Guidance Document for GHG Accounting and Reporting

Prepared for:

ARC Portfolio Companies

Oilfield Service Companies, Renewable Fuel Producers & Energy Transition Companies

Prepared by:

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1 INTRODUCTION

In general, oilfield service companies, energy transition companies, and others such as renewable fuel producers will follow similar methodologies when reporting greenhouse gas (GHG) emissions to provincial and federal regulatory agencies as well as for their sustainability programs. This document presents a set of calculation methods to be used consistently by these companies that provide regular reports to ARC and is not intended to replace, nor are they intended to be a substitute for, any prescribed methodologies that companies may already be using for regulatory and/or sustainability reporting. There are a variety of different oilfield service companies, energy transition, and renewable energy companies within ARC's portfolio, and this document aims to provide overall guidance and consistency for these types of companies.

The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (GHG Protocol) [1] and the *Alberta greenhouse gas quantification methodologies – technology innovation and emissions reduction regulation Version 2.2* (AQM) [2] will serve as the main references for this document.

Additional references for this document include the *ECCC – Canada's Greenhouse Gas Quantification Requirements – Greenhouse Gas Reporting Program December 2021 Version 5.0* (ECCC) [3], and *GHG Protocol Scope 2 Guidance* [4].

2 BOUNDARY SETTING

2.1 Organizational Boundaries

Organizational boundaries define the assets or operations that are to be included in a company's GHG inventory. The GHG Protocol provides detailed descriptions regarding the selection of appropriate greenhouse gas inventory boundaries. It highlights two main approaches for setting organizational boundaries – the equity share approach and the control approach. Under the equity share approach, a company accounts for GHG emissions from assets or operations that they have an equity share in and based on their share of equity or economic interest. Under the control approach, companies account for 100% of the emissions from assets or operations that they have financial or operational control over. Note that a company could have operational control over an operation, facility, building, or activity even without having ownership.

Once an organizational boundary has been determined, it needs to be applied consistently across the reporting organization [1]. For the purpose of reporting to ARC, this document follows the operational control approach.

Figure 1 and Figure 2 show the organizational boundary that is to be considered on a high level by oilfield service provider companies (Figure 1), renewable fuel producer companies, and energy transition companies (Figure 2) within ARC's portfolio for the purpose of reporting to ARC. Energy transition and renewable fuel producers have been presented together in Figure 2, merely because they both have a physical product; otherwise, the process of determining organizational boundaries is the same for any type of company.

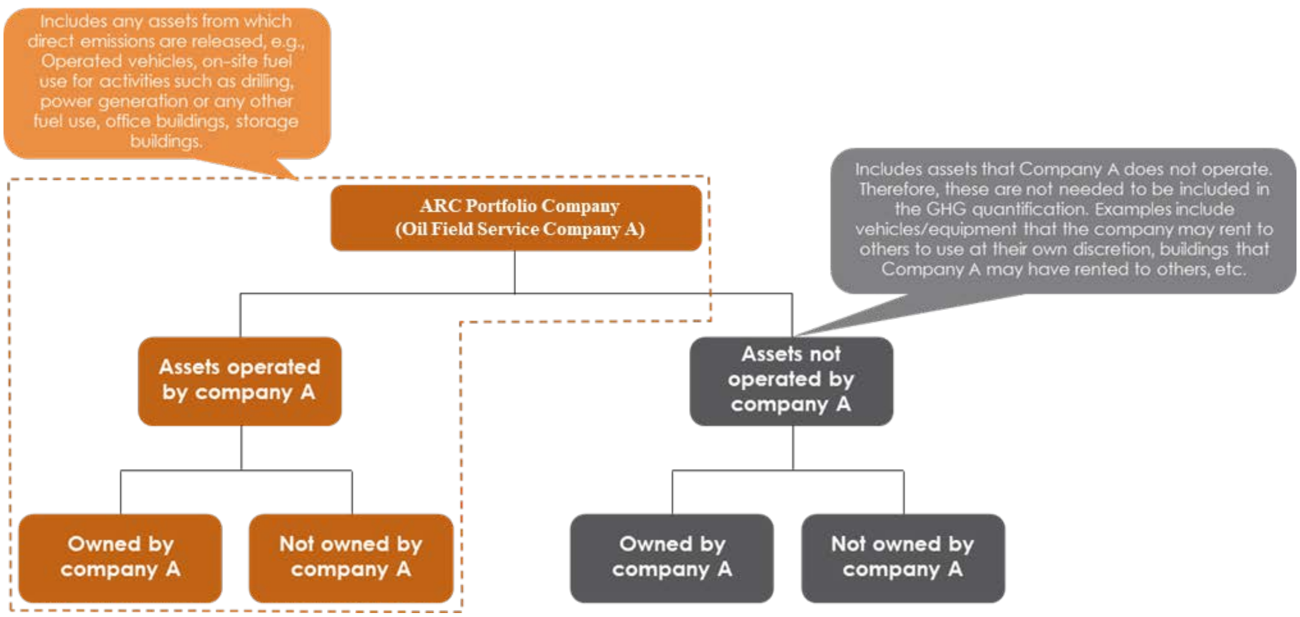

Figure 1 – Organizational boundary for oilfield service provider companies within ARC's portfolio. Assets highlighted in orange within the orange dotted line fall within the organizational boundary of ARC Portfolio Companies based on the operational control approach

