A Guidance Document for Reporting Greenhouse Gas Emissions for Large Industry in Newfoundland and Labrador

Government of Newfoundland and Labrador
Office of Climate Change

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1. Introduction

1.1 Disclaimer

This guidance document is not a substitute for legal requirements. Users should consult the *Management of Greenhouse Gas Act* and *Reporting Regulations*. In the event there is a discrepancy between this guidance document and the *Act* or the *Regulations,* the *Act* and *Regulations* will prevail*.*

1.2 Background

On June 7, 2016, the *Management of Greenhouse Gas Act* was passed in the House of Assembly of Newfoundland and Labrador. This *Act* establishes a legislative basis for regulating greenhouse gas (GHG) emissions from large, on-shore industrial emitters operating in the province. The *Act* is available at http://www.assembly.nl.ca/legislation/sr/statutes/m01-001.htm In accordance with the *Act*, industrial facilities that emit, on an annual basis, more than 15,000 tonnes of carbon dioxide equivalent (CO_2e) will be required to report their GHG emissions to the Government of Newfoundland and Labrador.

The *Management of Greenhouse Gas Reporting Regulations* are implemented pursuant to Section 29 of the *Act* and came into force on March 7, 2017. The regulations are available at http://www.assembly.nl.ca/legislation/sr/tableregulations/tableofregulations_m.htm . Among other provisions, the *Regulations* set out reporting requirements, including timelines and items to be contained within reports to be submitted, GHG quantification methodologies, verification requirements, including items to be contained in the verification reports and ISO requirements for verification bodies, and requirements for records retention.

To facilitate reporting by industrial companies in a timely, consistent and accurate manner, Government has also developed a facility-specific spreadsheet for each known large industrial facility. It has also developed a generic spreadsheet for other facilities that may be required to report. Copies of the spreadsheets are available upon request. Additionally, to assist facilities in fulfilling their GHG reporting obligations, Government has developed this technical guidance document.

This guidance document provides guidance that is, in almost all respects, the same as that contained in comparable guidelines prepared by other Canadian provinces, including Ontario, British Columbia and Quebec, which along with some US states are members of the Western Climate Initiative Inc. (WCI). The WCI is a non-profit corporation formed to provide administrative and technical services to support the implementation of US state and Canadian provincial GHG emissions trading programs, including a GHG reporting protocol. The WCI protocol is found at http://www.westernclimateinitiative.org/document-archives/Reporting-Committee-Documents/Final-Essential-Requirements-of-Mandatory-Reporting-(Second-Update) . Furthermore, the guidance provided in this document is similar to the guidance provided by Environment and Climate Change Canada, and as such is generally consistent with reporting requirements under the Federal GHG Emissions Reporting Program.

Key Information and Dates
GHG Emissions Reports

Operators of industrial facilities that emit 15,000 tonnes or more of GHG emissions in a given year are required to file an emissions report no later than June 1 of the following year outlining their gross and net emissions. Completed forms must be e-mailed to statenv@gov.nl.ca

Operators of industrial facilities that have GHG emissions of 25,000 tonnes or more in a given year must also have their emissions report verified and a verification report submitted no later than September 1 of the following year.

Operators of industrial facilities that have not previously been subject to these Regulations and that exceed 15,000 tonnes in a given year must notify the Minister no later than March 31 of the following year that its emissions exceeded 15,000 tonnes. An emissions report is due no later than June 1 as previously outlined. For the purposes of this requirement, an operator may use e-mail notification at statenv@gov.nl.ca.

If, after an emissions report is filed for a given year, the operator becomes aware of an error, omission or misrepresentation that exceeds the lesser of 1 percent or 1,000 tonnes of GHG emissions, the operator shall file a revised emissions report within the following 60 days.

An industrial facility is defined as a facility engaged in manufacturing and processing, mining, quarrying and oil and gas extraction, and electricity generation.

A facility is defined to mean a plant or structure where GHG emissions are released, and a site of two or more contiguous or adjacent sites that are operated and function in an integrated fashion where GHG emissions are released, including all buildings, equipment, machinery and vehicles.

The reporting period is for the calendar year from January 1 to December 31 of a given year. For a facility that starts operations in a given year, the reporting period for that year is from the starting date of operations to December 31.

For reporting purposes, operators are required to use the Western Climate Initiative (WCI) GHG reporting protocol for GHG emissions from stationary combustion, refinery gas combustion, electricity generation and mobile equipment. For process emissions, operators may use the WCI protocol or another GHG reporting protocol, with the prior consent of the Minister, if the operator can demonstrate that the other protocol produces GHG estimates at least as accurate as the WCI protocol.

If a facility emits GHGs from a source other than those listed in this file, the operator should contact the Office of Climate Change (729-1210) for guidance.

Operators are required to maintain all records used to complete this form, and for any subsequent verification, for a period of at least 7 years.

Key Information and Dates
GHG Verification Reports

Operators of industrial facilities that have GHG emissions of 25,000 tonnes or more in a given year must have their emissions report verified and a verification report submitted no later than September 1 of the following year. For the purposes of this requirement, an operator may submit verification reports at statenv@gov.nl.ca.

A verification is not required for the year in which an industrial facility permanently closes.

Verification bodies and members of the verification team must meet the requirements of ISO 14064-3 and ISO14065, as appropriate. Qualified verifiers may include professional engineers, certified accountants, or other accredited companies.

Verification processes must adhere to the requirements of ISO 14064-3. Notwithstanding this, verification must occur as a reasonable level of assurance.

In the event that an operator receives notice of adverse outcomes from a verification process, it may request a review of the verification by the minister within seven days of receiving the notice. If the minister, in reviewing such a request, requires further information beyond that previously provided to the minister, the operator or verification body shall provide the information within 21 days.

The minister may reject a verification statement if it determines that the verification was not free from threat of independence. In this case, the operator shall complete a second verification using another verification body within 120 days.

The minister may reject a verification statement if it determines that there is no reasonable level of assurance associated with the work. In this case, the operator shall complete a second verification using the same verification body within 60 days or using another verification body within 120 days.

Operators are required to maintain all records used to complete verification processes for a period of at least 7 years.

1.3 Organization of the Guidance Document

Sections 2 to 5 includes a listing of definitions (Section 2), acronyms and abbreviations (Section 3), testing references and standards (Section 4) and technical tables for emissions factors, HHVs, and related matters (Section 5).

Section 6.0 focuses on general stationary combustion and Section 7.0 on mobile equipment. These sections are applicable to any facility that combusts fossil fuels in stationary equipment, such as boilers, induration furnaces, other types of furnaces, and kilns, or that has on-site mobile equipment within the facility.

Section 8.0 focuses on refining-specific emissions.

Section 9.0 addresses on-site electricity generation, such as at the Voisey's Bay mine site.

Sections 10 to 12 includes mining specific emissions, such as mining explosives, iron ore pelletizing, base metal hydrometallurgical processing and lime production

Section 13 provides guidance on methods for estimating missing data.

WCI Reference Chapters and Potential Application by Facility
(As of January 2017)

	IOC	NARL	Vale (Voisey's Bay)	Vale (HMP)	CBPP
WCI.020 General Stationary Combustion	X	X	X	X	X
WCI.030 Refinery Fuel Gas Combustion		X			
WCI.040 Electricity Generation			X		
WCI.130 Hydrogen Production		X			
WCI.150 Iron and Steel Manufacturing	X				
WCI.170 Lime Manufacturing				X	
WCI.200 Petroleum Refining		X			
WCI.260 Nickel and Copper Manufacturing				X	
WCI.280 Mobile Equipment	X	X	X	X	X
Mining Explosives	X		X		

Provided for illustrative purposes only. Actual emissions reports must follow WCI GHG reporting protocol requirements.

1.4 Threshold for Reporting

Facility(ies) that own and operate an industrial facility in the province, which combusts fossil fuels, uses feedstocks and materials, or has processes that can reasonably be expected to result in total emissions of greenhouse gases, excluding biomass, equal to or greater than 15,000 metric tonnes per year (as CO_2e) are required to calculate and report facility GHG emissions for each emissions source at the facility. Once a facility reaches 15,000 tonnes of GHG emissions in a given year, it is required to report emissions for all future years regardless of GHG emissions in future years, unless the facility emits less than 15,000 tonnes for three consecutive years and receives an exemption for reporting from the minister.

1.5 Alternative Calculation Methods

Facility(ies) that have process emissions may use an alternative methodology for process emissions to the WCI reporting protocol where the minister is satisfied that the emissions estimate is at least as accurate as the WCI standard.

Where a WCI quantification methodology does not exist, facility(ies) may use another quantification method approved by the minister.

Facility(ies) may identify one or more GHG emissions sources for which they may quantify using methods other than the quantification methods set out in the WCI reporting protocol, if the total amount of all GHG (expressed as CO_2e) quantified using these methods does not exceed the lesser of 3% of the total facility CO_2e generated from all sources, and 20,000 tonnes per year.

1.6 Consistency Requirement

Person(s) that calculate emissions for a facility must select one calculation method for each emission source and continue to use that method for all subsequent year quantifications, unless approved to do so by the minister.

2.0 Definitions

“**Barrel” (bbl**) means a volume equal to 159 litres or 42 U.S. gallons.

“**Biogenic emissions**” means the emissions from the combustion of biomass.

“**Bottoming cycle plant**” means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

“**Calcination**” means the thermal decomposition of carbonate-based minerals, into one or more oxides and carbon dioxide

“**Calcine**” means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or reduction.

“**Calcined byproduct/waste type**” means lime kiln dust and other partially calcined materials and co-products generated during the production of quicklime.

“**CAS number**” means the Chemical Abstracts Service Registry number.

“**Catalytic cracking**” means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.

“**Catalytic reforming**” means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

“**CO_2e**” means carbon dioxide equivalent, which is calculated by multiplying the amount of greenhouse gas by its associated global warming potential (GWP) (also see global warming potential below).

“**Cogeneration unit**” means a stationary fuel combustion device which simultaneously generates multiple forms of useful energy (electrical and thermal – e.g., steam, hot water) that is (i) used by the person where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

“**Cogeneration system**” means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

“**Coke** ” means a solid residue consisting mainly of carbon, which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulphur bituminous coal (coal coke).

“Coke breeze” means a solid consisting mainly of carbon, which is derived from the production of metallurgical coke produced in the iron and steel industry.

“**Combustion emissions**” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

“**Continuous emissions monitoring system (CEMS**)” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

“Consensus Based Standards Organization” means American Society for Testing and Materials (ASTM International), the American Gas Association (AGA), the American Petroleum Institute (API), the CSA Group, the Gas Processors Association (GPA), the Canadian General Standards Board (CGSB), the Gas Processors Suppliers Association (GPSA), the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB), International Organization for Standardization (ISO), Environment Canada, United State Environmental Protection Agency (EPA), British Standard Institution (BSI), or Measurement Canada.

“**Distillate fuel oil**” means fuels oils No. 1, 2 and 4 and diesel fuel.

“**dSm3**” means dry standard cubic metre – the amount of gas that would occupy a volume of one cubic metre if free of combined water at standard conditions.

“**Electricity generating unit**” (“**EGU**”) 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 includes cogeneration (combined heat and power) units. This source does not include portable or emergency generators less than 10 megawatt (MW) in nameplate generating capacity.

“**Emergency generator**” means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the person of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

“**Emergency equipment**” means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

“**Emission factors**” (“**EF**”) means the rate at which a pollutant is released into the atmosphere (or captured) as a result of some process activity or unit throughput.

“**Engineering estimates**” means estimating emissions from engineering principles and judgment, using knowledge of the chemical and physical processes involved, the design features of the source, and an understanding of the applicable physical and chemical laws.

“**Equipment leak**” means fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

“**Fluid catalytic cracking unit**” (“**FCCU**”) means a process unit in a refinery in which crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

“**Fluid coking**” means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

“**Fuel analytical data**” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

“**Fuel gas system**” means a system of compressors, piping, knock-out pots, mix drums, sulphur removal units and flaring units that collects fuel gas from one or more sources for treatment, and transports it to a stationary combustion unit.

“General stationary combustion” means the combustion of solid, liquid or gaseous fuel for the purposes of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or providing energy for pollution control; or reducing the volume of waste by removing combustible matter.

“Global warming potential (GWP)” is a measure of relative of amount of heat-trapping potential of a greenhouse gas. GWP is calculated as the ratio of the time-integrated radiative forcing (i.e., the amount of heat-trapping potential, measured in units of power per unit of area, e.g., watts per square metre) that would result from the emission of 1 kg of a given greenhouse gas to that from the emission of 1 kg of carbon dioxide.

“**High heat value**” (“**HHV**”) means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel.

“**Hydrogen plant**” means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

“**Kiln**” means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of lime and other products, and which includes any associated preheater or precalciner devices.

“**Lime kiln dust**” (“**LKD**”) means lime dust produced in the course of production of quick lime. LKD may be captured and contained in particulate matter (PM) emission control devices.

“**Lime type**” means three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:

- High calcium quicklime, which is derived from limestone containing 0 to 5 per cent magnesium carbonate.
- Magnesium quicklime, which is derived from limestone containing 5 to 35 per cent magnesium carbonate.
- Dolomitic quicklime, which is derived from limestone containing 35 to 46 per cent magnesium carbonate.

“**Liquefied petroleum gas**” (**LPG**) means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.

“**Low heat content gas**” means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.

“**Low Heat Value**” (**LHV**) means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.

“**Mass balance**” means the application of the law of conservation of mass to a facility, process or piece of equipment to determine emissions based on the difference in the input and output of a unit operation, where the accumulation and depletion of a substance are included in the calculations.

“**Measurement uncertainty**” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.

“Nameplate generating capacity” means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

“**Net power generated**” means the gross electricity generation minus station service or unit service electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value includes internal consumption of electricity for the purposes of a production process, as well as including power put on the grid.

“**Non-calcined calcium oxide**” means calcium oxide that remains in the lime or LKD in the form of calcium carbonate ($CaCO_3$).

“Person(s)” means the owner(s) or operator(s) of a facility as of December 31 that generated greenhouse gases on the last day of the reporting period (December 31). Person(s) are responsible for calculating and reporting GHG emissions.

“**Pipeline quality natural gas**” means natural gas having a high heat value equal to or greater than 36.3 MJ/m3 or less than 40.98 MJ/m3, and which is at least ninety per cent methane by volume, and which is less than five per cent carbon dioxide by volume.

“**Portable**” means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

- The equipment is attached to a foundation.
- The equipment or a replacement resides at the same location for more than 12 consecutive months.
- The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year. The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

"**Prime mover**" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

"**Process**" means the intentional or unintentional reactions between substances or their transformation, including, but not limited to: the chemical or electrolytic reduction of metal ores; the thermal decomposition of substances; and the formation of substances for use as product or feedstock.

"**Process emissions**" means the emissions from industrial processes (e.g., hydrogen production) involving chemical or physical transformations other than fuel combustion. Examples are: the calcination of carbonates in a kiln during lime production; the oxidation of methane in a hydrogen production process; and calcination of heated carbonates contained, which result in the release of process CO_2 emissions to the atmosphere as process emissions. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment from which the "process emissions" are generated.

