) ^a kg NMHC/m ³ wastewater treated
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF ^b or IAF ^c - uncovered	4.00e-03 ^d
DAF or IAF - covered	1.20e-04 ^d
DAF or IAF – covered and connected to a destruction device	0
^a EFs do not include ethane ^b DAF = dissolved air flotation type ^c IAF = induced air flotation device ^d EFs for these types of separators apply where they are installed as secondary treatment systems	

Table 200-4. Data for Preparing the Asphalt Chemical Database

Parameter	Database Entry
Liquid Molecular Weight	1000
Vapor Molecular Weight	105
Liquid Density (lb/gal. at 60 °F)	8.0925
Antoine's Equation Constants (using K)	A = 75350.06
	B = 9.00346

Table 200-5. Gas Service Components Fugitive Emissions

Component Type / Service Type	Default Zero Factor (kg/hr)	Correlation Equation (kg/hr)	Pegged Factor (kg/hr)
			10,000 ppmv (SV > 9,999) PF _{IP-10}
	Z _{f0}	σ _i and β _i	
Valves (1)	7.8 x 10 ⁻⁶	2.27 x 10 ⁻⁶ (SV) ^{0.747}	0.064
Pump seals (2)	1.9 x 10 ⁻⁵	5.07 x 10 ⁻⁵ (SV) ^{0.622}	0.089
Others (3)	4.0 x 10 ⁻⁶	8.69 x 10 ⁻⁶ (SV) ^{0.642}	0.082
Connectors (4)	7.5 x 10 ⁻⁶	1.53 x 10 ⁻⁶ (SV) ^{0.736}	0.030
Flanges (5)	3.1 x 10 ⁻⁷	4.53 x 10 ⁻⁶ (SV) ^{0.706}	0.095
Open-ended lines (6)	2.0 x 10 ⁻⁶	1.90 x 10 ⁻⁶ (SV) ^{0.724}	0.033

21. PHOSPHORIC ACID PRODUCTION

BC.340 Phosphoric Acid Production

BC.341 Source category definition

The phosphoric acid production source category consists of facilities that convert phosphate rock to phosphoric acid using the wet-process.

BC.342 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions report must contain the following information:

- Annual CO₂ process emissions from all wet-process phosphoric acid production lines, as specified in BC.343 (metric tons);
- CO₂, N₂O, and CH₄ emissions from stationary combustion units, as specified in WCI.23 (metric tons);
- Annual consumption of phosphate rock (metric tons); and
- Annual phosphoric acid production and concentration by origin of phosphate rock (metric tons).

BC.343 Calculation of GHG emissions

You must calculate CO₂ process emissions using Equation 340-1 and the measured inorganic carbon content and feedstock input of the phosphate rock.

$$CO_2 = \sum_{i=1}^{12} FS_i \times CF_i \times 3.664 \quad \text{Equation 340-1}$$

Where:

- CO₂ = Annual carbon dioxide emitted (metric tons/year).
- FS_i = Feedstock consumption in month i (metric tons/month).
- CF_i = Carbonate content of feedstock (kg C/ton of feedstock) for month i.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

BC.344 Monitoring requirements

You must comply with the following monitoring requirements:

- Measure the quantity of phosphate rock consumed and the quantity and concentration of phosphoric acid produced by direct measurement using the same instruments used for accounting purposes.
- Collect samples of each batch of phosphate rock consumed and measure the inorganic carbon content using the applicable test method in section IX of the “Book of Methods Used and Adopted by the Association of Florida Phosphate Chemists”, Seventh Edition, 1991. If more than one batch of phosphate rock is consumed in a month, use the highest inorganic carbon content measured during that month to calculate the CO₂ process emissions.

22. PULP AND PAPER PRODUCTION

WCI.210 Pulp and Paper Manufacturing

WCI.211 Source category definition

The pulp and paper manufacturing source category consists of facilities that produce pulp either at stand-alone pulp facilities or integrated pulp and paper mills.

WCI.212 Greenhouse gas reporting requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

- (a) Annual biogenic CO₂ process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213.
- (b) Annual fossil CO₂ process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213.
- (c) CO₂, N₂O, and CH₄ emissions from stationary combustion units in metric tons, as specified in WCI.23.
- (d) Annual consumption of carbonate in metric tons.
- (e) Annual black liquor production in metric tons.
- (f) Under consideration: Annual N₂O, and CH₄ emissions from onsite wastewater treatment plants in metric tons, as specified in WCI.200(g).