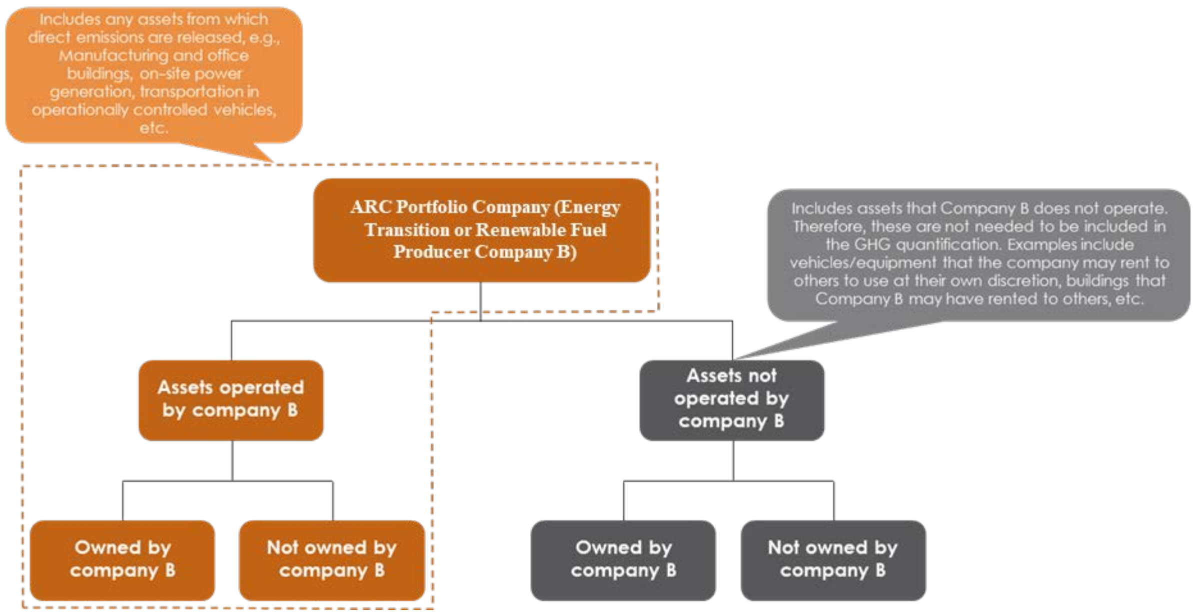

Figure 2 – Organizational boundary for energy transition and renewable fuel producer companies within ARC's portfolio. Assets highlighted in orange within the orange dotted line fall within the organizational boundary of ARC Portfolio Companies based on the operational control approach

2.2 Operational Boundaries

Operational boundaries identify various relevant GHG sources, and categorize them as either direct (Scope 1) or indirect (Scope 2, and scope 3) emissions. Scope 1 emissions will include direct emissions resulting from the operations of a company (e.g., fuel combustion), and Scope 2 emissions include indirect GHG emissions from purchased energy, including purchased and consumed electricity, steam, heating, and cooling. Scope 3 emissions (indirect emissions from the organization's value chain) are not being addressed in this document at this time. Detailed descriptions of operational boundaries are included in **Chapter 4 of the GHG Protocol** [1]. Figure 3 and Figure 4 show the GHG sources that are likely to fall within the operational boundary of oilfield service, renewable fuel producer, and energy transition companies within ARC's portfolio, respectively.

If a company reports to the federal Greenhouse Gas Reporting Program (GHGRP), they may set their operational boundary based on the same categories that they report on to GHGRP, and include Scope 2 (typically electricity) if it is not being reported under the GHGRP requirements. Otherwise, companies need to complete an analysis internally or by retaining a third-party expert to identify and quantify their Scope 1 and Scope 2 sources of GHG emissions.

