The Climate Registry

General Reporting Protocol

Version 2.0

Accurate, transparent, and consistent measurement of **greenhouse gases** across North America

March 2013

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Please Note: Annually updated defaults are available on The Climate Registry's website at www.theclimateregistry.org.

ABBREVIATIONS AND ACRONYMS

Btu	British thermal unit(s)
CEMS	Continuous Emissions Monitoring System
CHP	Combined heat and power
CH_4	Methane
COP	Coefficient of performance
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRIS	Climate Registry Information System
EPS	Electric Power Sector
EU-ETS	European Union Emission Trading Scheme
GCV	Gross caloric value
GHG	Greenhouse gas
GRP	General Reporting Protocol
GVP	General Verification Protocol
GWP	Global warming potential
HFC	Hydrofluorocarbon
HHV	Higher heating value
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram(s)
kWh	Kilowatt-hour(s)
lb	Pound
LGO	Local Government Operations
LHV	Lower heating value
LPG	Liquefied petroleum gas
MMBtu	One million British thermal units
MWh	Megawatt-hour(s)
NF_3	Nitrogen trifluoride
N_2O	Nitrous oxide
PFC	Perfluorocarbon
SEM	Simplified Estimation Methods
SF_6	Sulfur hexafluoride
U.S. EPA	United States Environmental Protection Agency
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

ABOUT THE CLIMATE REGISTRY

The Climate Registry (The Registry) envisions a world on a measurable path to sustainability. Our mission is to empower the world's leading organizations with the highest quality carbon data so they can operate more efficiently, sustainably and competitively. The Registry is the only voluntary carbon reporting program that is backed by state government, provides hands-on support and service, and that generates high quality, consistent, and credible data to help organizations become more efficient, sustainable and competitive.

The Climate Registry was established in 2007 as a 501 (c)(3) by U.S. states and Canadian provinces, and today is governed and supported by a Board of Directors comprised of senior officials from U.S. states, Canadian provinces and territories, Mexican states and Native Sovereign Nations covering more than 80% of the North American population. It is the only voluntary GHG registry supported by this level of government collaboration. It is aligned with international standards and provides a nexus between business, government and NGO's to share policy information and exchange best practices.

The Registry provides leading organizations with high visibility recognition opportunities and welcomes participation from climate-leading organizations, both public and private, across a broad range of sectors. For more information, please visit: www.theclimateregistry.org.

Benefits of Reporting

Reporting is open to all legally constituted bodies (e.g., corporations, institutions, and organizations) recognized under U.S., Canadian, or Mexican law. In addition, cities, counties, and government agencies may also participate in The Registry. Organizations that measure and report their emissions to The Registry will:

- **Save money and improve your energy efficiency**
  Measuring your emissions and having a thorough understanding of your carbon footprint means that you can better understand how and where you can reduce your emissions – and reducing emissions is almost always associated with reducing operational and energy costs.

- **Protect and build your reputation**
  The issues of climate change and resource management are increasingly important to government, customers, shareholders and the community at large. Demonstrating your leadership and environmental stewardship are integral to maintaining your social license to operate. Measuring and reporting your emissions to The Registry ensures that your efforts are transparent and credible.

- **Receive recognition for your leadership**
  The Registry and its Board – which is comprised of regulators from across North America - recognizes leading organizations for their leadership in measuring and managing their GHGs. Programs include the Climate Registered™ program; the national Climate Leadership Awards, sponsored by the U.S. Environmental Protection Agency; and the Cool Planet Awards.

- **Build competitive advantage**
  Your GHG inventory can help drive cost savings, improve operational efficiency, and reduce emissions. As a result, you have the opportunity to become more energy efficient, re-design

your business operations and processes, implement technological innovations, improve your products and services, and ultimately build sustainable competitive advantage.

- **Manage risks**
  Measuring your emissions will help you engineer your operations so that they are less GHG-intensive. This will help you be prepared in light of potential increases in energy costs and carbon-related regulation. Measuring and reporting your GHG emissions may also be required by future state, provincial, federal or international regulatory GHG programs.

- **Build your in-house capacity and exchange best practices**
  The Registry provides a range of services to help develop your capacity as you build and report your GHG inventory, including a live help desk, trainings, webinars, reporting tools and software.

You will also benefit from learning from and networking with The Registry's community, which includes its Board members as well as the hundreds of leaders from across industries and sectors who report to The Registry. Throughout the year there are many opportunities for you to share best practices, including national and regional meetings, conferences, webinars and policy briefings.

Getting Started

The Registry has resources and staff available to help you build and report your annual carbon footprint. We are here to support our members throughout the process. We suggest that you begin by taking these first steps:

- Download and read the General Reporting Protocol, focusing on Parts I and II
- Register for our trainings on the General Reporting Protocol and Climate Registry Information Systems (CRIS) reporting software by visiting the calendar on our website at www.theclimateregistry.org
- Visit the reporting toolkit on our website to browse additional resources, including the Getting Started Guide, CRIS User's Guide, Inventory Management Plan and Reporting Timeline

The Member Services team is available to assist members Monday through Friday from 9:00am to 5:00pm Pacific at help@theclimateregistry.org or (866) 523-0764 extension 3. A helpful associate will be standing by to answer your reporting questions.

PART I: INTRODUCTION

Chapter 1: Introduction

The General Reporting Protocol (GRP) is divided into several parts. These parts mirror the chronology of the reporting process:

- Determining what to report;
- Quantifying emissions; and
- Reporting emissions.

Figure 1.1 illustrates the reporting process, and explains where related guidance is contained in the GRP.

Part I provides an overview of this General Reporting Protocol.

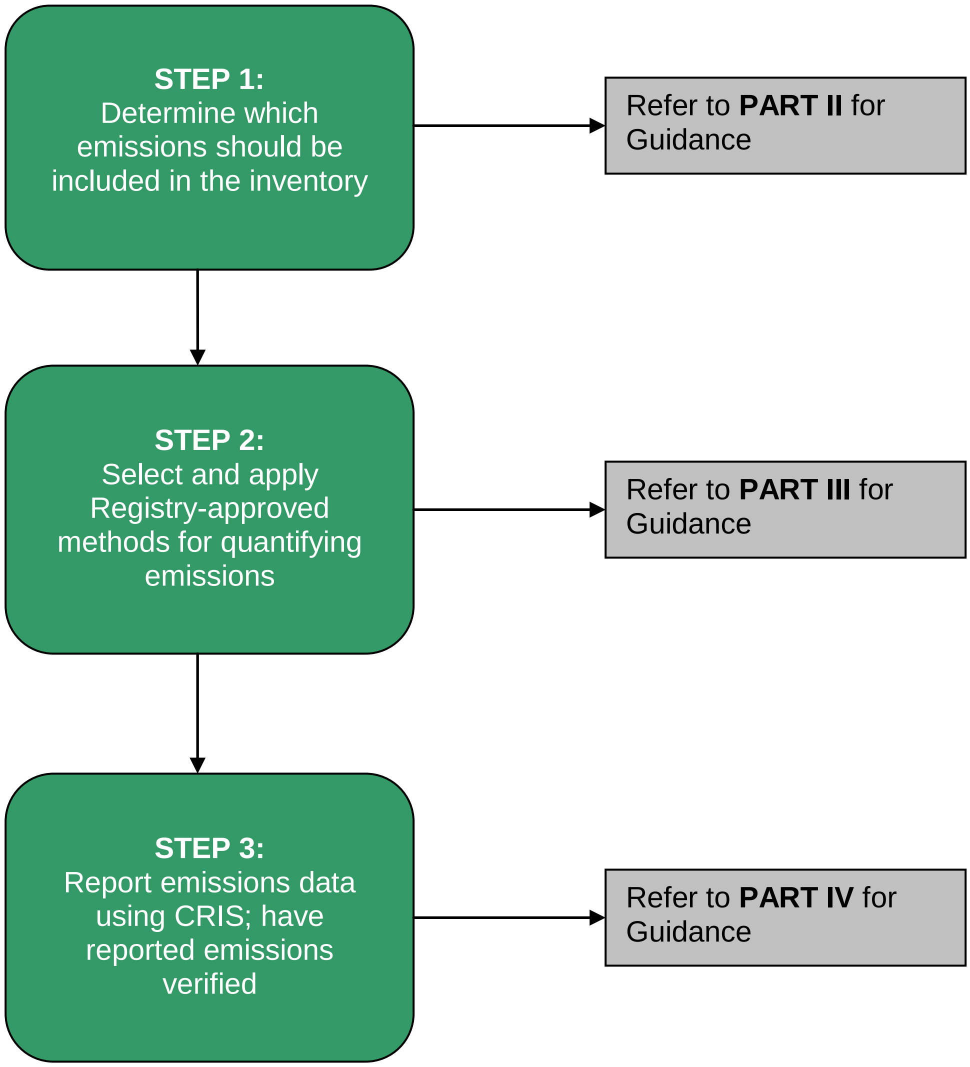
Part II provides guidance on determining the specific emissions sources that must be reported and how emissions data should be categorized and consolidated in your inventory.

Part III provides the methodologies approved by The Registry for quantifying emissions from various emission sources. Part III pertains to emission sources likely to be pertinent to a wide variety of Members.

Part IV describes the process for reporting emissions to The Registry once they have been quantified using the methodologies outlined in Part III.

For more information about The Climate Registry, visit our website at www.theclimateregistry.org.

Figure 1.1. Process for Reporting Emissions and Corresponding Protocol Guidance



1.1 GHG Accounting and Reporting Principles

The Registry has adopted five overarching accounting and reporting principles that are intended to help ensure that GHG data represent a faithful, true, and fair account of an organization's GHG emissions. The principles are consistent with the World Resource Institute and the World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition) and the International Organization for Standardization (ISO) 14064-1, *Specification Accounting and Reporting Standard* (Revised Edition).

When deciding on data collection procedures or whether to report certain categories of emissions, you are encouraged to consult these accounting principles:

- **Relevance**: Ensure that the GHG inventory appropriately reflects an organization's GHG emissions and serves the decision-making needs of users—both internal and external to the organization.

- **Completeness**: Account for and report all GHG emission sources and activities within the defined inventory boundary.

- **Consistency**: Use consistent methodologies to allow for meaningful comparisons of emissions over time. Clearly document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.

- **Transparency**: Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.

- **Accuracy**: Ensure that the quantification of GHG emissions is neither systematically overstating nor understating true emissions, and that uncertainties are reduced as much as practicable. Achieve sufficient accuracy enabling users of the data to be able to make decisions with reasonable assurance of the integrity of the reported information.

1.2 Origin of The Registry's GRP

The Registry's GRP embodies GHG accounting best practices. The Registry has drawn from the following existing GHG programs and protocols to create its GRP:

- The World Resources Institute and the World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition)

- International Organization for Standardization (ISO) 14064-1, *Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals*

- The California Climate Action Registry, *General Reporting Protocol* Version 3.1 and various industry-specific protocols

- U.S. Environmental Protection Agency Climate Leaders *Greenhouse Gas Inventory Guidance*

1.3 Updates to the GRP

The Registry may update this document in the future to reflect changes in international best practices and to provide additional clarity and guidance.

Any updates to the GRP will be documented in an Updates and Clarifications document that will be posted on The Registry's website at www.theclimateregistry.org**.** Until the next version of the GRP is released, all Members and Verification Bodies should refer to the latest Updates and Clarifications document for the most current interpretation and explanation of reporting policies, processes, and activities.

The Registry will inform stakeholders of changes to the GRP in a timely manner, and will provide explicit direction for when new reporting and verification policies or procedures will be required.

1.4 Emissions Inventory Boundary

Member inventories can be reported based on either a complete or transitional reporting boundary.

Complete Inventories

Complete inventories include emissions of all Kyoto-defined greenhouse gases, except where exclusion of miniscule sources is disclosed, from operations in Canadian provinces and territories, Mexican states, and U.S. states and dependent areas.

Transitional Inventories

The reporting boundary of a transitional inventory is self-defined by the Member using the following parameters:

- Scopes
- Gases
- Activity types (stationary combustion, etc.)
- Geographic/operational boundaries (country, state, business units, facility, etc.)

For more information on transitional inventories, see Chapter 8.

Table 1.1 introduces the concepts in Part II and provides a concise summary of the reporting and verification requirements and options for Members depending on the selected inventory boundary.

1.5 Annual Emissions Reporting

Members must report emissions on a **calendar year basis**.

The calendar year in which the emissions occurred is known as the emissions year. For example, if you report an inventory in 2010 for an organization's 2009 emissions, the emissions year is 2009.

Members may join The Registry at any time.

Members are encouraged to report the previous year's emissions annually by June 30th, and successfully verify emissions by December 15th. For exact reporting deadlines in a given year, refer to the most recent Reporting and Verification Timeline on The Registry's website at www.theclimateregistry.org.

Table 1.1. Key Registry Reporting and Verification Requirements and Options

Issue	Requirements		Optional
	Transitional	Complete	
Geographical Boundaries (Chapter 2)	• Report emissions from activities that occur within self-defined geographic boundary	• Report all emissions in Canadian provinces and territories, Mexican states, and U.S. states and dependent areas.	• May report worldwide emissions • Miniscule emission sources may be excluded if disclosed
Greenhouse Gases (Chapter 3)	• Report emission of gases included within self-defined boundary	• Report emissions of all internationally recognized GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6 and NF_3)	
Organizational Boundaries (Chapter 4)	• Report using operational or financial control		• Encouraged to additionally report using equity share
Operational Boundaries (Chapter 5)	• Report emissions from activities that occur within self-defined operational boundary • If direct emissions of CO_2 from biomass combustion are part of the self-defined operational boundary, they must be reported separately	• Report all required scope 1 and scope 2 emissions • Report direct emissions of CO_2 from biomass combustion separately	• May additionally report scope 3 emissions
Level of Detail (Chapter 6)	• Report at the entity-level		• May separately report emissions by facility. Must report in accordance with The Registry's facility-level reporting requirements in order to have a public facility-level report • If reporting by facility, may aggregate emissions from: a. Commercial buildings (e.g., office buildings) b. Mobile sources (fleets) c. Other special categories (e.g., oil and gas wells) d. Emissions calculated using simplified estimation methods
Tracking Emissions Over Time (Chapter 7)	• N/A	• Reporting a base year to The Registry is optional but recommended	• A base year may be set provided the inventory is complete

Issue	Requirements		Optional
	Transitional	Complete	
Getting Started (Chapter 8)	• First five years of public reporting may be transitional inventories. After five years, you may apply for a waiver to continue to report on a transitional basis.	• N/A	• May join The Registry as a basic Member. No public reporting or verification is required. Allows organizations to increase capacity for building a high-quality inventory.
Previously Reported Emissions (Chapter 9)	• There is no requirement to report historical emissions.		• May report historical emissions data for any year preceding your first reporting year as long as your data meets the minimum historical reporting and verification requirements, • You may submit historical data from other programs or registries to The Registry
Emissions Quantification Methods (Part III)	• Use the Registry-approved methods described in Part III, Appendix D, Annexes to the GRP (Registry-developed industry-specific reporting protocols) or calculation methodologies mandated by a state, provincial or federal GHG regulatory reporting program.		• May use simplified estimation methods for small emission sources. Total emissions computed using simplified methods cannot exceed five percent of Member's total entity (scope 1, scope 2 and direct biogenic emissions from stationary and mobile combustion) emissions
Performance Metrics (Chapter 17)	• There is no requirement to report performance metrics, unless reporting in conformance with the Electric Power Sector (EPS) Protocol.		• May report chosen performance metrics to show relevant, comparable data that enables tracking of emissions relative to indicators of performance (e.g., output).
Verifications (Chapter 19)	• Third-party verification is required.		• If the following information is optionally reported, it must be third-party verified: a) Worldwide scope 1 and 2 emissions; b) Equity share GHG inventory; c) Adjustment to base year; and, d) Transit and power delivery metrics. • The following information is not subject to verification: a) Scope 3 emissions; b) Optional scope 1 and 2 emissions; and, c) Non-combustion biogenic CO_2 emissions.

PART II: DETERMINING WHAT TO REPORT

About Part II

All organizations that report to The Climate Registry's voluntary reporting program should read Part II in its entirety. This section sets forth the general reporting requirements and options that pertain to Members.

Chapter 2: Defining the Geographic Boundary

Issue	Requirements		Optional
	Transitional	Complete	
Geographical Boundaries	• Report emissions from activities that occur within self-defined geographic boundary	• Report all emissions in Canadian provinces and territories, Mexican states, and U.S. states and dependent areas.	• May report worldwide emissions • Miniscule emission sources may be excluded if disclosed

Geographic boundary requirements vary dependent on the inventory boundary selected. Members reporting transitional inventories can self-define their geographic boundaries. The Registry requires that complete inventories include emissions from all operations in Canadian provinces and territories, Mexican states, and U.S. states and dependent areas.[1] All Members also have the option to report worldwide emissions.

2.1 Transitional Geographic Boundaries

The geographic boundary of a transitional inventory is determined by the reporting Member. Parameters that may be used to describe the self-defined geographic boundary include:

- Countries
- States, Provinces or Territories
- Business Units
- Facilities

Please note, transitional inventories can include some or all of a Member's global emissions. See Chapter 8 for more information on and transitional reporting.

2.2 Complete Geographic Boundaries

The Registry requires that, at a minimum, complete inventories include emission sources in all Canadian provinces and territories, Mexican states, and U.S. states and dependent areas. Members choosing to report emissions beyond Canada, Mexico and the U.S. as part of a complete inventory,

[1] Members must use default U.S. emission factors to report scope 1 and 2 emissions from U.S. dependent areas, namely, American Samoa, Baker Island, Guam, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Islands, Navassa Island, Northern Mariana Islands, Palmyra Atoll, Puerto Rico, Virgin Islands, and Wake Island.

must report GHG emissions from total global operations. See Section 2.3 for more information on worldwide reporting.

2.3 Reporting Worldwide Emissions

The Registry strongly encourages Members to report emissions associated with worldwide operations. Members may begin reporting your worldwide GHG emissions at any time.

There are several reasons to report worldwide emissions:

- Environmental management system captures emissions globally;
- It helps to prepare for regulatory programs worldwide;
- Corporate decision-making must look at the "big picture" when making efforts to improve efficiency and make cost-effective reductions in GHG emissions, which requires understanding of worldwide emissions;
- It enhances credibility to investors and customers; and
- Climate change is a global challenge requiring a global understanding of emission sources and profiles.