WCI.213 Calculation of GHG emissions

- (a) Calculate biogenic CO₂ process emissions from recovery furnaces and kilns using Equation 210-1.

$$CO_{2,biogenic} = \sum_{i=1}^{12} (BL_i \times CC_i \times 3.664) \quad \text{Equation 210-1}$$

Where:

- CO_{2,biogenic} = Biogenic CO₂ process emissions from recovery furnaces and kilns (metric tons/year).
- BL_i = Black liquor produced in month i (metric tons/month).
- CC_i = Carbon content of the black liquor (weight fraction)..
- 3.664 = Ratio of molecular weights, CO₂ to carbon.

- (b) Calculate fossil CO₂ process emissions from make-up carbonates used in the recovery furnace and kiln system using Equation 210-2.

$$CO_{2,fossil} = \sum_{i=1}^{12} \left(\sum_{j=1}^n RM_j \times EF_j \right)_i \quad \text{Equation 210-2}$$

Where:

- $CO_{2, \text{fossil}}$ = Fossil CO_2 process emissions from recovery furnace and kiln systems (metric tons/year).
- RM_j = Amount of make-up carbonate j consumed in month i (metric tons/month).
- EF_j = Carbonate content of carbonate material j for month i (weight fraction as CO_2).
- 3.664 = Ratio of molecular weights, CO_2 to carbon.

WCI.214 Monitoring requirements

- (a) Measure the quantity of black liquor produced each month.
- (b) Collect monthly samples of black liquor and analyze each sample for carbon content using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.
- (c) For the amount of carbonate material consumed, either use records provided by the material supplier or monitor carbonate material consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- (d) For the carbonate content of each carbonate material consumed, either use carbonate content data provided by the supplier, the appropriate default factor from Table 1, or collect monthly samples of each carbonate material consumed and analyze each sample for carbonate content using ASTM Methods C25, C1301 or C1271.

Table 1: Formulae, Formula Weights, and Carbon Dioxide Emission Factors for Common Carbonate Species.

Carbonate	Mineral Name	Formula Weight	Emission Factor (metric tons CO_2 /metric ton Carbonate)
$CaCO_3$	Calcite	100.1	0.4397
$CaMg(CO_3)_2$	Dolomite	184.4	0.4773
Na_2CO_3	Soda ash (sodium carbonate)	106.0	0.4149

23. REFINERY FUEL GAS COMBUSTION

WCI.030 Refinery Fuel Gas Combustion

WCI.031 Source category definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

WCI.032 Greenhouse gas reporting requirements

In addition to the information required by WCI.3, the emissions data report shall include the following information at the facility level:

- (a) Annual CO₂, CH₄, and N₂O emissions from refinery fuel gas combustion in metric tons.
- (b) Annual fuel consumption in units of million standard cubic feet or cubic meters.
- (c) Average carbon content of each fuel, if used to compute CO₂ emissions.
- (d) Average high heat value of each fuel, if used to compute CO₂ emissions.

WCI.033 Calculation of greenhouse gas emissions

- (a) Calculation of CO₂ Emissions. Owners and operators shall calculate daily CO₂ emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO₂ emissions from combustion of all fuel gas by summing the CO₂ emissions from each fuel gas system.
 - (1) Use a CEMS that complies with the provisions in section WCI.23(d).
 - (2) Calculate CO₂ emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \quad \text{Equation 30-1 (English Units)}$$

Where:

- CO₂ = Carbon dioxide emissions, metric tons/year.
- Fuel_i = Daily refinery fuel or flexigas combusted (scf).
- CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
- MW = Daily sample of molecular weight of fuel.
- MVC = Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
- 3.664 = Conversion factor for carbon to carbon dioxide.
- 0.001 = Conversion factor for kg to metric tons.
- n = Number of days in a year.

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \quad \text{Equation 30-1 (Metric Units)}$$

Where:

- CO₂ = Carbon dioxide emissions, metric tons/year.
- Fuel_i = Daily refinery fuel or flexigas combusted (scm).
- CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
- MW = Daily sample of molecular weight of fuel.
- MVC = Molar volume conversion factor (24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere).
- 3.664 = Conversion factor for carbon to carbon dioxide.
- 0.001 = Conversion factor for kg to metric tons.
- n = Number of days in a year.