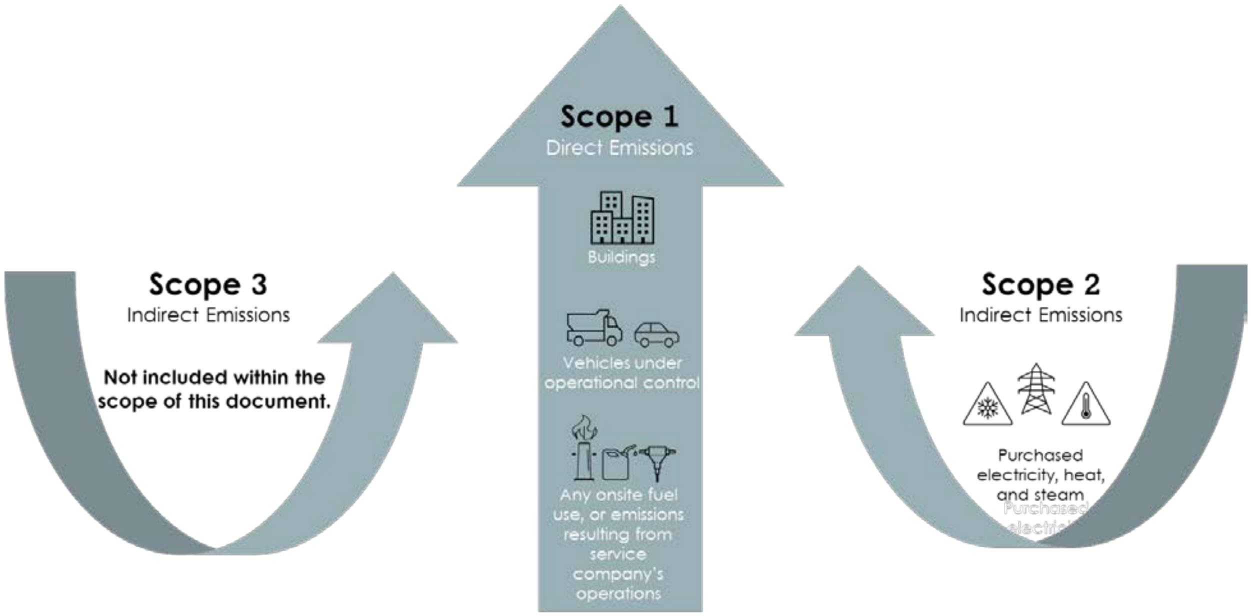

Figure 3 – Typical operational boundary for oilfield service provider companies

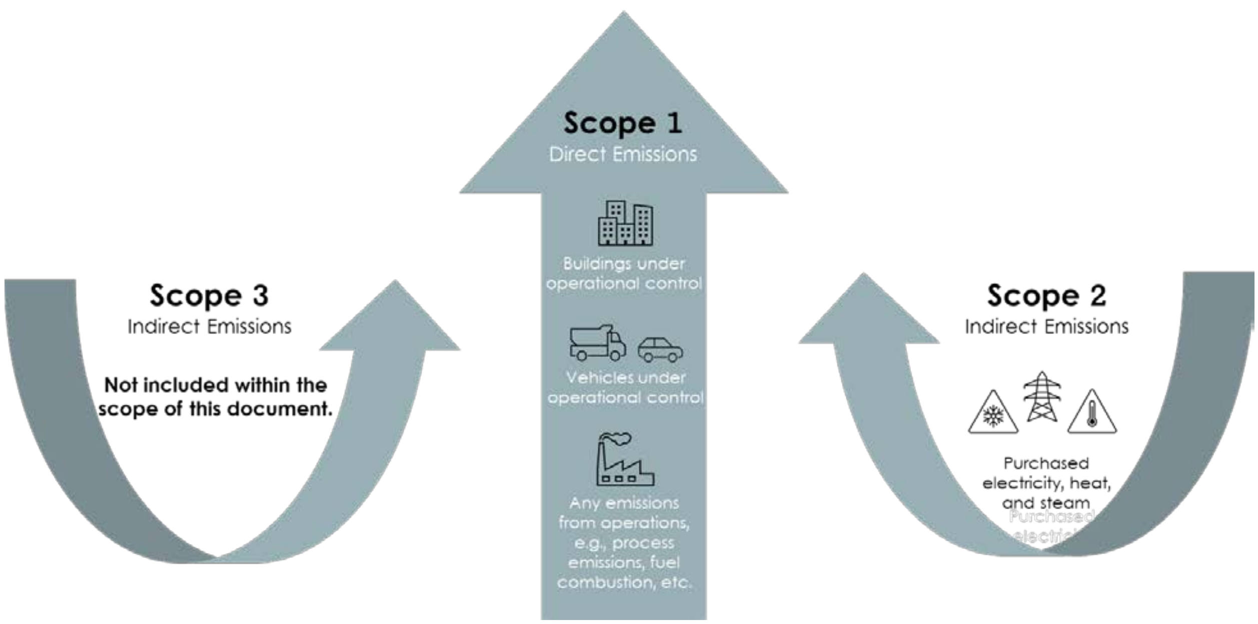

Figure 4 – Typical operational boundary for renewable fuel producers & energy transition companies

Two hypothetical examples of setting organizational and operational boundaries are provided below for illustrative purposes.

Examples

Example 1: Company A is a typical oil field service provider that provides drilling and completion and leak detection and repair (LDAR) services. The organizational and operational boundaries for this company are presented in Table 1.

The company operates an office building, a fleet of vehicles to travel to sites, drilling equipment, leak detection equipment, and trucks to transport heavy machinery to and from sites. The company also has a number of buildings that they own but have rented to other entities. In some instances, the company rents their equipment to customers to use on their own.

Note that this is just an example for illustrative purposes, and companies must conduct an analysis to ensure all relevant emissions are included in the GHG quantification.

Example 2: Company B is a Renewable Natural Gas (RNG) producer that uses an anaerobic decomposition process to produce RNG from biomass waste. The organizational and operational boundaries for this company are presented in Table 2. The company operates one office building in Calgary and operates one RNG production facility near Edmonton. Company B owns and operates a fleet of company vehicles to travel between the Calgary office and the Edmonton facility but does not own any trucks for the transportation of biomass. Instead, biomass is transported to the RNG production facility by a third-party trucking company. After RNG is produced, it is transported by pipeline to an end user.

Note that in this example, the company may need to use fossil fuels and/or some of the produced RNG for heating, power generation, etc. All emissions associated with the combustion of the fuels need to be included. In addition, note that the emissions associated with RNG combustion are not zero and should be quantified using the emission factors provided in Table 5 (use the emission factor for natural gas). However, the carbon dioxide (CO_2) portion of the estimated emissions (biogenic CO_2) is not to be included in a company's total GHG emissions for comparison purposes (only methane (CH_4) and nitrous oxide (N_2O) emissions will be included). Companies are still required to quantify the CO_2 emissions from RNG combustion (using the CO_2 emission factor for natural gas in Table 5) and report separately to ARC for completeness purposes only.

Table 1 – An example of operational and organizational boundaries for an oilfield service provider company

Asset/Operation	Included/Excluded in Organizational Boundary	Operational Boundary	Comment
Buildings and offices operated by company A	Included	Direct (Scope 1): NG Indirect (Scope 2): Electricity	The buildings may or may not be owned by the company.
Drilling operations	Excluded	Excluded (see comment)	Reason for exclusion is that fuel used on-site commonly gets purchased by the client of company A and any associated emissions would be included in their scope 1 (and in Alberta also reported to the Government).
Company-operated vehicles used to travel to different sites to complete LDAR activities.	Included	Direct (Scope 1): Vehicle fuel emissions. Indirect (Scope 2): Electric vehicle charging emissions	The vehicles may or may not be owned by company A.
Company-operated trucks used to transport drilling equipment to different sites	Included	Direct (Scope 1): Vehicle fuel emissions. Indirect (Scope 2): Electric vehicle charging emissions	The trucks may or may not be owned by the company. If fuel is reported to the client and included in their scope 1, then Company A may exclude this source from their GHG inventory.
Buildings that company A has rented to other entities	Excluded	Excluded	Scope 3, not in the scope for reporting.
Drilling equipment that company A may rent to other entities to use	Excluded	Excluded	Scope 3, not in the scope for reporting.
Purchased transportation services (e.g., trucking)	Excluded	Excluded	Scope 3, not in the scope for reporting.

Asset/Operation	Included/Excluded in Organizational Boundary	Operational Boundary	Comment
Employee personal vehicles	Excluded	Excluded	Scope 3, not in the scope for reporting.