Reporting complete worldwide emissions ensures the most comprehensive accounting of emissions. A full accounting of worldwide GHG emissions helps to enhance the credibility of an inventory by demonstrating to data users that Members have fully documented emissions in *all* regions and countries; not just in areas where emissions may be small or declining.

The Registry's reporting guidance primarily includes defaults specific to North America. Members who choose to report any worldwide emissions must use appropriate methodologies and defaults based on the location where the emissions occur. Country-specific emission factors and IPCC defaults are excellent resources for organizations reporting emissions from sources outside of North America.

Members choosing to report and verify worldwide emissions must select one of the following two verification options:

- **Two Reports/Two Verifications**: This approach requires the preparation of two emissions reports (one for North America-only and one for non-North American operations) and separate verification statements. Each inventory and verification must conform to The Registry's criteria (e.g. five percent materiality threshold, five percent threshold for simplified estimation methodologies, etc.) separately.

  Members must always use a Registry-recognized Verification Body for verification of North American emissions inventories. However a different, ISO 14065-accredited Verifier may be used for verification of non-North American emissions inventories. Separate verification statements are required for each emissions inventory even if one Registry-recognized Verification Body conducts both the North American and non-North American verifications.

- **Two Reports/One Verification**: Members choosing this option must prepare separate emissions reports, one for North America-only and one for worldwide emissions (including North America).[2] With this option, The Registry's verification criteria (e.g. five percent materiality threshold, five percent threshold for simplified estimation methodologies, etc.) are applied to

[2] North American and non-North American inventories must be combined to create the worldwide inventory.

North American and worldwide emissions separately.

Under this option, Members must use one Registry-recognized Verifier for both reports (as they both contain North American emissions). Separate verification statements must be provided for each emissions report.

Organizations that do not have GHG emissions in Canada, Mexico or the U.S., may still join The Registry and report worldwide emissions transitionally or completely.

Chapter 3: Gases to Include in the Inventory

Issue	Requirements		Optional
	Transitional	Complete	
Greenhouse Gases	• Report emission of gases included within self-defined boundary	• Report emissions of all internationally recognized GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6 and NF_3)	

Complete inventories must include emissions of all internationally-recognized GHGs regulated under the Kyoto Protocol. These are:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride (SF_6)
- Nitrogen trifluoride (NF_3)[3]

A complete list of the internationally-recognized GHGs, including individual HFCs and PFCs, is provided in Appendix B. This list also includes the Global Warming Potential (GWP) of each GHG, which is used to calculate the carbon dioxide equivalence (CO_2e) of the individual gases.

Members must account for emissions of each gas separately and publicly report emissions in metric tons. CRIS will automatically convert reported emissions of most gases to CO_2e. For more information on converting to units of CO_2e, refer to Appendix B.

3.1 Transitional Gas Reporting

Transitional inventories can include less than all of the internationally-recognized GHGs regulated under the Kyoto Protocol. Reported gases must be described in the self-defined transitional boundary for transparency.

[3] This GHG was added to the Kyoto Protocol's second compliance period in 2012.

Chapter 4: Identifying the Organizational Boundary

Issue	Requirements		Optional
	Transitional	Complete	
Organizational Boundaries	• Report using operational or financial control		• Encouraged to additionally report using equity share

The organizational boundary is the sum of the operations that make up an organization. Business operations may include wholly owned operations, subsidiaries, incorporated and non-incorporated joint ventures, among others.

Emissions from these operations may be consolidated using different approaches. Ultimately the selected consolidation approach and a Member's unique business operations together determine which emissions sources are included within an inventory.

If an organization wholly owns and controls all of its operations, its organizational boundary will be the same whichever consolidation approach is used. For other organizations, however, the organizational boundary and the resulting emissions will differ depending on the consolidation approach used.

When reporting to The Registry, Members must include emissions from the activities within their organizational boundary for to the part of the year each activity is within its control. For most activities this will be the total annual emissions from the operation.

4.1 Two Approaches to Organizational Boundaries: Control and Equity Share

The Registry follows the WRI/WBSCD GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition) in defining the boundaries and structure of the reporting entity. There are two general approaches to defining the organizational boundary, the "equity share" approach and the "control" approach, defined as follows:

- **Equity Share Approach:** Members reporting using the equity share approach must report all emissions sources that are wholly owned and partially owned according to the Member's equity share in each. It is important to note that, when reporting to The Registry, Members that choose to report using this approach do so in addition to using one of the control approaches (financial or operational control).

- **Control Approach**: Under the control approach, Members must report 100 percent of the emissions from sources that are under their control, including both wholly owned and partially owned sources. Control can be defined in either financial or operational terms.

When using the control approach, Members must choose either the operational control approach or financial control approach to consolidate emissions, defined as follows:

- An entity has **operational control** over an operation (e.g. a business unit or facility) if the entity or one of its subsidiaries has the full authority to introduce and implement its operating policies. The entity that holds the operating license for an operation typically has operational control.

- An entity has **financial control** over an operation if the entity has the ability to direct the financial policies of the operation with an interest in gaining economic benefits from its activities. Financial control usually exists if the entity has the right to the majority of the benefits of the operation, however these rights are conveyed. An entity has financial control over an operation if the operation is considered a group company or subsidiary for the purpose of financial consolidation, i.e., if the operation is fully consolidated in financial accounts.

Members must apply the same organizational boundary approach (or approaches) consistently to all operations.

Each consolidation approach—equity share, operational control, and financial control—has different uses. The operational and financial control approaches may best facilitate performance tracking of GHG management policies and be most compatible with the majority of regulatory programs. However, these may not fully reflect the financial risks and opportunities associated with climate change, compromising financial risk management.

On the other hand, the equity share approach best facilitates financial risk management by reflecting the full financial risks and opportunities associated with climate change, but may be less effective at tracking the operational performance of GHG management policies.

Likewise, stakeholders may find each approach useful for different purposes. Member should consider their unique business needs and priorities when selecting an organizational boundary consolidation approach(s).

Requirements for Setting the Organizational Boundary

Members have two options for setting the organizational boundary:

- ***Option 1:*** Report based on both the equity share approach and a control approach (either operational or financial control); or

- ***Option 2:*** Report based on a control approach (either operational or financial control)

The control and equity share approaches both yield a meaningful picture of entity-wide emissions. Therefore, the most comprehensive approach is to consolidate emissions based on ***both*** the equity share and a control approach. The Registry strongly encourages Members to report using both approaches (Option 1).

If a Member cannot report based on the equity share and control approach (Option 1)—for instance, because it cannot obtain the necessary data from operations it does not control—the Member should report according to Option 2.

Members that initially report on a control basis (Option 2) and later choose to additionally report on an equity share basis (Option 1), should continue to report using Option 1 going forward.

Figure 4.1 is a decision tree that provides guidance on the reporting requirements for the equity share approach as well as for the control approaches. These requirements are described in the following sections.

4.2 Option 1: Reporting Based on Both Equity Share and Control

Equity Share Approach

Under the equity share approach, an organization accounts for GHG emissions from operations according to its share of equity in each operation. The equity share reflects economic interest, which is the extent of rights an organization has to the risks and rewards flowing from an operation. Typically, the share of economic risks and rewards in an operation is aligned with the organization's percentage ownership of that operation, and equity share will normally be the same as the ownership percentage. Where this is not the case, the economic substance of the relationship the organization has with the operation always overrides the legal ownership form to ensure that equity share reflects the percentage of economic interest.

Members should apply the equity share consolidation approach to report emissions sources within each owned company/subsidiary, associated/affiliated company, and joint venture/partnership/operation. Members need not include emissions from fixed asset investments, where the parent company has neither significant influence nor financial control See Table 4.3 for a breakdown of the difference between reporting equity share emissions and those under an organization's financial control. In addition, Table 4.1 provides an illustration of prorating facility emissions using the equity share approach.

Table 4.1. Accounting for Equity Share Emissions

Percent of Ownership	Percent of Emissions Attributed to Organization
Wholly-owned	100%
90% owned, with control	90%
90% owned, without control	90%
10% owned, with control	10%
10% owned, without control	10%
Fixed asset investments	0%

Control Approach with Equity Share

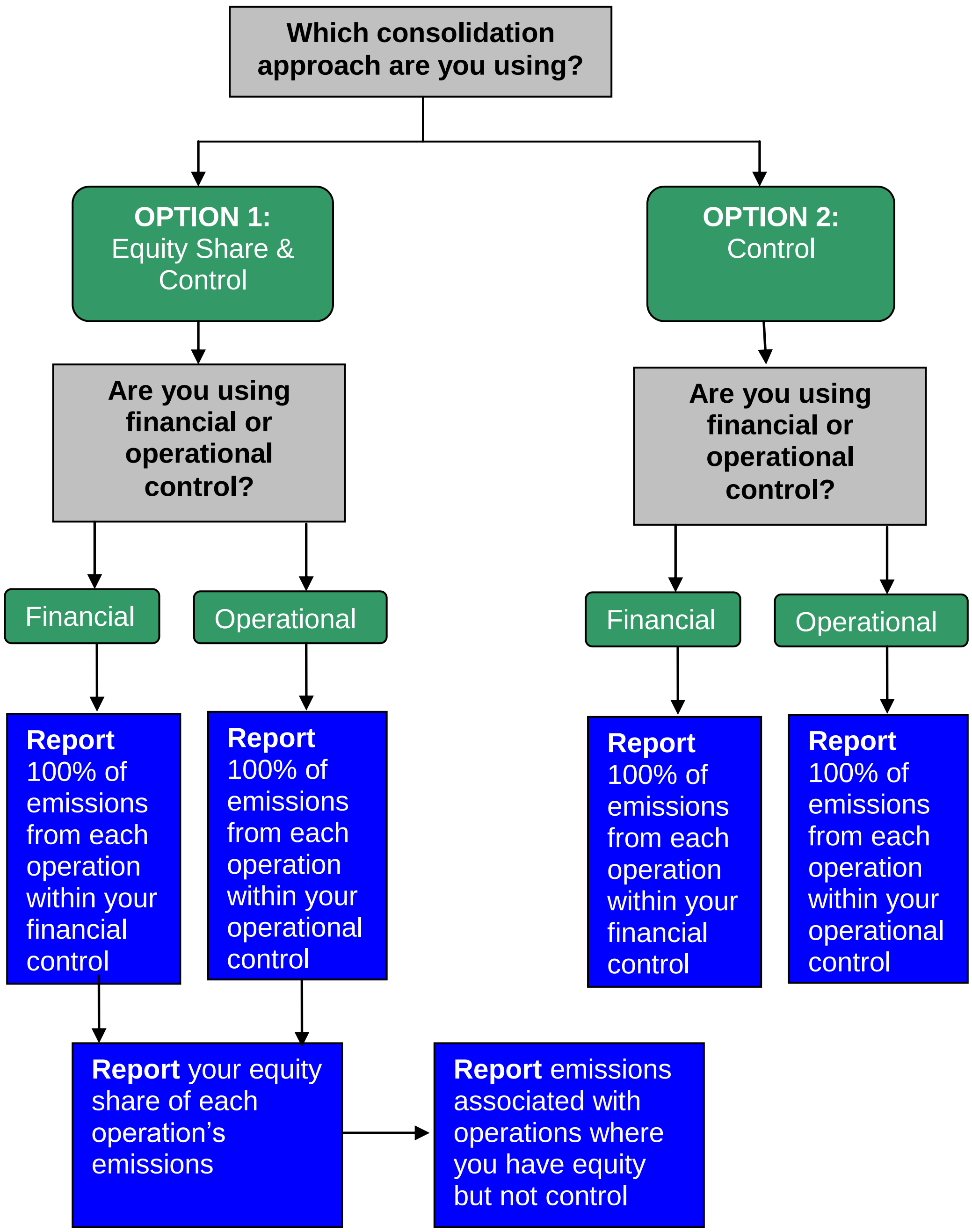
The Registry requires that when Members report using the equity share approach, they also report a control-based emissions inventory. This requirement ensures that all Members report consistently using the same method (i.e., control) in order to enhance the comparability of emissions reports. Consistency across reports also avoids double counting when multiple emission reports are compared.

Reporting based on equity share is similar to reporting based on the control approach. In many cases equity share emissions totals can be easily derived from control-based emissions. To obtain equity share-based emissions from control-based emissions, simply multiply each source or facility's total emissions by the percent equity in each.

Once emissions associated with operations within a Member's control are quantified, and the equity share emissions associated with those operations are identified, Members reporting under Option 1 must additionally report emissions associated with operations where they have an equity share but no control.

CRIS, The Registry's online GHG calculation and reporting tool, computes separate summaries of entity-wide emissions based on both the equity share and the control approach.

Figure 4.1. Decision Tree for Determining Reporting Requirements for the Different Consolidation Methods



4.3 Option 2: Reporting Using the Control Consolidation Approach

Control can be defined in either operational or financial terms. When using control to determine how to report GHG emissions associated with joint ventures and partnerships, first select between either the financial or operational approach and consistently apply the definitions below to those activities.

If a Member has have control over a particular joint venture or partnership, it should report 100 percent of the emissions from that entity, including all of its operations, facilities, and sources. If Members do not have control, they must not report any of the emissions associated with the entity.

In most cases, the organization that has financial control of an operation typically also has operational control.

However, in some sectors such as the oil and gas industry, complex joint ventures and ownership or operator structures can exist where financial and operational control are not vested with the same organization. In these cases, the choice to apply a financial or operational definition of control can be significant. In making this decision, Members should take into account their individual situation and select a criterion that best reflects the actual level of control and the standard practice within the industry. Table 4.2 provides an illustration of the reporting responsibility under the two different control reporting options. One or more conditions from those listed below can be used to choose a control approach.

Operational Control Approach

Operational control is the authority to develop and carry out the operating or health, safety and environmental (HSE) policies of an operation or at a facility. One or more of the following conditions establishes operational control:

- Wholly owning and controlling an operation, facility, or source.

- Having the full authority to introduce and implement operational and health, safety and environmental policies (including both GHG- and non-GHG related policies). In many instances, the authority to introduce and implement operational and health, safety, and environmental (HSE) policies is explicitly conveyed in the contractual or legal structure of the partnership or joint venture. In most cases, holding an operator's license is an indication of your organization's authority to implement operational and HSE policies. However, this may not always be so. If a Member holds an operating license and believes it does not have operational control, it will need to explicitly demonstrate that the Member's authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

It should be noted that an organization need not be able to control all aspects of operations within a joint venture to have operational control. For instance, an entity with operational control may not have the authority to make decisions on major capital investments without the approval of other parties in a venture.

Outsourcing Transportation Services

Unique circumstances often occur for transportation companies or agencies that contract with a third party to provide transportation services. Examples may include a major airline's regional carriers or a transportation agency's bus service.

In these cases, if a Member can demonstrate that they meet at least part of the following criteria, then they may assume operational control of the associated emissions:

- Control of HSE policies
- Operation and maintenance of the equipment with the entity's employees
- Responsibility for replacing equipment or asset cost in event of accident
- Determining the operating policies (e.g. schedule, routes) that directly impact GHG emissions

Financial Control Approach

Financial control is the ability to dictate or direct the financial policies of an operation or facility with the ability to gain the economic rewards from activities of the operation or the facility. One or more of the following conditions establishes financial control:

- Wholly owning an operation, facility, or source.
- Considering an operation to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in an organization's financial statements.
- Governing the financial policies of a joint venture under a statute, agreement or contract.
- Retaining the rights to the majority of the economic benefits and/or financial risks from an operation or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed. These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include an organization casting the majority of votes at a meeting of the board of directors or having the right to appoint/remove a majority of the members of the board in the case of an incorporated joint venture.

Joint Financial Control

In the case of joint control, financial decisions require unanimous agreement by multiple organizations. Generally the organizations that have joint financial control are determined as a result of percent equity ownership, as equity share in a venture determines which of the organizations must unanimously agree for the decision to pass. In addition, no stipulations may exist that demonstrate that any one organization has control of the financial policies of the venture. If a Member has joint financial control of a joint venture and is reporting to The Registry using the financial control consolidation approach, the Member should report emissions based on its equity share in the joint venture, that is, based on the Member's economic interest in and/or benefit derived from the operation or activities at a facility.

Providing a List of Equity Investments

Members who choose one of the control organizational boundary approaches (Option 2), are encouraged to provide additional information about any entities in which the Member has an equity investment without control. By providing this additional information, the Member will enhance disclosure of its emissions profile by shedding light on operations that are omitted from a control-based emission report. This is also valuable information for Members considering reporting scope 3 emissions. See Chapter 5 for more information on scope 3.

Examples of information that The Registry encourages Members to disclose regarding equity investments include:

- A list of all entities and jointly owned operations in which the Member has an equity share but not control, including subsidiaries, associated/ affiliated entities, and joint ventures/partnerships/ operations
- The percent ownership interest held for each entity or operation
- The identity of the legal entity that has control over each listed entity or operation
- A brief description of the emitting activities and emissions profile for each listed entity or operation

Because investment portfolios change over time, Members should include those investments held by your entity only for the portion of time that you maintained each investment.

See Example 4.8 (Table 4.4) in this chapter for an example of equity investment information provided by a Member.