- (A) For refinery fuel gas, the daily carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in WCI.34.
- (B) For flexigas, the daily carbon content shall be determined once per day using the methods specified in WCI.34.
- (3) Calculate CO₂ emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average high heat value that is monitored using a continuous on-line instrument.

$$CO_2 = \sum_{i=1}^n HHV_i \times Fuel_i \times EF_{CO_2,i} \times 0.000001 \quad \text{Equation 30-2 (English Units)}$$

Where:

- CO₂ = CO₂ emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
- HHV_i = Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (Btu/scf).
- Fuel_i = Daily fuel consumption from all fuel combustion units burning gas from the system (scf/d).
- EF_{CO₂,i} = Daily CO₂ emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO₂/MMBtu).
- 0.000001 = Conversion factor for Btu to MMBtu.
- n = Number of days per year.

$$CO_2 = \sum_{i=1}^n HHV_i \times Fuel_i \times EF_{CO_2,i} \quad \text{Equation 30-2 (Metric Units)}$$

Where:

- CO₂ = CO₂ emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
- HHV_i = Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (MJ/m³).
- Fuel_i = Daily fuel consumption from all fuel combustion units burning gas from the system (m³/d).
- EF_{CO₂,i} = Daily CO₂ emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO₂/MJ).
- n = Number of days per year.

$$EF_{CO_{2,i}} = CC/HHV \times MW/MVC \times 3.664 \times 1,000 \quad \text{Equation 30-3 (English Units)}$$

Where:

- EF_{CO₂,i} = Daily CO₂ emission factor for an individual fuel gas system (metric tons CO₂/MMBtu).
- CC = Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
- HHV = Daily sample of gas high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (Btu/scf).
- MW = Refinery fuel A molecular weight (kg/kg-mole).
- MVC = Molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
- 3.664 = Conversion factor for carbon to carbon dioxide.
- 1,000 = Conversion factor for kg/Btu to metric tons/MMBtu.

$$EF_{CO_{2,i}} = CC/HHV \times MW/MVC \times 3.664 \times 0.001 \quad \text{Equation 30-3 (Metric Units)}$$

Where:

- EF_{CO₂,i} = Daily CO₂ emission factor for an individual fuel gas system (metric tons CO₂/MJ).
- CC = Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
- HHV = Daily sample of gas high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (MJ/m³).
- MW = Refinery fuel A molecular weight (kg/kg-mole).
- MVC = Molar volume conversion (24.06 m³/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m³/kg-mole for STP of 60°F and 1 atmosphere).
- 3.664 = Conversion factor for carbon to carbon dioxide.
- 0.001 = Conversion factor for kg/MJ to metric tons/MJ.

- (A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in WCI.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.
- (B) For facilities that meet the definition of a small refiner in WCI.10, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.
- (4) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.
- (5) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO₂ emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO₂ emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO₂ emissions from the mixture. CO₂ emissions for each fuel stream must be estimated using the following methods:
 - (A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).
 - (B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.
 - (C) For low heat content gas, use the methodology in paragraph (a)(2) of this section.
- (b) Calculation of CH₄ and N₂O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH₄ and N₂O emissions.

WCI.034 Sampling, analysis, and measurement requirements

- (a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).
- (b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). Where these methods do not adequately quantify all major hydrocarbons, then an owner or operator may request use of an alternative ASTM or other method to be approved by B.C. Ministry of Environment.
- (c) Measure high heat value using the monitoring requirements specified in WCI.25(c) for gaseous fuels.

24. ZINC PRODUCTION

BC.240 Zinc Production

BC.241 Source category definition

The zinc production category includes three primary production processes used to produce zinc (i.e., electro-thermic distillation, pyrometallurgical, and electrolytic). In addition, secondary zinc production is also included in this category.

BC.242 Greenhouse gas reporting requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

- (a) Annual emissions of CO₂ at the facility level (metric tons).
- (b) Annual quantities of each reducing agent used (metric tons).
- (c) Carbon content of each reducing agent used (metric tons C/metric ton reducing agent).

BC.243 Calculation of CO₂ emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- (a) Determine facility CO₂ emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
- (b) Determine facility CO₂ emissions using facility-specific emission factors and material quantities and equation 243-1.

$$E_{CO_2} = \sum_i (Q_i \times C_i) \times 3.664 \quad \text{Equation 243-1}$$

Where:

- E_{CO_2} = Annual CO₂ emissions from reducing agents (metric tons);
- Q_i = Annual quantity of reducing agent i (metric tons);
- C_i = Carbon content of reducing agent i (metric tons C/metric ton process input);
- 3.664 = Stoichiometric conversion factor from C to CO₂.