"**Process vent**" means an opening where a gas stream is continuously or periodically discharged during normal operation.

"**Purge gas**" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or used to provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

"**Quicklime**" means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone or other highly calcareous materials such as aragonite, chalk, coral, marble and shell.

"**Refinery fuel gas**" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

"**Rm3**" means reference cubic metre - the amount of gas that would occupy a volume of one cubic metre under standard or specified reference temperature and pressure conditions.

"**Standard conditions**"" means either a temperature of 15 degrees Celsius and a pressure of 101.325 kPa. unless otherwise stated or required in the standard quantification, testing or analytical methods.

"**Standard Temperature and Pressure**" has the same meaning as standard conditions.

“**STP**” means Standard Temperate and Pressure.

“**Sm3**” means standard cubic metre - the amount of gas that would occupy a volume of one cubic metre under standard conditions.

“**Steam reforming**” means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

“**Still gas**” has the same meaning as “Refinery Fuel Gas”

“**Sulphur recovery unit**” (“**SRU**”) means a process unit that recovers elemental sulphur from gases that contain reduced sulphur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulphur dioxide and hydrogen sulfide.

“**Supplemental firing**” means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.

“**Topping cycle plant**” means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

“**Useful thermal output**” means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

“**Wastewater separator**” means equipment used to separate oils and water from locations downstream of process drains.

3.0 Acronyms and Abbreviations

ASTM	American Standards for Testing and Materials International
Btu	British thermal units
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
GHG	Greenhouse gas(es)
GJ	Gigajoule
GWP	Global warming potential
h, hr	Hour
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
IP	Industrial process
IPCC	Intergovernmental Panel on Climate Change
ISAE	International Standard on Assurance Engagements
ISO	International Organization for Standardization
J	Joule
kg	Kilogram
kJ	Kilojoule
kt	Kilotonne
LHV	Lower heating value
MM	Million
MWh	Megawatt-hour
N_2O	Nitrous oxide
N/A	Not applicable
NAICS	North American Industry Classification System
NCASI	National Council for Air and Stream Improvement
NGCC	Natural gas combined cycle
psia	Pounds per square inch absolute
PFC	Perfluorocarbon
SF_6	Sulphur hexafluoride
t	Metric tonnes
TAPPI	Technical Association of the Pulp and Paper Industry
WCI	Western Climate Initiative Inc.

4.0 Technical References and Standards

4.1 Technical References

Table 1 lists technical references that contain emission factors, conversion factors, and other useful information for calculating GHG emissions. Some of these resources are referenced in this Guidance Document and may be specified for the calculation methodology required. These technical references may be modified from time to time, and as such, it is the responsibility of the person(s) calculating annual emissions to obtain and use the most up-to-date versions of the documents.

Table 1: Reference Quantification Methodology Resources

Quantification Method Resources	Link
Alberta Environment and Parks (2009) Technical Guidance For Completing Baseline Emissions Intensity Applications: Specified Gas Emitters Regulation	http://environment.gov.ab.ca/info/listing.asp?page=9&categoryid=6
Alberta Environment and Parks (January 2013) Technical Guidance for Greenhouse Gas Verification at Reasonable Level Assurance	http://environment.gov.ab.ca/info/listing.asp?page=9&categoryid=6
Alberta Environment and Parks, (2014) Technical Guidance for Completing Specified Gas Compliance Reports Version 7.0 (and accompanying quantification methodology protocols)	http://environment.gov.ab.ca/info/listing.asp?page=9&categoryid=6
American Petroleum Institute (API) Compendium of GHG Emission Methodology for the Oil and Gas Industry, August 2009	http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf
American Society of Mechanical Engineers, ASME Performance Test Codes (For Power Production, Combustion and Heat Transfer, Fluid Handling, and Emissions)	https://www.asme.org/about-asme/standards/performance-test-codes
B.C. Ministry of Environment (December 2009) B.C. Reporting Regulation - Methodology Manual, Version 1 (Superseded by Western Climate Initiative Inc. methodologies.)	http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/one-window/methodology-manual.pdf
B.C. Ministry of the Environment (2011) British Columbia Reporting Regulation Guidance Document	http://www2.gov.bc.ca/gov/content/environment/climate-change/stakeholder-support/reporting-regulation
Environment Canada, Sector Specific Protocols and Guidance Manuals	https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=07B0E55A-1
Environment Canada (2004) Base Metals Smelting/Refining - Guidance Manual for Estimating Greenhouse Gas Emissions	http://publications.gc.ca/site/eng/257700/publication.html
Environment Canada (2004) Lime Production - Guidance Manual for Estimating Greenhouse Gas Emissions	http://publications.gc.ca/site/eng/257572/publication.html
Environment Canada (2004) Metal mining: a guidance manual for estimating greenhouse gas emissions.	http://publications.gc.ca/collections/Collection/En49-2-9-2E.pdf

Quantification Method Resources	Link
Environment Canada (2008) Sulphur hexafluoride (SF6) Emission Estimation and Reporting Protocol for Electric Utilities	http://publications.gc.ca/collections/collection_2013/ec/En4-229-2008-eng.pdf
Environment Canada (October 2014) Facility Greenhouse Gas Emissions Reporting: Technical Guidance on Reporting Greenhouse Gas Emissions	https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=47B640C5-1
Environment Canada (2012) Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7	https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromThermalPowerGeneration.pdf
European Union, Monitoring & Reporting Guidelines for EU Emission Trading System, Annex I - General Guidelines.	http://ec.europa.eu/clima/policies/ets/monitoring/documentation_en.htm
Intergovernmental Panel on Climate Change (2006) 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3 -Industrial Processes and Product Use	http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol3.html
Intergovernmental Panel on Climate Change (IPCC) (2006) IPCC Guidelines for National Greenhouse Gas Inventories	http://www.ipcc-nggip.iges.or.jp/public/2006gl/
Intergovernmental Panel on Climate Change (IPCC), Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories	http://www.ipcc-nggip.iges.or.jp/public/2006gl/
International Standards Organization, ISO 14064-1, Greenhouse Gases: Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals.	http://www.iso.org/iso/
International Standards Organization, ISO 14064-2, Greenhouse gases -- Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements	http://www.iso.org/iso/
International Standards Organization, ISO 14064-3: Greenhouse gases — Part 3: Specification with Guidance for the Validation and Verification of Greenhouse Gas Assertions) by a qualified third-party verifier.	http://www.iso.org/iso/
International Standards Organization, ISO 14065:2013 - Greenhouse gases - Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms of recognition; Second Edition.	http://www.iso.org/iso/
Mining Association of Canada (2015) Energy and GHG Emissions Management Reference Guide	http://mining.ca/documents/energy-and-ghg-emissions-management-reference-guide

Quantification Method Resources	Link
NCASI (2005) Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (Version 1.1 updated)	http://www.ncasi.org/Programs/Climate-Change/Resources/GHG-Calculation-Tools/Index.aspx
Ontario Ministry of the Environment (December 2015) Guideline for Greenhouse Gas Emissions Reporting	http://www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2015/012-4549_d_Guideline.pdf
Quebec Ministry of the Environment (October 2015) Regulation Respecting Mandatory Reporting of Certain Emissions of Contaminants into the Atmosphere	http://www.mddelcc.gouv.qc.ca/publications/lois-reglem-en.htm
The Climate Registry (TCR), (May 2008) General Reporting Protocol (GRP) for the Voluntary Reporting Program	https://www.theclimateregistry.org/tools-resources/reporting-protocols/general-reporting-protocol/
U.S. EPA, (2009) Technical Support Document for the Lime Manufacturing Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases	http://www.epa.gov/sites/production/files/2015-07/documents/subpartstsd.pdf
U.S. EPA, 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Subparts A to Subpart PP	http://www.epa.gov/ghgreporting.
U.S. EPA, Mandatory Reporting of Greenhouse Gases, Final Rule, 40 CFR 98, Oct. 30, 2009.	http://www.epa.gov/sites/production/files/2014-09/documents/ghg-mrr-finalrule.pdf
Western Climate Initiative (December 21, 2011) Final Essential Requirements of Mandatory Reporting 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions	http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/
Western Climate Initiative (November 12, 2010) Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule.	http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/
Western Climate Initiative (WCI) (2010) Final Harmonization of Essential Reporting Requirements in Canadian Jurisdictions (Quantification Methods)	http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/
Western Climate Initiative (WCI) (2013) Revised Canadian Quantification Methods	http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/
Western Climate Initiative (WCI), (2011) Final Essential Requirements for Mandatory Reporting, 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions	http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/

Note: Some web links may not be current.

4.2 Technical Testing and Analytical Standards

Table 2 lists technical testing and analytical standards developed and published by consensus-based standards organizations, such as ASTM. These contain specific procedures for sampling, analyzing and calculating concentrations of carbon in materials, other elements, heating values and other input data required to develop GHG emissions estimates. Some of these standards are referenced in this Guidance Document and may be specified for the required calculation methodology. Other or newly developed standards that would result in more accurate calculations of a facility's GHG emissions might be relevant to a facility's fuels, raw materials, products, wastes and processes. Furthermore, these standards may be modified from time to time, and as such, it is the responsibility of the person(s) calculating annual emissions for the facility to obtain and use the most up-to-date and most appropriate standards available.

Where no appropriate standard is published by a consensus-based standards organization, the person(s) calculating facility emissions shall use an industry standard method, noting which methods have been used for the specific emission source calculations.

Table 2: Technical Testing and Analytical Standards

Reference Titles
ASTM C25 - Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime
ASTM D70 - Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)
ASTM D240 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimetre
ASTM D1298 - Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1826 - Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimetre
ASTM D1945 - Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D1946 - Standard Practice for Analysis of Reformed Gas by Gas Chromatography
ASTM D2013 - Standard Practice of Preparing Coal Samples for Analysis.
ASTM D2163 - Standard Test Method for Determination of Hydrocarbons in Liquefied Petroleum (LP) Gases and Propane/Propene Mixtures by Gas Chromatography
ASTM D2234/D2234M - Standard Practice for Collection of a Gross Sample of Coal
ASTM D2502 - Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements
ASTM D2503 - Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements
ASTM D2597 - Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.
ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.
ASTM D3238 - Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method
ASTM D3588 - Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels
ASTM D3682 - Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes.
ASTM D4057 - Standard Practice for Manual Sampling of Petroleum and Petroleum Products
ASTM D4177 - Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.
ASTM D4809 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D4891 - Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion

Reference Titles
ASTM D5142 - Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and Coke by Instrumental Procedures, for petroleum liquid based fuels and liquid waste-derived fuels
ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants
ASTM D5373 - Standard Test Methods for Determination of Carbon, Hydrogen and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke
ASTM D5468 - Standard Test Method for Gross Calorific and Ash Value of Waste Materials
ASTM D5580 - Standard Test Method for Determination of Benzene, Toluene, Ethylbenzene, p/m-Xylene, o-Xylene, C9 and Heavier Aromatics, and Total Aromatics in Finished Gasoline by Gas Chromatography
ASTM D5865 - Standard Test Method for Gross Calorific Value of Coal and Coke
ASTM D6348 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy
ASTM D6609 - Standard Guide for Part-Stream Sampling of Coal.
ASTM D6866 - Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis
ASTM D6883 - Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles
ASTM D7430 - Standard Practice for Mechanical Sampling of Coal
ASTM D7459 - Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources
ASTM D7633 - Standard Test Method for Carbon Black Carbon Content
ASTM D7662 - Standard Test Method for Carbon Content in Carbon Black Feedstock Oils
ASTM E415 - Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry
ASTM E1019 - Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques
ASTM E1915 - Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials for Carbon, Sulfur, and Acid-Base Characteristics
ASTM E1941 - Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys by Combustion Analysis
ASTM UOP539 - Refinery Gas Analysis by Gas Chromatography
CCME EPC-73E: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993)
Environment Canada, “Protocols and Performance specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7 (“EPS 1/PG/7”)
Gas Processors Association (GPA) 2261–00, Revised 2000 - Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.
Gas Processors Association (GPA) 2172:1996, Calculation of Gross Heating Value, Relative Density and Compressibility For Natural Gas Mixtures From Compositional Analysis
ISO 13909 - All Parts: Hard coal and coke -- Mechanical sampling
ISO/TR 15349-1: 1998 - Unalloyed steel – Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak

Reference Titles
separation)
ISO/TR 15349-3: 1998 - Unalloyed steel – Determination of low carbon content, Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating)
ISO 3170: Petroleum Liquids— Manual sampling.
ISO 3171: Petroleum Liquids— Automatic pipeline sampling.
National Lime Association, CO_2 Emissions Calculation Protocol for the Lime Industry, English Units Version.
U.S. EPA Method 320 (40 CFR part 63, Appendix A), Test Methods Pollutant Measurement Methods From Various Waste Media
U.S. EPA TANKS Version 4.09D, U.S. Environmental Protection Agency, October 2005
U.S. EPA AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources

5.0 Technical Tables

Table 5-1: Default High Heat Value by Fuel Type

Liquid Fuels	**High Heat Value (GJ/kL)**
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane[1]	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline – Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (No. 5 & No. 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke – Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	32.41
Biodiesel (100%)	35.67
Rendered Animal Fat	34.83
Vegetable Oil	33.44
Solid Fuels	**High Heat Value (GJ/tonne)**
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste (at 0% moisture content)2	19.23
Spent Pulping Liquor (at 0% moisture content)3	13.53
Municipal Solid Waste	11.57
Tires	31.18
Agricultural By-products	8.6
Solid By-products	26.93
Gaseous Fuels	**High Heat Value (GJ/m3)**
Natural Gas	0.038
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (methane fraction)	0.0359
Biogas (methane fraction)	0.0281

1. The default high heat value for “propane” is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 4-1a should be used instead.
2. HHV can be readily calculated for any moisture content as HHVdry = HHVwet / (1 – percent_moisture/100).
3. A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment.

Table 5-1a—Fuels for which Section 6 Calculation Methodologies 1 or 2 may be used

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**GJ/kilolitre**	**kg CO_2/GJ**
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied Petroleum Gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs) [1]	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40
Aviation Gasoline	33.52	69.87
Kerosene-type Jet Fuel	37.66	68.40

1. The default factors for “propane” are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 5-1b: Other Emissions Factors – Section 6 for Used Oil (CBPP)

	GJ/kilolitre	kg CO_2/GJ
Used oil	38.07	68.98

Source: ECC calculation based on data provided by CBPP.