Table 2 – An example of operational and organizational boundaries for a RNG producer

Asset/Operation	Included/Excluded in Organizational Boundary	Operational Boundary	Comment
Buildings and offices operated by company B	Included	Direct (Scope 1): NG Indirect (Scope 2): Electricity	The buildings may or may not be owned by the company.
RNG production facility (On-site operations)	Included	Direct (Scope 1): Fuel used to run pumps, power generation, and heating. Venting and/or fugitive emissions. Indirect (Scope 2): Electricity	All sources of GHG emissions need to be identified and quantified. If a company reports to the federal GHGRP program, they may report on the same categories that they report to GHGRP. Otherwise, an evaluation to determine operational boundaries is required.
Fleet vehicles	Included	Direct (Scope 1): Vehicle fuel emissions. Indirect (Scope 2): Electric vehicle charging emissions	The vehicles may or may not be owned by the company.
Feedstock transportation	Excluded	Excluded	Scope 3, not in the scope for reporting.
Employee personal vehicles	Excluded	Excluded	Scope 3, not in the scope for reporting.

2.3 Reporting Period

In this document, the reporting period is assumed to be a calendar year.

3 Quantification Methodology

For each asset/operation that falls within an ARC Portfolio Company's organizational boundary, all relevant direct (Scope 1) and indirect (Scope 2) emissions are to be quantified. Scope 3 emissions are not within the scope of this document.

For the GHG calculations, the Global Warming Potential (GWP) values from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4) based on a 100-year timeline are to be used [5]. These GWPs are listed in Table 3.

Table 3 – IPCC AR4 100-year GWPs

GHG Species	GWP
CO_2	1
CH_4	25
N_2O	298

If releases of other GHGs, such as Hydrofluorocarbons (HFCs) and Sulphur hexafluoride (SF_6), are relevant to your operations, please contact ARC Ffor additional guidance.

3.1 Scope 1 Methodology

3.1.1 Introduction / What to Report

As discussed above, Scope 1 emissions include direct emissions from the operations of a company. The following sources of emissions may be applicable based on the overall guidance from the GHG Protocol companies:

- Stationary fuel combustion
- Mobile combustion
- Process emissions
- Flaring emissions
- Venting and fugitive emissions

Each company has its unique, relevant GHG sources. **Chapter 7 of the GHG Protocol** includes a discussion surrounding inventory management and data quality controls. The protocol highlights some of the key components of generic quality control, which companies might find as a useful reminder [1]. Companies may report on the same categories that they report to the federal government under the GHGRP program. Otherwise, they may conduct an evaluation to identify and quantify the relevant sources of GHG emissions to their operations.

3.1.2 Data Sources

Data sources for emissions inventories often come from similar sources for each industry. Stationary and Mobile fuel combustion data come from either internal tracking of fuel usage or from third-party invoices of purchased fuel used for combustion. Regardless, companies should keep proper supporting documents to allow for the verification of their data. Process emissions, venting, or other relevant sources need to be calculated and tracked internally for each specific industrial process, and fugitive emissions may be calculated internally or measured by a third-party leak detection and repair company.

3.1.3 Stationary Combustion

Stationary fuel combustion emissions include any fuel that is combusted (e.g., to generate heat or power), and sources include equipment such as boilers, heaters, furnaces, engines, and combustion turbines [2]. Emission calculations for each type of fuel combusted are required.

3.1.3.1 Data Inputs

For the purposes of this document, stationary fossil fuel types and volumes may be used along with proper emission factors from Table 4 and Table 5 to quantify the emissions.

Combustion of fuels produced from organic feedstock (biomass), for example, ethanol or biodiesel, follows a similar calculation methodology using a unique set of emission factors (Table 4). However, CO_2 emissions should be reported separately as "biogenic CO_2 emissions," while CH_4 and N_2O will be reported on and included as part of the stationary fuel combustion inventory [2].

3.1.3.2 Calculation Methodology

The following equations may be used to quantify stationary fuel combustion emissions.

$$CO_2\ emissions\ (tonnes\ CO_{2e}) = fuel\ volume\ (kl)\ \times fuel\ emission\ factor\ (\frac{tonne\ CO_2}{kl\ fuel}) \tag{1}$$

$$CH_4\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl) \times fuel\ Emission\ factor\ \left(\frac{tonne\ CH_4}{kl\ fuel}\right) \times\ CH_4\ GWP \tag{2}$$

$$N_2O\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl) \times fuel\ Emission\ factor\ \left(\frac{tonne\ N_2O}{kl\ fuel}\right) \times\ N_2O\ GWP \tag{3}$$

$$Total\ stationary\ combustion\ emissions\ (tonnes\ CO_{2e}) = CO_2\ emissions\ (tonnes\ CO_{2e}) + CH_4\ emissions\ (tonnes\ CO_{2e}) + N_2O\ emissions\ (tonnes\ CO_{2e}) \tag{4}$$

Table 4 and Table 5 list the emission factors that should be used for each fuel type for the purpose of reporting to ARC. Natural gas refers to fuel being used in utilities, residential, and commercial areas, and fuel gas refers to raw/unprocessed natural gas that a company may use in its operations.

Table 4 – Stationary fuel combustion emission factors for liquid fuels [2,6]

Fuel Type	CO_2 Emission Factor (tonne/kl)	CH_4 Emission Factor (tonne/kl)	N_2O Emission Factor (tonne/kl)
Diesel	2.681	7.8E–05	2.0E–05
Diesel in Alberta[1]	2.610	7.8E–05	2.0E–05
Gasoline	2.307	1.0E–04	2.0E–05
Gasoline in Alberta[1]	2.174	1.0E–04	2.0E–05
Propane	1.515	2.4E–05	1.08E–04
Light Fuel Oil	2.753	6.0E–06	3.1E–05
Heavy Fuel Oil	3.156	1.2E–04	6.4E–05
Biodiesel[2]	2.472	7.8E–05	2.0E–05
Ethanol[2]	1.508	1.0E–04	2.0E–05
Butane	1.747	2.4E–05	1.08E–04
Ethane	0.986	2.4E–05	1.08E–04

[1] Diesel & Gasoline emission factors in Alberta adjusted for biofuel content under Alberta's Renewable Fuels Standard

[2] These are considered to be biomass CO_2 and should be reported under the biogenic CO_2 category

Table 5 – Stationary fuel combustion emission factors for gaseous fuels [2,6]

Fuel Type	CO_2 Emission Factor (tonne/m³)	CH_4 Emission Factor (tonne/m³)	N_2O Emission Factor (tonne/m³)
Natural Gas[1]	0.0019	6.4E–06	6.0E–08
Fuel Gas	0.00233	6.4E–06	6.0E–08

[1] Natural gas emission factors may be use to quantify RNG emissions. However, CO_2 emissions from RNG combustion are to be reported separately as biogenic emissions.