BC.244 Sampling, analysis, and measurement requirements

- (a) None if owner or operator uses method BC.243(a), above, based upon continuous emissions monitoring systems (CEMS). Carbon contents of reducing agents shall be determined as specified under paragraph (b) of this section.
- (b) Carbon contents from reducing agents must be determined from at least three representative samples of the material per year in the following manner:

- (1) For coal and coke, use ASTM D5373-02 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke”.
- (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) “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 D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).
- (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

25. NATURAL GAS TRANSMISSION, NATURAL GAS DISTRIBUTION OR NATURAL GAS STORAGE

BC.350 Natural Gas Transmission, Natural Gas Distribution or Natural Gas Storage

BC.351 Source category description

BC.352 Greenhouse gas reporting requirements

Emissions for all source types listed for activities in Table 2 of the regulation must be reported.

Additional Information to be reported:

- (1) Total pipeline length
- (2) A list of all emission sources quantified, including
 - (i) Quantification methods used
 - (ii) Emission factors used, if applicable.
- (3) A list of all compressors (if the sum of all compressors at the site is equal to or greater than 250 horsepower in specification), the horsepower, and the amount of operating time within the year.

BC.353 Calculation of greenhouse gas emissions

For general stationary combustion, quantification methods and emission factors (where appropriate to the natural gas transmission, natural gas distribution and/or natural gas storage industry) provided in WCI.020 (and the annex to this methodology manual) must be used. For quantification of other sources, refer to the Methodology Manual – *Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI) by Clearstone Engineering, September 25th, 2007.

26. OIL AND GAS EXTRACTION AND GAS PROCESSING ACTIVITIES, OIL TRANSMISSION AND CARBON DIOXIDE TRANSPORTATION

BC.360 Oil and Gas Extraction and Gas Processing Activities, Oil Transmission and Carbon Dioxide Transportation

BC.361 Source category description

BC.362 Greenhouse gas reporting requirements

In addition to the information that must be reported under section 12 of the Reporting Regulation for all source types listed for activities in Table 2, reporting operations carrying out oil and gas extraction and gas processing activities, oil transmission and carbon dioxide transportation are required to report:

- (a) The methodologies used to quantify the reporting operation emissions by source type, including identification of any different methodologies used to calculate a specific emission source.
- (b) The emission factors used to quantify emissions by source type, including identification of any different emission factors used to calculate a specific emission source.
- (c) The sum total of emissions for each greenhouse gas type for each linear facilities operation by the following:
 - (1) lease fuel combustion;
 - (2) mobile drilling rigs; and
 - (3) other combustion sources,
disaggregated by:
 - (4) emissions from equipment, systems, items, structures or buildings that are part of the facility and operated and owned or leased by a contractor; and
 - (5) emissions other than those referred to in paragraph (vii).

Emissions reported under this paragraph will also be reported under section 12 of the Reporting Regulation and should not be subtracted from amounts reported under section 12.

- (d) The sum total of the following source type emissions for each greenhouse gas type for:
 - (1) each individual facility within the reporting operation that has attributable emissions that are greater than or equal to 1,000 metric tons carbon dioxide equivalent, and
 - (2) as an aggregate amount for all facilities within the reporting operation that have attributable emissions that are less than 1,000 metric tons carbon dioxide equivalent.
 - (A) Fuel combustion emissions, including:
 - (i) lease fuel combustion;

- (ii) mobile drilling rigs; and
- (iii) other combustion sources.
- (B) Flaring and incineration emissions.
- (C) Fugitive emissions, including:
 - (i) drilling fluid degassing;
 - (ii) well head and casings;
 - (iii) centrifugal compressor seals;
 - (iv) pump seals; (v) pressure related valves;
 - (v) reciprocal compressor seals;
 - (vi) valves, flanges and fittings;
 - (vii) oil-waste separators and treatment;
 - (viii) field gathering lines; and
 - (ix) other fugitive sources.
- (D) Venting emissions, including:
 - (i) condensate tanks;
 - (ii) oil tanks;
 - (iii) pneumatic control devices;
 - (iv) pneumatic pumps;
 - (v) well completion venting;
 - (vi) well blowdowns and maintenance;
 - (vii) compressor purge and starts;
 - (viii) equipment purge and blowdowns;
 - (viii) dehydrator vents;
 - (ix) acid gas removal vents;
 - (x) compressor seal degassing vents;
 - (xi) plunger lift systems;
 - (xii) gas sampling and analysis; and
 - (xiii) other venting sources.