Table 5-2: Default Emission Factors by Fuel Type

	Physical-Based Emission Factors			Energy-Based Emission Factors		
Liquid Fuels	**CO_2 (kg/L)**	**CH_4 (g/L)**	**N_2O (g/L)**	**CO_2 (kg/GJ)**	**CH_4 (g/GJ)**	**N_2O (g/GJ)**
Aviation Gasoline	2.342	2.2	0.23	69.87	65.63	6.862
Diesel	2.663	0.133	0.4	69.53	3.473	10.44
Aviation Turbo Fuel	2.534	0.08	0.23	67.75	2.139	6.150
Kerosene						
- Electric Utilities	2.534	0.006	0.031	67.25	0.159	0.823
- Industrial	2.534	0.006	0.031	67.25	0.159	0.823
- Producer Consumption	2.534	0.006	0.031	67.25	0.159	0.823
- Forestry, Construction, and Commercial/ Institutional	2.534	0.026	0.031	67.25	0.69	0.823
Propane						

	Physical-Based Emission Factors			Energy-Based Emission Factors		
- Residential	1.51	0.027	0.108	59.66	1.067	4.267
- All other uses	1.51	0.024	0.108	59.66	0.948	4.267
Ethane	0.976	N/A	N/A	56.68	N/A	N/A
Butane	1.73	0.024	0.108	60.83	0.844	3.797
Lubricants	1.41	N/A	N/A	36.01	N/A	N/A
Motor Gasoline – Off-Road	2.289	2.7	0.05	65.40	77.14	1.429
Light Fuel Oil						
- Electric Utilities	2.725	0.18	0.031	70.23	4.639	0.799
- Industrial	2.725	0.006	0.031	70.23	0.155	0.799
- Producer Consumption	2.643	0.006	0.031	68.12	0.155	0.799
- Forestry, Construction, and Commercial/ Institutional	2.725	0.026	0.031	70.23	0.67	0.799
Residual Fuel Oil (No. 5 & No. 6)						
- Electric Utilities	3.124	0.034	0.064	73.51	0.800	1.506
- Industrial	3.124	0.12	0.064	73.51	2.824	1.506
- Producer Consumption	3.158	0.12	0.064	74.31	2.824	1.506
- Forestry, Construction, and Commercial/ Institutional	3.124	0.057	0.064	73.51	1.341	1.820
Naphtha	0.625	N/A	N/A	17.77	N/A	N/A
Petrochemical Feedstocks	0.5	N/A	N/A	14.22	N/A	N/A
Petroleum Coke - Refinery Use	3.826	0.12	0.0265	82.55	2.589	0.572
Petroleum Coke - Upgrader Use	3.494	0.12	0.0231	86.12	2.958	0.569
Biomass	**CO_2 (kg/kg)**	**CH_4 (g/kg)**	**N_2O (g/kg)**	**CO_2 (kg/GJ)**	**CH_4 (g/GJ)**	**N_2O (g/GJ)**
Landfill Gas	2.989	0.6	0.06	54.63	1.0	0.1
Wood Waste (at 0% moisture content)	1.81	0.576	0.077	93.71	302	42
Spent Pulping Liquor (at 0% moisture content)	1.239	0.039	0.026	91.81	2.93	1.93
Agricultural By-products	NA	NA	NA	112	NA	NA
Solid By-products	NA	NA	NA	100	NA	NA
Biogas (captured methane)	NA	NA	NA	49.4	NA	NA
Ethanol (100%)	NA	NA	NA	64.9	NA	NA
Biodiesel (100%)	NA	NA	NA	70	NA	NA
Rendered Animal Fat	NA	NA	NA	67.4	NA	NA
Vegetable Oil	NA	NA	NA	77.3	NA	NA
Other Solid Fuels						
Coal Coke	2.48	0.03	0.02	86.02	1.041	0.694
Tires	N/A	N/A	N/A	85	N/A	N/A
Gaseous Fuels	**CO_2 (kg/m3)**	**CH_4 (g/m3)**	**N_2O (g/m3)**	**CO_2 (kg/GJ)**	**CH_4 (g/GJ)**	**N_2O (g/GJ)**

	Physical-Based Emission Factors			Energy-Based Emission Factors		
Coke Oven Gas	1.6	0.037	0.035	83.60	1.933	1.829
Still Gas – Refineries	1.75	N/A	0.0222	48.50	N/A	0.615
Still Gas – Upgraders	2.14	N/A	0.0222	49.49	N/A	0.513

1. A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. prepared for BC Ministry of Environment
2. US EPA (2009). U.S. Environmental Protection Agency. *Mandatory reporting of greenhouse gases, final rule*. Washington, DC, 2009.
3. IPCC (2006). Intergovernmental Panel on Climate Change. 2006 *IPCC Guidelines for National Greenhouse Gas Inventories*. Japan, 2006.

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

Table 5-3: Default Carbon Dioxide Emission Factors for Natural Gas

	Marketable Gas[1] (kg/m3)	Marketable Gas[1] (kg/GJ)	Non-Marketable Gas[2] (kg/m3)
Newfoundland and Labrador	1.891	49.35	2.482

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2012
Marketable Gas (kg/GJ) figure for Newfoundland and Labrador (i.e., 49.35 kg/GJ) is based on Quebec, Ontario, Manitoba, and British Columbia calculated average of 26.09536 cubic metres per gigajoule (M^3/GJ).

1. The term “marketable” applies to fuel consumed by the Electric Utilities, Manufacturing Industries, Residential/Commercial and Transport subsectors.
2. The term “non-marketable” applies to raw gas consumption, mainly by natural gas producers.

Table 5-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH_4 (g/m3)	CH_4 (g/GJ)	N_2O (g/m3)	N_2O (g/GJ)
	(grams/m3)	(grams/GJ)	(grams/m3)	(grams/GJ)
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566

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

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

	Emission Factor (kg CO_2/kg coal)	Emission Factor (kg CO_2/GJ)
Newfoundland and Labrador		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3

Newfoundland and Labrador emission factors assumed the same as those for Quebec.
Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007.

Table 5-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH_4 Emission Factor (g/kg)	N_2O 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 5-7: Other Emission Factors

	CO_2 Emission Factor (kg/GJ)	CH_4 Emission Factor (g/GJ)	N_2O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO_2 emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

Table 5-8: Fuel Oil Default Density Values

Fuel Oil	No.1 Oil	No.2 Oil	No.6 Oil
Default Density, kg/litre	0.81	0.86	0.97

6.0 General Stationary Fuel Combustion (WCI.020)

6.1 Source category definition

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of generating steam, producing electricity, or providing useful heat or energy for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources are boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), process heaters, furnaces, and any other stationary combustion device that is not specifically addressed under the methods for another source category. Stationary fuel combustion includes the combustion of biomass fuels, although these should be reported separately from fossil-based stationary fuel combustion given the variable climate impact that biomass fuel combustion presents. The stationary fuel combustion source category does not include portable equipment, mobile vehicles, emergency generators, and emergency equipment (including emergency flares, explosives blasting).

Emissions from refinery fuel gas are included in Section 8.0, emissions from on-site electricity generation are included in Section 9.0, and emissions from mining explosives are included in Section 10.0.

6.2 Greenhouse Gas Reporting Requirements

Except as noted in the previous paragraph, the emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:
  (1) Total CO_2 emissions for fossil fuels, reported by fuel type.
  (2) Total CO_2 emissions for biomass, reported by fuel type.
  (3) Total CH_4 emissions, reported by fuel type.
  (4) Total N_2O emissions, reported by fuel type.
(b) Annual fuel consumption:
  (1) For gases, report in units of standard cubic metres.
  (2) For liquids, report in units of kilolitres.
  (3) For non-biomass solids, report in units of tonnes.
  (4) For biomass solid fuels, report in units of bone dry tonnes.
(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions.
(d) Annual weighted average high heat value of each fuel, if used to compute CO_2 emissions.
(e) Annual steam in kilograms, for units that burn biomass fuels and generate steam, where Equation 6-3 and Equation 6-5 are used.

6.3 Calculation of CO_2 emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the following restrictions.

(a) Calculation Methodology 1 (below)

- May be used by a facility that is not subject to the verification requirements by regulation for any type of fuel for which a default high heat value (Table 5-1, 5-1a and 5-1b) and a default CO_2 emission factor (Tables 5-1a, 5-1b, 5-2, 5-3, or 5-5, as applicable) is specified.

- May be used for a facility emitting at any level for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 5-1a and 5-1b.

- May be used for a facility emitting at any level from the combustion of municipal solid waste in a unit that does not generate steam.
- May be used for the combustion of biomass listed in Table 5-2.
- May not be used at a facility emitting at any level from a fuel for which you routinely perform fuel sampling and analysis for the fuel's high heat value or can obtain the results (i.e. high heat value) of fuel sampling and analysis from the fuel supplier at the minimum frequency specified in Section 6.5.1, or at a greater frequency. In such cases, Calculation Method 2, 3 or 4 shall be used for those fuels.

(b) Calculation Methodology 2 (below).

- May not be used by a facility that is subject to the verification requirements, except as specified in the following two bullets. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Tables 5-1a, 5-1b, 5-2, 5-3, 5-5, or 5-7, as applicable.
- May be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level. Notwithstanding the provisions in paragraph (a) of this section, Calculation Methodology 2, 3, or 4 shall be used for combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr), when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter.
- May be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 5-1a and 5-1b, and for biomass.

(c) Calculation Methodology 3 (below) may be used for the combustion of any type of fuel, except as specified in the following bullets.

- Notwithstanding the provisions in paragraphs (a) and (b) of this section, Calculation Methodology 3 or 4 must be used at a facility subject to verification for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr), except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 5-1a or 5-1b, or the fuel is biomass.
- Must be used for all other combustion at a facility subject to verification, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (a) and (b).
- May not be used when the use of Calculation Methodology 4 is required.

(d) Calculation Methodology 4 (below) may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (a) through (c), Calculation Methodology 4 must be used for a combustion unit with a CEMS that is required by any federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(e) Users may elect to use any applicable higher calculation methodology for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate fuel oil, users may elect to use Calculation Methodology 1 for natural gas and Calculation Methodology 2 for the fuel oil, even though Calculation Methodology 1 could have been used for both fuels. However, for units that use Calculation Methodology 4, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

If a fuel or fuels is not listed in all of Tables 5-1 through 5-7, or in Table C-1 or C-2 of U.S. EPA 40 CFR Part 98, Subpart C, then emissions from such fuels do not need to be reported so long as the sum of emissions from these fuels does not exceed 0.5% of total facility emissions. If the sum of emissions from these fuels exceeds 0.5% of total facility emissions, then calculate and report emissions from one or more of these fuels as needed so that the sum of emissions from the remaining unlisted fuels does not exceed 0.5% of total facility emissions.

6.3.1 Calculation Methodology 1

Calculate the annual CO_2 mass emissions for each type of fuel by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into Equation 6-1 or Equation 6-1a:

Equation 6-1:

$$CO_2 = \text{Fuel} \times HHV_D \times EF_D \times 0.001$$

Equation 6-1a:

$$CO_2 = \text{Fuel} \times HHV_D \times EF_{DP} \times 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions for the specific fuel type (tonnes).
Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV_D = Default high heat value of the fuel, from Table 5-1, 5-1a and 5-1b (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF_D = Fuel-specific default energy-based CO_2 emission factor, from Tables 5-1a, 5-1b, 5-2, 5-3, 5-5, or 5-7, as applicable (kg CO_2/GJ).
EF_{DP} = Fuel-specific default physical-based CO_2 emission factor, from Tables 5-2 or 5-5 (kg CO_2 per tonne for solid fuel, kg CO_2 per kilolitre for liquid fuel, or kg CO_2 per cubic meter for gaseous fuel).
0.001 = Conversion factor from kilograms to tonnes.

6.3.2 Calculation Methodology 2

Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 6-2, except for emissions from the combustion of biomass fuels, for which the operator may instead elect to use the method shown in Equation 6-3.

(a) For any type of fuel for which an emission factor is provided in Tables 5-1a, 5-1b, 5-2, 5-3, 5-5, or 5-7, as applicable, use Equation 6-2 except biomass fuels when the operator elects to use the method in Section 6.3.2 paragraph (b). Please note that Refinery Fuel Gas is a fuel with an emission factor provided in Table 5-2 (under “Still Gas - Refineries”), but Refinery Fuel Gas CO2 emissions must be quantified using the requirements outlined in Section 8.0. On-site electricity generation is quantified in Section 9.0.

Equation 6-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions for the specific fuel type (tonnes).
n = Number of required heat content measurements for the year as specified in Section 5.5.
$Fuel_p$ = Mass or volume of the fuel combusted during the measurement period “*p*” (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV_p = High heat value of the fuel for the measurement period “*p*” (GJ per tonne for solid fuel, GJ per bone-dry tonne biomass solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF = Fuel-specific default CO_2 emission factor, from Tables 5-1a, 5-1b, 5-2, 5-3, 5-5, or 5-7, as applicable (kg CO_2/GJ).
0.001 = Conversion factor from kilograms to tonnes.

(b) Equation 6-3 may also be used for any biomass solid fuel listed in Table 5-2 provided that steam is generated by the unit. Biomass fuel combustion emissions should be calculated and reported separately.

Equation 6-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions from biomass solid combustion (tonnes).
Steam = Total mass of steam generated by biomass solid combustion during the reporting year (tonnes steam).
B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam)
EF = Default emission factor for biomass solid e, from Table 5-2 or Table 5-7, as applicable (kg CO_2/GJ). Site-specific emission factor determined through measurements may be used if updated no less often than every third year as provided in Section 6.5.1 paragraph (g)(2).
0.001 = Conversion factor from kilograms to tonnes.

6.3.3 Calculation Methodology 3

Calculate the annual CO_2 mass emissions for each fuel 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.

(a) For a solid fuel, except for the combustion of municipal solid waste, use Equation 6-4:

Equation 6-4:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (tonnes).
n = Number of carbon content determinations for the year.
$Fuel_i$ = Mass of the solid fuel combusted in measurement period "*i*" (tonnes)
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, CO_2 (44.01) to carbon (12.01).

(b) For biomass fuels which is combusted in units for producing steam, either use either Equation 6-5 or Equation 6-3**:**. Equation 6-5 may also be used for any solid biomass fuel listed in Table 5-2 provided that steam is generated by the unit.

Equation 6-5:

$$CO_2 = Steam \times EF \times 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
EF = Measured emission factor for biomass solid fuel or municipal solid waste, as applicable (kg CO_2/tonne steam), adjusted no less often than every third year.
0.001 = Conversion factor from kilograms to tonnes.

(c) For a liquid fuel, use Equation 6-6:

Equation 6-6:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$

Where:
CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (tonnes)
n = Number of required carbon content determinations for the year, as specified in Section 6.5.
$Fuel_i$ = Volume of the liquid fuel combusted in measurement period "*i*" (kilolitres).
CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement

period "*i*" (tonne C per kilolitre of fuel).
3.664 = Ratio of molecular weights, CO_2 (44.01) to carbon (12.01).

(d) For a gaseous fuel, use Equation 6-7. Please note that Refinery Fuel Gas is a gaseous fuel but Refinery Fuel Gas CO2 emissions must be quantified using the requirements outlined in Section 8.0.