3.1.3.3 Sample Calculation

Sample calculations for CO_2:

Fuel Type	Fuel volume (kl)	CO_2 Emission Factor (tonne/kl)	CO_2 Emissions (tonnes CO_{2e})
Diesel	100,000	2.681	268,100

Sample calculations for CH_4:

Fuel Type	Fuel volume (kl)	CH_4 Emission Factor (tonnes/kl)	CH_4 Emissions (tonnes CH_4)	GWP	CH_4 Emissions (tonnes CO_{2e})
Diesel	100,000	7.8E–05	7.8	25	195.0

Sample calculations for N_2O:

Fuel Type	Fuel volume (kl)	N_2O Emission Factor (tonnes/kl)	N_2O Emissions (tonnes N_2O)	GWP	N_2O Emissions (tonnes CO_{2e})
Diesel	100,000	2.0E–05	2.0	298	596.0

3.1.4 Mobile/Transportation Combustion

Transportation emissions include emissions from mobile sources such as owned company trucks, airplanes, cars, etc. [2]. Emission calculations for each type of fuel (gasoline, diesel, propane, etc.) combusted is required. Transportation emissions from sources that are not operated by a company, such as commercial air travel or employee-owned commuter vehicles, would be categorized as a Scope 3 GHG source and not required to be reported to ARC at this point.

3.1.4.1 Data Inputs

The inputs for transportation emissions are similar to the data inputs for stationary fuel combustion emissions. Non-variable fuels, such as diesel, gasoline, ethanol, etc., are typically reported as the amount of fuel (for example, liters or kiloliters) used in the calculation period. Additional data inputs include the emission factors specific to that fuel type using the same tables as the stationary fuel combustion calculations.

Combustion of fuels produced from organic feedstock (biomass), for example, ethanol or biodiesel, follows a similar calculation methodology using a unique set of emission factors. However, carbon dioxide (CO_2) emissions should be reported separately as biogenic CO_2 emissions, while methane (CH_4) and nitrous oxide (N_2O) are reported as part of the transportation fuel combustion emissions inventory [2].

Table 6 – Common transportation fuel emission factors

Fuel Type	CO_2 Emission Factor (tonne/kl)	CH_4 Emission Factor (tonne/kl)	N_2O Emission Factor (tonne/kl)
Diesel	2.681	7.8E–05	2.0E–05
Diesel in Alberta[1]	2.610	7.8E–05	2.0E–05
Gasoline	2.307	1.0E–04	2.0E–05
Gasoline in Alberta[1]	2.174	1.0E–04	2.0E–05
Propane	1.515	2.4E–05	1.08E–04
Biodiesel[2]	2.472	7.8E–05	2.0E–05
Ethanol[2]	1.508	1.0E–04	2.0E–05

[1] Diesel & Gasoline emission factors in Alberta adjusted for biofuel content under Alberta's Renewable Fuels Standard

[2] These are considered to be biomass CO_2 and should be reported under the biogenic CO_2 category

3.1.4.2 Calculation Methodology

The same default emission factors and calculation methodology used for the calculation of stationary fuel combustion emissions may be used for transportation fuel emission.

The following equations may be used to quantify transportation fuel combustion emissions. For an example of these calculations, please see the stationary fuel emissions calculations.

$$CO_2\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl)\ \times fuel\ emission\ factor\ (\frac{tonne\ CO_2}{kl\ fuel}) \tag{5}$$

$$CH_4\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl)\ \times fuel\ emission\ factor\ \left(\frac{tonne\ CH_4}{kl\ fuel}\right) \times\ CH_4\ GWP \tag{6}$$

$$N_2O\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl)\ \times fuel\ emission\ factor\ \left(\frac{tonne\ N_2O}{kl\ fuel}\right) \times\ N_2O\ GWP \tag{7}$$

$$\begin{aligned} &Total\ mobile/transportation\ emissions\ (tonnes\ CO_{2e}) = \\ &\qquad CO_2\ emissions\ (tonnes\ CO_{2e}) + \\ &\qquad CH_4\ emissions\ (tonnes\ CO_{2e}) + \\ &\qquad N_2O\ emissions\ (tonnes\ CO_{2e}) \end{aligned} \tag{8}$$

3.1.5 Process Emissions

Process emissions are the result of the physical or chemical transformation of raw materials into various products from processes other than combustion [2]. These emissions will be highly dependent on the type of processing being done by an individual company. ECCC's publication ***Canada's Greenhouse Gas Quantification Requirements – Greenhouse Gas Reporting Program December 2021 Version 5.0*** contains numerous methodologies related to process emissions [3]. The **AQM Chapter 8** also contains several methodologies for calculating process–related emissions [2]. The GHG Protocol Appendix D also highlights several industry sectors and their related process emissions [1]. Companies that have reporting requirements under the provincial GHG program in Alberta (TIER) should have a good understanding of their GHG emissions, including process emissions. Such companies may use directly the values that they report to TIER to ARC (note that TIER requires the GHG emissions reports to be third–party verified). Otherwise, companies are required to complete analysis to understand and quantify any relevant process emissions either internally or by retaining external experts. When AQM does not include relevant methods, the ECCC methods may be used to quantify process emissions. Table 7 provides a list of activities that result in process emissions and relevant quantification methods for them within the AQM and ECCC guidelines.