Emissions reported under this paragraph will be reported under section 12 of the Reporting Regulation and should not be subtracted from amounts reported under section 12.

- (e) The following information for each individual facility within the reporting operation that has attributable emissions that are greater than or equal to 1,000 metric tons carbon dioxide equivalent:
 - (1) Barrels of oil equivalent throughput/processed.

- (2) The sum total horsepower of all compressors at the facility, if that horsepower is equal or greater to 250 horsepower, and the multiple of operating hours times horsepower for the sum of all compressors at the site during the reporting year.
- (3) Identification (including geographic coordinates) of any facility that was acquired during the reporting year.
- (4) Identification (including geographic coordinates) of any facility that was disposed of (i.e. sold) during the reporting year that was above 1,000 metric tons of greenhouse gases in the previous reporting year and the greenhouse gas emissions attributable to that facility in the previous reporting year.

BC.363 Calculation of greenhouse gas emissions

- (a) For general stationary combustion, quantification methods and emission factors (where appropriate to the upstream oil and gas industry) provided in WCI.020 (and the annex to this methodology manual) must be used. For situations in which the general stationary combustion emission factors provided in WCI.020 are not appropriate to the oil and gas industry (e.g. producer consumption of lease fuel), those obtained through production accounting data or from the CAPP/Clearstone Energy technical report (referenced below) should be used.
- (b) Except for general stationary combustion, one of the following quantification methods, and associated oil and gas industry specific emission factors where applicable, should be used, in general order of preference:
 - (1) Production accounting data where applicable, appropriate and sufficient to both ensure accuracy and meet verification requirements.
 - (2) American Petroleum Institute Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, August 2009.
 - (3) Draft (or Final, when released) Climate Registry Upstream Oil and Gas Protocol.
 - (4) Draft (or Final, when released) U.S. Environmental Protection Agency Mandatory Reporting Regulation Subpart W: Oil and Gas Systems.
 - (5) Additional industry specific emission factors may be obtained from the CAPP/Clearstone Energy technical report: *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H₂S) Emissions by the Upstream Oil and Gas Industry*, published in September 2004.

All emission factors used must be appropriate and reasonable for British Columbia, the specific operation environment and the conditions at the facility.

27. ELECTRICITY TRANSMISSION (AND EMISSIONS FROM ELECTRICAL EQUIPMENT IN ELECTRICITY GENERATION)

BC.230 Emissions from Electrical Equipment

BC.231 Source category definition

Sulfur hexafluoride (SF₆) is a greenhouse gas that is used as a gaseous dielectric medium for electric power distribution equipment, including transmission and distribution systems, substations, high-voltage circuit breakers, switches, and other electrical equipment. This category includes fugitive emissions from equipment that is located at a facility that the operator is responsible for maintaining in proper working order.

BC.232 Greenhouse gas reporting requirements

For each facility, the emissions data report shall include the following information:

- (a) Annual greenhouse gas emissions in metric tons, reported as follows:
 - (1) Fugitive SF₆ emitted from equipment.

BC.233 Calculation of SF₆ emissions

SF₆ emissions must be calculated using either a mass-balance or direct measurement approach. Section (a) describes the mass balance approach; section (b) describes the direct measurement approach.

- (a) Mass Balance Approach.
 - (1) Calculate the annual SF₆ emissions using a mass balance approach that tracks and systematically accounts for all operator uses of SF₆, as follows. Any quantity of SF₆ that cannot be accounted for is then assumed to have been emitted into the atmosphere.
 - (2) Calculate the change in inventory of SF₆ in storage using Equation 230-1.

$$\Delta S_{Inv} = S_{Inv-Begin} - S_{Inv-End} \quad \text{Equation 230-1}$$

Where:

- ΔS_{Inv} = Change in inventory of SF₆ in storage, kilograms (“Storage” includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF₆ increases during the year);
- $S_{Inv-Begin}$ = Quantity of SF₆ in storage at the beginning of the year, kilograms;
- $S_{Inv-End}$ = Quantity of SF₆ in storage at the end of the year, kilograms.