Equation 6-7**:**

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (tonnes).
n = Number of required carbon content determinations for the year, as specified in Section 6.5.
$Fuel_i$ = Fuel combusted in measurement period "*i*" (a day or month, as applicable) (volume of the gaseous fuel in Rm3 at reference temperature and pressure conditions as used by the facility, or mass of the gaseous fuel in kg if a mass flow meter is used).
CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the measurement period "*i*" (day or month, as applicable) (kg C per Rm3 or kg C per kg of fuel if a mass flow meter is used).
3.664 = Ratio of molecular weights, CO_2 (44.01) to carbon (12.01).
0.001 = Conversion factor from kilograms to tonnes.

6.3.4 Calculation Methodology 4

Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (a) through (g). This methodology requires a CO_2 monitor and a flow monitoring subsystem except as otherwise provided in paragraph (c) of this section. CEMS shall use methodologies provided in Environment and Climate Change Canada's *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation* (Reference Method) (June 2012) (or by other document that supersedes it).

(a) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in the Reference Method.

(b) Report CO_2 emissions for the reporting year in tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to tonnes.

(c) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the combustion products) and if only the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.

    (1) If the unit combusts waste-derived fuels (e.g. waste oils, plastics, solvents, dried sewage, municipal solid waste, tires), emissions calculations shall not be based on O_2 concentrations.

(2) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that the calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in the Reference Guidance or superseding standard.

(d) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in Section 6.3.5.

(e) For any units for which CO_2 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.

(f) If a facility is subject to requirements for continuous monitoring of gaseous emissions, and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, select and operate the added devices pursuant to the appropriate requirements for the facility as applicable in Canada.

(g) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO_2 concentrations, select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada. Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (a) through (e) of Section 6.3.4, if applicable.

6.3.5 CO_2 Emissions from Combustion of Mixtures of Biomass or Biomass Fuel and Fossil Fuel

Use the procedures of this Section to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste, tires, etc.) that are partially biomass.

(a) If CEMS are not used to measure CO_2 and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Calculation Methodology 1, 2, or 3, as applicable, to calculate the annual biogenic CO_2 mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.

(b) If a CEMS is used to measure CO_2 (or O_2 as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels, use Calculation Methodology 1, 2, or 3 to calculate the annual CO_2 mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO_2 emissions determined from the CEMS-based methodology.

(c) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented, or if the owner or operator combusts a biomass fuel for which a CO_2 emission factor is not provided in Table 5-2, use the following to estimate biogenic CO_2 emissions:

(1) Use Calculation Methodology 1, 2, 3, or 4 to calculate the total annual CO_2 mass emissions, as applicable.

(2) Determine the biogenic portion of the CO_2 emissions using ASTM D6866-08 “Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis”, 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 CO_2 emissions.

(3) Conduct ASTM D6866-08 analysis on a representative fuel or exhaust gas sample at least every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08 “Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.” If municipal solid waste is combusted, the ASTM D6866-08 analysis must be performed on the exhaust gas stream.

(4) Divide total CO_2 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.

(5) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for only one of the units sharing the common fuel source.

(d) If Equation 6-1 or 6-1a is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 6-8 may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

Equation 6-8:

$$(Fuel)_p = \frac{[H \times S] - (HI)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}}$$

Where:
(Fuel)p = Quantity of biomass consumed during the measurement period *p* (tonnes/year or tonnes/month, as applicable)
H = Average enthalpy of the boiler steam for the measurement period (GJ/tonne).
S = Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable).
$(HI)_{nb}$ = Heat input from co-fired fossil fuel and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable)
$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (GJ/tonne)
$(Eff)_{bio}$ = Efficiency of biomass-to-energy conversion, expressed as a decimal fraction

6.4 Calculation of CH_4 and N_2O emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraphs (a) through (f), as appropriate. Users are not required to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 5-2, 5-3, 5-4 and 5-6. However, users may use engineering estimates to calculate the annual CH_4 and N_2O emissions for fuels that are not listed in Tables 5-2, 5-3, 5-4 and 5-6.

Use of the CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (f) of this Section is subject to the following requirements and restrictions:

(1) Equation 6-9 and Equation 6-10 may not be used by a facility that is subject to regulatory verification requirements, 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, Equation 6-9 and Equation 6-10 may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 5-2, 5-4, 5-6, and 5-7) and a default high heat value (Table 5-1, 5-1a and 5-1b) is specified.

(2) Equation 6-11 and Equation 6-12 may be used for a unit of any size combusting any type of fuel.

(3) Equation 6-13 may only be used for biomass or municipal solid waste combustion.

(4) Equation 6-14 may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO_2 emissions and heat input is monitored on a year round basis.

  (a) For fuel(s) other than coal: If the High Heat Value (HHV) for fuels is not measured directly, use Equation 6-9 and default HHV to calculate the emissions for each fuel type.

Equation 6-9:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF_D \times 0.000001$$

  (b) For coal: If the emissions factors are not measured directly or provided by suppliers, use Equation 6-10 and default HHV to calculate the emissions for each type of coal:

Equation 6-10:

$$CH_4 \text{ or } N_2O = Fuel \times EF_{DP} \times 0.001$$

Where:
CH_4 or N_2O = Combustion emissions from specific fuel type (tonnes CH_4 or N_2O per year).
Fuel = Mass or volume of fuel type combusted (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV_D = Default high heat value specified by fuel type provided in Table 5-1, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF_D = Default energy-based CH_4 or N_2O emission factor for each fuel type provided in Tables 5-2 or 5-4, as applicable, grams CH_4 or N_2O per GJ. Equipment-specific factors from U.S. EPA AP-42 may also be used for specific equipment, as appropriate.
EF_{DP} = Default physical-unit CH_4 or N_2O emission factor for each coal type provided in Table 5-6 (grams CH_4 or N_2O per kg of coal). Equipment-specific factors from U.S. EPA AP-42 may also be used for specific equipment, as appropriate.
0.000001 = Factor to convert grams to tonnes in Equation 6-9.
0.001 = Factor to convert kg to tonne in Equation 6-10.

(c) For fuels other than coal: If the HHVs for fuels are measured directly or provided by suppliers then use Equation 6-11 and measured HHV to calculate the emissions for each type of fuels:

Equation 6-11:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001$$

(d) *For coal only:* If the emission factors are measured directly or provided by suppliers then use Equation 6-12 and measured HHV to calculate the emissions for each coal type:

Equation 6-12:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001$$

Where:

CH_4 or N_2O = Combustion emissions from specific fuel type (tonnes CH_4 or N_2O per year).

Fuelp = Mass or volume of fuel type during measurement period "*p*" (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).

HHVp = High heat value of the specific fuel during measurement period "*p*" measured directly or provided by supplier(s) (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF = Default energy-based CH_4 or N_2O emission factor for fuel other than coal provided in Tables 5-2 or 5-4, as applicable, grams CH_4 or N_2O per GJ. Equipment-specific factors from U.S. EPA AP-42 may also be used for specific equipment, as appropriate.

EFc = CH_4 or N_2O emission factor for each coal type during measurement period "p" measured directly or provided by supplier(s) (grams CH_4 or N_2O per tonne of coal)

0.000001 = Factor to convert grams to tonnes in Equation 6-11 and Equation 6-12.

(e) For biomass combustion where either Equation 6-3, Equation 6-4 or Equation 6-5 is used to calculate CO_2 emissions, use Equation 6-13 to estimate CH_4 and N_2O emissions:

Equation 6-13:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a biomass or municipal solid waste (tonnes).

Steam = Total mass of steam generated by biomass or municipal solid waste combustion during the reporting year (tonnes steam).

B = Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/tonne steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Tables 5-2, 5-4, 5-6, or 5-7 as applicable (grams per GJ).
0.000001 = Conversion factor from grams to tonnes.

(f) Use Equation 6-14 for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

Equation 6-14:

$$CH_4 \text{ or } N_2O = (HI)_A \times EF \times 0.000001$$

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (tonnes).
$(HI)_A$ = Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information used for accounting purposes (e.g., fuel feed rate measurements, fuel heating values, engineering analysis, etc.). For coal cumulative mass of coal (kilograms) from the best available information (e.g., fuel feed rate measurements, cumulative heat input, fuel heating values, engineering analysis).
EF = Fuel-specific emission factor for CH_4 or N_2O, from Tables 5-2, 5-4, or 5-6, as applicable (grams per GJ or grams per kilogram for coal).
0.000001 = Conversion factor from grams to tonnes.

(1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 6-14 to calculate the annual CH_4 or N_2O emissions.
(2) If more than one type of fuel listed is combusted during normal operation, use Equation 6-14 separately for each type of fuel.

(g) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equation 6-9, Equation 6-10, Equation 6-11, Equation 6-12 and Equation 6-13 or Equation 6-14 (as applicable) to obtain the total annual CH_4 and N_2O emissions, in tonnes.

6.5 Sampling, analysis, measurement and monitoring requirements

6.5.1 Fuel Sampling Requirements

Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the minimum frequency specified in paragraphs (a) through (g), subject to the requirements of Section 6.3 and Section 6.4. All fuel samples shall be taken at a location in the fuel handling system that is representative of the fuel combusted.
(a) Once for each new fuel shipment or delivery for coal.
(b) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 5-1a and 5-1b (when required).
(c) Semi-annually for natural gas.

(d) Quarterly for liquid fuels and fossil fuel-derived gaseous fuels other than fuels listed in Table 5-1a and 5-1b (when Table 5-1a and 5-1b is used).

(e) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment.

(f) For gaseous fuels other than natural gas, gases derived from biomass, and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. If the necessary equipment is not in place to make the measurements, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight must determine fuel carbon content accurate to ±5 percent.

(g) Monthly for solid fuels other than coal and waste-derived fuels, as specified below:
  (1) The monthly solid fuel sample shall be a composite sample of weekly samples.
  (2) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel combustion, and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
  (3) 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.
  (4) 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.
  (5) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
  (6) 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.

(h) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of Section 6.5.1 paragraph (e):
  (1) If CO_2 emissions are calculated using Equation 6-3 or Equation 6-4, the fuel-specific high heat value or carbon content is determined annually. If CO_2 emissions are calculated using Equation 6-5, adjust the emission factor, in kg CO_2/GJ not less frequently than every third year, through a stack test measurement of CO_2 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.

6.5.2 Fuel Consumption Monitoring Requirements

(a) 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, litres, million standard cubic metres, tonnes or bone dry tonnes) using Equation 6-15. For facilities that are covered by Section 8 (Petroleum Refining), an operator may calculate fuel consumption for gasoline, propane and diesel using Equation 6-15 without correcting for the difference in inventory at the beginning and end of the year or using Equation 6-15a.

Equation 6-15:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored (or reading) at Beginning of Year – Amount Stored (or reading) at Year End

Equation 6-15a:

$$Fuel = \sum_{j=1}^{n} \frac{P_{rated\ j}}{\eta_j} \times \frac{LD_j}{HHV_j} \times OH_j \times 0.0036$$

Where:

Fuel = Annual theoretical volume of liquid fuel combusted by fired equipment *j* (m^3/year).

Prated j = Maximum rated power for fired equipment *j* (kW).

ηj = Thermal efficiency for fired equipment *j*.

LDj = Average Load for fired equipment *j* (load fraction).

HHVj = High heat value of the liquid fuel combusted by fired equipment *j* (GJ/m^3).

OHj = Annual operating hours for fired equipment *j* (hours/year).

n = Number of fired equipment units.

0.0036 = Conversion factor from kWh to GJ.

(b) 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 5-1.

(c) All fuel oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using calibration procedures specified by the flow meter manufacturer.

(d) Fuel flow meters shall be recalibrated once every three years, upon replacement of a previously calibrated meter or at the minimum frequency specified by the manufacturer. For orifice, nozzle, and venturi flow meters, the calibration shall consist of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. For flow meters used for natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas. For clarity, this provision also applies to flow meters used in upstream oil and gas, and natural gas transmission and distribution applications.

(e) For fuel oil, tank drop measurements may also be used.

(f) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) “Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.”

(g) Facilities using Calculation Methods 1 or 2 for CO_2 emissions may use the Table 5-8 default density values for fuel oil, in lieu of using the ASTM method in paragraph (f) of this section. These default densities may not be used for facilities using Calculation Method 3.

6.5.3 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, using an applicable analytical method listed by regulation. For fuel heat content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.

(a) For gases, use the most appropriate method published by a consensus-based standards organization, if such a method exists. Specific test procedures that may be required to be used include ASTM D1826 "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter", ASTM D3588 "Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels", or ASTM D4891-, GPA Standard 2261 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used. 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, convert the low heat value to high heat value as follows:

Equation 6-16:

$$HHV = LHV \times CF$$

Where:
HHV = Higher heating value of gaseous fuel or fuel mixture (MJ/sm^3).
LHV = Lower heating value of gaseous fuel or fuel mixture (MJ/sm^3).
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:
    i. By concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
    ii. 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 the most appropriate method published by consensus-based standards organization. Specific test procedures that may be required to use include ASTM D240 "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter" or ASTM D4809 "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
(3) For solid biomass-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM D5865 "Standard Test Method for Gross Calorific Value of Coal and Coke." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
(4) For waste-derived fuels, use the most appropriate method published by a consensus- based standards organization. Specific test procedures that may be required to use include ASTM D5865 and ASTM D5468 "Standard Test Method for

Gross Calorific and Ash Value of Waste Materials." Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in Section 6.3.5, if applicable. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(5) Use Equation 6-17 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO_2 emissions

Equation 6-17:

$$(HHV)_{annual} = \frac{\sum_{p=1}^{n} (HHV)_p * (Fuel)_p}{\sum_{p=1}^{n} (Fuel)_p}$$

Where:
(HHV)annual = Weighted annual average high heat value of the fuel (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
(HHV)p = High heat value of the fuel, for measurement period "*p*" (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
(Fuel)p = Mass or volume of the fuel combusted during measurement period "*p*" (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).
n = Number of measurement periods in the year that fuel is burned in the unit.

6.5.4 Fuel Carbon Content Monitoring Requirements

The determination of fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, using an applicable analytical method listed by regulation. For carbon content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.

1) For coal and coke, solid biomass fuels, and waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM 5373"Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal". If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

2) For liquid fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required include the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on ASTM D3238, and either ASTM D2502 "Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements" or ASTM D2503 "Standard Test Method for Relative Molecular Mass (Molecular Weight) of

Hydrocarbons by Thermoelectric Measurement of Vapor Pressure." If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

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

4) Use Equation 6-18 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO_2 emissions.

Equation 6-18:

$$(CC)_{annual} = \frac{\sum_{p=1}^{n} (CC)_p \times (Fuel)_p}{\sum_{p=1}^{n} (Fuel)_p}$$

Where:

(CC)annual = Weighted annual average carbon content of the fuel (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

(CC)p = Carbon content of the fuel, for measurement period "*p*" (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).

(Fuel)p = Mass or volume of the fuel combusted during measurement period "*p*" (mass in tonnes for solids, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid).

n = Number of measurement periods in the year that fuel is burned in the unit.

6.5.5 Fuel Analytical Data Capture

When the applicable emissions estimation methodologies in Section 6.3 and Section 6.4 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 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 Section 6.3 and Section 6.4, use the methods in Section 6.5.6 paragraph (2)(b) to substitute for the missing values for the period of missing data.