Table 7 – Quantification methods for activities that result in process emissions

AQM [2]	ECCC [3]
Hydrogen Production	Lime Production
Calcining Carbonates	Cement Production
Use of Carbonates	Aluminum Production
Ethylene Oxide Production	Iron & Steel Production
Carbon as Reductant	Electricity & Heat Generation
Nitric Acid Production	Ammonia Production
	Nitric Acid Production
	Hydrogen Production

AQM [2]	ECCC [3]
	Petroleum Refining
	Pulp & Paper Production
	Base Metal Production

For example, hydrogen is typically produced in petroleum refineries, fertilizer plants, or in its own production facility using steam–methane reforming, utilizing CH_4 feedstocks and water to create hydrogen and $\mathbf{CO_2}$ as its products. If a company were to include hydrogen production within its organizational boundaries it would need to follow the methodology for calculating the process CO_2 emissions (AQM or ECCC) [2,3].

3.1.6 Flaring emissions

Flaring emissions are emissions resulting from the combustion of gases such as fuel gas in flares. Certain industries may include flaring as part of their operations. Flaring volumes will typically be tracked internally. This methodology document uses the default emission calculation equations.

3.1.6.1 Data Inputs

The data required to calculate flaring emissions is the volume of gas flared in standard cubic meters (m^3) at standard conditions, as well as the flare gas type (sales gas, lean gas, landfill gas, etc.) or high heating value (HHV) reference, and the appropriate flare combustion efficiency as highlighted in Chapter 2 of the AQM [2]. This document will assume a combustion efficiency of 98%. Additional combustion efficiencies and its associated emission factors can be found in the AQM.

3.1.6.2 Calculation Methodology

The following equations derived from Chapter 2 of the AQM may be used to quantify the emissions from flaring [2].

$$CO_2\ emissions\ (tonnes\ CO_{2e}) = Flared\ Volume\ (m^3) \times Flare\ Emission\ Factor\ \left(\frac{g\ CO_2}{m^3 flare}\right) \times 10^{-6} \tag{9}$$

$$CH_4\ emissions\ (tonnes\ CO_{2e}) = Flared\ Volume\ (m^3) \times Flare\ Emission\ Factor\ \left(\frac{g\ CH_4}{m^3\ flare}\right) \times\ CH_4\ GWP \times 10^{-6} \tag{10}$$

$$N_2O\ emissions\ (tonnes\ CO_{2e}) = Flare\ Volume\ (m^3) \times Flare\ Emission\ Factor\ \left(\frac{g\ N_2O}{m^3\ flare}\right) \times\ N_2O\ GWP \times 10^{-6} \quad (11)$$

$$Total\ Flare\ Emissions\ (tonnes\ CO_{2e}) = CO_2\ emissions\ (tonnes\ CO_{2e}) + CH_4\ emissions\ (tonnes\ CO_{2e}) + N_2O\ emissions\ (tonnes\ CO_{2e}) \quad (12)$$

The emission factors to be used in the above equations are listed in Table 8. These emission factors are developed based on the following default gas compositions, which may be used to help determine the proper emission factor that needs to be used:

- Sales gas – 98% CH_4, 1% C_2H_6, 0.3% C_3H_8, 0.1% C_4H_{10}, 0.3% CO_2, 0.3% N_2
- Lean gas – 92% CH_4, 5% C_2H_6, 1.9% C_3H_8, 0.5% C_4H_{10}, 0.3% CO_2, 0.3% N_2
- Medium gas – 86% CH_4, 10% C_2H_6, 2.5% C_3H_8, 0.9% C_4H_{10}, 0.3% CO_2, 0.3% N_2
- Rich gas – 80% CH_4, 15% C_2H_6, 5% C_3H_8
- Landfill gas – 50% CH_4, 50% CO_2
- Gas with HHV > 50 MJ/m3 – 70% CH_4, 20% C_2H_6, 10% C_3H_8

If the type of flared gas cannot be determined, use the emission factors for Rich gas.

Table 8 – Flaring emission factors (emission factors are taken from the AQM table 2-2 to 2-4 for open flares with 98% efficiency, for additional combustor efficiencies and emissions factors please refer to the AQM [2])

Flare Gas Types	CO_2 Emission Factor (g/m^3)	CH_4 Emission Factor (g/m^3)	N_2O Emission Factor (g/m^3)
Sales gas	1,853	13.27	0.033
Lean gas	2,006	12.46	0.033
Medium-rich gas	2,141	11.65	0.033
Rich gas	2,280	10.83	0.033
Still gas (Upgrading)	2,097	31	0.02
Still gas (Refinery & others)	2,081	31	0.02
100% Methane (C1)	1,824	13.54	0.033
100% Ethane (C2)	3,648	0.00	0.0005
100% Propane (C3)	5,472	0.00	0.00035
100% Butane (C4)	7,296	0.00	0.00027
Flaring of landfill gas[1]	1,843	6.77	0.0064

1 These are considered to be biomass CO_2 and should be reported under the biogenic CO_2 category.

3.1.6.3 Sample Calculation

Sample calculations for CO_2:

Flare Type	Flare gas volume (m^3)	CO_2 Emission Factor (g/m^3)	CO_2 Emissions (tonnes CO_2)
Sales Gas	100,000	1,853	185.3

Sample calculations for CH_4:

Flare Type	Flare gas volume (m^3)	CH_4 Emission Factor (g/m^3)	CH_4 Emissions (tonnes CH_4)	GWP	CH_4 Emissions (tonnes CO_{2e})
Sales Gas	100,000	13.27	1.327	25	33.18

Sample calculations for N_2O:

Flare Type	Flare gas volume (m^3)	N_2O Emission Factor (g/m^3)	N_2O Emissions (tonnes N_2O)	GWP	N_2O Emissions (tonnes CO_{2e})
Hydrocarbon (Sales) Gas	100,000	0.033	0.0033	298	0.98

3.1.7 Venting and Fugitive Emissions

Fugitive emissions are the result of unintended releases of greenhouse gases from sources such as leaks from equipment (valves, gauges, gaskets, etc.), leakage of methane during natural gas transportation, and leaks from other various processes [1]. Venting emissions are releases of GHGs such as methane that happen as part of the normal operation of devices such as pneumatic pumps. The relevance of venting and fugitive emissions will depend on operations of each individual company and will be identified during the determination of each company's organizational boundaries. For example, a manufacturer of solar panels may not have venting or fugitive emissions from its operations whereas a landfill operation may have venting or fugitive emissions from its waste decomposition.

