Guidance Document for GHG Accounting and Reporting

Prepared for:

ARC Portfolio Companies

Exploration and Production Companies

Prepared by:

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Version 1.0

December 2022

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1 INTRODUCTION

Exploration and production (E&P) companies typically follow similar methodologies when reporting greenhouse gas (GHG) emissions to provincial and federal regulatory agencies as well as for other disclosures such as sustainability disclosure programs. This document presents a set of calculation methods to be used consistently by all E&P companies that provide regular reports to ARC and is not intended to replace, nor are they intended to be a substitute for any approved methodologies that companies may already be using for regulatory and/or sustainability reporting.

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

The GHG Protocol provides detailed descriptions regarding the selection of appropriate GHG 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 will account for its GHG emissions based on its share of equity or economic interest in the operations of an asset or operation. Under the control approach, companies may categorize their emissions based on financial or operational control. Once an organizational boundary has been determined, it needs to be applied consistently across the reporting organization [1]. For the purposes of reporting to ARC, this document follows the operational control boundary approach, as this is the recommended approach for most Portfolio Companies. Using the operational control approach indicates that "a company accounts for 100% of emissions from the assets or operations over which it has operational control" [1]. Figure 1 shows the organizational boundary that is to be considered by Portfolio Companies specifically for the purpose of reporting to ARC.

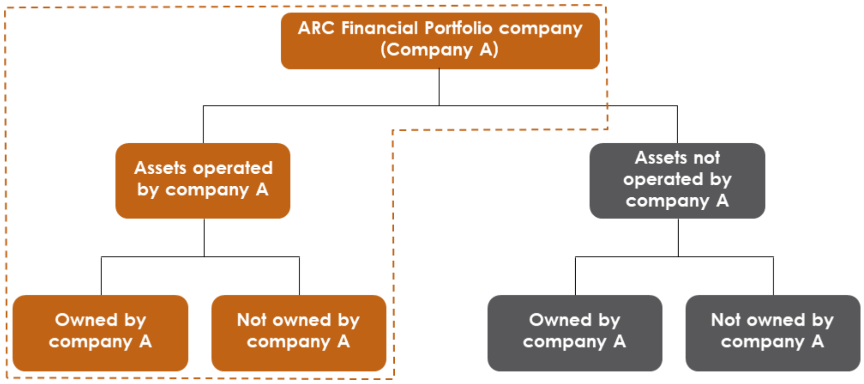

Figure 1 – Organizational boundary for Portfolio companies. Assets highlighted in orange within the orange dotted line fall within the organizational boundary based on the operational control approach

2.2 Operational Boundaries

Operational boundaries identify various GHG sources relevant to a company's operations and determine whether those GHG sources are direct (Scope 1) or indirect (Scope 2) 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 2 shows the GHG sources that are most likely to fall within the operational boundary of E&P companies within ARC's portfolio.