6.5.6 Procedures for Estimating Missing Data

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

1) For all units subject to the requirements of Section 6 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation* (June 2012) (or by other relevant document, if superseded) shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content.

2) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:
   a. For each missing value of the high heat value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions must be calculated, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.
   b. For missing records of CO_2 concentration, stack gas flow rate, moisture percentage, and fuel usage, the substitute data value shall be the best available estimate of that parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

7.0 Fuel Combustion by Mobile Equipment at Facilities (WCI.280)

7.1 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 rail locomotives, tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers, and other industrial equipment, but does not include on-road vehicles, aircraft, or marine vessels.

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 gear (unless the vehicle is a motorcycle), a differential, and safety features required by federal or provincial laws,
but *does not include* vehicles that exhibit features that render use on a highway unsafe, impractical, or highly unlikely, such as tracked road contact or inordinate size.

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

7.2 Greenhouse Gas Reporting Requirements

The annual emissions data report shall contain the following information:
(a) Total emissions of CO_2, CO_2 from biomass, CH_4, and N_2O at the facility level by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (tonnes).
(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.

7.3 Calculation of CO_2 emissions

Calculate the annual CO_2 mass emissions from mobile equipment using the procedures in paragraph (a) or (b). If neither (a) or (b) is appropriate for a source(s), method (c) may be used. Use method (d) as required.

(a) If fossil fuel quantities are measured, calculate total CO_2 emissions using Equation 7-.

Equation 7-1:

$$E_{i,CO_2} = Q_i \times EF_i$$

Where:

E_{i,CO_2} = Quarterly CO_2 emissions from mobile equipment for fuel *i* (metric tonnes);

Q_i = Quarterly quantity of fuel *i* used in mobile equipment (litres);

EF_i = Emission factor for the fuel (metric tonnes CO_2e/litre, required emission factors provided in Section 5).

(b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CO_2 emissions using Equation 7-19 and Equation 7-3.

Equation 7-19:

$$E_{i,k,CO2} = \left(h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}\right) \times EF_{i,CO2}$$

Equation 7-3:

$$E_{Total,i,CO2} = \sum_{k} E_{i,k,CO2}$$

Where:

E_{i,k,CO_2} = Quarterly CO_2 emissions from mobile equipment *k* for fuel *i* (metric tonnes);
$h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);
$hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);
$LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1)
EF_{i,CO_2} = Emission factor for fuel *i* (metric tonnes CO_2e/litre, required emission factors provided in Section 5);
E_{Total,i,CO_2}= Total quarterly CO_2 emissions for fuel *i* (metric tonnes).

(c) If neither methods (a) nor (b) is appropriate for a source(s), determine emissions using the site-specific emission factor method. Conduct analysis of hourly fuel use from mobile sources at the facility during a range of typical operations.
- (1) A range of typical operating conditions for the mobile source(s) at the facility must be documented and analyzed (e.g., including the type of mobile equipment in operation).
- (2) The average hourly fuel use rate for each of the typical operations must be calculated.
- (3) The number of hours of each type of operation at the facility in the year must be determined.
- (4) The annual total mobile emissions must be calculated by multiplying the hours of operation with the average fuel use rate and the fuel-specific emission factor for each of the typical operations.

(d) CO_2 Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass CO_2 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, CO_2 from the biomass component of biofuels shall be reported separately from CO_2 from fossil fuels.

7.4 Calculation of CH_4 and N_2O emissions

Calculate the annual CH_4 and N_2O mass emissions from mobile equipment using the procedures in paragraph (a) or (b), as appropriate. If neither (a) or (b) is appropriate, method (c) may be used. 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.

(a) If fossil fuel quantities are measured, calculate total CH_4 and N_2O emissions using Equation 7-4 and the emission factors provided in Section 5.

Equation 7-4:

$$E_{i,g} = Q_i \times EF_{i,g} \times \left(\frac{1}{10^6}\right)$$

Where:

$E_{i,g}$ = Quarterly emissions of greenhouse gas *g* (CH_4 or N_2O) from mobile equipment for fuel *i* (metric tonnes)

Q_i = Quarterly quantity of fuel *i* (litres)

$EF_{i,g}$ = Greenhouse gas *g* (CH_4 or N_2O) mobile equipment emission factor for fuel *i* (grams/litre) (required emission factors provided in Table 5.2)

$(1/10^6)$ = Conversion factor from grams to metric tonnes.

(b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CH_4 or N_2O emissions using Equations 7-5 and 7-6.

Equation 7-5:

$$E_{i,k,g} = \left(h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}\right) \times EF_{i,g} \times \left(\frac{1}{10^6}\right)$$

Equation 7-6:

$$E_{Total,i,g} = \sum_{k} E_{i,k,g}$$

Where:

$E_{i,k,g}$ = Quarterly greenhouse gas *g* (CH_4 or N_2O) emissions from mobile equipment *k* for fuel *i* (metric tonnes)

$h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);

$hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);

$LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1)

$BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment *k* for fuel *i* (litres/horsepower-hour)

$EF_{i,g}$ = Emission factor for greenhouse gas *g* (CH_4 or N_2O) for fuel *i* (grams/litre, required emission factors provided in Table 5.2)

$(1/10^6)$ = Conversion factor from grams to metric tonnes

$E_{Total,i,g}$ = Total quarterly emissions greenhouse gas *g* (CH_4 or N_2O) for fuel *i* (metric tonnes).

(c) If neither methods (a) or (b) is appropriate, determine emissions using the site-specific emission factor method. Conduct analysis of hourly fuel use from mobile sources at the facility during a range of typical operations.

(1) A range of typical operating conditions for the mobile source(s) at the facility must be documented and analyzed (e.g., include the type of mobile equipment in operation).
(2) The average hourly fuel use rate for each of the typical operations must be calculated.
(3) The number of hours of each type of operation at the facility in the year must be determined.
(4) The annual total mobile emissions must be calculated by multiplying the hours of operation with the average fuel use rate and the fuel-specific emission factor for each of the typical operations.

7.5 Sampling, analysis, measurement and monitoring 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 Section 5.
(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.

8.0 Petroleum Refining (WCI.200), Hydrogen Production (WCI.130) and Refinery Fuel Gas Combustion (WCI.030)

This section of the Guidance Document applies to the single petroleum refinery facility in Newfoundland and Labrador, that is, North Atlantic Refining LP. Guidance is provided in a general way in order to be consistent with WCI guidance provided in Quebec, Ontario and British Columbia. As a result there may be some sources for which guidance is provided, but which may not currently exist at the North Atlantic Refining LP refinery.

8.1 Source category definition

8.1.1 Petroleum Refining (WCI.200)

A petroleum refinery consists of all processes at a facility that may be used to produce gasoline, diesel, kerosene, jet fuel, distillate fuel oils, residual fuel oils, lubricants, asphalt, aromatics, refinery fuel gases, or other products through distillation of petroleum or through redistillation, cracking, reforming of unfinished petroleum derivatives or other processes.

8.1.2 Hydrogen Production (WCI.130)

Hydrogen (H_2) is used at petroleum refineries to remove sulphur contained in the crude oil and for other purposes. Typically, hydrogen is mostly produced from methane, although other gaseous hydrocarbons (such as ethane and propane) as well as hydrocarbon liquids can be used. Hydrogen is generated by the catalytic steam methane reforming process where light hydrocarbons are reacted with steam over a catalyst to produce H_2 and CO_2. The primary reforming reaction produces carbon monoxide (CO) and H_2. The shift reaction uses water (H_2O) to convert the CO to CO_2. The key reaction equations for production are shown below.

Steam Methane Reforming Reaction:	$CH_4 + H_2O \rightarrow CO + 3H_2$
Shift Reaction:	$CO + H_2O \rightarrow CO_2 + H_2$

Fuels (e.g., refinery gases) are combusted in reformer furnaces to generate the required heat for the reactions.

This section provides guidance for calculating the process CO_2 emissions that are generated from the hydrogen forming reactions. Guidance for calculating and reporting emissions from the fuel combustion used in hydrogen production is in section 6.0.

8.2 Greenhouse Gas Reporting Requirements

In addition to the reporting requirements specified in sections 6.0 and 7.0, the following are required.

8.2.1 Petroleum Refining (WCI.200)

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

Emissions, Feedstock and Fuel Consumption

(a) Total annual greenhouse gas emissions, as CO_2e.
(b) Total annual CO_2, CH_4, and N_2O emissions.

(c) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the calendar year (including petroleum coke) in units of cubic metres for gases, kilolitres for liquids tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
(d) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of standard cubic metres for gases, kilolitres for liquids, metric tonnes for non-biomass solids, and bone dry metric tonnes for biomass-derived solid fuels.

Process Emissions
(a) Catalyst Regeneration (CO_2, CH_4, and N_2O)
(b) Process Vents (CO_2, CH_4, and N_2O)
(c) Asphalt Production (CO_2 and CH_4)
(d) Sulphur Recovery (CO_2)
(e) Flares and Other Control Devices (CO_2, CH_4, and N_2O)
(f) Above-Ground Storage Tanks (CH_4)
(g) Wastewater Treatment (CH_4 and N_2O from anaerobic treatment)
(h) Oil-water Separators (CH_4)
(i) Equipment Leaks (CH_4)
(j) Coke calcining units (CO_2, CH_4, and N_2O)
(k) Uncontrolled blowdown systems (CH_4)
(l) Loading Operations (CH_4)
(m) Delayed Coking Units (CH_4)

8.2.2 Hydrogen Production (WCI.130)

In addition to the reporting requirements specified in section 6.0 and section 7.0 the following reporting requirements are required.

A person shall set out the following information, calculated for the calendar year using standard quantification methods as outlined in this section, in an emission report prepared for a calendar year in respect of hydrogen production at a facility:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen production process (tonnes).
(b) Feedstock Consumption (if estimating emissions using mass balance approach in this section). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic metres for gases, cubic metres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
(c) Production. Annual hydrogen produced (tonnes).

8.2.3 Refinery Fuel Gas Use (WCI.030)

The use of Refinery Fuel Gas in a petroleum refinery requires the reporting of the following information:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in tonnes.
(b) Annual fuel consumption in units of standard cubic metres.
(c) Average carbon content of each fuel used to compute CO_2 emissions

8.3 Calculation of GHG emissions

8.3.1 Petroleum Refining (WCI.200)

Emissions from stationary fuel combustion units shall be calculated and reported as outlined in section 6.0 General Stationary Fuel Combustion, and emissions from mobile equipment shall be calculated and reported as outlined in section 7.0.

Calculate GHG emissions using the methods in this section for the following sources: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; and sulphur recovery plants.

If a continuous emissions monitor is used to measure CO_2 emissions from process vents, asphalt production, sulphur recovery, or other control devices then calculate CO_2 emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in Calculation Methodology 4 of section 6.0 General Stationary Fuel Combustion. When the flue gas from two or more processes or stationary combustion sources are discharged through a common stack or duct before exiting to the atmosphere and if CEMS is used to continuously monitor the CO_2 emissions, the facility may report the combined emissions from the processes or stationary combustion sources sharing the common stack or duct instead of separately reporting the GHG emissions from individual processes or stationary combustion sources.

8.3.1.1 Catalyst Regeneration

(1) For units equipped with CEMS, calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with Calculation Methodology 4 of section 6.0. In the absence of CEMS data, use the methods in paragraphs (1)(A) through (1)(C).

(A) (i) Calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equation 8-1, Equation 8-1b, Equation 8-2 and Equation 8-3 in section (1)(A)(ii) below.

Equation 8-1:

$$CO_2 = \sum_{i=1}^{n} CR_i \times CF \times 3.664 \times 0.001$$

Where:
CO_2 = CO_2 emissions (tonnes/yr)
n = number of hours of operation in the report year
CRi = hourly coke burn rate in kg/hr
CF = carbon fraction in coke burned
3.664 = ratio of molecular weights, carbon dioxide to carbon
0.001 = conversion factor from kg to tonnes

A (ii) Alternatively, calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equation 8-1b and Equation 8-2.

Equation 8-1b:

$$CO_2 = \sum_{p=1}^{n} \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right]$$

Where:
CO_2 = CO_2 emissions (tonnes/yr)
Q_r = volumetric flow rate of exhaust gas before entering the emission control system using equation 200-2 and at reference temperature and pressure conditions as used by the facility (dRm^3/hr)
$\%CO_2$ = average hourly CO_2 concentration in regenerator exhaust, per cent by volume – dry basis
%CO = average hourly CO concentration in regenerator exhaust, per cent by volume – dry basis. When there is no post combustion device, assume %CO to be zero.
44 = molecular weight of CO_2 (kg/kg-mole)
MVC = molar volume conversion factor at the same reference conditions as the above Q_r (Rm^3/kg-mole)
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
0.001 = conversion factor from kg to tonnes
n = number of hours of operation in the report year

A (iii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation 8-2.

Equation 8-2:

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2}$$

Where:
Qr = volumetric flow rate of exhaust gas from regenerator before entering the emission control system at reference temperature and pressure conditions as used by the facility (dRm3/min)
Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation at reference temperature and pressure conditions used for Qr (dRm3/min)
$\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, per cent 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 at reference temperature and pressure conditions used for Qr (dRm3/min)

$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, per cent by volume – dry basis

$\%CO$ = CO concentration in regenerator exhaust, per cent 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, per cent by volume – dry basis

A (iv) Calculate the hourly coke burn rate using Equation 8-3 or from facility measurement or engineering estimate.

Equation 8-3:

$$CR_i = K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times \left[\%CO/2 + \%CO_2 + \%O_2\right] + K_3 Q_{oxy} \times (\%O_{oxy})$$

Where:

CR_i = hourly coke burn rate in kg/hr

K_1, K_2, K_3 = material balance and conversion factors (K1, K2, and K3 from Table 8.3.1.1: Coke Burn Rate Material Balance and Conversion Factors, or from facility measurement or engineering estimate

Q_r = volumetric flow rate of exhaust gas before entering the emission control system from Equation 8-2 (dRm3/min)

Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in Qr (dRm3/min)

$\%CO_2$ = CO_2 concentration in regenerator exhaust, per cent by volume – dry basis

$\%CO$ = CO concentration in regenerator exhaust, per cent by volume – dry basis

$\%O_2$ = O_2 concentration in regenerator exhaust, per cent by volume – dry basis

Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in Qr (dRm3/min)

$\%O_{xy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, per cent by volume – dry basis

Table 8.3.1.1: Coke Burn Rate Material Balance and Conversion Factors

		(kg min)/(hr dRm^3%)	**(lb min)/(hr dscf %)**
K_1	Carbon burn term	0.2982	0.0186
K_2	Hydrogen burn term from O_2 in Air	2.0880	0.1303
K_3	Hydrogen burn equivalent in excess O_2 and carbon oxides	0.0994	0.0062

(B) Calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g., catalytic reforming) using Equation 8-4.