Table 4.2. Reporting Based on Financial Versus Operational Control

Level of Control of Facility	Percent of Emissions to Report Under Financial Control	Percent of Emissions to Report Under Operational Control
Wholly owned	100%	100%
Partially owned with financial and operational control	100%	100%
Partially owned with financial control; no operational control	100%	0%
Partially owned with operational control; no financial control	0%	100%
Joint financial control with operational control	Based on equity share	100%
Joint financial control; no operational control	Based on equity share	0%
Subsidiary with operational control	100%	100%
Subsidiary; no operational control	100%	0%
Associated entity (not consolidated in financial accounts) with operational control	0%	100%
Associated entity (not consolidated in financial accounts); no operational control	0%	0%
Fixed asset investments	0%	0%
Not owned but have a capital or financial lease	100%	100%
Not owned but have an operating lease	0%	100%

Table 4.3. Reporting Based on Equity Share versus Financial Control

Accounting Category	Financial Accounting Definition	GHG Consolidation Approach	
		Equity Share	Financial Control
Group companies/ subsidiaries	The parent company has the ability to direct the financial and operating policies of the company with a view to gaining economic benefits from its activities. Normally, this category also includes incorporated and non-incorporated joint ventures and partnerships over which the parent company has financial control. Group companies/ subsidiaries are fully consolidated, which implies that 100 percent of the subsidiary's income, expenses, assets, and liabilities are taken into the parent company's profit and loss account and balance sheet, respectively. Where the parent's interest does not equal 100 percent, the consolidated profit and loss account and balance sheet shows a deduction for the profits and net assets belonging to minority owners.	Equity share of GHG emissions	100% of GHG emissions
Associated/ affiliated companies	The parent company has significant influence over the operating and financial policies of the company, but does not have financial control. Normally, this category also includes incorporated and non-incorporated joint ventures and partnerships over which the parent company has significant influence, but not financial control. Financial accounting applies the equity share method to associated/ affiliated companies, which recognizes the parent company's share of the associate's profits and net assets.	Equity share of GHG emissions	0% of GHG emissions
Non-incorporated joint ventures/ partnerships/ operations where partners have joint financial control	Joint ventures/partnerships/operations are proportionally consolidated, i.e., each partner accounts for their proportionate interest of the joint venture's income, expenses, assets, and liabilities.	Equity share of GHG emissions	Equity share of GHG emissions
Fixed asset investments	The parent company has neither significant influence nor financial control. This category also includes incorporated and non-incorporated joint ventures and partnerships over which the parent company has neither significant influence nor financial control. Financial accounting applies the cost/dividend method to fixed asset investments. This implies that only dividends received are recognized as income and the investment is carried at cost.	0% of GHG emissions	0% of GHG emissions
Franchises	Franchises are separate legal entities. In most cases, the franchiser will not have equity rights or control over the franchise. Therefore, franchises should not be included in consolidation of GHG emissions data. However, if the franchiser does have equity rights or operational/financial control, then the same rules for consolidation under the equity or control approaches apply.	Equity share of GHG emissions	100% of GHG emissions

Source: *GHG Protocol Corporate Accounting and Reporting Standard Revised Edition*. "Table 1. Financial Accounting Categories." Based on a comparison of UK, U.S., Netherlands, and International Financial Reporting Standards (KPMG, 2000).

4.4 Corporate Reporting: Parent Companies and Subsidiaries

Parent companies or entities that report completely to The Registry are required to report on behalf of all subsidiaries and group operations.

A subsidiary may be a Member of and report to The Registry when its parent company is not a Registry Member.

A subsidiary company of an existing Registry Member may also maintain its own membership and report separately from its parent company if it chooses to do so. If the subsidiary wishes to be a Climate Registered Member, it is required to meet the following conditions:

- The subsidiary must report using the same organizational boundary approach as its parent,
- When the parent has a verified report, the emission totals of the subsidiary must be included within the report of the parent,[4]
- The subsidiary must obtain a separate verification statement,
- The subsidiary's emission totals must appear identical in the public subsidiary and parent reports, and
- The subsidiary must disclose its parent company as it appears in CRIS in its public report.

These requirements are necessary to ensure that emissions are not double counted. Subsidiaries are also encouraged to submit a corporate organizational chart that clearly defines the Member's relationship to its parent(s) and other subsidiaries.

4.5 Government Agency Reporting

Similar to corporate reporting, The Registry strongly encourages government entities (local, county, state, provincial, national, etc.) to report emissions from their operations at the highest organizational level possible (city, province, or state). Individual government agencies and departments may report to The Registry without restriction, provided the government unit of which they are a part is not also a Registry Member.

Agencies that are under the authority of other Registry Members may maintain their own memberships and reports separately provided the following conditions are met:

- The governed agency reports using the same organizational boundary approach as its governing agency,
- When the governing agency has a verified report, the emission totals of the governed agency must be included within the report of the governing agency,[5]
- The governed agency must obtain a separate verification statement,
- The governed agency's emission totals appear identical in the public governed agency's and governing agency's reports, and
- The governed agency indicates its governing agency as it appears in CRIS in its public report.

[4] If an organization is acquired or divested by another Registry Member during an emissions year, the information in the parent and subsidiary report do not need to be identical for that year to allow for the parent to accurately reflect the amount of time the operations of the subsidiary were within its organizational boundary.
[5] If an agency is brought under or removed from the authority of another Registry Member during an emissions year, the information in the governing agency and governed agency reports do not need to be identical for that year to allow for the governing agency to accurately reflect the amount of time the operations of the governed agency were within its organizational boundary.

General purpose local governments reporting to The Registry must report in conformance with the Local Government Operations (LGO) Protocol. The LGO Protocol requires that local governments report emissions associated with the following operations:

- Buildings and other facilities,
- Streetlights and traffic signals,
- Water delivery facilities,
- Wastewater facilities,
- Port facilities,
- Airport facilities,
- Vehicle fleets,
- Transit fleets,
- Power generation facilities,
- Solid waste facilities, and
- Other process and fugitive emissions.

Local Government Operations Protocol

The Local Government Operations (LGO) Protocol is a program-neutral protocol designed to allow local governments to quantify and report GHG emissions resulting from their operations. General purpose local governments at the city or county level must calculate and report their GHG emissions according to the LGO Protocol's program-neutral guidance and the requirements in The Registry's Program-specific appendix. Contributors to the LGO Protocol included the California Climate Action Registry, the California Air Resources Board, ICLEI Local Governments for Sustainability, and The Climate Registry.

County governments that choose to report completely to The Registry must include all of the individual departments and operations (e.g., county roads departments) within the county government in the county's report.

Should a state or provincial government choose to report to The Registry, all of the individual state/provincial agencies which report to that state/provincial government must be included in the state's complete report. However, local governments located within the state/province (e.g., municipalities, townships and counties) should continue to report separately from the state/province or county, as emissions from municipal government operations will not be rolled up into county and state/province emission reports.

4.6 Leased Facilities/Vehicles and Landlord/Tenant Arrangements

Members should account for and report emissions from leased facilities and vehicles according to:

1. The type of lease associated with the facility or source
2. The organizational boundary approach selected.

There are two types of leases:

Operating lease. This type of lease enables the lessee to operate an asset, like a building or vehicle, but does not give the lessee any of the risks or rewards of owning the asset. Any lease that is not a finance or capital lease is an operating lease. In most cases, operating leases cover rented office space and leased vehicles, whereas finance or capital leases are for large industrial equipment. If a Member has an asset under an operational lease, The Registry requires that the emissions from this asset be reported only if the Member is using the operational control approach.

Finance or capital lease. This type of lease enables the lessee to operate an asset and also gives the lessee all the risks and rewards of owning the asset. Assets leased under a capital or finance lease are considered wholly owned assets in financial accounting. If a Member has an asset under a finance or capital lease, The Registry considers this asset to be wholly owned by the Member.

Reporting Emissions from Leased Assets

Under a financial or capital lease Members are required to account for and report emissions from a facility or source regardless of the organizational boundary approach selected. Therefore, Members should account for and report these emissions under the financial control, operational control, and equity share approaches.

With respect to operating leases (e.g., most office space rentals and vehicle leases), the organizational boundary approach selected (operational control, financial control, or equity share) will determine whether reporting the asset's associated emissions is required or optional.

Operating leases transfer operational control from the lessor to the lessee. Therefore, Members reporting using the operational control approach must report emissions from assets for which they have an operating lease. This transfer of control is illustrated by the following example: the way a lessee uses its office equipment (computers, copy machines, etc.) *controls* the amount of electricity consumed and as a result, the GHG emissions associated with those operations.

If a Member uses either the equity share approach or the financial control approach, then the emissions from a facility or source with an operating lease would fall in scope 3 (see Chapter 5 for a detailed discussion of scopes, including scope 3). Table 4.4 summarizes reporting requirements in common lessee scenarios.

Figure 4.2 is a decision tree designed to help *lessees* determine how to report emissions from leased assets.

Reporting Requirements for Lessors

In general, the requirements for a lessor are the opposite of the lessee's reporting requirements. For example, the lessor is *not* required to report emissions for assets leased under an operating lease *if* the lessor is using the operational control consolidation method. However, the lessor *must* report such emissions *if* it is using the equity share or financial control approach. Similarly, the lessor is *not* required to report emissions for assets leased under a capital or finance lease regardless of the consolidation method applied by the lessor (although the lessor may *opt* to report these emissions as scope 3 emissions).

Figure 4.3 is a decision tree providing guidance in determining reporting requirements for *lessors*.

Table 4.4. Lessee Reporting Scenarios

Emissions Source	Report under Operational Control	Report under Financial Control
Leased Properties (lessee)	Yes	No
Natural gas in Leased Properties (lessee)	Yes, if you are individually metered; otherwise, optional scope 2	No
Outsourcing	Determine who has operational control?	Determine who has financial control?
Rental Cars (lessee)	Long term leases – Yes Business Travel – No	Long Term Leases – No Business Travel – No
Employee Home Offices	Optional scope 3	Optional scope 3

4.7 Examples of Control versus Equity Share Reporting

Examples 4.1 through 4.8 are provided to assist in determining which consolidation approach to use and how to implement each approach. Members must apply the chosen consolidation approach consistently for every facility, source, and operation throughout the organization.

Figure 4.2. Decision Tree for Determining the Lessee's Reporting Requirements for a Leased Asset

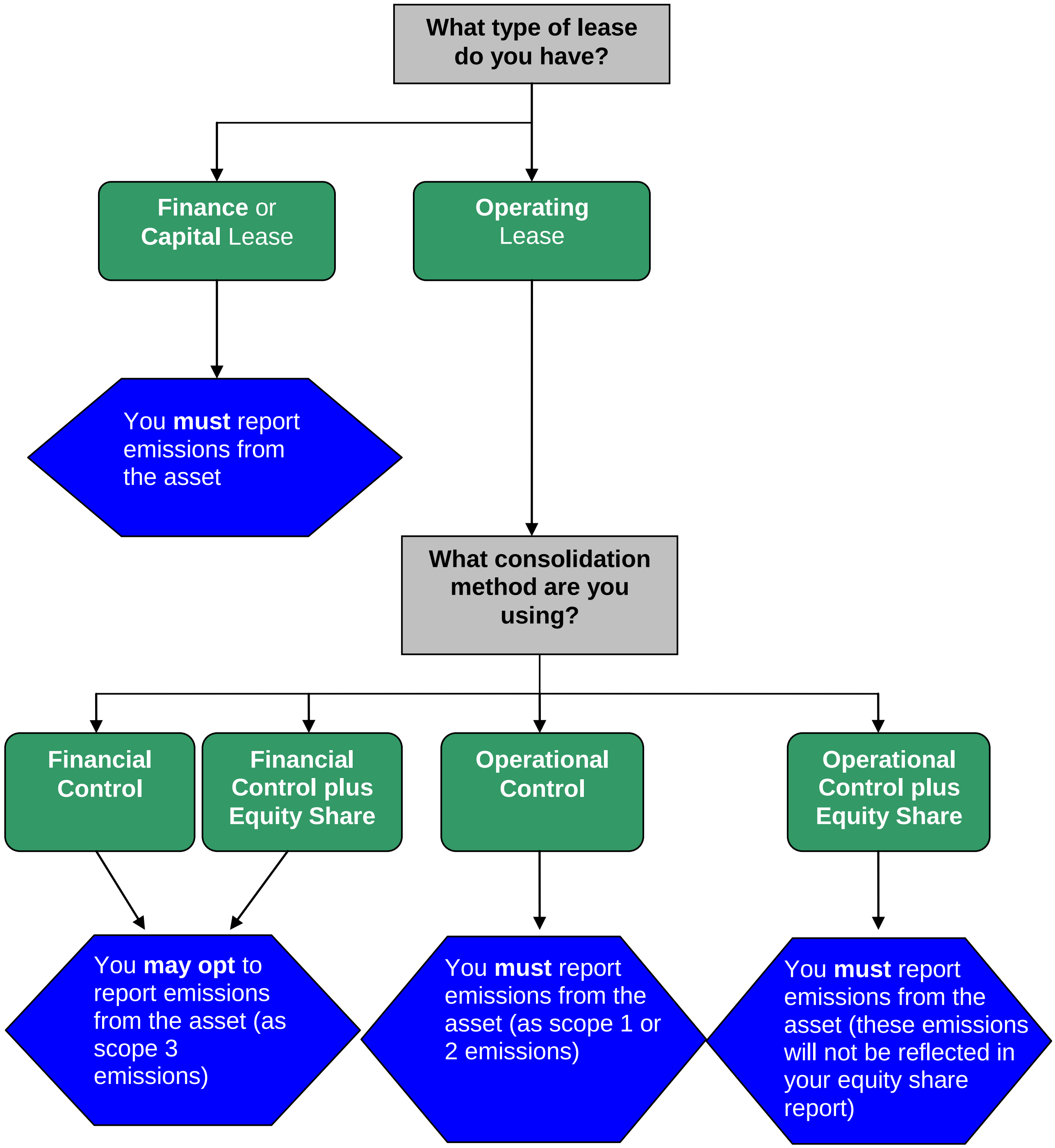
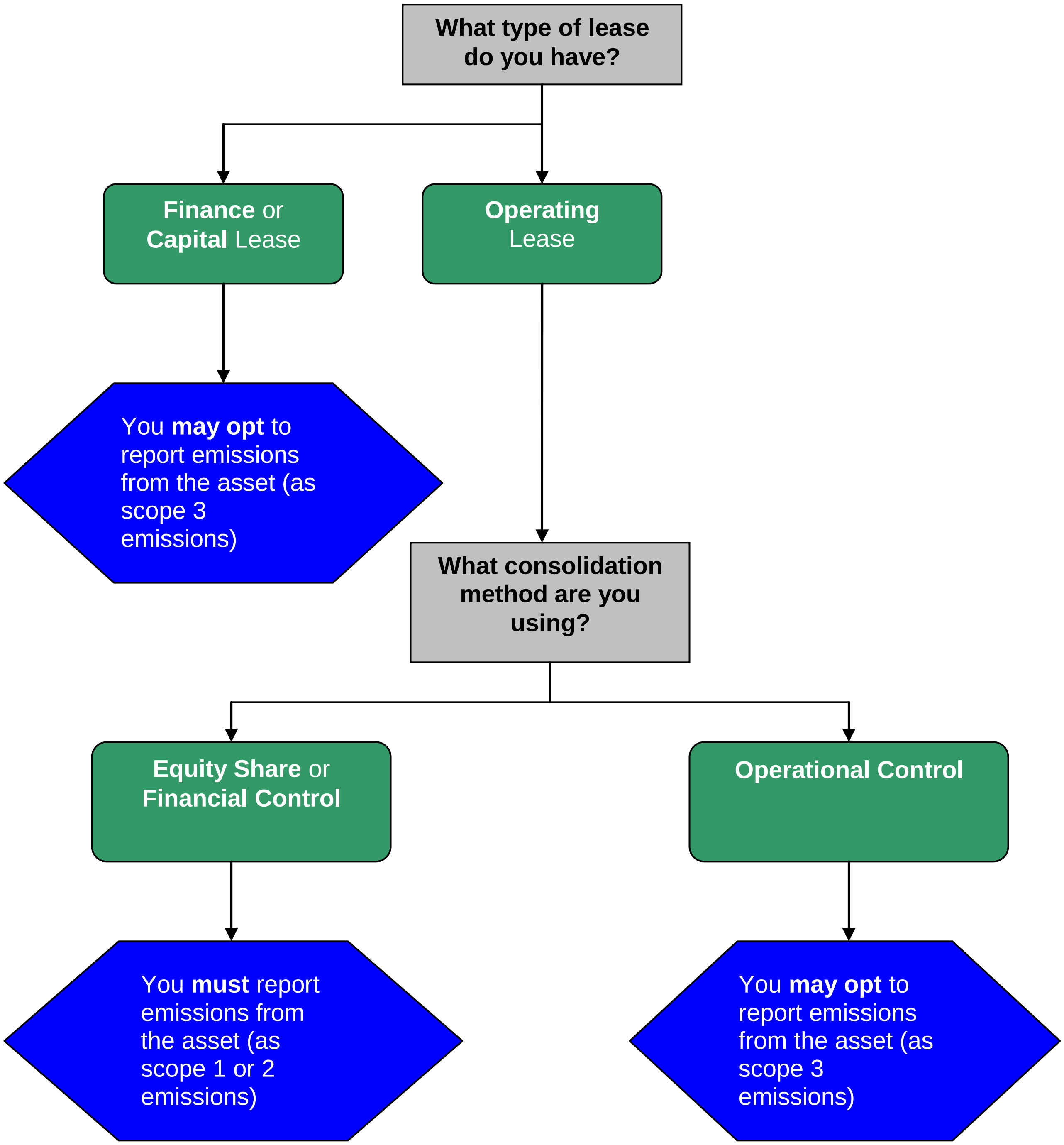


Figure 4.3. Decision Tree for Determining the Lessor's Reporting Requirements for a Leased Asset



Example 4.1. Responsibility for Reporting Emissions Under an Operating Lease

The Pacific, a real estate investment trust, owns and rents out a 10 story office building. They lease the 10th floor of the building to Green Associates under an operating lease. Green Associates reports to The Registry using the operational control approach. Because it has operational control over the space and all of the emission sources within the space, Green Associates must include all of the direct and indirect emissions resulting from its use of the 10th floor space in its report. However, Green Associates cannot report emissions resulting from activities on the first floor because the first floor is not within its operational control.

The first floor of this building is occupied by a second Registry Member, Climate Advisors. Climate Advisors is reporting to The Registry using Option 1 (equity-share plus control) with financial control. Due to the Climate Advisors' selected organizational boundary approach, and the fact that it has an operating lease, it is *not* required to report emissions associated with its first floor office. This follows from the fact that Climate Advisors does not *own* (or has a financial interest in) the office building, and under the equity share and financial control approaches, *ownership* (or financial interest) is the criterion that determines reporting requirements.