3.1.7.1 Data Inputs

In most cases, third-party Leak Detection and Repair (LDAR) reports include the magnitude of the fugitive emissions at each site. In such cases, companies may consolidate the LDAR reports for all their sites and report their fugitive GHG emissions to

ARC. Otherwise, if only the volume of the fugitive emissions is known, the same equations used for venting (see section 3.1.7.2) may be used by replacing the "vented gas volume" with "fugitive gas volume".

Venting emissions may be calculated following the methodology from the AER's manual 15 document.

A gas sample, ideally from the location where venting or fugitive emissions are being released, is required to determine the mole fraction of CO_2 and CH_4. Additional constant inputs include the density of CO_2 or CH_4 at standard conditions as well as the proper unit conversions [2]. If a gas composition analysis is not available, the reporting company should conservatively assume the vent/fugitive source is made up of 100% CH_4. If more than one gas analysis is available, average values across the gas analyses may be used.

3.1.7.2 Calculation Methodology

CO_2 and CH_4 emissions are most simply calculated using an equation modified from equation 4–1b in the AQM.

$$\begin{aligned} CO_2\ emissions\ (tonnes\ CO_{2e}) \\ = Vent\ volume\ (m^3) \times mole\ fraction\ of\ CO_2\ in\ vent\ gas\ (\%) \\ \times CO_2\ density\ \left(1.861\,\frac{kg\ CO_2}{m^3 CO_2}\right) \times 10^{-3} \end{aligned} \tag{13}$$

$$\begin{aligned} CH_4\ emissions\ (tonnes\ CO_{2e}) \\ = Vent\ volume\ (m^3) \times mole\ fraction\ of\ CH_4\ in\ vent\ gas\ (\%) \\ \times CH_4\ density\ \left(0.6785\,\frac{kg\ CH_4}{m^3 CH_4}\right) \times GWP\ CH_4 \times 10^{-3} \end{aligned} \tag{14}$$

$$\begin{aligned} Total\ vent\ emissions\ (tonnes\ CO_{2e}) = \\ CO_2\ emissions\ (tonnes\ CO_{2e}) + \\ CH_4\ emissions\ (tonnes\ CO_{2e}) \end{aligned} \tag{15}$$

3.1.7.3 Sample Calculation

The below example will assume a mole fraction of 2% CO_2 and 90% CH_4. Mole fractions of CO_2 and CH_4 will need to be obtained from gas analyses.

Sample calculations for CO_2 and CH_4:

Emission Type	Total Volume Vent gas (m^3)	Mole Fraction	Density at standard conditions (kg/m^3)	GWP	Emissions (tonne CO_{2e})
CO_2	100,000	2.0% (example only)	1.861	1	3.7
CH_4	100,000	90.0% (example only)	0.6785	25	1526.6

3.1.8 Reporting Table – Results for Scope 1

For reporting to ARC please provide the following results for the total Scope 1 corporate emissions for each of the metrics shown in Table 6. Total biogenic emissions are reported separately from the other emission categories and not included in the total direct GHG emissions.

Table 9 – Scope 1 Corporate Reporting Table

Emission Categories (Scope 1)	Units	Reporting Year
Total direct GHG emissions	Metric tonnes CO_{2e}	
Stationary Combustion Emissions	Metric tonnes CO_{2e}	
Transportation Emissions	Metric tonnes CO_{2e}	
Flaring Emissions	Metric tonnes CO_{2e}	
Process Emissions	Metric tonnes CO_{2e}	
Venting Emissions	Metric tonnes CO_{2e}	
Fugitive Emissions	Metric tonnes CO_{2e}	
Total Biogenic Emissions[1]	Metric tonnes CO_2	

[1] Total biogenic CO_2 emissions are reported separately and not included in the total direct GHG emissions

3.2 Scope 2 Methodology

3.2.1 Introduction / What to Report

As discussed earlier, Scope 2 or indirect emissions are comprised of the emissions associated with purchased energy, including purchased and consumed electricity, steam, heating, and cooling in a company's owned or controlled operations [1]. There are two main methods that can be used to calculate Scope 2 emissions: the location-based method and the market-based method [4]. For the purpose of this document, the location-based methodology is the preferred calculation methodology.

3.2.2 Purchased Electricity

3.2.2.1 Data Inputs

Using a simple location-based approach, the data required to calculate Scope 2 emissions from the purchase of electricity include electricity purchased and utilized at all facilities within a company's determined boundaries. These amounts will typically be available from utility bills or metered electricity consumption readings [4].

National Inventory Report (NIR), published every year by the Government of Canada, includes the emission factors for each Canadian province and is typically used in Canada for Scope 2 GHG quantification. Table 10 shows the most recent (2020) grid electricity consumption intensities for Alberta and Ontario [7]. At the time of reporting the most recent grid electricity emission factors should be used, updates to these emission factors may be found here: Environment Canada: National Inventory Report. Table 11 shows select grid electricity emission factors for several states as well as the average grid electricity emission factors for the United States. Additional states / eGRID subregions can be found in the GHG Emission Factors Hub [8].