- (3) Calculate the sum of all SF₆ acquired from other entities during the year either in storage containers or in equipment using Equation 230-2.

$$S_{PA} = S_{Cyl} + S_{Equip} + S_{Recyc-ret} \quad \text{Equation 230-2}$$

Where:

- S_{PA} = Sum of all SF₆ acquired from other entities during the year either in storage containers or in equipment, kilograms;
- S_{Cyl} = Quantity of SF₆ purchased from producers or distributors in cylinders, kilograms;
- S_{Equip} = Quantity of SF₆ provided by equipment manufacturers with/inside equipment, kilograms;
- $S_{Recyc-ret}$ = Quantity of SF₆ returned to site after off-site recycling, kilograms.

- (4) Calculate the sum of all SF₆ sold or otherwise disbursed during the year either in storage containers or in equipment using Equation 230-3.

$$S_{SD} = S_{Sales} + S_{Returns} + S_{Destruct} + S_{Recyc-off} \quad \text{Equation 230-3}$$

Where:

- S_{SD} = Sum of all SF₆ sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
- S_{Sales} = Quantity of SF₆ sold to other entities (including gas left in equipment that is sold), kilograms;
- $S_{Returns}$ = Quantity of SF₆ returned to suppliers, kilograms;
- $S_{Destruct}$ = Quantity of SF₆ sent to destruction facilities, kilograms;
- $S_{Recyc-off}$ = Quantity of SF₆ sent off-site for recycling, kilograms.

- (5) Calculate the change in nameplate capacity of equipment using Equation 230-4.

$$\Delta S_{Cap} = S_{Cap-new} - S_{Cap-retire} \quad \text{Equation 230-4}$$

Where:

- ΔS_{Cap} = Change in total nameplate capacity of equipment using SF₆ in storage, kilograms (“Total nameplate capacity” refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. Value will be negative if retiring equipment has a total nameplate capacity larger than the total nameplate capacity of new equipment);
- $S_{Cap-new}$ = Total nameplate capacity (proper full charge) of new equipment, kilograms;
- $S_{Cap-retire}$ = Total nameplate capacity (proper full charge) of retired or sold equipment, kilograms.

- (6) Calculate total annual emissions using Equation 230-5.

$$S = (\Delta S_{Inv} + S_{PA} - S_{SD} - \Delta S_{Cap}) / 1,000 \quad \text{Equation 230-5}$$

Where:

- S = Annual SF₆ emissions, metric tons;
- ΔS_{Inv} = Change in inventory of SF₆ in storage, kilograms (“Storage” includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF₆ increases during the year);
- S_{PA} = Sum of all SF₆ acquired during the year either in storage containers or in equipment, kilograms;
- S_{SD} = Sum of all SF₆ sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
- ΔS_{Cap} = Change in total nameplate capacity of equipment using SF₆ in storage, kilograms (“Total nameplate capacity” refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. Value will be negative if retiring equipment has a total nameplate capacity larger than the total nameplate capacity of new equipment);
- 1,000 = Factor to convert kilograms to metric tons.

(b) Direct Measurement Approach.

SF₆ emissions are estimated by directly measuring the mass of SF₆ added to electrical equipment during operation (operation phase) and the amount of SF₆ collected from any decommissioned equipment (decommissioning phase).

In the operation phase, SF₆ added to equipment can be measured using one of two methods: automated mass-flow measurement or weigh-scale measurement. In automated mass-flow measurement, mass-flow meters attached to electrical equipment directly measure the amount of SF₆ added to equipment. In weigh-scale measurement, an SF₆ cylinder is measured before and after its contents are added to electrical equipment, the difference being equal to the SF₆ added to the equipment. Annual SF₆ emissions for both methods are calculated according to Equation 230-6.

$$S_O = \sum_i^N s_i \quad \text{Equation 230-6}$$

Where:

- S_O = Annual SF₆ emissions during operation phase, kilograms;
- N = Number of SF₆ additions in a given year;
- s_i = SF₆ added to equipment during ith addition, kilograms.

Annual SF₆ emissions during the decommissioning phase are calculated according to Equation 230-7.

$$S_D = \sum_i^N (NC_i - S_i) \quad \text{Equation 230-7}$$

Where:

- S_D = Annual SF₆ emissions during decommissioning phase, kilograms;
- N = Number of equipment decommissioned in a given year;
- NC_i = Nameplate capacity of i^{th} decommissioned equipment, kilograms;
- S_i = SF₆ collected from i^{th} decommissioned equipment, kilograms.