Example 4.2. Reporting Responsibilities from the Lessor's Perspective

The Pacific in Example 4.1 is also a Registry Member. If The Pacific leases out the entire building under an operational lease and reports using either the equity share or financial control approaches, it is required to report the building's emissions. If, however, The Pacific uses the operational control method to define its organizational boundaries, it would not be required to report the building's emissions, since effective control over the building's emissions passes to the tenant under an operating lease.

Example 4.3. Reporting Responsibilities Under a Capital or Finance Lease

With the passage of time, Green Associates (the 10th floor tenant in Example 4.1) expands its business until it occupies floors two through 10. At this point, Green Associates signs a finance lease with The Pacific for the entire building, giving Green Associates not only operational control over floors two through 10, but the financial rights (and risks) associated with the entire building including the rental space on the first floor. Under a finance lease (also known as a capital lease), Green Associates is required to report all of the emissions associated with floors two through 10 of the building *regardless* of the consolidation method the firm uses (because Green Associates both controls and effectively owns these floors under the terms of a finance lease). Furthermore, if Green Associates is using the equity share or financial control approach, it must also report all emissions associated with the first floor. This is because ownership or financial interest is the criterion used to determine reporting requirements under the equity share and financial control approaches, and Green Associates holds the financial interest in the first floor space under the terms of a finance lease. However, Green Associates would not be required to report emissions associated with the first floor if it reports using the operational control approach, because Climate Advisors occupies and controls the first floor space.

Once the finance lease is signed, effective ownership of the building passes from The Pacific to Green Associates; hence, The Pacific would no longer be required to report emissions associated with the building.

See the next page for a summary of reporting requirements under these examples.

Examples 4.1 through 4.3 Continued: Leased Office Space

The following tables summarize reporting responsibilities for Green Associates, Climate Advisors, and The Pacific under the various consolidation approaches and types of leases considered in the above examples.

Reporting Responsibilities of Green Associates and Climate Advisors (Lessees)

Consolidation Approach	Type of Lease	
	Finance or Capital Lease	Operating Lease
Equity Share or Financial Control	**Must** report emissions from leased asset	**May opt** to report emissions from leased asset
Operational Control	**Must** report emissions from portion of leased asset with operational control	**Must** report emissions from leased asset

Reporting Responsibilities of The Pacific (Lessor)

Consolidation Approach	Type of Lease	
	Finance or Capital Lease	Operating Lease
Equity Share or Financial Control	**May opt** to report emissions from leased asset	**Must** report emissions from leased asset
Operational Control	**May opt** to report emissions from leased asset	**May opt** to report emissions from leased asset

It is possible that both the lessees and The Pacific may report the same emissions. For example, if an operating lease is signed, Green Associates reports on an operational control basis and The Pacific reports on equity share basis, both Green Associates and The Pacific are required to report the electricity-related emissions from the leased space. However, as long as the lessor and the lessees use the *same* consolidation approach, the same emissions will *not* be reported in the same scope. See Chapter 5 for more information about scopes.

Example 4.4. Companies with Ownership Divided 60 percent-40 percent

Midwest Turbine has 60 percent ownership and full control of Facility 1 under both the financial and operational control approaches. Batemen LLC has 40 percent ownership of the facility and does not have control.

Under either control approach, Midwest Turbine would report 100 percent of the GHG emissions for Facility 1 while Batemen LLC would report none. Under the equity share approach, Midwest Turbine and Batemen LLC would report 60 percent and 40 percent of the GHG emissions, respectively, based on their share of ownership and voting interest.

Member	Ownership of Facility 1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Midwest Turbine	60% ownership and voting interest	100%	100%	60%
Batemen LLC	40% ownership and voting interest	0%	0%	40%

Example 4.5. Companies with Ownership Divided 60-40 and Voting Interests Divided 45-55

Midwest Turbine has 60 percent ownership of Facility 1 and a 45 percent voting interest. Batemen LLC has 40 percent ownership of the facility and a 55 percent voting interest. Batemen LLC is also explicitly named as the operator and has the authority to implement its operational and HSE policies. Batemen LLC has control according to both the financial and operational criteria.

Under either control approach (financial or operational), Batemen LLC would report 100 percent of GHG emissions and Midwest Turbine would report none, because Batemen LLC has a majority voting interest and operational control. Under equity share, Midwest Turbine would report 60 percent of GHG emissions and Batemen LLC would report 40 percent, based on ownership share.

Member	Ownership of Facility 1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Midwest Turbine	60% ownership and 45% voting interest	0%	0%	60%
Batemen LLC	40% ownership and 55% voting interest	100%	100%	40%

Example 4.6. Two Companies with 50 Percent Ownership

Midwest Turbine and Batemen LLC each have 50 percent ownership of Facility 1. Batemen LLC has the authority to implement its operational and HSE policies, but all significant capital decisions require approval of both Midwest Turbine and Batemen LLC since they have joint financial control. Each reports 50 percent of GHG emissions under the financial control and equity share approaches. Under the operational control approach, Batemen LLC reports 100 percent of the facility's emissions while Midwest Turbine reports none.

Member	Ownership of Facility 1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Midwest Turbine	50% ownership and voting interest	50%	0%	50%
Batemen LLC	50% ownership and voting interest	50%	100%	50%

Example 4.7. Three Companies with Ownership Divided 55-30-15 Percent

Midwest Turbine has 55 percent ownership of Facility 1, Batemen LLC has 30 percent ownership, and Cushing Inc. has 15 percent ownership. The majority owner has the authority to implement its operational and HSE policies.

Under either control approach, Midwest Turbine would report 100 percent of GHG emissions because it holds financial and operational control of the facility, and Batemen LLC and Cushing Inc. would report no emissions. Under the equity share approach, each company would report according to its equity share of ownership and voting interests.

Member	Ownership of Facility 1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Midwest Turbine	55% ownership and voting interest	100%	100%	55%
Batemen LLC	30% ownership and voting interest	0%	0%	30%
Cushing Inc.	15% ownership and voting interest	0%	0%	15%

Example 4.8. Alpha, Inc.

Alpha, Inc. has five wholly owned or joint operations: Beta, Gamma, Delta, Pi, and Omega. The following table outlines the organizational structure of Alpha, Inc. and the percent of emissions from each of its sub-entities that it includes in the parent company's entity-wide emissions total using equity share, operational control, and financial control.

Wholly owned and joint operations of Alpha, Inc.	Legal structure and partners	Economic interest held by Alpha, Inc.	Control of operating policies	Treatment in Alpha, Inc.'s financial accounts	Percent of GHG emissions accounted for and reported by Alpha, Inc. under each consolidation approach		
					Equity Share	Operational Control	Financial Control
Beta	Incorporated company	100%	Alpha	Wholly owned subsidiary	100%	100%	100%
Gamma	Incorporated company	40%	Alpha	Subsidiary	40%	100%	100%
Delta	Non-incorporated joint venture; partners have joint financial control; other partner is Epsilon	50% by Beta	Epsilon	via Beta	50% (50% x 100%)	0%	50%
Pi	Subsidiary of Gamma	75% by Gamma	Gamma	via Gamma	30% (75% x 40%)	100%	100%
Omega	Incorporated joint venture; other partner is Lambda	56%	Lambda	Subsidiary	56%	0%	100%

Alpha, Inc. also provides additional information about its entity-wide emissions profile, under certain consolidation approaches. The following table illustrates the relevant information Alpha, Inc. can provide depending on whether it uses operational control, financial control, or equity share.

Example continued on next page.

Example 4.8 Continued.

Consolidation Approach Used By Alpha, Inc.	Emissions Included in Alpha, Inc.'s Entity-Wide Total	Additional Information Optionally Provided
Operational control	100% of the emissions from Beta, Gamma, and Pi	The company includes additional information about Delta and Omega because they are entities in which Alpha, Inc. has an equity share without control and are therefore not included in its entity-wide total (see the table below for the information Alpha, Inc. provides for Delta and Omega).
Financial control	100% of the emissions from Beta, Gamma, Pi, and Omega, and 50% of the emissions from Delta	The company does not include any additional information on equity investments, since the financial control approach captures all of its sub-entities and includes them all in its entity-wide emissions total.
Equity share	100% of the emissions from Beta; 40% of the emissions from Gamma; 50% of the emissions from Delta; 30% of the emissions from Pi; and 56% of the emissions from Omega	The company does not include any additional information, since all equity investments are included in the equity share entity-wide emissions total.

If Alpha Inc. reports using a control approach, it is encouraged to provide additional information about entities and operations in which it has an equity share without control. In this case, Alpha will only provide this information if it reports based on operational control, because the operational control approach excludes some of its business activities, namely Delta and Omega. Therefore, Alpha Inc. provides the following information in addition to its total emissions based on operational control.

Optional Documentation of Equity Share Investments

Entity/ Operation *(Required)*	Description *(Required)*	Equity Share *(Required)*	Legal Entity with Operational Control *(Optional)*	Description of Emitting Activities *(Optional)*
Delta	Non-Incorporated Joint Venture	50%	Epsilon	Delta is an electric generating facility containing two coal-fired units with a total capacity of 1,600 MW
Omega	Incorporated Joint Venture	56%	Lambda	Omega is a cement manufacturing company with five U.S. facilities and significant emissions of carbon dioxide from stationary combustion and clinker calcination

Chapter 5: Emissions to Include in the Inventory

Issue	Requirements		Optional
	Transitional	Complete	
Operational Boundaries	• Report emissions from activities that occur within self-defined operational boundary • If direct emissions of CO_2 from biomass combustion are part of the self-defined operational boundary, they must be reported separately	• Report all required scope 1 and scope 2 emissions • Report direct emissions of CO_2 from biomass combustion separately	• May additionally report scope 3 emissions

5.1 Direct, Indirect, and Biogenic Emissions

The Registry follows the WRI/WBCSD GHG Protocol *Corporate Standard* in categorizing direct and indirect emissions into "scopes" as follows:

- **Scope 1:** All direct anthropogenic GHG emissions.

  The Registry requires that you report all scope 1 emissions with the exception of fugitive emissions from hydropower reservoirs. Members electing to report emissions from this source can elect to report them as optional information.

- **Scope 2:** Indirect anthropogenic GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling.

  The Registry requires that you report all scope 2 emissions with the exception of imported heating and district cooling in leased spaces where there is no contract with the provider. Members who report emissions from this source can elect to report them as optional information.

- **Scope 3:** All other (non-scope 2) indirect anthropogenic GHG emissions that occur in the value chain. Examples of scope 3 emissions include emissions resulting from the extraction and production of purchased materials and fuels, employee commuting and business travel, use of sold products and services, and waste disposal.

  The Registry does not require the reporting of scope 3 emissions. Members can elect to report scope 3 emissions as optional information.

- **Additional GHGs:** Certain GHG emissions, such as biogenic emissions, are excluded from the scope categories defined in the GHG Protocol Corporate Standard.

  The Registry requires the reporting of biogenic carbon dioxide resulting from the combustion of biomass. All other biogenic emissions can be reported as optional information.

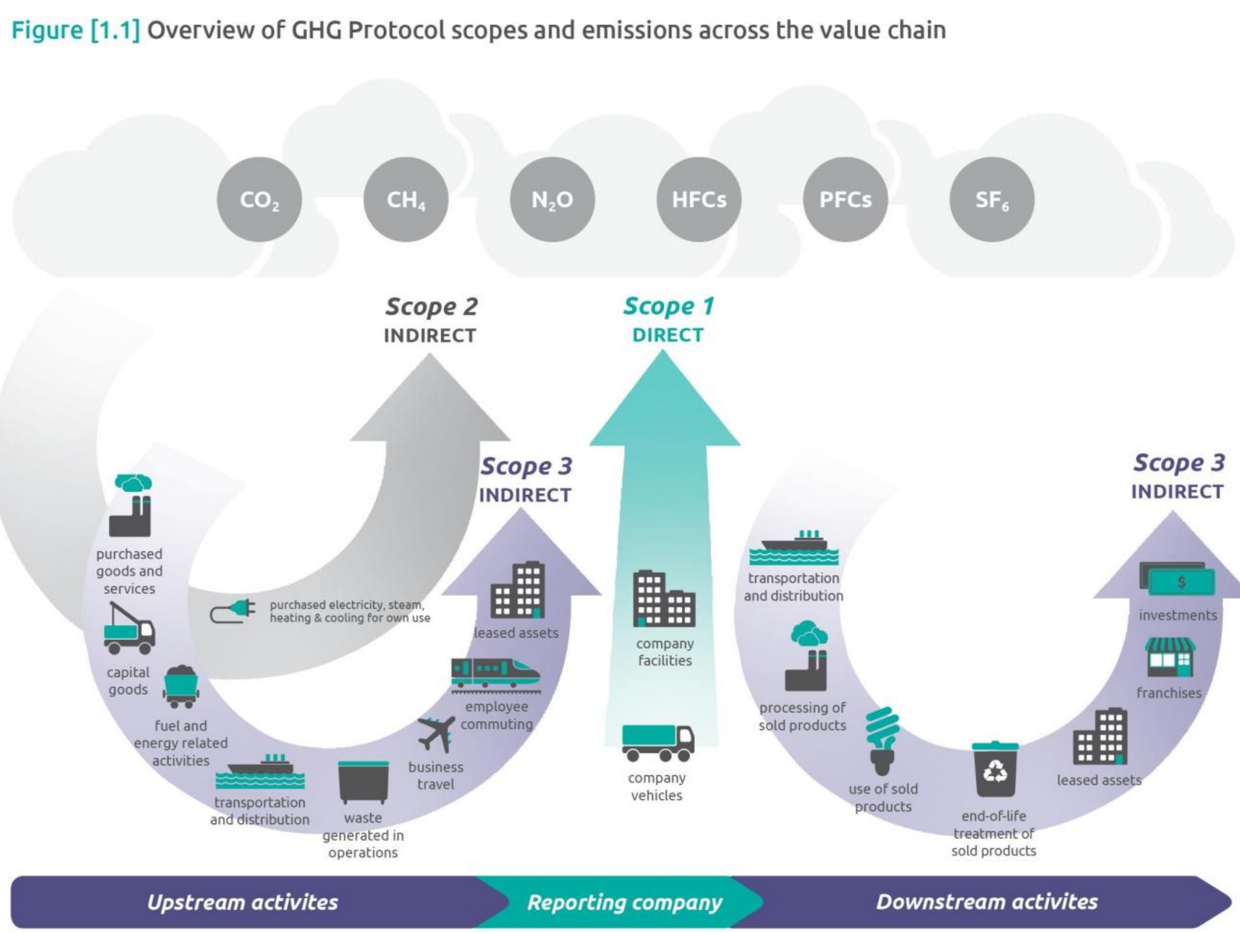
  The Registry does not support the reporting of non-Kyoto GHG emissions. These gases are *outside of the scopes and can be disclosed along with your report as part of a separate public document.*

Together these categories provide a comprehensive accounting framework for managing and reducing direct and indirect emissions. Figure 5.1 provides an overview of the relationship between the scopes and the activities that generate direct and indirect emissions along your value chain.

For effective and innovative GHG management, setting operational boundaries that are comprehensive with respect to direct and indirect emissions will help better manage the full spectrum of GHG risks and opportunities that exist along your value chain.

The Registry requires that you report both scope 1 and scope 2 emissions data as well as direct CO_2 emissions from the combustion of biomass. Reporting of scope 3 emissions are *optional*.

Figure 5.1. Overview of Scopes and Emissions throughout an Entity's Operations



Source: WRI/WBCSD GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard. Please note, The Registry also requires the reporting of NF_3 in scope 1.

5.2 Direct Emissions: Scope 1

Direct GHG emissions are emissions from sources within the entity's organizational boundaries (see previous chapter) that the reporting entity owns or controls.

Scope 1 emissions are all direct emissions resulting from the impact of human beings on nature. These generally result from the use of fossil fuels or other man-made chemicals and must be subdivided in your report into the four types of sources they result from:

- *Stationary combustion* of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.;

- *Mobile combustion* of fuels in transportation sources (e.g., cars, trucks, marine vessels and planes) and emissions from non-road equipment such as those in construction, agriculture and forestry;

- *Physical and chemical processes* other than fuel combustion (e.g., for the manufacturing of cement, aluminum, adipic acid, ammonia, etc.); and

- *Fugitive sources*, i.e., intentional or unintentional releases from the production, processing, transmission, storage, and use of fuels and other substances, that do not pass through a stack, chimney, vent, exhaust pipe or other functionally-equivalent opening (such as releases of sulfur hexafluoride from electrical equipment; hydrofluorocarbon releases during the use of refrigeration and air conditioning equipment; and methane leakage from natural gas transport or landfills).

5.3 Indirect Emissions: Scope 2

Indirect GHG emissions are a consequence of activities that take place within the organizational boundary of the reporting entity, but occur at sources owned or controlled by another entity. For example, emissions that occur at a utility's power plant as a result of electricity used by a manufacturing company represent the manufacturer's indirect emissions. While a company has control over its direct emissions, it has *influence* over its indirect emissions.

Scope 2 is a special category of indirect emissions and refers only to indirect emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. It typically makes up a large portion of an entity's GHG inventory; and therefore, represents a significant opportunity to identify GHG management opportunities and report reductions. Also, in comparison to other indirect emissions, data for scope 2 emissions can be gathered in a consistent manner with a relative low degree of uncertainty.

Reporting Emissions from Leased Assets

If a Member is reporting completely and has leased space within its organizational boundary, it must report all scope 1 and scope 2 emissions associated with that space. Emissions from electricity use are scope 2. Emissions from heating and district cooling should be reported in scope 1 when the Member contracts for those services directly with its provider(s). Members who do not contract directly with their provider(s) but wish to estimate emissions associated with acquired heating and district cooling (e.g. emissions resulting from natural gas combustion in a centralized boiler) must report those emissions to The Registry as "scope 2 optional." This classification is required because The Registry explicitly excludes these scope 2 emissions from its reporting requirements due to the difficulty Members can face in securing high quality data.

Please Note: Fugitive emissions associated with imported cooling in the form of central air conditioning are not part of scope 2 or scope 2 optional. Please see Chapter 16 for more information on air conditioning emissions.

Indirect emissions reported by one entity may also be reported as direct emissions by another entity. For example, the indirect emissions from electricity use reported by a manufacturing entity may also be reported as direct emissions by the utility that generated the electricity. This dual reporting does not constitute double counting of emissions as the entities report the emissions associated with the electricity production and its use in different scopes (scope 1 for the electricity generating utility and scope 2 for the manufacturing entity). Therefore, emissions can only be aggregated meaningfully *within* a scope, not across scopes. Scope 2 and scope 3 emissions will always be part of another entity's scope 1 emissions.