Table 10 – Canada Grid Electricity Consumption Intensity for select provinces [7]

Location (Canada)	Grid Electricity Emission Factor 2020
Alberta	640 g CO_{2e}/kWh
British Columbia	7.8 g CO_{2e}/kWh
Saskatchewan	620 g CO_{2e}/kWh
Ontario	28 g CO_{2e}/kWh

Table 11 – United States Grid Intensity for select states [8]

Location (United States / eGRID Subregion)	Grid Electricity Emission Factor CO_2 (lb/MWh)	Grid Electricity Emission Factor CH_4 (lb/MWh)	Grid Electricity Emission Factor N_2O (lb/MWh)
California (CAMX)	513.5	0.032	0.004
Georgia (SRSO)	860.2	0.060	0.009
Texas (ERCT)	818.6	0.052	0.007
Washington (NWPP)	600.0	0.056	0.008
US Average	818.3	0.065	0.009

3.2.2.2 Calculation Methodology

To calculate GHG emissions from grid electricity in Canada use the following equation.

$$Total\ GHG\ emissions\ (tonnes\ CO_{2e}) = Electricity\ consumed\ (kWh) \times Grid\ emission\ intensity\ \left(\frac{g\ CO_{2e}}{kWh}\right) \times 10^{-6} \tag{16}$$

To calculate GHG emissions from grid electricity in the United States use the following equations.

$$\boldsymbol{CO_2\ emissions\ (tonnes\ CO_{2e}) = Electricity\ consumed\ (MWh) \times Grid\ emission\ intensity\ \left(\frac{lb\ CO_2}{MWh}\right) \times 0.000453\ \left(\frac{tonne}{lb}\right)} \tag{17}$$

$$CH_4\ emissions\ (tonnes\ CO_{2e}) = Electricity\ consumed\ (MWh) \times Grid\ emission\ intensity\ \left(\frac{lb\ CH_4}{MWh}\right) \times 0.000453\ \left(\frac{tonne}{lb}\right) \times CH_4\ GWP \tag{18}$$

$$N_2O\ emissions\ (tonnes\ CO_{2e}) = Electricity\ consumed\ (MWh) \times Grid\ emission\ intensity\ \left(\frac{lb\ N_2O}{MWh}\right) \times 0.000453\ \left(\frac{tonne}{lb}\right) \times N_2O\ GWP \tag{19}$$

$$Total\ GHG\ emisions\ (tonnes\ CO_{2e}) = CO_2\ emissions\ (tonnes\ CO_{2e}) + CH_4\ emissions\ (tonnes\ CO_{2e}) + N_2O\ emissions\ (tonnes\ CO_{2e}) \tag{20}$$

Note that in situations where a fuel such as gasoline is used to generate electricity on-site, the associated emissions would get included in the stationary fuel combustion emissions.

3.2.2.3 Sample Calculations

Location	Electricity Usage	Grid Emission Factor ($g\ CO_{2e}/kWh$)	Calculated Emissions
Alberta	10,000 kWh	640 $g\ CO_{2e}/kWh$	6.4 tonnes CO_{2e}

3.2.3 Heat / Cooling / Steam

The methodology for reporting emissions from the purchase and consumption of heat, cooling, and steam is the same as for the purchase of electricity. It may follow a location or market-based approach. Appendix A of the **Scope 2 Guidance** details the accounting procedures for steam, heating, and cooling [4]. If a company purchases heat or steam, they should obtain the relevant emission factors from their suppliers and discuss their use with ARC.

3.2.4 Reporting Table – Results for Scope 2

For reporting to ARC please provide the following results for the total Scope 2 corporate emissions for each of the metrics shown in Table 12.

Table 12 – Scope 2 Corporate Reporting Table

Emission Categories	Units	Reporting Year
Total indirect GHG emissions (Scope 2)	Metric tonnes CO_{2e}	
Total Electricity Usage	kWh	

References

[1] World Business Council for Sustainable Development and World Resources Institute, The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard, Revised Edition, available online at: https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf

[2] Government of Alberta, 2021, Alberta greenhouse gas quantification methodologies – Technology innovation and emissions reduction regulation, Version 2.2, available online at: Alberta Greenhouse Gas Quantification Methodologies (Version 2.2)

[3] Environment and Climate Change Canada, 2022, Canada's Greenhouse Gas Quantification Requirements, Greenhouse Gas Reporting Program, December 2021, Version 5.0, available online at: Canada's Greenhouse Reporting Program – Quantification Requirements (publications.gc.ca)

[4] World Resources Institute, World Business Council for Sustainable Development, 2015, GHG Protocol Scope 2 Guidance, An amendment to the GHG Protocol Corporate Standard, available online at: https://ghgprotocol.org/sites/default/files/standards/Scope%202%20Guidance_Final_Sept26.pdf

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[6] Environment and Climate Change Canada, 2022, National Inventory Report 1990–2020: Greenhouse Gas Sources and Sinks in Canada Part 2, available online at: https://publications.gc.ca/collections/collection_2022/eccc/En81-4-2020-2-eng.pdf

[7] Environment and Climate Change Canada, 2022, National Inventory Report 1990–2020: Greenhouse Gas Sources and Sinks in Canada Part 3, available online at: https://publications.gc.ca/collections/collection_2022/eccc/En81-4-2020-3-eng.pdf

[8] United States Environmental Protection Agency, April 2022, GHG Emission Factors Hub, available online at: https://www.epa.gov/system/files/documents/2022-04/ghg_emission_factors_hub.pdf

Additional Links

Environment and Climate Change Canada, Greenhouse Gas Reporting Program, https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/facility-reporting/about.html

GHG Protocol Emissions Calculation Tool: https://ghgprotocol.org/ghg-emissions-calculation-tool

United States Environmental Protection Agency Center for Corporate Climate Leadership, GHG Inventory Process Development Process and Guidance: https://www.epa.gov/climateleadership/ghg-inventory-development-process-and-guidance

United States Environmental Protection Agency, 2022, Simplified Guide to Greenhouse Gas Management for Organizations, available online at: https://www.epa.gov/system/files/documents/2022-09/Simplified_Guide_GHG_Management_Organizations.pdf

United States Environmental Protection Agency Center for Corporate Climate Leadership, 2022, GHG Emission Factors Hub, available online at: https://www.epa.gov/system/files/documents/2022-04/ghg_emission_factors_hub.pdf

Alberta Energy Regulator, 2020, Manual 015: Estimating Methane Emissions, available online at: https://static.aer.ca/prd/documents/manuals/Manual015.pdf

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