Equation 8-4:

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664$$

Where:
CO_2 = CO_2 emissions (tonnes/yr)
CCirc = average catalyst regeneration rate (tonnes/hr)
CFspent = 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, CO_2 to carbon

(C) Calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 8-5.

Equation 8-5:

$$CO_2 = \sum_{1}^{n} \left[\left(CB_Q \right)_n \times CC \times 3.664 \times 0.001 \right]$$

Where:
CO_2 = Annual CO_2 emissions (tonnes/year).
CBQ = Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n = Number of regeneration cycles in the calendar year.
CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
3.664 = ratio of molecular weights, carbon dioxide to carbon
0.001 = Conversion factor (tonne/kg).

(2) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 8-6.

Equation 8-6:

$$\mathrm{CH_4} = \left(\mathrm{CO_2} * \frac{\mathrm{EmF_2}}{\mathrm{EmF_1}} \right)$$

Where:
CH_4 = Annual methane emissions from coke burn-off (tonnes CH_4/year).
CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraph (1) of this section, as applicable (tonnes/year).
EmF_1 = Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ
EmF_2 = Default CH_4 emission factor of 2.8×10^{-3} kg CH_4/GJ.
CH_4 = Annual methane emissions from coke burn-off (tonnes CH_4/year).
CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraph (1) of this section,

as applicable (tonnes/year).
EmF_1 = Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ

(3) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 8-7.

Equation 8-7:

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right)$$

Where:
N_2O = Annual nitrous oxide emissions from coke burn-off (tonne N_2O/year).
CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraph (1) of this section, as applicable (tonnes/year).
EmF_1 = Default CO_2 emission factor for petroleum coke of 97 kg CO_2/GJ
EmF_3 = Default N_2O emission factor of 5.7 x10-4 kg N_2O/GJ

8.3.1.2 Process Vents

Except for process emissions reported under other requirements, calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 8-8 for each process vent that can be reasonably expected to contain greater than 2 per cent by volume CO_2 or greater than 0.5 per cent by volume of CH_4 or greater than 0.01 per cent by volume (100 parts per million) of N_2O.

Equation 8-8:

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:
E_x = Annual emissions of x (tonnes/yr), where x = CO_2, N_2O, or CH_4
VR_i = Average volumetric flow rate for venting event i from measurement data, process knowledge or engineering estimates at reference temperature and pressure conditions as used by the facility (Rm^3/unit time). If a mass flow meter is used, measure the flow rate in kg/unit time and replace the term “MW_x/MVC” with “1”.
Fxi = Molar fraction of x in vent gas stream during event i from measurement data, process knowledge or engineering estimates.
MW_x = molecular weight of x (kg/kg-mole)
MVC = molar volume conversion factor at the same reference conditions as the above VR_i (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
VT_i = time duration of venting event i, in same units of time as VR_i
n = number of venting events in report year
0.001 = conversion factor from kg to tonnes

8.3.1.3 Asphalt Production

Calculate CO_2 and CH_4 process emissions from asphalt blowing activities using either process vent method specified in 8.3.1.2 or according to the applicable provisions in paragraphs (1) and (2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2 and CH_4 emissions using Equation 8-9 and Equation 8-10, respectively.

Equation 8-9:

$$CO_2 = \left(Q_{AB} \times EF_{AB.CO2}\right)$$

Where:

CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (tonnes CO_2/year)

Q_{AB} Quantity of asphalt blown (million barrels per year, MMbbl/year).

EFAB,CO_2 = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (tonnes CO_2/MMbbl asphalt blown); default = 1,100.

Equation 8-10:

$$CH_4 = \left(Q_{AB} \times EF_{AB,CH4}\right)$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (tonnes CH_4/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,}CH_4$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equation 8-11 and

(3) Equation 8-12, respectively, provided these emissions are not already included in the flare emissions calculated in 8.3.1.5 or in the stationary combustion unit emissions required under Section 6.0.

Equation 8-11:

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times 3.664\right)$$

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (tonnes CO_2/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

CEF_{AB} = Carbon emission factor from asphalt blowing from facility specific test data (tonnes C/MMbbl asphalt blown); default = 2,750.

3.664 = ratio of molecular weights, carbon dioxide to carbon

Equation 8-12:

$$CH_4 = 0.02 \times \left(Q_{AB} \times EF_{AB,CH4}\right)$$

Where:

CH_4 = Annual methane emissions from controlled asphalt blowing (tonnes CH_4/year).

0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

$EF_{AB,}CH_4$ = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4/MMbbl asphalt blown); default = 580.

8.3.1.4 Sulphur Recovery

Calculate CO_2 process emissions from sulphur recovery units (SRUs) using Equation 8-13. For the molar fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20, engineering estimates or a source specific molar fraction value derived from source tests conducted at least once per calendar year. The source test shall be repeated in each future year to update the source specific emission factors annually.

Equation 8-13:

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001$$

Where:

CO_2 = emissions of CO_2 (tonnes/yr)

FR = volumetric flow rate of acid gas to SRU at reference temperature and pressure conditions as used by the facility (Rm3/year). If a mass flow meter is used, measure the acid gas flow in kg per year and replace the term "$MWCO_2$/MVC" with "1"

$MWCO_2$ = molecular weight of CO_2 (44 kg/kg-mole)

MVC = molar volume conversion factor at the same reference conditions as the above FR (Rm3/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

MF = molar fraction (%) of CO_2 in sour gas based on measurement or engineering estimate (default MF = 20% expressed as 0.20)

0.001 = conversion factor from kg to tonnes

8.3.1.5 Flares and Other Control Devices

(1) Calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot gas using the appropriate method(s) specified in section 6.0.

(2) Calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(i) Heat value or carbon content measurement. If the person has a continuous high heat value monitor or gas composition monitor on the flare or if the person monitors these parameters at least weekly, use the measured heat value or carbon content value in calculating the CO_2 emissions from the flare using the applicable methods in paragraphs (2)(i)(A) and (2)(i)(B).

(A) If the person monitors gas composition, calculate the CO_2 emissions from the flare using Equation 8-14. If daily or more frequent measurement data is available, use daily values when using Equation 8-14; otherwise, use weekly values.

Equation 8-14

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (tonnes/year).
0.98 = Assumed combustion efficiency of a flare.
0.001 = Conversion factor from kg to tonnes.
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
3.664 = Ratio of molecular weights, carbon dioxide to carbon
$(Flare)_p$ = Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm^3/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term “$(MW)_p$/MVC” with “1”.
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor at the same reference conditions as the above $(Flare)_p$ (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

(B) If the person monitors heat content but does not monitor gas composition, calculate the CO_2 emissions from the flare using Equation 8-15. If daily or more frequent measurement data is available, use daily values when using Equation 8-15; otherwise, use weekly values.

Equation 8-15

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[(Flare)_p \times (HHV)_p \times EmF \right]$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (tonnes/year).

0.98 = Assumed combustion efficiency of a flare.

0.001 = Conversion factor from kg to tonnes.

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

$(Flare)_p$ = Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm^3/period). If a mass flow meter is used, the person shall also measure molecular weight and convert the mass flow to a volumetric flow as follows: $Flare[m^3] = Flare [kg] \times MVC/(MW)_p$, where MVC is the molar volume conversion factor at the same reference conditions as $(Flare)_p$ (Rm^3/kg-mole) and $(MW)_p$ is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).

= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal])

$(HHV)_p$ = High heat value for the flare gas combusted during measurement period (GJ per Rm^3). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

EmF = Default CO_2 emission factor of 57 kilograms CO_2/GJ (HHV basis).

(ii) Alternative Method. For startup, shutdown, and malfunctions during which the facility is unable to measure the parameters required by Equation 8-14 and Equation 8-15, determine the quantity of gas discharged to the flare separately for each start-up, shutdown, or malfunction, and calculate the CO_2 emissions as specified in paragraphs (2)(ii)(A).

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process activity knowledge and data to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.

(iii) Calculate the CO_2 emissions using Equation 8-16.

Equation 8-16

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[3.664 \times \left(Flare_{SSM} \right)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right)$$

Where:
CO_2 = Annual CO_2 emissions for a specific fuel type (tonnes/year).
0.98 = Assumed combustion efficiency of a flare.
0.001 = Conversion factor from kg to tonnes.
n = Number of start-up, shutdown, and malfunction events during the calendar year.
p = Start-up, shutdown, malfunction and other measurement period index.
$_{SSM})_p$ = Volume of flare gas combusted during indexed startup, shutdown, or malfunction event from engineering calculations, at reference temperature and pressure conditions as used by the facility (Rm^3/event). If a mass flow meter is used, measure the flare gas combusted in kg per event and replace the term "$(MW)_p$/MVC" with "1".
$(MW)_p$ = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kgmole).
MVC = Molar volume conversion factor at the same reference conditions as the above $(Flare_{SSM})_p$ (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
$(CC)_p$ = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).
3.664 = Ratio of molecular weights, carbon dioxide to carbon

(3) Calculate and report CH_4 and N_2O emissions resulting from the combustion of hydrocarbons routed to flares for destruction using the methods specified in paragraphs (3)(A) and (3)(B):

(A) Calculate CH_4 using Equation 8-17.

Equation 8-17

$$\mathrm{CH_4} = \left(\mathrm{CO_2} \times \frac{\mathrm{EmF_{CH4}}}{\mathrm{EmF}} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4}$$

Where:
CH_4 = Annual methane emissions from flared gas (tonnes CH_4/year).
CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (1) and (2) ofd this section (tonnes/year)
EmF_{CH4} = Default CH_4 emission factor for Petroleum Products of 2.8 x 10^{-3} kg/GJ
EmF = Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis)
0.02/0.98 = correction factor for flare combustion efficiency.
16/44 = correction factor ratio of the molecular weight of CH_4 to CO_2
f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4

(B) Calculate N_2O emissions using Equation 8-18.

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Equation 8-18:

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF} \right)$$

Where:

N_2O = Annual nitrous oxide emissions from flared gas (tonnes N_2O/year)

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (1) and (2) of this section (tonnes/year)

$EmFN_{2O}$ = Default N_2O emission factor for petroleum products of 5.7×10^{-4} kg/GJ

EmF = Default CO_2 emission factor for flare gas of 57 kilograms CO_2/GJ (HHV basis)

(4) If a person uses methods other than flares (e.g., incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low HHV (or low Btu) gases (e.g., coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 8-19. Determine CC_A and MW_A quarterly using methods specified in section 6.0 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

Equation 8-19:

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$

Where:

CO_2 = CO_2 emissions (tonnes/year)

GV_A = volume of gas A destroyed annually at reference temperature and pressure conditions as used by the facility (Rm^3/year). If a mass flow meter is used, measure the gas destroyed in kg and replace the term “MW_A/MVC” with “1”

CC_A = carbon content of gas A (kg C/kg fuel)

MW_A = molecular weight of gas A

MVC = molar volume conversion factor at the same reference conditions as the above GV_A (Rm^3/kg-mole)
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]

3.664 = ratio of molecular weights, carbon dioxide to carbon

0.001 = conversion factor from kg to tonnes

8.3.1.6 Storage Tanks

For storage tanks other than those processing unstabilized crude oil except as provided in paragraph (3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (1) and (2) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume per cent or more using tank-specific methane composition data (from measurement data or product knowledge) and the U.S. EPA AP-42 emission estimation methods provided in Section 7.1 of the U.S. EPA AP-42: “Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources”, including U.S. EPA TANKS Model (Version 4.09D) or similar programs, or estimate CH_4 emissions from storage tanks using Equation 8-20.

Equation 8-20

$$CH_4 = \left(0.1 \times Q_{Ref}\right)$$

Where:

CH_4 = Annual methane emissions from storage tanks (tonnes/year).

0.1 = Default emission factor for storage tanks (tonne CH_4/MMbbl).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation 8-21.

Equation 8-21

$$CH_4 = (995{,}000 \times Q_{un} \times \Delta P) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001$$

Where:

CH_4 = Annual methane emissions from storage tanks (tonnes/year).

Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).

$MFCH_4$ = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kgmole gas); use 0.27 as a default if measurement data is not available.

995,000 = Correlation Equation factor (cubic feet gas per MMbbl per psi)

16 = Molecular weight of CH_4 (kg/kg-mole)

MVC = Molar volume conversion (849.5 cubic feet/kg-mole).

0.001 = Conversion factor (tonne/kg).

(3) The person does not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:
  (i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
  (ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
  (iii) Bottoms receivers or sumps;
  (iv) Vessels storing wastewater; or
  (v) Reactor vessels associated with a manufacturing process unit.

8.3.1.7 Industrial Wastewater Processing

(1) Calculate CH_4 emissions from anaerobic wastewater treatment (such as anaerobic reactor, digester, or lagoon) using Equation 8-22 or Equation 8-23.

Equation 8-22

$$CH_4 = Q \times COD_{qave} \times B \times MCF \times 0.001$$

Equation 8-23

$$CH_4 = Q \times BOD_{5qave} \times B \times MCF \times 0.001$$

Where:

CH_4 = emission of methane (tonnes/yr)

Q = volume of wastewater treated (m^3/yr)

COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)

BOD_{5qave} = average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m^3)

B = methane generation capacity (B = 0.25 kg CH_4/kg COD and 0.06 kg CH_4/kg BOD_5)

MCF = methane correction factor for anaerobic decay (0-1.0) from ***Table*** 8.3.1.7: Default MCF Values for Industrial Wastewater

0.001 = conversion factor from kg to tonnes

Table 8.3.1.7: Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Sea, river and lake discharge	Untreated, rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Aerobic treatment plant	Treated, well maintained, some CH_4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Treated, not well maintained, overloaded	0.3	0.2 – 0.4

Anaerobic digester for sludge	Treated, CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	Treated, CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Treated, depth less than 2 metres	0.2	0 – 0.3
Anaerobic deep lagoon	Treated, depth more than 2 metres	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_2O from discharged wastewater (EFN_{2O}) is 0.005 kg N_2O-N/kg-N. MCF = methane conversion factor (the fraction of waste treated anaerobically). COD = chemical oxygen demand (kg COD/m^3).

(2) For anaerobic processes from which biogas is recovered and not emitted, adjust the CH_4 emissions calculated in paragraph (1) by the amount of CH_4 collected.

(3) Calculate N_2O emissions from wastewater treatment using Equation 8-24.

Equation 8-24

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$

Where:
N_2O = emissions of N_2O (tonnes/yr)
Q = volume of wastewater treated (m^3/yr)
Nqave = average of quarterly determinations of N in effluent (kg N/m^3)
EFN_{2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor from kg to tonnes

8.3.1.8 Oil-Water Separators

Calculate CH_4 emissions from oil-water separators using Equation 8-25. For the CFN_{MHC} conversion factor, use either a default factor of 0.6 or species specific conversion factors determined by sampling and analysis.

Equation 8-25

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$

Where:
CH_4 = emission of methane (tonnes/yr)
EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 8.3.1.8: Emission Factors for Oil-Water Separators
V_{water} = volume of waste water treated by the separator (m^3/yr)
CFN_{MHC} = NMHC to CH_4 conversion factor
0.001 = conversion factor from kg to tonnes

Table 8.3.1.8: 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] of 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

8.3.1.9 Equipment leaks

Calculate CH_4 emissions using the method specified in either paragraph (1) or (2).