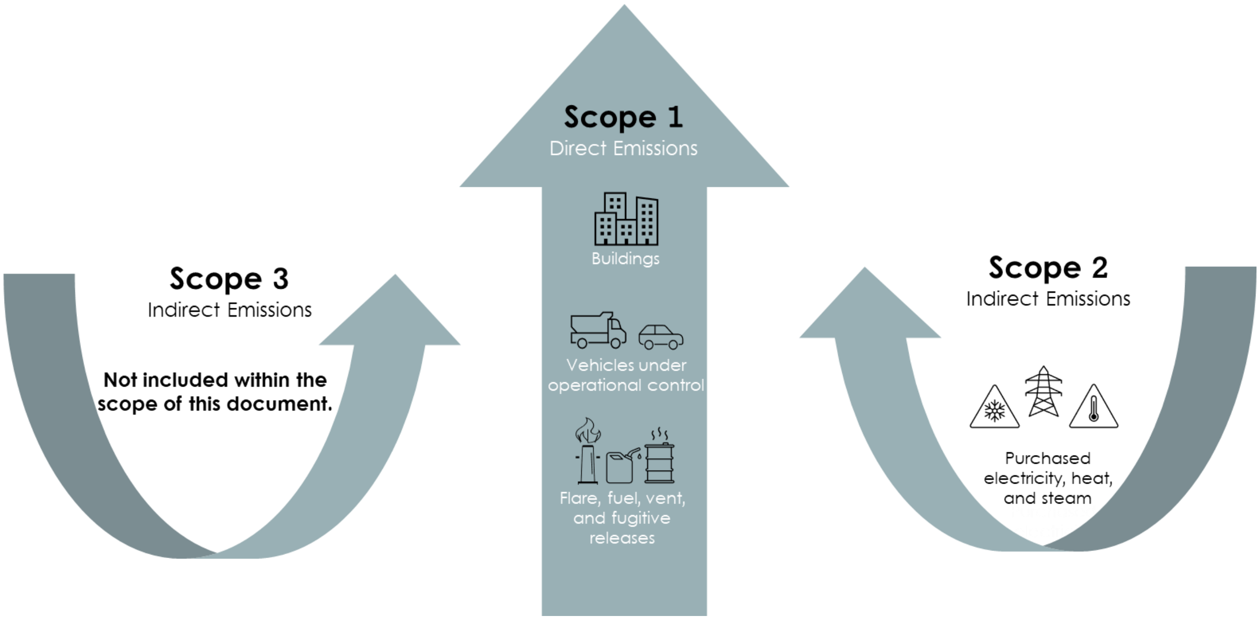

Figure 2 – Typical operational boundary for E&P companies

2.3 Reporting Period

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

3 Quantification Methodology

For each asset or 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 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 1.

Table 1 – IPCC AR4 100-year GWPs

GHG Species	GWP
Carbon Dioxide (CO_2)	1
Methane (CH_4)	25
Nitrous Oxide (N_2O)	298

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. Scope 1 GHG sources for exploration and production companies typically include the following:

- Stationary fuel combustion emissions (e.g., fuel use for heating or power generation)
- Flaring emissions
- Venting and fugitive emissions
- Transportation emissions

This document provides a streamlined method to allow for the calculation of each of these sources consistently across Portfolio Companies. Data inputs required to complete the calculations, the calculation procedure, as well as sample examples are also provided. While more in-depth calculations are possible, Portfolio Companies are asked to follow the methods provided in this document. If methods for quantification of one or more GHG sources that apply to a company are not provided in this document, or when an alternative method needs to be used due to data availability issues, companies are requested to contact ARC for further guidance.

3.1.2 Data Sources

The most common data source in Alberta, Saskatchewan, and British Columbia utilized during Scope 1 emissions calculations includes information reported to Petrinex and/or collected and tracked as part of a company's data management procedures, such as production accounting reporting practices. Data may be sourced from calculations completed for other regulatory reporting programs such as TIER or OneStop in Alberta. Other data sources may include fuel volumes and electricity usage reported by third–party suppliers. Table 2 highlights various data sources for each GHG source.

For companies that do not report to Petrinex and/or have different data requirements, please use internal data sources, third party–invoicing, and/or sources reported to the appropriate regulatory agencies where applicable.

Table 2 – Typical Data Sources

GHG source	Data Sources
Stationary Fuel Emissions	• Petrinex (fuel gas and/or natural gas volumes) • 3rd Party Invoicing (natural gas, gasoline, diesel, propane, etc. volumes)
Flaring Emissions	• Petrinex (flared gas volumes) • Internal meters and data systems
Venting Emissions	• Petrinex (vented gas volumes) • OneStop in Alberta (vented gas volumes and/or emissions) • Direct measurement • Data needed for estimation of vent emissions as per the Alberta Manual 15 (equipment inventory data)
Transportation Emissions	• 3rd Party Invoicing (e.g., gasoline and diesel invoices)

3.1.3 Stationary Fuel Combustion emissions

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

3.1.3.1 Data Inputs

For the purpose of ARC reporting, the volumes of the fuels obtained from the sources mentioned in Table 2 may be used to quantify the emissions. For example, in Alberta, fuel gas volumes may be obtained from the company's Petrinex reports, and the volumes of other fuels, such as gasoline, diesel, and propane, may be obtained from third-party records or invoices. Data may also exist within the companies' data management systems (e.g., production accounting) and may be used. Liquid fuel volumes should be reported as or converted to kilolitres (kl), and natural gas/fuel gas volumes should be reported as cubic meters (m^3).

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 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 3 and Table 4 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 mainly used by E&P company operations.

Table 3 – Stationary fuel combustion emission factors for liquid fuels [2,9]

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 4 – Stationary fuel combustion emission factors for gaseous fuels [2,9]

Fuel Type	CO_2 Emission Factor (tonne/m^3)	CH_4 Emission Factor (tonne/m^3)	N_2O Emission Factor (tonne/m^3)
Natural Gas	0.0019	6.4E–06	6.0E–08
Fuel Gas	0.00233	6.4E–06	6.0E–08

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	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	Emissions (tonnes CO_{2e})
Diesel	100,000	2.0E–05	2.0	298	596.0

3.1.4 Flaring emissions

Flaring emissions are emissions resulting from the combustion of gases such as fuel gas in flares. For exploration and production companies operating in Alberta, British Columbia and Saskatchewan, flaring volumes are typically reported to Petrinex and tracked internally as well. This methodology document uses the default emissions calculation equations. The method described in this section should also be used in situations where gas is destroyed in enclosed combustors.