5.4 Emissions from Biomass

Members must track and report biogenic CO_2 emissions separately from other emissions because the carbon in biomass was recently contained in living organic matter. This sets it apart from the carbon in fossil fuels that has been trapped in geologic formations for millennia. Because of this difference, the Intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* requires that CO_2 emissions from biogenic sources be reported separately.

The Registry's requirement to report biogenic emissions applies only to stationary combustion and mobile combustion. The Registry does not require the reporting of other biogenic emissions (e.g. fugitive CO_2 emissions from solid waste management) due to a lack of scientific consensus around the methods used to quantify these emissions.

Because biofuels are often mixed with fossil fuels prior to combustion (e.g., wood waste with coal in a power plant), when quantifying GHG emissions from combustion, Members must calculate biomass combustion CO_2 emissions separately from fossil fuel CO_2 emissions. Chapters 12 and 13 provide methodologies Members can use to separate biogenic emissions from other CO_2 combustion emissions.

The separate reporting of CO_2 emissions from biomass combustion applies only to CO_2 and not to methane (CH_4) and nitrous oxide (N_2O), which are also emitted during biomass combustion. Unlike CO_2 emissions, the CH_4 and N_2O emitted from biomass combustion are not of a biogenic origin and are therefore scope 1 emissions. When biomass is combined with fossil fuel combustion, the biomass-based CH_4 and N_2O emissions should be reported together with fossil-fuel based CH_4 and N_2O emissions.

5.5 Indirect Emissions: Scope 3

Reporting of scope 3 emissions is optional, but doing so provides an opportunity for innovation in GHG management. All Members are encouraged to report scope 3 emissions in accordance with the Greenhouse Gas Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard, which classifies scope 3 emissions into the following categories:

1. Purchased goods and services
2. Capital goods
3. Fuel- and energy-related activities (not included in scope 1 or 2)
4. Upstream transportation and distribution
5. Waste generated in operations
6. Business travel
7. Employee commuting
8. Upstream leased assets
9. Downstream transportation and distribution
10. Processing of sold products
11. Use of sold products
12. End-of-life treatment of sold products
13. Downstream leased assets
14. Franchises
15. Investments

While data availability and reliability may influence which scope 3 activities are included in the inventory, it is accepted that data accuracy may be lower than scope 1 and scope 2 data. It may be more important to understand the relative magnitude of and possible changes to scope 3 activities. Emission estimates are acceptable as long as there is transparency with regard to the estimation approach, and the data used for the analysis are adequate to support the objectives of the inventory.

It is possible that the same scope 3 emissions may be reported as scope 3 emissions by more than one Member. For example, the scope 1 emissions of a power generator are the scope 2 emissions of an electrical appliance user, which are in turn the scope 3 emissions of both the appliance manufacturer and the appliance retailer. For this reason, scope 3 emissions should never be summed across Members.

While the GRP and CRIS do not include calculation methodologies for scope 3 emissions at this time, Members can include scope 3 emissions in their inventory reports. The Registry recommends that Members interested in reporting scope 3 emissions reference the WRI/WBCSD GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard, a supplement to the GHG Protocol Corporate Standard (available at www.ghgprotocol.org).

For guidance on how to report scope 3 emissions in conformance with the Scope 3 Standard, please see the CRIS Users Guide. Optionally reported scope 3 emissions are not required to be verified in order to be part of your public report.

Greenhouse Gas Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard

This new standard (the Scope 3 Standard) provides requirements and guidance for entities to prepare and publically report a GHG emissions inventory that includes indirect emissions resulting from value chain activities.

Key aspects of the Scope 3 Standard include:

- 15 distinct categories that provide a systematic framework to organize, understand and report on the diversity of scope 3 emissions within a value chain
- Minimum scope 3 boundary that is designed to ensure major value chain activities are included in the scope 3 inventory
- Guidance for prioritizing data collection efforts
- An overview of the quantification methods and types of data that may be available for scope 3 emissions
- Information about allocating scope 3 emissions
- Guidance on and a description of the benefits of assurance of GHG emissions data
- Reporting requirements for a complete value chain inventory
- Discussion of uncertainty in scope 3 emissions
- Scope 3 data management recommendations

5.6 Excluding Miniscule Sources

Miniscule sources are very small sources of emissions present in a Member's inventory that represent a high reporting burden, such as hand-held fire extinguishers.

Members may opt to exclude miniscule sources from their inventory because the difficulty in measuring emissions from these sources does not justify the insignificant impact these sources have on the overall inventory. The Registry expects that exclusion of miniscule sources will not:

- Compromise the relevance of the reported inventory;
- Significantly reduce the combined quantity of scope 1, scope 2, and biogenic CO_2e emissions reported;
- Impact ability to identify the Member's viable opportunities for emissions reductions projects;
- Impact the ability to ascertain whether the Member has achieved a reduction (of five percent or greater) in total entity emissions from one year to the next;
- Impact ability to assess the Member's climate change related risk exposure; or,
- Impact the decision-making needs of users (i.e. is not expected to be deemed critical by key stakeholders).

Selecting Minuscule Sources

The Registry has identified a list of miniscule sources, which is available on The Registry's Exclusion of Miniscule Sources Form. The Registry has determined that these miniscule sources are justified exclusions because of their insignificant impact on overall emissions, the excessive burden associated with compiling the associated site-specific data and the common use of these sources across various industries. This form can be downloaded from The Registry's website (www.theclimateregistry.org).

The Registry recognizes that a Member may identify additional miniscule sources that are not itemized on The Registry's Exclusion of Miniscule Sources Form. In this case, the Member must submit a

Request for Excluding a New Minuscule Source Form, available on The Registry's website (www.theclimateregistry.org), to The Registry (help@theclimateregistry.org) to make a determination as to whether the source is eligible for exclusion. All proposed sources deemed eligible for exclusion by The Registry will be added to the Exclusion of Miniscule Sources Form.

Disclosing Minuscule Sources

Members that choose to exclude miniscule sources from their inventory must publicly disclose these sources using the Exclusion of Miniscule Sources Form. See the CRIS Users Guide for information on how to enter this information in CRIS.

Whenever possible, Members are encouraged to report emissions from miniscule sources using Registry-approved methods or Simplified Estimation Methods (SEMs). (See Chapter 11 for more information on SEMS).

Chapter 6: Organizing the Emissions Inventory

<table>
<tr><th rowspan="2">Issue</th><th colspan="2">Requirements</th><th rowspan="2">Optional</th></tr>
<tr><th>Transitional</th><th>Complete</th></tr>
<tr><td>Level of Detail</td><td colspan="2">• Report at the entity-level</td><td>• May separately report emissions by facility. Must report in accordance with The Registry’s facility-level reporting requirements in order to have a public facility-level report
• If reporting by facility, may aggregate emissions from:
e. Commercial buildings (e.g., office buildings)
f. Mobile sources (fleets)
g. Other special categories (e.g., oil and gas wells)
h. Emissions calculated using simplified estimation methods</td></tr>
</table>

6.1 Reporting Options

There are two ways Members can choose to report their GHG inventory to The Registry:

- **Entity-Level:** Report all Kyoto-defined GHG emissions by gas and scope only

- **Facility-Level:** Report Kyoto-defined GHG emissions for each facility either by reporting activity data, such as fuel and energy consumption totals, or by reporting facility-level emissions by gas and scope

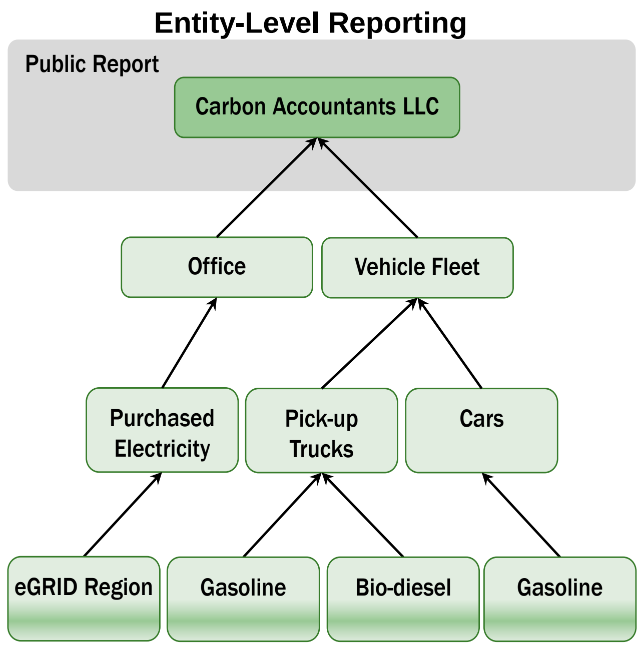
The approach that Members select should:

1. Align with reporting goals and GHG data management systems,
3. Balance granularity of data with data entry,
4. Transparently convey facility boundaries and names so that it is clear to the public, and
5. Transparently demonstrate GHG reductions over time.

Members are encouraged but not required to report emissions separately for each facility. At a minimum, Members must publicly report total entity-level emissions. Members who choose to report at the entity-level will not have public facility-level reports, regardless of how data was entered in CRIS.

All Members seeking verification must be prepared to provide source-level information for each sampled facility to their Verification Body upon request.

Figure 6.1. Entity- and Facility-Level Reporting Example



6.2 Entity-Level Reporting

Entity-level reporting allows for high-level disclosure of GHG emissions. Members that use this reporting option are not required to meet the facility-level reporting requirements outlined in this chapter, but they must have sufficient data records to support verification. Emissions information will be presented in public reports only at the entity-level by gas and scope, although facility- and source-level data will be available to the Member in private reports.

Members who elect to report at the entity-level must notify The Registry by emailing help@theclimateregistry.org. Upon notification, The Registry will update the Member's CRIS account to reflect entity-level reporting.

Organizations interested in entity-level reporting because of concerns about Confidential Business Information (CBI) are encouraged to take advantage of The Registry's Public Disclosure Exemption Request Form. This form allows Members to publicly report at the entity-level while conforming to The Registry's facility-level reporting requirements. See Chapter 20 for more information on CBI.

6.3 Facility-Level Reporting

Members are encouraged but not required to report emissions separately for each facility. Members that choose to publicly report facility-level data must report in conformance with The Registry's facility-level reporting requirements. Emissions information will be presented in public reports at the facility-level by gas and scope.

The Registry strongly endorses public reporting of facility-level information as it enables tracking of GHG emissions at a disaggregated level, including emission changes associated with discrete business operations or facilities and because it is the required reporting boundary for mandatory reporting programs.

6.4 Source-Level Reporting

Members are encouraged to report emissions data at the source-level, if data is available. Reporting data at this level of granularity is valuable for internal data management and can help streamline verification (especially for stationary combustion sources). Source-level data is not made available publicly through The Registry but Members will have access to this information in private reports.

Defining Facility Boundaries

In general, a facility is defined as a single physical premise, although certain industries, such as the oil and gas sector, are subject to unique facility definitions based on their atypical operations. Regulatory programs often define a facility as any stationary installation or establishment located on a single site or on contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way that are owned or operated by an entity. The Registry uses this definition for stationary facilities as well. Guidelines for vehicle fleets can be found in Section 6.6.

The Registry understands that some emission sources, such as pipelines and electricity transmission and distribution (T&D) systems, do not easily conform to this traditional definition of a facility. Please see the box below for information on reporting emissions from these sources.

Pipeline and T&D Systems

For purposes of reporting, emissions from each pipeline, pipeline system, or electricity T&D system should be assigned to the state or country in which the facility is located. For example, emissions from a pipeline that extends from Alberta to Manitoba would be assigned to Canada, rather than to a specific Canadian province.

If a pipeline or T&D system crosses national boundaries, you should try to subdivide the system into two separate facilities and report the emissions from each facility thus defined. However, if you do not have the data necessary to estimate emissions from each national segment of a pipeline or T&D system, you may treat the pipeline or T&D system as a single facility. Emissions from such a facility must be reported in the "North American" geographic region, which is a separate geographic category provided by CRIS to handle this and other special situations (see Example 6.1).

Example 6.1. Interstate Natural Gas Pipeline

A pipeline transports natural gas from Alberta to a pipeline distribution system in Seattle, Washington. By comparing natural gas receipts at the supply source in Alberta with deliveries at the distribution point in Seattle, the company that owns the pipeline can determine the amount of natural gas that is lost due to leakage throughout the length of the pipeline. However, the company cannot break this total estimate down into emissions that occur in the Canada and U.S. segments of the pipeline. Therefore, emissions from the pipeline should be assigned to the North American category.

Aggregation of Emissions from Stationary Facilities

In order to streamline the reporting of emissions separately for numerous small stationary facilities, The Registry provides facility-level reporters with the *option* of aggregating emissions within a geographic boundary (i.e. state/province, national, North American, or non-North American level) for certain qualifying facility categories. The Registry encourages Members to aggregate facilities by type, as this will increase transparency in facility-level reporting and may streamline some verification activities.

Members may aggregate their emissions for the following stationary facility categories:

- **Commercial Buildings**: office-based or retail facilities that do not conduct industrial operations and for which emission sources are limited to:
  - Purchased or acquired electricity, heating or cooling;
  - Stationary combustion of fuel for building heating;
  - Refrigerants for building and vehicle air conditioning; Standard fire extinguishers (as opposed to more complex PFC systems);
  - Non-commercial refrigeration;
  - Commercial refrigeration operations when an organization centrally manages refrigerant stocks;
  - Emergency generators;
  - Automobiles and on-road trucks; and,
  - Off-road equipment limited to building and landscape maintenance.

- **Other Special Facilities:** including oil and gas wells, pipelines, electricity transmission, telecom towers, wastewater interceptor systems, parking lots, transit systems, traffic lights, distribution (T&D) systems, and air monitoring stations. *If you are unsure of whether your facilities are eligible for aggregation, please contact The Registry at 866-523-0764 ext. 3.*

- **Simplified Estimation Method Emissions:** Please see Chapter 11 for more information on reporting emissions estimated using simplified estimation methods.

Emissions from all other stationary facility categories *must* be reported separately if Members are publicly reporting facility-level data or have submitted a CBI Exemption Form.

Categorizing Mobile Facilities

Criteria to guide the categorization of emissions from ground-based vehicles, marine vessels, and aircraft are presented in the following subsections.

Ground-Based Vehicle Fleets

The Registry makes a distinction between ground-based vehicles that operate exclusively on the grounds of a single stationary facility, and ground-based vehicles that operate beyond a single stationary facility. Examples of the former might include forklifts, front end-loaders, off-road trucks, mobile cranes, etc.

When a vehicle is assigned to a single stationary facility and does not operate beyond that facility's premises, the vehicle is considered to be part of the facility and the emissions from the equipment must be included in the stationary facility's emissions. For example, emissions from vehicles that operate on a mine site must be included in the mine's emissions.

However, when reporting emissions from vehicles that operate beyond the confines of a single stationary facility (e.g., automobiles and on-road trucks), Members may choose to either assign those sources to a stationary facility or report them separately as a ground-based vehicle fleet.

Please Note: General purpose local governments must separately report sector totals (including vehicle fleets and transit fleets) as prescribed in the LGO Protocol.

Example 6.2. NYC Limousine Company

A New York City limousine company owns a fleet of limousines that operate throughout the city and surrounding suburbs. Each limousine is assigned to one of five garages owned by the company, where the limousines are dispatched, serviced, fueled, and parked when not in use. Four of the garages are located in New York City: one in Manhattan, one in Brooklyn, one in Queens, and one in the Bronx. The fifth garage is located across the Hudson River in Newark, New Jersey. The limousines assigned to the four New York City garages operate exclusively within the city boundaries; the limousines assigned to the Newark garage handle all trips between New York and New Jersey, and beyond. In addition to the limousines, each of the garages has a forklift which is used to move and stack spare auto parts stocked for limousine maintenance.

The limousine company wishes to report its emissions to The Registry. It has two different reporting options.

Option 1: The company may separate the limousines into two fleets—the fleet comprising the limousines assigned to the four New York City garages and a fleet including the limousines assigned to the Newark garage. This option would allow the company to separately report part of its fleet emissions at a higher level of detail (i.e., emissions for the fleet assigned to New York City would be clearly broken out). Because the limousines assigned to the Newark garage are used for interstate trips, emissions from the Newark fleet would be assigned to the U.S. country category.

Option 2: The company could choose to report emissions from *all* of the limousines as a single fleet. In this case, since the fleet is used for both intra-state and interstate travel, the fleet emissions would have to be assigned to the U.S. country category.

Using either option, the company will also need to calculate its emissions associated with electricity usage, as well as the forklifts, to complete their emission report. NYC Limousine Company has chosen to report their limousines separately from the garages, because they operate beyond the physical boundaries of the garages and they find it easier to interpret their reports when the limousine emissions are reported separately.

Members who choose to report emissions from vehicles as a ground-based vehicle fleet have the option of aggregating emissions from mobile sources by:

- Geographic location (e.g., state/province, national or North American), or by
- Vehicle type (e.g., automobile, truck, train) within each geographic location.

Alternatively, Members may report emissions from mobile sources at a more disaggregated level, including, e.g., by individual vehicle.

Regardless of the level at which Members choose to aggregate their vehicle emissions, it is necessary to assign these emissions (like all other emissions) to a geographic location. The Registry has developed guidance and special geographic categories to support public reporting of these emissions.

For *ground-based* vehicles (e.g. automobiles, trucks, and trains), the guidance is as follows:

1. **State/Province Level Reporting:** Emissions from ground-based vehicles that operate exclusively within a single state, province, or territory may be aggregated and assigned to that state, province or territory.

2. **National Level Reporting:** Emissions from ground-based vehicle fleets that operate within a single state, province or territory and fleets that operate across state or provincial boundaries but exclusively within one country must, at a minimum, be assigned to the *country* in which they operate. However, ground-based vehicle fleets that operate across state or provincial borders must not be reported at the state/province level. For example, an inter-provincial truck fleet that

operates within Canada must be assigned to Canada, rather than any particular province. Likewise, a railroad that crosses state borders in the U.S. must be assigned to the U.S., rather than a single state.