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the U.S. EPA *Protocol for Equipment Leak Emissions Estimates* (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation 8-26 of this section.

Equation 8-26

$$CH_4 = \left(0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}\right)$$

Where:
CH_4 = Annual methane emissions from equipment leaks (tonnes/year)
N_{CD} = Number of atmospheric crude oil distillation columns at the facility.
NPU1 = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
NPU2 = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
N_{H2} = Total number of hydrogen plants at the facility.
NFGS = Total number of fuel gas systems at the facility.

8.3.1.10 Coke Calcining

Calculate GHG emissions according to the applicable provisions in paragraphs (1) through (3).

(1) If the person operates and maintains a CEMS that measures CO_2 emissions according to section 6.0, calculate and report CO_2 emissions for coke calcining by following the

CEMS Calculation Methodology 4 specified in section 6.0. If the coke calcining unit is not equipped with CEMS, either install a CEMS that complies with the CEMS requirements in section6.0, or follow the requirements of paragraph (2) of this section.

(2) Calculate the CO_2 emissions from the coke calcining unit using Equation 8-27 of this section.

Equation 8-27:

$$CO_2 = 3.664 \times \left(M_{in} \times CC_{GC} - (M_{out} + M_{dust}) \times CC_{MPC}\right)$$

Where:

CO_2 = Annual CO_2 emissions (tonnes/year).

M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (tonnes/year).

CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (tonne carbon/tonne green coke).

M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (tonnes petroleum coke/year).

Mdust = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (tonne petroleum coke dust/year)

CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (tonne carbon/tonne petroleum coke).

3.664 = ratio of molecular weights, carbon dioxide to carbon

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (1) or (2), as applicable, and calculate CH_4 and N_2O using the following methods:

(A) Calculate CH_4 emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or

(B) Equation 8-28.

Equation 8-28:

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1}\right)$$

Where:

CH_4 = Annual methane emissions (tonnes CH_4/year).

CO_2 = Emission rate of CO_2 calculated in paragraphs (1) and (2) of this section, as applicable (tonnes/year).

EmF_1 = Default CO_2 emission factor for petroleum coke (97.12 kg CO_2/GJ).

EmF_2 = Default CH_4 emission factor of 2.8×10^{-3} kg CH_4/GJ.

(C) Calculate N_2O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 8-29 of this section.

Equation 8-29:

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right)$$

Where:
N_2O = Annual nitrous oxide emissions (tonnes N_2O/year).
CO_2 = Emission rate of CO_2 from paragraphs (1) and (2) of this section, as applicable (tonnes/year).
EmF_1 = Default CO_2 emission factor for petroleum coke (97 kg CO_2/GJ)
EmF_3 = Default N_2O emission factor of 5.7×10^{-4} kg N_2O/GJ).

8.3.1.11 Uncontrolled Blowdown Systems

For uncontrolled blowdown systems, use the methods for process vents in 8.3.1.2.

8.3.1.12 Loading Operations

For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume per cent or more, calculate CH_4 emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the U.S. EPA AP-42: “Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.” For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume per cent, assume zero methane emissions.

8.3.1.13 Delayed coking units

Calculate the CH_4 emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (1) or (2), provided no water or steam is added to the vessel once it is vented to the atmosphere. Use the method in paragraph (1) of this section if the person adds water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in section 8.3.1.2 and also calculate the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations using Equation 8-30. If the person has coke drums or vessels of different dimensions, use Equation 8-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

Equation 8-30

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 101.325)}{101.325} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001 \right)$$

Where:
CH_4 = Annual methane emissions from the delayed coking unit vessel opening (tonnes/year).
N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H = Height of coking unit vessel (metres).
P_{CV} = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (l)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (kilopascals)
101.325 = Assumed atmospheric pressure (kilopascals, kPa)
f_{void} = Volumetric void fraction of coking vessel prior to steaming
D = Diameter of coking unit vessel (metres).
16 = Molecular weight of CH_4 (kg/kg-mole).
MVC = Molar volume conversion factor at the same reference conditions as the cooking vessel (Rm^3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
$MFCH_4$ = Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis)
0.001 = Conversion factor from kg to tonne

(2) Calculate the CH_4 emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation 8-30 and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If the person has coke drums or vessels of different dimensions, use Equation 8-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH_4 emissions for all delayed coking units.

8.3.2 Hydrogen Production (WCI.130)

Calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The person may calculate CO_2 process emissions using CEMS. The person shall comply with the requirements in section 6.0.

(b) Feedstock Material Balance. The person may calculate CO_2 process emissions using the following method.

(1) <u>Gaseous fuel and feedstock.</u> Calculate the annual CO_2 process emissions from gaseous fuel and feedstock according to Equation 8-31.

Equation 8-31

$$CO_2 = (\sum_{n=1}^{k} 3.664 * Fdstk_n * CC_n * \frac{MW}{MVC}) * 0.001$$

Where:
CO_2 = Annual CO_2 process emissions arising from fuel and feedstock consumption (tonnes/yr).
$Fdstk_n$ = Volume of the gaseous fuel and feedstock used in month n at reference temperature and pressure conditions (Rm^3). If a mass flow meter is used, measure the gaseous product
CC_n = Weighted average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (Rm^3 at reference temperature and pressure conditions as used by the facility). If a mass flow meter is used, measure the feedstock used in month n in kg and replace the term “MW/MVC” with “1”.
MW = Molecular weight of the gaseous fuel and feedstock (kg/kgmole).
MVC = Molar volume conversion factor at the same reference conditions as the above $Fdstk_n$ (Rm^3/kg-mole). MVC can be
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].
k = Months in the year.
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to tonnes.

(2) Liquid fuel and feedstock. Calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation 8-32.

Equation 8-32

$$CO_2 = (\sum_{n=1}^{k} 3.664 * Fdstk_n * CC_n) * 0.001$$

Where
CO_2 = Annual CO_2 emissions arising from fuel and feedstock consumption (tonnes/yr).
$Fdstk_n$ = Volume of the liquid fuel and feedstock used in month n (m^3 of fuel and feedstock). If a mass flow meter is used, measure the fuel and feedstock used in month n in kg and measure the carbon content of feedstock in kg C per kg of feedstock.
CC_n = Weighted average carbon content of the liquid fuel and feedstock, from the results of daily analyses for month n (kg of C per m^3 of fuel and feedstock when the usage is measured in $m^{3,}$ or kg of C per kg of feedstock and fuel when the usage is measured in kg).
k = Months in the year.
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to tonnes.

(3) Solid fuel and feedstock. The person shall calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation 8-33.

Equation 8-33:

$$CO_2 = \sum_{n=1}^{k} 3.664 * (Fdstk_n * CC_n) * 0.001$$

Where:	
CO_2	= Annual CO_2 emissions from fuel and feedstock consumption in tonnes per year (tonnes/yr).
$Fdstk_n$	= Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).
CC_n	= Weighted average carbon content of the solid fuel and feedstock, from the results of daily analyses for month n (kg carbon per kg of fuel and feedstock).
k	= Months in the year.
3.664	= Ratio of molecular weights, CO_2 to carbon.
0.001	= Conversion factor from kg to tonnes.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with section 6.0, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The person shall report the combined stack emissions according to the CEMS methodology in section 6.0.

8.3.3 Refinery Fuel Gas (WCI.030)

8.3.3.1 Calculation of CO_2 Emissions

Calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (1) through (4). This requirement supersedes the requirement to calculate CO_2 emissions using methods outlined in Section 6.0 (for the gaseous fuel listed in Table 5-2 as “Still Gas - Refineries”) with a higher frequency of carbon content analysis. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in Calculation Methodology 4 of Section 6.0.

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 8-34.

Equation 8-34:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$

Where:
CO_2 = Annual CO_2 mass emissions for the specific fuel type (tonnes).
$Fuel_i$ = Daily refinery fuel or flexigas combusted (Rm3) at reference temperature and

pressure conditions as used by the facility. If a mass flow meter is used, measure the daily fuel combusted in kg and replace the term “MW/MVC” with “1”.
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel (kg/kg-mole).
MVC = Molar volume conversion factor at the same reference conditions as the above Fueli (Rm3/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal].
3.664 = Ratio of molecular weights, carbon dioxide to carbon.
0.001 = Conversion factor from kilograms to tonnes.
n = Number of days in a year.

(3) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary combustion in Calculation Methodologies 3 or 4 of Section 6.0, as appropriate for each fuel.

(4) Where individual fuels are mixed prior to combustion, the person may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (1) or (2) of this section. In this case, determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream shall be estimated using the following methods:
- (i) For natural gas and associated gas, use the appropriate methodology specified in Calculation Methodologies 2 or 3 of Section 6.0.
- (ii) For refinery fuel gas, flexigas, and low heat content gas, use the methodology in paragraph (2) of this section.

8.3.3.2 Calculation of CH_4 and N_2O Emissions

Use the methods specified in Section 6.0 to calculate the annual CH_4 and N_2O emissions.

8.4 Sampling, Analysis, and Measurement Requirements

8.4.1 Petroleum Refining (WCI.200)

8.4.1.1 Catalyst Regeneration

(1) For FCCUs and fluid coking units, measure the following parameters:
- (i) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
- (ii) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
- (iii) Weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas (or continuous measurements if the equipment necessary to make continuous measurements is already in place).
- (iv) Daily determinations of the carbon content of the coke burned.
- (v) The number of hours of operation.
- (vi) The measured daily or weekly values can be used to derive the minute or hourly parameters as required by the corresponding equations.

(2) For periodic catalyst regeneration, measure the following parameters.
  (i) The mass of catalyst regenerated in each regeneration cycle.
  (ii) 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, measure the following parameters.
  (i) The hourly catalyst regeneration rate.
  (ii) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
  (iii) The number of hours of operation.

8.4.1.2 Process vents

Measure the following parameters for each process vent.
(1) The vent flow rate for each venting event from measurement data, process knowledge or engineering estimates.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event from measurement data, process knowledge or engineering estimates.
(3) The duration of each venting event.

8.4.1.3 Asphalt Production

Measure the mass of asphalt blown.

8.4.1.4 Sulphur Recovery

Measure the volumetric flow rate of acid gas to the SRU. If using source specific molar fraction that is based on measurements instead of the default factor or engineering estimates, conduct an annual test of the molar fraction value.

8.4.1.5 Flares and Other Control Devices

Measure the following:
(1) If the person has a continuous flow monitor on the flare, use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If the person does not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(2) If using the method specified in section 6.0, monitor the carbon content of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

(3) If using the method specified in section 6.0, monitor the high heat value of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).

8.4.1.6 Storage Tanks

Determine the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using company record or applicable plant instruments.

8.4.1.7 Wastewater Treatment

Measure the following parameters:

(1) Collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). Collect and analyze samples for COD or BOD_5 concentration once each calendar week.

(2) Measure the flow rate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location shall correspond to the location used to collect samples analyzed for COD or BOD_5 concentration.

(3) The quarterly nitrogen content of the wastewater.

8.4.1.8 Oil-Water Separators

Measure the daily volume of waste water treated by the oil-water separators.

8.4.1.9 Coke Calcining

Determine the mass of petroleum coke as required using measurement equipment used for accounting purposes including purchase records or direct measurement. Determine the carbon content of petroleum coke as using any one of the following methods.

a. ASTM D3176.
b. ASTM D5291.
c. ASTM D5373.
d. Any of the other analytical methods listed in section 4.0.
e. The most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

8.4.2 Hydrogen Production (WCI.130)

(a) Persons using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in Calculation Methodology 4 of section 6.0.

(b) Persons using the methods in Section 8.3.2 paragraph (b) or (c) shall perform the following monitoring:
  (1) The person shall measure the feedstock consumption rate daily.
  (2) The person shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in paragraph (c) of this section. For all feedstocks, samples shall be collected and analyzed daily and a weighted

average established for each month of the year. Daily samples may be combined to generate a weighted average monthly composite sample for carbon analysis. 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) Persons shall quantify the hydrogen produced daily.

(4) Persons shall quantify any CO_2 and CO collected from the process and transferred offsite quarterly.

(c) The person shall use the following methods, as applicable, to determine the carbon content of the feedstocks:

(1) Any of the applicable analytical methods listed in the section 4.0.

(2) The most appropriate method published by a consensus-based standards organization to determine the carbon content of the feedstocks. If no appropriate method is published by a consensus based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

8.4.2 Refinery Fuel Gas (WCI.030)

(a) Measure the fuel consumption rate daily using methods specified in Section 6.0.

(b) Daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if there is sampling at a frequency of daily or more currently or if there is online instruments in place to monitor carbon content. Otherwise, weekly sampling and analysis of carbon content and molecular weight shall be performed.

(c) Measure the carbon content for fuel gas and flexigas using either ASTM D1945 or ASTM D1946, or any of the other analytical methods listed in the Technical Testing and Analytical Standards listed in Section 4.0, or the most appropriate method published by a consensus-based standards organization. Alternatively, the results of chromatographic analysis of the fuel gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in a plan.

9.0 On-site Electricity Generation (WCI.040)

At this time, this section of the Guidance Document applies to Vale Voisey's Bay mine site only.

9.1 Source Category Definition

This section applies to facilities with combustion devices, including cogeneration (combined heat and power) devices, that combust any solid, liquid, or gaseous fuel for the purpose of producing electricity, excluding the following:

1. The operation of stationary emergency generators with a nameplate generating capacity of less than 10 megawatt (MW); and
2. The operation of portable emergency generators.

The guidance in this section is not intended for owners and operators of dedicated electric power utility facilities with associated transmission systems for public distribution.

9.2 Greenhouse Gas Reporting Requirements

In addition to the reporting requirements specified in section 6.0, the following reporting requirements are required.

A person shall set out the following information, calculated for the calendar year using standard quantification methods outlined in this section, in an emission report prepared for a calendar year in respect of electricity generation at a facility:

(a) Annual greenhouse gas emissions in tonnes, reported as follows:
  (1) Total CO_2 emissions for fossil fuels, reported by fuel type.
  (2) Total CO_2 emissions for all biomass fuels combined.
  (3) Total CH_4 emissions for all fuels combined.
  (4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:
  (1) For gases, report in units of standard cubic metres.
  (2) For liquids, report in units of cubic metres.
  (3) For non-biomass solids, report in units of tonnes.
  (4) For biomass-derived solid fuels, report in units of bone dry tonnes.

(c) Annual weighted average carbon content of each fuel, if used to compute CO_2 emissions as specified in this section.

(d) Annual weighted average high heating value (HHV) of each fuel, if used to compute CO_2 emissions as specified in this section.

(e) The total nameplate generating capacity in megawatts (MW) and net power generated in the calendar year in megawatt hours (MWh).

(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, report this purpose and fuel consumption by fuel type using the units as specified in this section.