3.1.4.1 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 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%. Emission factors for combustion efficiencies of

99.5% and 100% are available in Chapter 2 of the AQM [2] and may be used if deemed to be a better representative of the facility's operations.

3.1.4.2 Calculation Methodology

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

$$CO_2\ emissions\ (tonnes\ CO_{2e}) = Flared\ Volume\ (m^3) \times Flare\ Emission\ Factor\ \left(\frac{g\ CO_2}{m^3}\right) \times 10^{-6} \tag{5}$$

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

$$N_2O\ emissions\ (tonnes\ CO_{2e}) = Flare\ Volume\ (m^3) \times Flare\ Emission\ Factor\ \left(\frac{g\ N_2O}{m^3}\right) \times\ N_2O\ GWP \times 10^{-6} \tag{7}$$

$$\begin{aligned} Total\ Flare\ Emissions\ (tonnes\ CO_{2e}) = \\ CO_2\ emissions\ (tonnes\ CO_{2e}) + \\ CH_4\ emissions\ (tonnes\ CO_{2e}) + \\ N_2O\ emissions\ (tonnes\ CO_{2e}) \end{aligned} \tag{8}$$

The emission factors listed in Table 5 have been 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 5 – Flaring emission factors (emission factors are taken from the AQM table 2-2 to 2-4 for open flares with 98% efficiency [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	31.00	0.02
Still gas (Refinery & others)	2,081	31.00	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.

3.1.4.3 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})
Sales Gas	100,000	0.033	0.0033	298	0.98

3.1.5 Venting & Fugitive emissions

Venting emissions for exploration and production companies occur as either a routine venting of gas during normal operations or a non-routine release (planned or unplanned) [2]. These releases are expected and occur as part of the operations of the facilities.

Fugitive emissions are unwanted releases of greenhouse gases into the atmosphere, e.g., fuel gas leaks from valves. Both vent and fugitive emissions are required to be reported to ARC.

3.1.5.1 Data Inputs

The minimum data required is the total volume of vented gas (including defined vent gas, non-routine vent gas, pneumatic devices, compressor seals, glycol dehydrators) and volume of fugitive emissions.

In Alberta, Saskatchewan, and British Columbia, E&P companies report their vent volumes monthly to Petrinex. These vent volumes may be used for ARC reporting purposes. Regardless, all E&P companies in Canada should already have an inventory of their venting equipment and their vent volumes. In the absence of Petrinex data, companies may use these volumes to report to ARC. Companies may either use direct field measurement to measure the vent from their facilities or follow the methods from the AER Directive 060 to estimate the vent volumes [6].

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

Fugitive emissions are not reported into Petrinex. In Alberta, oil and gas facilities have requirements for completing fugitive emissions surveys, quantifying their fugitive emissions, and reporting these to the AER separately as part of the AER's OneStop reporting requirements. Companies in Alberta can use the values they report to OneStop for reporting to ARC. Note that the reporting deadline for OneStop is June 1 of each year for the prior year [7]. Therefore, companies may need to plan ahead and make arrangements to meet ARC's reporting deadlines which may be earlier in the year.

Facilities in Saskatchewan and British Columbia also have fugitive emissions survey requirements. However, the details of the requirements (e.g., frequency of the required fugitive surveys) may be different than in Alberta. Regardless, facilities may use the results of their fugitive emissions surveys that are completed following their province's requirements for reporting fugitive emissions to ARC. Fugitive emissions surveys may be conducted by third–party service providers or internally by companies if they have the proper equipment and qualifications.

Third–party companies often provide oil and gas facilities with both volumes and estimated emissions of fugitive gasses. Facilities may use these estimated emissions directly for reporting to ARC. Otherwise, where only the volume of the releases is provided, facilities will need a gas sample, ideally from the site/location where fugitive gasses are being released, to determine the mole fraction of CO_2 and CH_4 and estimate the fugitive emissions as explained in 3.1.5.2. If a gas composition analysis is not available, the reporting company should conservatively assume the vent source to be 100% CH_4. If more than one gas analysis for one site/location is available, average values across the gas analyses may be used. Additional constant inputs include the density of CO_2 or CH_4 at standard conditions as well as the proper unit conversions.