3. **North America Level Reporting:** Emissions from ground-based vehicles that cross national borders but that do *not* operate beyond Canada, Mexico, and the United States must be assigned to North America.

Members are not required to report emissions from ground-based vehicles that operate outside of Canada, Mexico, and the United States. For example, a trucking company with a fleet that operates in Mexico as well as in Belize and Guatemala is not required to report emissions from this fleet. However, The Registry encourages Members to report worldwide emissions. If reporting emissions from such sources, the emissions should be assigned to the non-North American geographic category. Similarly, Members reporting worldwide emissions, including emissions from ground-based mobile sources operating entirely outside North America, should include these emissions in the non-North American category.

Marine Voyages and Aircraft Flights

Emissions from marine vessels and aircraft are disaggregated by geographic location on a flight or voyage basis, rather than on an aircraft or vessel basis. Thus, whereas the emissions from a single automobile or truck will always be assigned to a single geographic category, the emissions from a single aircraft or a marine vessel may be disaggregated and assigned to different geographic locations depending, for example, on whether or not the airplane or marine vessel is used for both domestic and international transportation.

In addition, marine vessels and aircraft are often difficult to track at the state/province level. Therefore, The Registry recommends that emissions from marine vessels and aircraft be assigned to the national, North American or non-North American geographic categories as follows:

1. **National Level Reporting:** Emissions occurring entirely within one country must be assigned to that country. Emissions from domestic flights and voyages must be assigned to the specific country in which the flight/voyage originated and terminated. For example, emissions from a flight from Montreal to Vancouver must be assigned to Canada, while emissions from a voyage from New York to Miami must be assigned to the United States. If an international flight or voyage includes a domestic stopover or port of call, the emissions from the domestic leg of the flight or voyage should be assigned to the country in which the domestic leg originates and terminates. For example, if a flight from Washington, D.C. to London, England includes a stopover in New York, the emissions from the Washington-to-New York leg of the flight should be assigned to the U.S. Similarly, if a ship sails from Los Angeles to Vancouver but has a port of call in Seattle, emissions from the Los Angeles to Seattle segment of the voyage should be assigned to the U.S.

2. **North America Level Reporting:** Emissions occurring within North America, but not entirely within a single country, must be assigned to North America. Emissions from international flights and voyages that both originate and terminate within North America must be assigned to the North American category. For example, emissions from a flight that originates in Mexico City and terminates in Los Angeles would be assigned to the North American category, as would emissions from a voyage that originated in New York and terminated in Cancun. If an intercontinental flight or voyage originating or terminating in one North American country includes a stopover or port of call in another North American country, the emissions from the

North American leg of the flight or voyage should be assigned to the North American category. For example, if a flight from Houston, Texas to Caracas, Venezuela includes a stopover in Mexico City, the emissions from the Houston-to-Mexico City leg of the flight should be assigned to the North American category.

3. **Worldwide Reporting:** Members are strongly encouraged, but not required, to report emissions from legs of flights or voyages that originate and/or terminate outside of Canada, the U.S., or Mexico. For example, emissions from a direct voyage from Los Angeles to Tokyo, or a non-stop flight from London to New York, should not be included in your North American emissions inventory. However, you *may opt* to report such emissions. If you do choose to report these emissions, they should be assigned to the worldwide geographic category. Similarly, if you choose to report your worldwide emissions, including emissions from legs of flights or voyages that both originate and terminate outside North America (e.g., London to Paris, or Hong Kong to Singapore) these emissions must be reported in the worldwide category.

Indirect emissions from electricity purchased for use by a vessel when it is in port should be treated as occurring while the vessel is in port. The emissions associated with this electricity consumption should be assigned to the state, province or territory in which the port is located. Generally the owner/operator of the marine vessel, not the fueling facility, must report the vessel's emissions from in-port electricity use as well as fuel use during voyages.

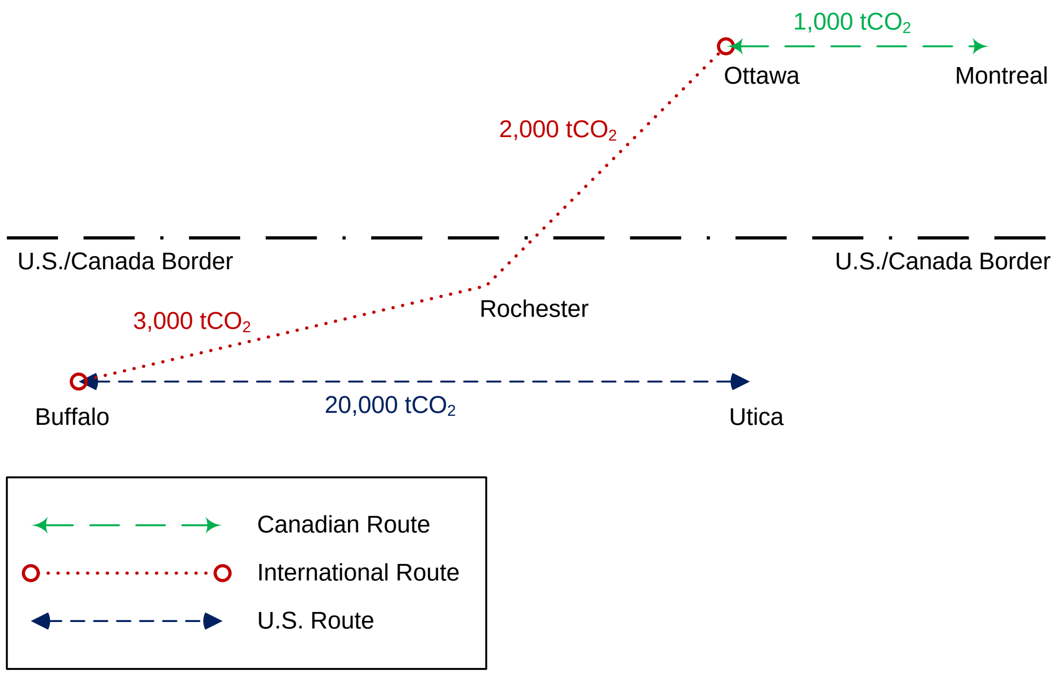
Example 6.3. Categorization of Airline Flight Emissions

A small regional airline operates a fleet of 10 planes serving Buffalo, Rochester, and Utica in upstate New York, as well as Ottawa and Montreal in Canada. Its fleet flies one U.S., one Canadian, and one international route. The Canadian route is Ottawa to Montreal (with a return). The U.S. route is Utica to Buffalo. Finally, the international route is Buffalo to Ottawa, with an intermediate stop in Rochester (and a return). The schematic below shows each of these routes.

The airline calculates and categorizes its emissions as follows:

- **Canadian Emissions:** Total of 1,000 tons CO_2e from all flights along the Ottawa-Montreal route
- **U.S. Emissions:** Total of 23,000 tons CO_2e, consisting of:
    a. 20,000 tons CO_2e from all flights along the Utica-Buffalo route
    b. 3,000 tons CO_2e, representing total emissions from the Buffalo-Rochester leg of the Buffalo-Ottawa flight.
- **North American Emissions:** Total of 2,000 tons CO_2e, representing emissions from the Rochester-Ottawa leg of the Buffalo-Ottawa flight.

A schematic of the routes is provided below:



Example 6.4. Categorization of Emissions from Marine Vessels

A shipping company owns and operates a fleet of seven container ships. These ships serve the ports of Los Angeles, Seattle, Vancouver, Tokyo, Hong Kong, and Singapore. In order to report 2008 emissions for the fleet to The Registry, the shipping company first used fuel purchasing records for each port of call to estimate total CO_2 emissions for its *direct* shipments (i.e., shipments without intermediate port calls) between each pair of ports, as follows:

Port Pairings		Number of Direct Shipments in 2008	CO_2 Emissions in Metric Tons
Port 1	Port 2		
United States:			
Los Angeles	Seattle	43	5,722
Total U.S.		43	5,722
North America:			
Los Angeles	Vancouver	22	3,121
Seattle	Vancouver	52	1,309
Total North American		74	4,430
Worldwide:			
Hong Kong	Los Angeles	2	1,823
Los Angeles	Singapore	35	14,750
Los Angeles	Tokyo	42	18,903
Total International		79	35,476
Fleet Grand Total Direct (Scope 1) Emissions		**196**	**45,628**

In addition to reporting emissions due to bunker fuel consumption while at sea, the shipping company also reported emissions resulting from the fleet's use of electricity while in port. These emissions were assigned to the state or province in which each port is located, as follows:

Port	State or Province	Country	Indirect CO_2 Emissions from Fleet Electricity Use (Metric Tons)
Los Angeles	California	United States	452
Seattle	Washington	United States	214
Vancouver	British Columbia	Canada	311
Fleet Grand Total Indirect (Scope 2) Emissions			**977**

Chapter 7: Tracking Emissions over Time

Issue	Requirements		Optional
	Transitional	Complete	
Tracking Emissions Over Time	• N/A	• Reporting a base year to The Registry is optional but recommended	• A base year may be set provided the inventory is complete

7.1 Setting a Base Year

Tracking GHG emissions over time enables Members to meet a variety of business goals, such as public reporting of GHG reductions, establishing and measuring progress towards GHG targets, managing risks and opportunities, and addressing the needs of investors and other stakeholders. The first step to tracking corporate-level GHG emissions over time is to set a base year.

A base year is a benchmark against which an entity's emissions are compared over time. Setting and adjusting a base year provides a standardized benchmark that reflects an entity's evolving structure, allowing changes in organizational structure to be tracked in a meaningful fashion. Adjustments to base year emissions are generally made to reflect organizational changes such as mergers, acquisitions, or divestments.

Setting a base year allows Members to scale structural changes to their entity back to a benchmarked emission profile. For example, an acquisition of a facility could dramatically increase an entity's emissions relative to previous reporting years. To accurately describe the impact of that facility over time, the Member would adjust its base year emissions to incorporate the additional emissions associated with the acquired facility in the base year, thereby normalizing the real (organic) change in emissions from the base year (now accounting for the acquired facility) and the current year. Base year emissions may also need to be adjusted if there are significant changes in generally accepted GHG emissions accounting methodologies or if significant errors are identified.

Members must set a base year in order for their inventories to be in conformance with the international standards on corporate GHG accounting and reporting (the GHG Protocol Corporate Standard and ISO 14064-1). The Registry strongly encourages all Members to publicly set a base year.

Setting a base year is not a requirement for Registry reporting. However, Members must set a public base year through The Registry for The Registry to recognize any GHG reductions.

Members that opt to set a public base year through The Registry must select a single calendar year inventory that that meets The Registry's definition for complete reporting and is verified by a Registry-recognized Verification Body except on a case-by-case basis. Please contact The Registry (help@theclimateregistry.org) if you would like The Registry to consider recognizing a base year inventory reported in accordance with other requirements.

Members may elect to set an historical base year using data that has been previously quantified and verified to another standard, provided the inventory contains complete data that is verified by a third-party to a reasonable level of assurance and a five percent materiality threshold. See Chapter 9 for information on historical reporting and Chapter 19 for information about The Registry's verification requirements.

Members wishing to set an historical base year must contact The Registry (help@theclimateregistry.org) to request recognition of a historical base year inventory. [6] Please note that complete data reported in accordance with The Registry's reporting requirements and verified by a Registry-recognized Verification Body in accordance with The Registry's verification requirements, meets The Registry's non-historical base year requirements.

The purpose of having a base year in The Registry is to have a benchmark to illustrate the trends in a Member's emissions over time within The Registry. A Member may have an existing regulatory baseline requirement that it must meet for a mandatory reporting program. This external benchmark does not change or affect the base year with The Registry. The Registry's base year is for analysis of a Member's entity-wide emissions over time only, and should not be confused with regulatory baselines.

7.2 Adjusting Base Year Emissions

To ensure that the comparison of emissions over time is internally consistent, base year emissions must closely reflect an organization's current organizational structure.

For this reason, The Registry requires Members who choose to set a base year publicly through The Registry to adjust (recalculate) their base year emissions when:

1. A structural change in organizational boundaries (i.e., merger, acquisition, or divestiture) triggers a significant cumulative change in the entity's base year emissions; *or*

2. A change in calculation methodologies or emission factors triggers a significant cumulative change in the entity's base year emissions; *or*

3. A significant error or a number of cumulative errors that are collectively significant are discovered.

Significant is defined as a cumulative change of five percent or larger in an entity's total base year emissions (scope 1, scope 2 and direct biogenic emissions from stationary and mobile combustion, as well as any optionally reported emissions, on a CO_2e basis).

If a base year must be adjusted, the Member must have its third-party Verification Body attest to the accuracy of the base year adjustment. For more information on verification, see Chapter 19.

Members should **not** adjust base year emissions in any of the following situations:

- Acquisition (or insourcing) or divestiture (or outsourcing) of a facility or business unit that did not exist in the base year (see Examples 7.1 through 7.3);

- Structural changes due to 'outsourcing' if an entity is reporting its indirect emissions from relevant outsourced activities in the current reporting year (see Example 7.4);

- Structural changes due to 'insourcing' (the converse of outsourcing) if the Member already included the indirect emissions associated with the insourced activities in its base year report (see Example 7.5);

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[6] Base year inventories submitted to U.S. EPA's Climate Leaders Program that have undergone technical review by an EPA-contracted reviewer and have been found to be consistent with the requirements of that program are an example of historical data that can be designated as the base year for the purpose of reporting to The Registry.

- Organic growth or decline, which refers to increases or decreases in production output, changes in product mix, and closures and openings of operating units owned or controlled by an entity.

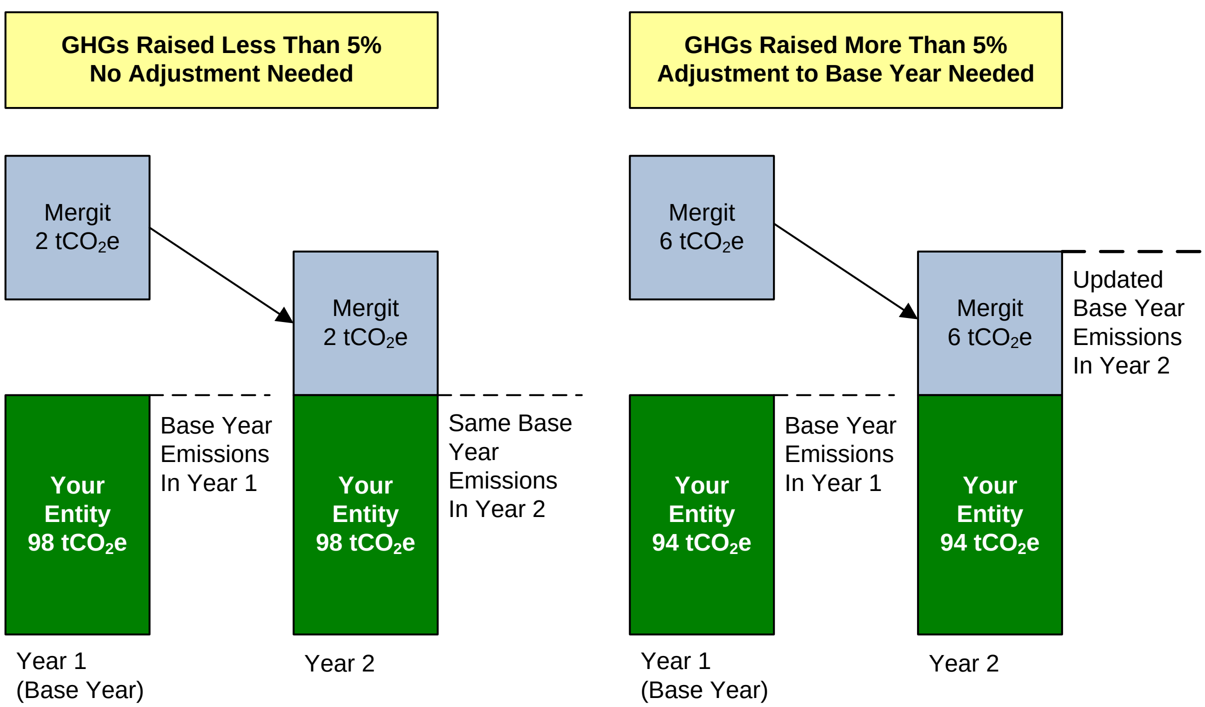
Adjustments to base years may not take the place of previously reported data. Instead, this information can be used to generate an alternate report that reflects the appropriate structural organization so that both an entity's emissions in any given year and its emission trend over time are transparent. Members may elect to adjust intervening years in a similar way.

Members that have acquired or merged with a company where the base year data from the new company needed to use any of The Registry's approved emission calculation methods (see Part III) is not available, may instead use an alternative simplified method for adjusting the base year emissions using available data.

If absolutely no data for the new company is available, making it impossible to estimate the impact of the organizational change on a Member's base year emissions, The Registry recommends that the base year be redefined to be the current emissions year (which would include the new acquisition, and thus, would reflect the Member's current organizational structure). Members should also disclose the structural change to ensure transparency.

Example 7.1. Mergers and Acquisitions

Your organization merges with Mergit. Depending on the percentage change in your total base year emissions, you may need to adjust your base year:

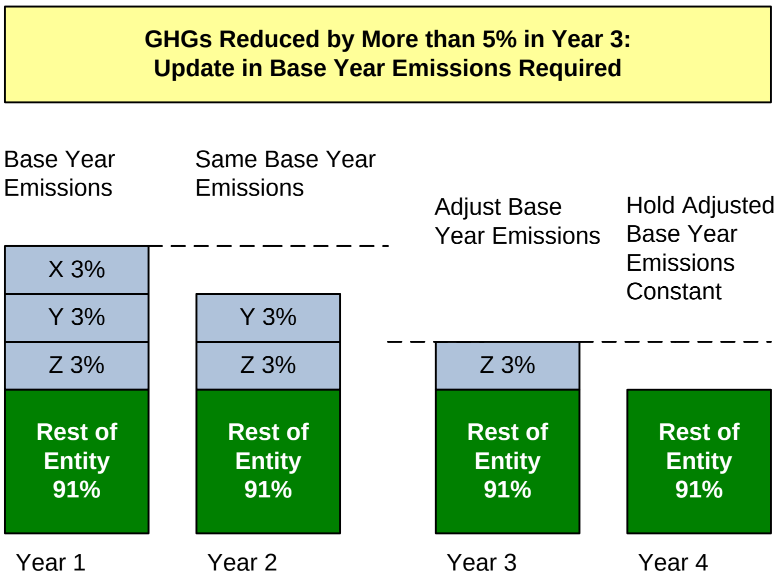


If, in the base year (Year 1), Mergit's emissions were less than five percent of your company's total base year emissions (or if Mergit did not exist in the base year), then you would not adjust your base year emissions in Year 2 to reflect the merger. In the example above left, your total base year emissions would remain 98 tons CO_2e in Year 2.