9.3 Calculation of Greenhouse Gas Emissions

9.3.1 Calculation of CO_2 Emissions

Use CEMS to measure CO_2 emissions if required to operate a CO_2 CEMS with flow monitors by any other federal or provincial regulation.

A person not required to operate a CEMS by another regulation may use either CEMS or the calculation methodologies specified in paragraphs (1) through (7) of this section. The person using CEMS to determine CO_2 emissions shall comply with the provisions in Calculation Methodology 4 of section 6.0.

(1) Natural Gas, and fuels in Table 5-1a and 5-1b. For electric generating units combusting natural gas or the fuels listed in Table 5-1a and 5-1b, use methods in accordance with section 6.0.

(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 6.0.

(3) Middle Distillates (including diesel), Gasoline, Residual Oil, or Liquid Petroleum Gases that are not listed in Table 5-1a. For electric generating units combusting middle distillates, gasoline, use Calculation Methodology 2 or 3 in accordance with section 6.0.

(4) 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 6.0.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use methods in accordance with section 6.0.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in Table 5-7, and the Calculation Methodology 2 in section 6.0 General Stationary Fuel Combustion. The person may also use CEMS to measure CO_2 emissions in accordance with Calculation Methodology 4 of section 6.0, or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of section 6.0.

(7) Start-up Fuels. The persons 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 CO_2 emissions from fossil fuel combustion using one of the following methods. Malfunction means the unplanned outage of equipment; breakdown of equipment; or failure of equipment to operate normally, associated with the operation of a combustion device for an electricity generation unit(s). It does not include normal changes in operation conditions such as variations in combustion temperature, oxygen levels or moisture content of the fuel.

- (i) The default emission factors from Tables 5-1a, 5-1b, 5-2, 5-3, 5-5 or 5-7, and default HHV from Tables 5-1 or 5-1a and 5-1b, as applicable, and Calculation Methodology 1 provided in section 6.0;
- (ii) The measured heat content of the fuel and Calculation Methodology 2 provided in section 6.0;
- (iii) The measured carbon content of the fuel and Calculation Methodology 3 provided in section 6.0; or
- (iv) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in Section 6.0.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the person shall calculate CO_2 emissions as follows.

- (i) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:
  - (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section 6.0. The person using this method needs not report emissions separately for each fossil fuel.
  - (B) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (1) through (4) of this section.
- (ii) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:
  - (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section 6.0. Determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in Calculation Methodology 4 of Section 6.0.
  - (B) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (1) through (7) of this section.

9.3.2 Calculation of CH_4 and N_2O Emissions

The person shall use the methods specified in section 6.0 to calculate the annual CH_4 and N_2O emissions.

9.4 Sampling, Analysis, and Measurement Requirements

Persons using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in Calculation Methodology 4 of 6.0.

Persons using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methodologies specified in section 6.0.

10.0 Mining explosives

10.1 Greenhouse Gas Reporting Requirements

In addition to the reporting requirements specified in Section 6.0, the following reporting requirements are required.

A person shall set out the following information, calculated for the calendar year using standard quantification methods specified in this section, in an emission report prepared for a calendar year in respect of mine production:

(a) Annual ore mined in tonnes.
(b) Total explosives that contain fossil fuels in tonnes.

10.2 Calculation of GHG Emissions

Calculate and report CO_2 as emissions from use of explosives made with fossil fuels such as, but not limited to, middle distillates (fuel oil, diesel) using Equation 10-1.

Equation 10-1:

$$\mathrm{CO_2} = \sum_{n=1}^{k} 3.664 * (\mathrm{FFexp_n} * \mathrm{CC_n}) * 0.001$$

Where:

CO_2 = Annual CO_2 emissions from fossil fuel consumption used in blasting explosives in tonnes per year (tonnes/yr).
$FFexp_n$ = Mass of fossil fuel contained in explosives used in month n (kg of fuel).
CC_n = Weighted average carbon content of the fossil fuel used in the explosive for month n (kg carbon per kg of fossil fuel).
k = Months in the year.
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to tonnes

11.0 Iron Ore Pelletizing (Iron and Steel Manufacturing) (WCI.150)

This section of the Guidance Document applies to the IOC-Rio Tinto facility at Labrador City.

11.1 Greenhouse Gas Reporting Requirements

A person shall set out the following information, calculated for the calendar year using standard quantification methods specified in this section, in an emission report prepared for a calendar year in respect of iron ore pellets production at a facility:

(a) Annual emissions of CO_2 at the facility level (tonnes).
(b) Annual quantities of each carbon-containing input materials used, including iron ore (as concentrate) raw material (tonnes).
(c) Carbon content of raw material and each other carbon-containing input material used (e.g., limestone, dolomite, soda ash) (tonnes C/tonne reducing agent).
(d) Annual iron ore pellets production (tonnes)

11.2 Calculation of CO_2 Emissions

Calculate and report industrial process CO_2 emissions from each carbon-containing raw material or other input material, including fluxes, from which the carbon is liberated as carbon dioxide as a result of heat or reaction from processing, as specified in Equation 11-1. Specific materials that contribute less than 1 per cent (1%) of the total carbon into the process do not have to be included in the calculation using Equation 11-1.

Equation 11-1:

$$E_{CO2} = \sum_{i=1}^{n} (Q_i \times C_i) \times 3.664 - \sum_{p=1}^{k} (Q_p \times C_p) \times 3.664$$

Where:
E_{CO2} = Annual CO_2 emissions from carbon-containing materials less annual CO_2 emissions from carbon remaining in products (tonnes)
Qi = Annual mass quantity of carbon-containing material i (tonnes)
Ci = Carbon mass content of carbon-containing material i (tonnes C/tonne process input)
n = total number of carbon-containing materials
Q_p = Annual mass quantity of carbon-containing product p (tonnes)
Cp = Carbon content of carbon-containing product p (tonnes C/tonne -product)
k = total number of carbon-containing products
3.664 = Stoichiometric conversion factor from C to CO_2.

11.3 Sampling, Analysis, and Measurement Requirements

The annual mass of each carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified in this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods, or any of the other analytical methods listed in Section 4.0, or the most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
  (1) For iron ore, iron ore concentrates, and other iron-bearing materials, use ASTM E1915.
  (2) For flux or other carbonate materials (e.g., limestone, dolomite), use ASTM C25.
  (3) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373.

(b) Obtain carbon content from material vendor or supplier.

12.0 Base Metal Hydrometallurgical Processing (Nickel and copper metal production (WCI.260) and Lime Production (WCI.170)

This section applies to the base metal hydrometallurgical facility in the province, namely Vale's facility in Long Harbour.

12.1 Source Category Definition – Lime Production

This section applies to any facility that produces lime (i.e., calcium oxide (CaO)) from limestone. Lime is produced from heating (referred as calcining) limestone, which is largely made of calcium carbonate ($CaCO_3$), but may contain other carbonates, such as magnesium carbonate ($MgCO_3$) that will result in some MgO production. Calcining carbonates liberates the carbon in the form of carbon dioxide.

12.2 Greenhouse Gas Reporting Requirements

12.2.1 Nickel and copper metal production (WCI.260)

A person shall set out the following information, calculated for the calendar year using standard quantification methods specified in this section, in an emission report prepared for the calendar year in respect of base metals production at the facility:

(a) Total annual emissions of CO_2 at the facility level (tonnes).
(b) Annual quantities of each carbon-containing input materials used, including feedstocks (tonnes).
(c) Carbon content of raw materials and each other carbon-containing input material used (e.g., limestone, dolomite, soda ash) (tonnes C/tonne).
(d) Annual production for each metal (tonnes).

12.2.2 Lime Production (WCI.170)

A person shall set out the following information, calculated for the calendar year using standard quantification methods specified in this section, in an emission report prepared for a calendar year in respect of calcium oxide or magnesium oxide production from carbonates at a facility:

(a) Total facility greenhouse gas emissions.
(b) CO_2 process emission from lime production for all kilns (excluding emissions from fuel combustion) in tonnes.
(c) CO_2 process emissions from lime production (tonnes) for all kilns combined and the following information if the process CO_2 emissions are calculated according to the procedures specified in this section:
    (1) For lime production:
        (i) The emission factor (tonne CO_2/tonne) for each lime type for each month.
        (ii) The quantity of each type of lime produced (tonnes) each month.
        (iii) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.
        (iv) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.
    (2) For the production of calcined by-products and wastes:

(i) The emission factor (tonne CO_2/tonne) for each calcined by-product/waste type for each quarter.
(ii) The quantity of each type of calcined by-product/waste type produced each quarter.
(iii) The calcium oxide (CaO) content (weight fraction) of each calcined by-product/waste type for each quarter.
(iv) The magnesium oxide (MgO) content (weight fraction) of each calcined by-product/waste type for each quarter.

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined (tonnes).
(e) The annual quantity of each type of lime and magnesium oxide produced (tonnes).

12.3 Calculation of CO_2 Emissions

12.3.1 Nickel and copper metal production (WCI.260)

Calculate and report industrial process emissions from each carbon containing raw material or other input material, including fluxes, electrodes from which the carbon is liberated as carbon dioxide as a result of heat, use, or neutralization reactions from processing, as specified in Equation 12-1:. Specific materials that contribute less than 1 per cent (1%) of the total carbon into the process do not have to be included in the calculation using
Equation 12-1.

Equation 12-1:

$$E_{CO_2} = \sum_{i} (Q_i \times C_i) \times 3.664$$

Where:
ECO_2 = Annual CO_2 emissions from carbon-containing materials (tonnes)
Qi = Annual quantity of carbon-containing material *i* (tonnes)
Ci = Carbon content of carbon-containing material *i* (tonnes C/tonne process input)
3.664 = Stoichiometric conversion factor from C to CO_2.

12.3.2 Lime Production (WCI.170)

(1) Calculate CO_2 emissions from the production of each type of lime using Equation 12-2 and a plant-specific lime emission factor and a plant-specific calcined by-product/waste emission factor as specified in this section.

Equation 12-2

$$E_{CO_2} = \sum_{m}^{12} \sum_{i} \left[QL_{mi} \times EF_{QL_{mi}} \right] + \sum_{q}^{4} \sum_{j} \left[CBW_{qj} \times EF_{CBW_{qj}} \right]$$

Where:
ECO_2 = Annual process CO_2 emissions in tonnes/yr.
QL_{mi} = Quantity of lime type i produced in month m, tonnes.

EF_{QLmi} = Emission factor of lime type i produced in month m (see below), tonnes CO_2/tonne lime

CBW_{qj} = Quantity of calcined byproduct and waste type j produced in quarter q, tonnes.

EFCBW,qj = Emission factor of calcined byproduct/waste type j produced in quarter q (see below), tonnes CO_2/tonne byproduct and waste.

(2) Monthly Lime Emission Factor. Calculate a plant-specific lime emission factor (EF_{QL}) for each type of lime and month based on the per cent of measured CaO and MgO content in lime and using Equation 12-3.

Equation 12-3:

$$EF_{QL} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092)$$

Where:

EF_{QL} = Process CO_2 emission factor for lime produced, tonnes CO_2/tonne lime.

f_{CaO} = CaO content of lime, calculated by subtracting CaO content of lime in uncalcined $CaCO_3$ remaining in lime from total CaO

0.785 = Ratio of molecular weights of CO_2 to CaO

f_{MgO} = MgO content of lime, calculated by subtracting MgO content of lime in uncalcined $MgCO_3$ remaining in lime from total MgO content of lime, tonnes MgO/tonne lime.

1.092 = Ratio of molecular weights of CO_2 to MgO

(3) Quarterly Calcined Byproduct/Waste Emission Factor. The calcined by-product/waste emission factor shall be calculated using Equation 12-4.

Equation 12-4:

$$EF_{CBW} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092)$$

Where:

EFCBW = Process CO_2 Emission factor for calcined byproduct and waste, tonnes CO_2/tonne calcined byproduct and waste

fCaO = CaO content of byproduct and waste, calculated by subtracting CaO content of byproduct and waste in uncalcined $CaCO_3$ remaining in calcined byproduct and waste from total CaO content of byproduct and waste, tonnes CaO/tonne byproduct and waste.

0.785 = Ratio of molecular weights of CO_2 to CaO.

fMgO = MgO content of byproduct and waste, calculated by subtracting MgO content of byproduct and waste in uncalcined $MgCO_3$ remaining in byproduct and waste from total MgO content of byproduct and waste, tonnes MgO/tonne byproduct and waste.

1.092 = Ratio of molecular weights of CO_2 to MgO

12.4 Sampling, Analysis, and Measurement Requirements

12.4.1 Nickel and copper metal production (WCI.260)

The annual mass of each carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods, or any of the other analytical methods listed in Section 4.0, or the most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
   (1) For any metal bearing ore, and other metal-bearing materials, use ASTM E1915.
   (2) For flux materials (i.e., limestone or dolomite), use ASTM C25.
   (3) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373.
(b) Obtain carbon content from material vendor or supplier.

12.4.2 Lime Production (WCI.170)

(a) The person shall determine the chemical composition (CaO and MgO contents) of each type of lime and each type of calcined by-product/waste according to the relevant ASTM and other methods and protocols contained in this section. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined by-product/waste type should be collected during the same month or quarter as the production data. At least one sample shall be collected monthly for each lime type produced during the month and quarterly for each calcined by-product/waste type produced.
   (1) ASTM C25.
   (2) The National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units.
   (3) Any of the other analytical methods listed in Section 4.0.
   (4) The most appropriate method published by a consensus-based standards organization. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
(b) 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.
(c) The quantity of calcined by-product/waste sold is to be estimated monthly using direct measurements (such as rail and truck scales) of calcined by-product/waste sales for each calcined by-product/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined by-product/waste type. The inventory period shall be annual at a minimum. The quantity of calcined by-product/waste not sold is to be determined no less often than annually for each calcined/by-product waste

type using direct measurements (such as rail and truck scales), or a calcined by-product/waste generation rate (i.e. calcined by-product produced as a factor of lime production).

(d) The person shall follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

13.0 Procedures for Estimating Missing Data

13.1 Unavailable Analytical Data

Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in this Guidance Document, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

13.2 Determination of Quantity

Whenever required sampling and measurement data for the calculation of emissions is missing, the person shall ensure that the data is replaced using the following missing data procedures:

(1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
   (i) Determine the sampling or measurement rate using
   Equation 13-1.

Equation 13-1:

$$R = Q_{S\ Act}/Q_{S\ Required}$$

Where:
R = Sampling or measurement rate that was used, expressed as a percentage
$Q_{S\ Act}$ = Quantity of actual samples or measurements obtained by the person
$Q_{S\ Required}$ = Quantity of samples or measurements required

   (ii) Replace the missing data as follows:
      (A) If $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the period missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
      (B) If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
      (C) If $R < 0.75$: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;

(2) When the missing data concerns gas consumption, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

For units that monitor and report emissions using a CEMS, the missing data backfilling procedures in Environment Canada's, "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7 (1) shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

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[1] Environment Canada (2012) Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7, Available at: https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromThermalPowerGeneration.pdf