Total annual SF₆ emissions are calculated as the sum of SF₆ emissions from equipment operation and decommissioning, according to Equation 230-8.

$$S = \frac{S_O + S_D}{1,000} \quad \text{Equation 230-8}$$

Where:

- S = Annual SF₆ emissions during, metric tons;
- S_O = Annual SF₆ emissions during operation phase, kilograms;
- S_D = Annual SF₆ emissions during decommissioning phase, kilograms.

BC.234 Sampling, analysis, and measurement requirements

Calibration of equipment used to measure the mass of SF₆ used for top-ups to electrical equipment must be conducted as specified in paragraphs (a) and (b) of this section.

- a) For automated mass-flow measurement, equipment must be calibrated according to Section 15 of the Reporting Regulation.
- b) For weigh-scale measurement, equipment must be calibrated every 6 months by weighing objects of pre-determined mass and zeroing the weigh scale accordingly.

28. ANNEX – EMISSION FACTORS

This summary of emission factors is provided to act as a quick reference for reporters for use where allowed in the relevant quantification methods. The emission factors provided with the relevant quantification methods – in their home location, should be considered the definitive version.

Table 20-1: Default Carbon Content and High Heat Value by Fuel Type

Liquid Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/kl)
Asphalt & Road Oil	19.8	44.46
Aviation Gasoline	19.25	33.52
Diesel	19.06	38.3
Aviation Turbo Fuel	18.67	37.4
Kerosene	18.53	37.68
Propane	16.35	25.31
Ethane	15.61	17.22
Butane	16.67	28.44
Lubricants	19.66	39.16
Motor Gasoline - Off-Road	18.02	35
Light Fuel Oil	19.35	38.8
Residual Fuel Oil (#5 & 6)	20.07	42.5
Crude Oil	19.8	38.32
Naphtha	19.33	35.17
Petrochemical Feedstocks	19.33	35.17
Petroleum Coke - Refinery Use	22.71	46.35
Petroleum Coke - Upgrader Use	22.71	40.57
Solid Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/metric ton)
Anthracite Coal	23.74	27.7
Bituminous Coal	20.97	26.33
Foreign Bituminous Coal	21.79	29.82
Sub-Bituminous Coal	25.05	19.15
Lignite	29.97	15
Coal Coke	23.69	28.83
Solid Wood Waste	28.41	18
Spent Puling Liquor	N/A	14
Gaseous Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/m3)
Natural Gas	14.12	0.03832
Coke Oven Gas	23.03	0.01914
Still Gas - Refineries	13.34	0.03608
Still Gas - Upgraders	13.34	0.04324
Landfill Gas	14.97	0.0359

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada.

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO₂ Emission Factor (kg /L)	CO₂ Emission Factor (kg /GJ)	CH₄ Emission Factor (g/L)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/L)	N₂O Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline - Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Ethanol	1.494	N/A	0.12	N/A	0.16	N/A
Biodiesel	2.449	N/A	0.12	N/A	0.082	N/A

	CO ₂ Emission Factor (kg /kg)	CO ₂ Emission Factor (kg /GJ)	CH ₄ Emission Factor (g/kg)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/kg)	N ₂ O Emission Factor (g/GJ)
Biomass and Other Solid Fuels						
Landfill Gas	29.89	833	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada) ¹	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA) ²	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor (Env.Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
	CO ₂ Emission Factor (kg /m ³)	CO ₂ Emission Factor (kg /GJ)	CH ₄ Emission Factor (g/m ³)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/m ³)	N ₂ O Emission Factor (g/GJ)
Gaseous Fuels						
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas - Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas - Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

¹ Assumes 50% moisture content of wood waste

² Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m ³)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m ³)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH ₄ (g/m ³)	CH ₄ (g/GJ)	N ₂ O (g/m ³)	N ₂ O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg/kg)	Emission Factor (kg/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH ₄ Emission Factor (g/kg)	N ₂ O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO ₂ Emission Factor (kg/GJ)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/GJ)
Municipal Solid Waste	91.7	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories

Table 200-2. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH ₄ may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0
For CH ₄ generation capacity (B) in kg CH ₄ /kg COD, use default factor of 0.25 kg CH ₄ /kg COD. The emission factor for N ₂ O from discharged wastewater (EF _{N2O}) is 0.005 kg N ₂ O-N/kg-N. MCF = methane conversion factor (the fraction of waste treated anaerobically). COD = chemical oxygen demand (kg COD/m ³).			



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