If, in the base year (Year 1), Mergit's emissions were more than five percent of your company's total base year emissions, then you must adjust your base year emissions in Year 2 to reflect the merger. Your emissions would be adjusted by adding Mergit's base year emissions (six tons CO_2e in the example to the right) to your company's base year emissions (94 tons CO_2e), to obtain a new base year emission total (100 tons CO_2e).

Example 7.2. Divestments

Your organization divests three divisions (X, Y, and Z) over the second, third, and fourth reporting years. Each of these divisions account for three percent of your GHG emissions, for a nine percent total reduction in emissions by Year 4.



Because the cumulative effect of these divestments reduces what your base year emissions would have been by more than five percent in Year 3, in that year you will need to adjust your base year emissions by subtracting the base year emissions of Divisions A and B from your originally-reported base year emissions.

Example 7.3. Acquisition of a Facility that Came into Existence After the Base Year Was Set

Your organization consists of two business units (A and B). In its base year, the company emits 50 tons of GHGs. In year two, the company undergoes organic growth, leading to an increase in emissions to 30 tons of GHGs per business unit, i.e., 60 tons CO_2 in total. The base year emissions should not be recalculated in this case, because the change in emissions was due to organic growth, not an acquisition.

At the beginning of year three, your organization acquires Production Facility C from another company. Facility C came into existence in year two, its emissions being 15 tons of GHGs in year two and 20 tons of GHGs in year three. The total emissions of your organization in year three, including Facility C, are therefore 80 tons of GHGs. In this acquisition case, the base year emissions of your organization should not be updated, because the acquired Facility C did not exist in the base year (or, in other words, the base year emissions of Facility C were zero).

Example 7.4. Outsourcing

If your organization contracts out activities previously included in your base year, you *may* need to adjust your base year to reflect the outsourcing. If you continue to include the emissions associated with the outsourced activities as part of your indirect (scope 2 or scope 3) emissions, you should *not* adjust your base year. If you continue to account for the emissions associated with the outsourced activities within your inventory, you will not have to adjust your base year to reflect the outsourcing.

If, on the other hand, you choose to exclude emissions from the outsourced activities, and if the outsourced activities accounted for five percent or more of your base year emissions (either by themselves or in combination with other structural and methodological changes), you must adjust your base year to reflect the outsourcing. Specifically, you should subtract the base year emissions caused by the activities now being outsourced from your base year to obtain an adjusted base year emissions total.

You should *not* adjust your base year report if the outsourced activities did not exist during your base year.

Example 7.5. Insourcing

Insourcing is the converse of outsourcing. If you did not include the emissions associated with insourced activities as indirect emissions in your base year, then you must adjust your base year emissions to reflect the insourced activities (assuming that the five percent significance threshold has been exceeded). To adjust for insourcing, you would add the emissions associated with the insourced activities as they occurred in your selected base year to your base year emissions. If the activities you are insourcing did not occur in the base year, you should not adjust your base year emissions.

For example, suppose that in the base year your company hired a delivery service to hand deliver proposals and deliverables to government clients located throughout Washington, DC. Suppose further that you included the delivery service's emissions associated with the delivery of your company's packages as indirect (scope 3) emissions in your base year inventory. If, in a subsequent year, your company terminated its contract with the delivery service and used its own employees and vehicles to make the deliveries, no change in your base year report would be required because the emissions you 'insourced' were already included (as indirect emissions) in your base year inventory. Alternatively, if you did ***not*** include the delivery company's emissions in your base year inventory, upon insourcing the delivery activities you would have to adjust your base year inventory to include the indirect emissions that were subsequently insourced.

However, if in the base year you did not submit any proposals or deliverables to clients in the Washington, DC area, but you subsequently hired the delivery service and then brought the delivery activities in house, you would not need to adjust your base year report because the insourced activities were not undertaken, either by your company or the delivery service, in the base year.

Example 7.6. Shifting the Location of Emission Sources

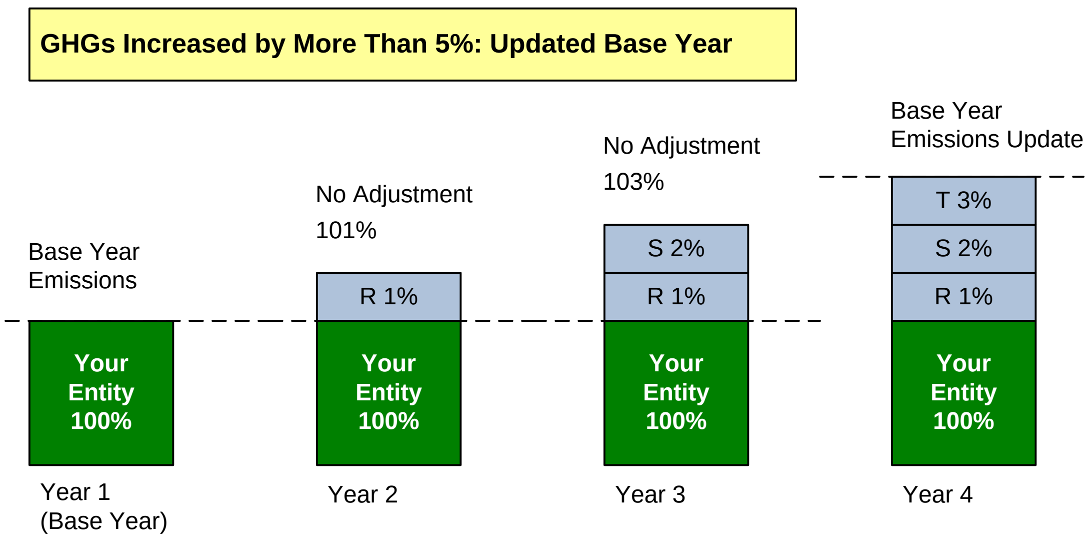
If you shift operations outside of the U.S., Mexico, and Canada, and this shift contributes to a total cumulative change in your base year exceeding five percent, you must adjust your base year by subtracting the base year emissions of the shifted operations from your base year total. Similarly if you shift operations into the U.S., Mexico, or Canada, you must increase your base year emissions by an amount equal to the base year emissions of the operations that were relocated. If you reported your worldwide emissions in the base year you will never need to adjust these emissions to reflect the relocation of your operations.

Example 7.7. Change in Emissions Accounting Methodologies

If you change emission calculation methodologies or data, for any reason (e.g., improvements in methodology/data or discovery of an error), and if application of the new methodologies would contribute to a cumulative total change in your base year emissions of more than five percent, you must recalculate your base year using the new methodologies. This ensures that your base year will remain comparable with your more recent emissions data.

Example 7.8. Cumulative Changes to Total Emissions

Your organization acquires three companies over three years, raising your total base year GHG emissions by six percent.



Your company acquires Reyes Rockets, Sierra Spaceworks, and Trinity Telescopes in your second, third, and fourth years of reporting. In your selected base year, these company's emission totals represent GHG base year emissions of one, two, and three percent respectively of your company's base year emissions. While these acquisitions *individually* represent less than the required five percent increase for a base year adjustment, they amount to a six percent *cumulative* increase in total base year emissions in CO_2e. Thus, you would be required to update your base year emissions in year four.

Chapter 8: Transitional Inventories

Issue	Requirements		Optional
	Transitional	Complete	
Getting Started	• First five years of public reporting may be transitional inventories. After five years, you may apply for a waiver to continue to report on a transitional basis.	• N/A	• May join The Registry as a basic Member. No public reporting or verification is required. Allows organizations to increase capacity for building a high-quality inventory.

8.1 Reporting Transitional Inventories

The Registry seeks to encourage broad participation in its voluntary reporting program. While complete GHG footprint reporting is the goal, some organizations may need additional time to develop a complete emissions inventory. For this reason, The Registry provides opportunities for Members to ramp up their reporting over time.

Transitional inventories allow organizations to begin publicly reporting and verifying less than all of their emissions according to a self-defined boundary. Members can elect to report transitional inventories for up to five years, unless a waiver is submitted to request an extension.

Members needing more than five years to submit a complete North American inventory to The Registry, may submit a waiver that sets a target date for complete reporting, provides justification for the requested extension, identifies the steps being taken to achieve a complete inventory (such as an inventory management plan) and identifies any obstacles or limitations prohibiting the reporting of a complete inventories after five years of reporting transitional inventories.

8.2 Transitional Inventory Boundaries

Members reporting transitional inventories must publicly define, disclose and justify their own transitional inventory boundaries. Parameters that must be used to define a transitional inventory boundary include:

- Scopes
- Gases
- Activity types (stationary combustion, etc.)
- Geographic/operational boundaries (country, state, business units, facility, etc.)

Transitional inventories are complete within the boundaries defined by the Member. Members may elect to additionally report emissions outside of their self-defined transitional inventory boundary. For example, if a company is reporting stationary combustion emissions from all facilities in North America but in some of those facilities only CO_2 emissions are reported, the transitional reporting boundary would be scope 1, CO_2 from stationary combustion in North America. All reported CH_4 and N_2O emissions will be part of the company's inventory, however they will be additional to the transitional reporting boundary.

For information on how to define, disclose and justify a transitional inventory boundary in CRIS, please see the CRIS Users Guide or contact The Registry (help@theclimateregistry.org).

8.3 Transitional Reporting with Sector-Specific Protocols

The Registry has developed sector-specific protocols in order to provide detailed reporting requirements for sectors with unique GHG emitting activities. Members that are part of a sector for which The Registry has a sector-specific protocol and are electing to report transitionally, have the option to use *either* the General Reporting Protocol (GRP) or a relevant sector-specific protocol to report their GHG emissions.

Members seeking to report transitionally using a sector-specific protocol, must report and verify the sources/information within the self-defined transitional boundary in accordance with the sector-specific protocol.[7]

8.6 Verification of Transitional Reports

All Transitional Reports must be third-party verified by a Registry-recognized Verification Body.

Members reporting using a sector-specific protocol for which there are sector-specific accreditation requirements for Verification Bodies,[8] must have the inventory third-party verified by a Verification Body accredited for the Member's sector.

8.7 Public Disclosure of Transitional Data

Like complete emission reports, transitional emission reports will be disclosed to the public after they are verified and submitted to The Registry. All transitional reports include a report heading identifying the report as "Transitional" to distinguish it from complete emission reports. See Chapter 20 for more information about the public disclosure of emission reports.

[7] Members completing transitional inventories that opt to report and verify emissions in accordance with a sector-specific protocol are not required to report any performance metrics. See Chapter 17 for more information on performance metrics.
[8] Currently there are accreditation requirements for the electric power and oil and gas sectors.

Example 8.1. Transitional Reporting

Alpha Company is a diverse manufacturer with operations throughout North America and emissions of carbon dioxide, methane, nitrous oxide, and HFCs. Alpha provided its first annual report to The Registry in 2010 (emissions year 2009 data). However, as Alpha had never conducted a full emissions inventory across all of its operations, it transitionally reported its 2009 emissions, focusing on stationary combustion CO_2 emissions from all of its facilities in Texas, Oklahoma, and Arkansas.

For emissions year 2010, Alpha expanded its report to include CH_4 as well as CO_2, for *all* sources (mobile combustion, process and fugitive emission sources as well as stationary combustion sources) from all of its operations in the United States. Finally, in 2012 Alpha became a complete reporter and reported all of its 2011 emissions for all internationally recognized GHGs, from all of its facilities and sources in the U.S., Canada and Mexico.

The following table represents Alpha Company's GHG emissions inventory, and the portions of the inventory reported in each year:

Geographic Location of Facilities	CO_2 Emissions:		CH_4 Emissions	N_2O Emissions	HFC Emissions
	Stationary Combustion	All Other Sources			
Texas, Oklahoma, and Arkansas	2009	2010	2010	2011	2011
All Other U.S. States	2010	2010	2010	2011	2011
Canada	2011	2011	2011	2011	2011
Mexico	2011	2011	2011	2011	2011

Chapter 9: Compiling Previous Inventories

Issue	Requirements		Optional
	Transitional	Complete	
Previously Reported Emissions	• There is no requirement to report historical emissions.		• May report historical emissions data for any year preceding your first reporting year as long as your data meets the minimum historical reporting and verification requirements, • You may submit historical data from other programs or registries to The Registry

9.1 Reporting Historical Data

Members who have conducted GHG inventories in conformance with other standards have the option to report that information to The Registry as historical data. Submitting historical data to The Registry enables Members to centralize GHG inventories and track emissions trends over time without requiring modification of reports or re-verification. Historical data is data that has been quantified and verified to another standard (e.g. EPA Climate Leaders, Carbon Disclosure Project, ICLEI, self-reported), but not reported and verified through The Registry's program in accordance with The Registry's reporting and verification protocols. Historical data must consist of calendar-year data with transparently defined inventory boundaries that has been third-party verified.

While historical data has not been reported and verified through The Registry's program, the data must:

- Have transparently defined inventory boundaries
- Be third-party verified
- Be entered into CRIS

If historical data was verified by an independent third party as part of another GHG program, The Registry does not require this data to be re-verified. Instead, a formal written attestation of verified data by a credible third-party Verification Body or documentation determined equivalent by The Registry must be submitted to The Registry along with the historical data emission report.

Members interested in inputting data into CRIS that has not been verified, should use a Registry-recognized Verification Body to verify this data. Emissions inventories that comply with The Registry's reporting requirements and are verified by Registry-recognized Verification Bodies will be labeled transitional or complete based on the reporting boundary used. If quantified emissions are not consistent with The Registry's reporting requirements, or if verification of the emissions inventory is conducted by a non-Registry recognized Verification Body, the emissions inventory will be labeled historical.

All historical emissions reports will be titled "Historical Data" in CRIS. Members must indicate the name of the GHG program to which the data was originally reported. If historical data was quantified, but not reported to another program, Members must indicate that their data are "Self Reported."

9.2 Historical Report Boundaries

There is no limit to the amount of historical data a Member may submit to The Registry; however, all historical reports must clearly state the boundaries of the inventory. Parameters that must be used to define an historical inventory boundary include:

- Scopes
- Gases
- Activity types (stationary combustion, etc.)
- Geographic/operational boundaries (country, state, business units, facility, etc.)

For information on how to define and disclose the inventory boundary for historical reports in CRIS, please see the CRIS Users Guide or contact the Registry (help@theclimateregistry.org).

9.3 Importing Historical Data

Members may "import" or transfer historical data from other GHG programs to The Registry. Like all other historical data, imported historical data that is transferred from other programs must meet the minimum reporting and verification requirements outlined in the above section.

9.4 Public Disclosure of Historical Data

Like complete and transitional data, The Registry will disclose historical data to the public. Historical reports are labeled "Historical Data" for transparency purposes. For more information about the public disclosure of data, please refer to Chapter 20.

PART III: QUANTIFYING YOUR EMISSIONS

Issue	Requirements		Optional
	Transitional	Complete	
Emission Quantification Methods	• Use the Registry-approved methods described in Part III, Appendix D, Annexes to the GRP (Registry-developed industry-specific reporting protocols) or calculation methodologies mandated by a state, provincial or federal GHG regulatory reporting program.		• May use simplified estimation methods for small emission sources. Total emissions computed using simplified methods cannot exceed five percent of Member's total entity (scope 1, scope 2 and direct biogenic emissions from stationary and mobile combustion) emissions

Chapter 10: Introduction to Quantifying Emissions

After setting the boundaries and identifying which sources to report, Members must quantify their emissions. In some cases, Members may be able to directly measure GHG emissions by monitoring exhaust streams, such as for large stationary combustion units equipped with continuous emissions monitoring systems (CEMS). More often, Members will apply calculation tools and methodologies to estimate GHG emissions using activity data such as fuel use. Part III provides emissions quantification guidelines that provide step-by-step guidance on how to quantify GHG emissions for different emission sources.

Cross-Sector and Sector-Specific Sources

Chapters 12 to16 of Part III provide guidelines for quantifying emissions from sources that are found in many sectors. These sources include:

Chapter 12: Stationary combustion
Chapter 13: Mobile combustion
Chapter 14: Electricity use
Chapter 15: Use of imported steam, district heating, cooling, and electricity from combined heat and power (CHP)[9]
Chapter 16: Use of refrigeration and air conditioning equipment

Members will need to use some or all of these chapters to quantify emissions, depending on the emissions sources in the inventory boundary.

Appendix D provides guidelines for quantifying various emissions from sector-specific sources—that is, sources that apply only to particular industry sectors. These sources are specific to the following industry sectors:

- Adipic acid production
- Aluminum production
- Ammonia production

[9] Combined heat and power (CHP) is also sometimes referred to as cogeneration.

- Cement production
- HCFC-22 production
- Iron and steel production
- Lime production
- Nitric acid production
- Pulp and paper production
- Refrigeration and air condition equipment manufacturing
- Semiconductor manufacturing

Only Members with emissions sources in these sectors need to refer to these sections.

Members will need to make use of all chapters and sections of Appendix D that are relevant to the organization. For example, an entity involved in iron and steel production may need to make use of each of the cross-sector chapters (Chapters 12 to 16) as well as Section D.6 of Appendix D, which provides methodologies specific to the iron and steel sector.

Calculation-Based Methodologies

Most Members will use calculation-based methodologies to quantify their organizations' GHG emissions. Calculation-based methodologies involve the calculation of emissions based on activity data and emission factors. Activity data can include data on fuel consumption, input material flow, or product output. Emission factors are determined by means of direct measurement and laboratory analyses or by using generalized default factors.