3.1.5.2 Calculation Methodology

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

$$CO_2\ emissions\ (tonnes\ CO_{2e}) = Vent\ volume\ (m^3) \times mole\ fraction\ of\ CO_2\ in\ vent\ gas\ (\%) \times CO_2\ density\ \left(1.861 \frac{kg\ CO_2}{m^3\ CO_2}\right) \times 10^{-3} \tag{9}$$

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

$$Total\ vent\ emissions\ (tonnes\ CO_{2e}) = CO_2\ emissions\ (tonnes\ CO_{2e}) + CH_4\ emissions\ (tonnes\ CO_{2e}) \tag{11}$$

Similarly, fugitive emissions need to be quantified and reported. In most cases, third–party Leak Detection and Repair (LDAR) reports include the magnitude of the fugitive emissions. 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 may be used by replacing the "vented gas volume" with "fugitive gas volume".

3.1.5.3 Sample Calculation

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

Sample calculations for CO_2:

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

3.1.6 Mobile/Transportation emissions

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 owned by the reporting company, such as commercial air travel or employee-owned vehicles, would be categorized as a Scope 3 GHG source and not included in the scope of this document.

3.1.6.1 Data Inputs

The inputs for transportation emissions are similar to the data inputs for stationary fuel emissions. Fuels, such as diesel, gasoline, ethanol, etc., are typically reported as the amount of fuel (for example, in liters or kiloliters) used during the reporting period. Additional data inputs include emission factors specific to a 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 inventory [2]. Common transportation fuel emission factors are provided in Table 6.

Table 6 – Common transportation fuel emission factors [2]

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

3.1.6.2 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 emissions.

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.

$$CO_2\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl)\ \times fuel\ emission\ factor\ (\frac{tonne\ CO_2}{kl\ fuel}) \tag{12}$$

$$CH_4\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl)\ \times fuel\ emission\ factor\ \left(\frac{tonne\ CH_4}{kl\ fuel}\right) \times\ CH_4\ GWP \tag{13}$$

$$N_2O\ emissions\ (tonnes\ CO_{2e}) = fuel\ Volume\ (kl)\ \times fuel\ emission\ factor\ \left(\frac{tonne\ N_2O}{kl\ fuel}\right) \times\ N_2O\ GWP \tag{14}$$

$$Total\ mobile/transportation\ emissions\ (tonnes\ CO_{2e}) = CO_2\ emissions\ (tonnes\ CO_{2e}) + CH_4\ emissions\ (tonnes\ CO_{2e}) + N_2O\ emissions\ (tonnes\ CO_{2e}) \tag{15}$$

3.1.7 Reporting Table – Results for Scope 1

For reporting to ARC please provide the following results for total Scope 1 corporate emissions for each of the metrics shown in Table 7. Total biogenic CO_2 emissions are reported separately from the other emission categories and are not included in the total direct GHG emissions.

Table 7 – Scope 1 Corporate Reporting Table

Exploration & Production (Scope 1)	Units	Reporting Year
Total direct GHG emissions	Metric tonnes CO_{2e}	
Stationary Combustion Emissions	Metric tonnes CO_{2e}	
Flaring Emissions	Metric tonnes CO_{2e}	
Venting Emissions	Metric tonnes CO_{2e}	
Transportation Emissions	Metric tonnes CO_{2e}	
Total Biogenic CO_2 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 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 company-owned facilities within the determined boundaries. These amounts are typically available from utility bills or metered energy 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 8 shows the most recent (2020) grid electricity consumption intensities for Alberta, British Columbia, and Saskatchewan [8]. 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 8 – Grid Electricity Consumption Intensity [8]

Province	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

3.2.2.2 Calculation Methodology

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

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 Calculation

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]. Purchased heat/cooling and steam are rarely applicable to E&P companies and are not discussed here. 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 Total Scope 2 corporate emissions for each of the metrics shown in Table 9.

Table 9 – Scope 2 Corporate Reporting Table

Exploration & Production	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)

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[7] 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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[9] 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

ADDITIONAL USEFUL LINKS

Petrinex: https://www.petrinex.gov.ab.ca/App/CMISECUR_00_FRM_Logon.aspx

OneStop: https://onestop.aer.ca/onestop/

Technology Innovation and Emissions Regulation (TIER): https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation.aspx#jumplinks-9

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

Environment and Climate Change Canada, Facility Greenhouse Gas Reporting, Technical Guidance on Reporting Greenhouse Gas Emissions, 2020, available online at: https://publications.gc.ca/collections/collection_2021/eccc/En81-29-2020-eng.pdf

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

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