Default emission factors sometimes change over time as the components of energy (electricity, fuel, etc.) change and as emission factor quantification methods are refined. The Registry updates emission factors on an annual basis in January to reflect the most up-to-date knowledge. In most cases, Members reporting emissions data from previous years can use the most up to date emission factors available when the inventory is being reported. In the case of default emission factors for electricity use, Members must use the emission factor closest to the emissions year reported that do not post-date the emissions year.

Members with access to high-quality site specific emission factors are encouraged to use those factors. Activity data and calculations should be reported in appropriately accurate detail.

Measurement-Based Methodologies

Measurement-based methodologies determine emissions by means of continuous measurement of the exhaust stream and the concentration of the relevant GHG(s) in the flue gas. Direct measurement will only be relevant to entities with facilities using existing continuous emission monitoring systems (CEMS), such as power plants or industrial facilities with large stationary combustion units. Members without existing monitoring systems will not need to install new monitoring equipment to comply with The Registry's quantification requirements. Those with CEMS should follow the guidance provided in Chapter 12.

Mandatory Methodologies

The Registry accepts all GHG emission calculation methodologies mandated by a state, provincial, or federal GHG Regulatory reporting program.[10] Like all information publically reported through The Registry, data calculated using mandatory methodologies must be included in the Verification Body's risk assessment in accordance with the guidelines of the General Verification Protocol.

Although it is encouraged, Members are not required to use mandatory calculation methods. Members may also elect to use some mandatory calculation methods for select sources or gasses and other Registry-approved methods for others. Please note, where mandatory requirements exclude certain emission sources, Members are still required to quantify emissions from those sources in accordance with The Registry's reporting requirements.

Data Quality

The use of common quantification guidelines ensures that facilities and entities reporting to The Registry quantify their emissions consistently, such that a "ton of CO_2 is a ton of CO_2" throughout The Registry.

Several Registry-approved quantification methods are available for each type of GHG emitting activity identified in Part III of this protocol. Each calculation methodology is assigned a unique reference identifier. These identifiers help provide transparency and streamline some verification activities.

In each section, the most rigorous methodologies are generally listed first. Members are always encouraged to use the most accurate methodology for each emissions source. Using the most rigorous methods feasible will result in the greatest likelihood that reported emissions data will be considered robust by stakeholders and reduces the risk that Members will need to increase the stringency of data collection methodologies in the future. Members that cannot use the most rigorous method—for example, due to technical constraints or excessive costs of data collection—should use the next best available method.

Regardless of the approach employed, Members must report consistently over time to ensure the comparability of emissions data. One exception to this rule is if a Member develops the capability to use a more accurate method for a particular source, it is encouraged to do so and should continue using the more accurate method consistently going forward (refer to Part II, Chapter 7 for requirements for adjusting a base year due to methodological changes).

When reporting activity-level data or entering pre-calculated data at the facility or entity-level, Members are not required to indicate in CRIS which methodology was used to quantify emissions. However, Members must be able to disclose the quantification approaches used to develop the inventory to the Verification Body if requested.

Quantifying Emissions from Sources without Registry-Approved Methodologies

If The Registry has not endorsed guidelines for quantifying emissions from a particular emissions source, Members should use existing industry best practice methods. Methods should be based on internationally accepted best practices whenever possible. The Registry defines industry best practice as calculation and measurement methodologies or factors that are documented and have been through

[10] Examples of mandatory programs include U.S. EPA's Mandatory Greenhouse Gas Reporting Program, California's Greenhouse Gas Reporting Program and Alberta Environment's Greenhouse Gas Reporting Program.

a reasonable peer review process conducted by industry experts. Examples of best practice resources include the Intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* (2006); the WRI/WBCSD GHG Protocol calculation tools and calculation guidance (available at www.ghgprotocol.org); and other internationally recognized sources.

In rare instances, Members find it necessary to develop a new methodology to complete their GHG inventory. Registry Members can propose new methodologies under two circumstances:

1. A Member is unable to use any Registry-provided methodology or published, peer reviewed industry best practice, or
2. A Member has developed a more accurate methodology than is included in The Registry's guidance or industry best practice for that source.

Members wishing to propose new methodologies must submit a Member Developed Methodology proposal form, which can be found on The Registry's website (www.theclimateregistry.org). Members are encouraged to submit this form prior to entering the verification stage.

Members struggling to quantify very small emission sources can also use simplified estimation methods (SEMs) or indicate that a source is miniscule without submitting a Member Derived Methodology form. For more information about SEMs see Chapter 11 and for minuscule sources, see Chapter 5.

Using CRIS to Calculate and Report Emissions

The Registry has developed a sophisticated GHG calculation, reporting, and verification tool to enable our members to submit and centralize GHG emissions data. The Climate Registry Information System (CRIS) provides multiple options to calculate and report GHG emissions annually, and produces user-friendly reports for both the Member and the public. Since Members have different approaches for collecting and reporting GHG emissions data, CRIS provides a number different methodologies that allow Members to follow an approach that aligns best with their own internal process.

Please see Chapter 18 for a description of the reporting options in CRIS.

Chapter 11: Simplified Estimation Methods (SEMs)

The rules, methodologies and standards in the GRP are designed to support complete reporting of a Member's total GHG emissions in North America. Members must quantify emissions using the Registry-approved methodologies described in Part III, Appendix D and any relevant sector-specific protocols.[11] However, The Registry understands that Members may have difficulty applying these methods to every source within the organizational boundary—either because it is not possible or not efficient to use them.

The Registry, therefore accepts emissions estimated using simplified methods in certain cases.

11.1 Simplified Estimation Methods

Members are allowed to use rough, upper-bound, Simplified Estimation Methods (SEMs) for any combination of individual emission sources (e.g., individual electricity generators, vehicles, furnaces, etc.) and/or gases, provided that the emissions from these sources and/or gases are less than or equal to five percent of the sum of reported scope 1, scope 2 and direct biogenic emissions aggregated on a CO_2e basis. Once estimated, these emissions must be included in the inventory.

Members must identify emissions that have been estimated using SEMs and maintain documentation of the source and application of the SEMs used to arrive at the estimated emission for verification.

Using SEMs

The Registry does not provide a list of SEMs for Members. No list would be comprehensive in accounting for all of the possible emissions sources. Instead, Members may develop and implement SEMs as necessary and appropriate. In developing SEMs, should always use upper-bound assumptions following the principle of conservativeness (i.e. erring on the side of overestimating rather than underestimating emissions).

Once a Member has completed an emissions inventory including simplified, upper-bound emissions estimates for a set of emission sources and/or gases, the Member does not have to re-estimate the emissions for this set of sources/gases in subsequent years unless the initial assumptions change. Instead, Members may simply report estimated emissions for each emissions year. However, if initial assumptions change, Members must recalculate simplified emissions estimates using new assumptions.

Furthermore, if a Member finds that recalculated emissions now exceed five percent of the total scope 1, scope 2 and direct biogenic emissions, *or* if total entity-wide emissions decline such that the Member's originally estimated emissions no longer represent five percent or less of the total, the Member must re-select the sources and/or gases included in the simplified estimation calculations such that the resulting simplified estimates will once again sum to less than five percent of total entity emissions.

Simplified Methods and Geographic Boundaries

The five percent threshold for using SEMs refers to the sum of a Member's total reported scope 1, scope 2 and direct biogenic emissions from all sources in North America.

[11] Including methods required by mandatory reporting programs.

If a Member is reporting worldwide emissions, this five percent threshold must also be met in regards to reported worldwide emissions (if the Member chooses to have worldwide emissions verified) or non-North American emissions (if the Member chooses to have a non-North American report verified). See Chapter 2 for information about reporting and verifying worldwide emissions.

Selecting Sources and Gases for the Application of Simplified Estimates

The sources and gases that may be estimated using SEMs will vary from Member to Member. For example, fugitive GHG emissions may fall under the five percent threshold for some Members, but will likely exceed five percent for Members involved in the transmission and distribution of natural gas. Similarly, some Members may choose to apply SEMs for their non-CO_2 GHGs, if non-CO_2 emissions are less than five percent of the Member's total emissions.

Throughout the following chapters, sources that are commonly reported using SEMs have been identified. These include CH_4 and N_2O emissions from ground-based vehicles and, HFC and PFC emissions from refrigeration.

Members have some discretion in identifying which emissions to estimate using SEMs. Example 11.1 provides guidance on the kinds of upper-bound methods that should be used as simplified alternatives to Registry-approved methods.

Reporting Emissions Estimated Using Simplified Methods at the Facility-Level

Members have two options when reporting emissions estimated using SEMs:

1. Emissions can be included in the facilities where the emissions occurred, either as part of the facility total or as emitting activities within facilities, or

2. Members can choose to report aggregated SEMs across facilities at the state/province, national, North American or non-North American levels as long as these emissions are reported in facilities made up exclusively of emissions estimated using SEMs within the appropriate geographic boundary. Emissions reported in this way can use methodologies that aggregate or extrapolate activity data across multiple facilities.

Both reporting options can be used within the same emissions inventory.

Example 11.1. Estimating Emissions Using Simplified Methods

Meridian, a hotel chain with hotels located throughout the U.S. is planning to report its GHG emissions to The Registry. Using the Registry-approved methods in Part III, Meridian has already calculated its GHG emissions for most of its sources, including:

- Indirect emissions from electricity purchases
- Direct emissions from fuel used in stationary combustion units
- Direct emissions from courtesy vans used at some of the hotels to shuttle customers to and from local airports
- Direct emissions of HFCs from the hotels' HVAC system.

Total emissions of all GHGs from these sources are calculated as 36,472 metric tons CO_2e.

There is one emissions source remaining to be quantified—the lawnmowers that are used to maintain the grounds at the hotels. There are 50 such lawnmowers in use at 47 different locations. However, only five of the hotels have kept fuel purchase records for their lawnmowers. Because data on all 50 lawnmowers are lacking, and the lawnmowers as a whole are likely to represent a very small source (less than five percent) of emissions relative to the other sources, Meridian decides to quantify emissions for one lawnmower, and multiply the result by 50 to obtain a simplified estimate of emissions for all 50 lawnmowers. Recognizing the importance of developing a conservative emissions estimate, Meridian selects the lawnmower in use at its Miami, Florida location for three reasons. First, fuel consumption data is available for this lawnmower. Second, unlike the lawnmowers at its more northerly locations, this lawnmower is in use year round, and hence its emissions tend to be relatively high. And third, the grounds at the Miami hotel are extensive, and hence more fuel is required to mow the lawn at this hotel than at most of the other hotels owned by Meridian.

Meridian calculates the emissions of the Miami lawnmower to be 0.32 metric tons CO_2e. Multiplying this result by 50, total lawnmower emissions for the chain as a whole are conservatively estimated as 16 metric tons CO_2e. Adding this value to the total emissions estimate for all other sources yields 36,488 metric tons CO_2e. The estimated lawnmower emissions represent less than 0.05 percent of this total—well below the five percent threshold for the use of SEMs. Therefore, Meridian's use of the SEM is allowable in this situation, and the chain reports the resulting 16-metric ton value as its estimate of emissions from its lawnmowers.

Chapter 12: Direct Emissions from Stationary Combustion

Who should read Chapter 12:
- Chapter 12 applies to Members who combust fuels in any stationary equipment.

What you will find in Chapter 12:
- This chapter provides guidance on determining direct emissions of CO_2, CH_4, and N_2O from stationary combustion, such as through power generation, manufacturing, or other industrial activities involving the combustion of fuels.

Information you will need:
- Continuous Emissions Monitoring System (CEMS) data or information about the type and quantity of fuels consumed.

Cross-References:
- If applicable, refer to Chapter 13 for guidance on imported steam or district heating or cooling.

Direct CO_2 Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
GRP ST-01-CO_2	Direct Monitoring	Continuous Emissions Monitoring Systems (CEMS)
GRP ST-02-CO_2	Calculation Based on Fuel Use	• Measured carbon content of fuels (per unit mass or volume), or • Measured carbon content of fuels (per unit energy) and measured heat content of fuels
GRP ST-03-CO_2	Calculation Based on Fuel Use	• Measured heat content of fuels and default carbon content (per unit energy), or • Measured carbon content (per unit energy) and default heat content of fuels
GRP ST-04-CO_2	Calculation Based on Fuel Use	Default CO_2 emission factors by fuel type

Direct CH_4 and N_2O Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
GRP ST-05-CH_4 & N_2O	Direct Measurement	Continuous emissions monitoring or periodic direct measurements
GRP ST-06-CH_4 & N_2O	Calculation Based on Fuel Use	Default emission factors by sector and technology type
GRP ST-07-CH_4 & N_2O	Calculation Based on Fuel Use	Default emission factors by sector and fuel type

Stationary combustion refers to the combustion of fuels in any stationary equipment. Typical large stationary sources include power plants, refineries, and manufacturing facilities. Smaller stationary sources include commercial and residential furnaces. Examples of stationary combustion units include boilers, burners, turbines, furnaces, and internal combustion engines. Figure 12.1 gives guidance on how to select a particular CO_2 emissions quantification methodology based on the data that is available. Figure 12.2 gives similar guidance for direct CH_4 and N_2O emissions from stationary combustion.

12.1 Measurement Using Continuous Emissions Monitoring System Data

GRP ST-01-CO_2: Direct Monitoring

Some facilities, such as power plants and large industrial plants, have continuous emissions monitoring systems (CEMS) that track their CO_2 emissions (e.g. monitors installed pursuant to 40 CFR Parts 60, 75 or 98). Entities that report CO_2 emissions data to federal and/or state/province or local environmental agencies are encouraged to report the same CO_2 emissions information to The Registry.

You may use either of the two following CEMS configurations to determine annual CO_2 emissions:

1. A monitor measuring CO_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

2. A monitor measuring CO_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas combined with theoretical CO_2 and flue gas production by fuel characteristics can be used to determine CO_2 flue gas emissions and CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

All methods of direct monitoring using CEMS pursuant to 40 CFR Parts 60, 75, 98 or Environment Canada's Report EPS 1/PG/7 (Revised) are consistent with GRP ST-01-CO_2.

Members that do not own or operate a stationary combustion unit equipped with a CEMS, should calculate emissions from stationary combustion using the method outlined in Section 12.2. For whichever method or combination of methods used to quantify CO_2 emissions, the same reporting methodology should be used from year to year to maintain consistency and comparability between years.

For Members in the electric power sector, additional specifications on using CEMS can be found in The Registry's EPS Protocol.

Figure 12.1. Selecting a Methodology: Direct CO_2 Emissions from Stationary Combustion

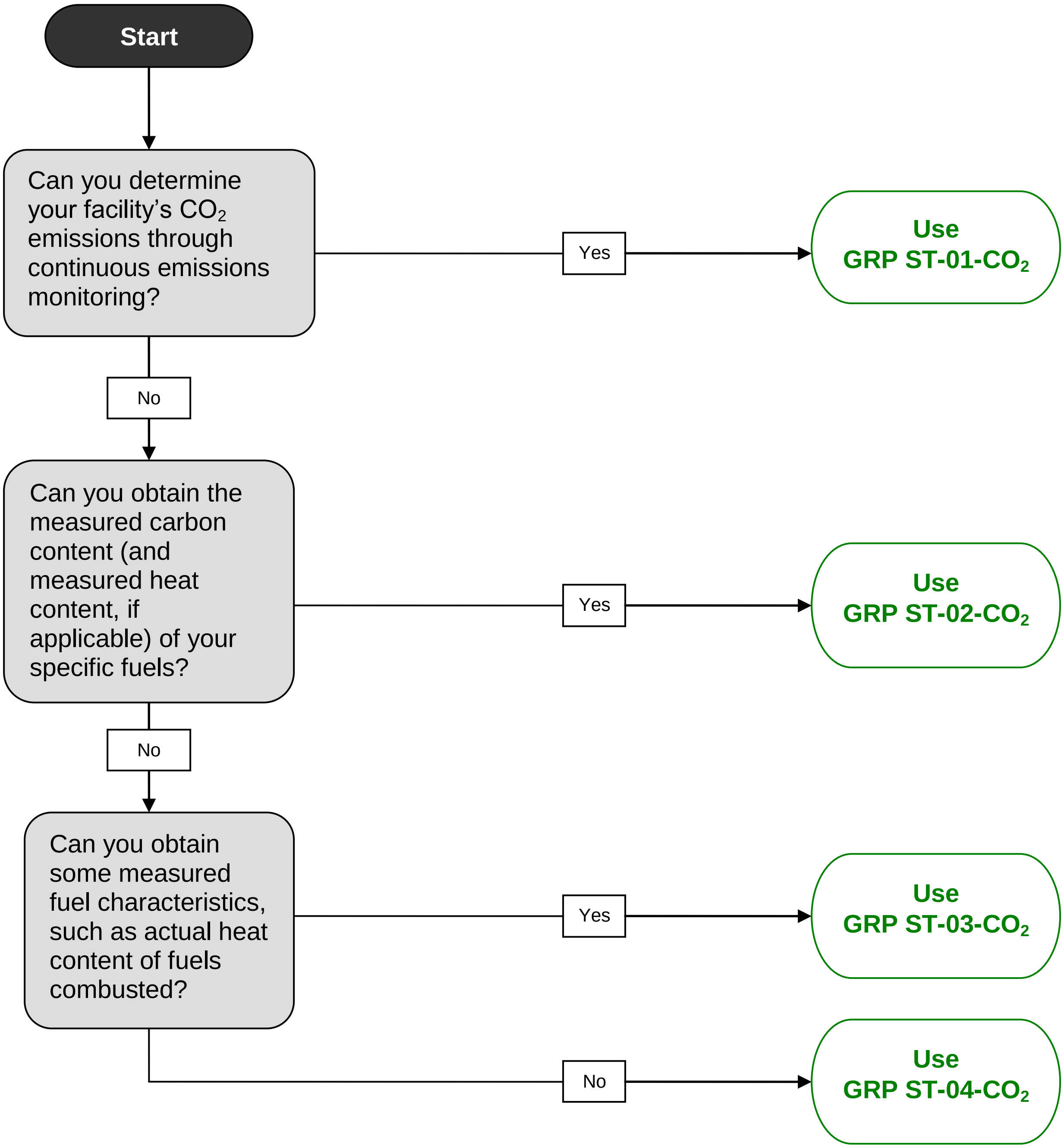
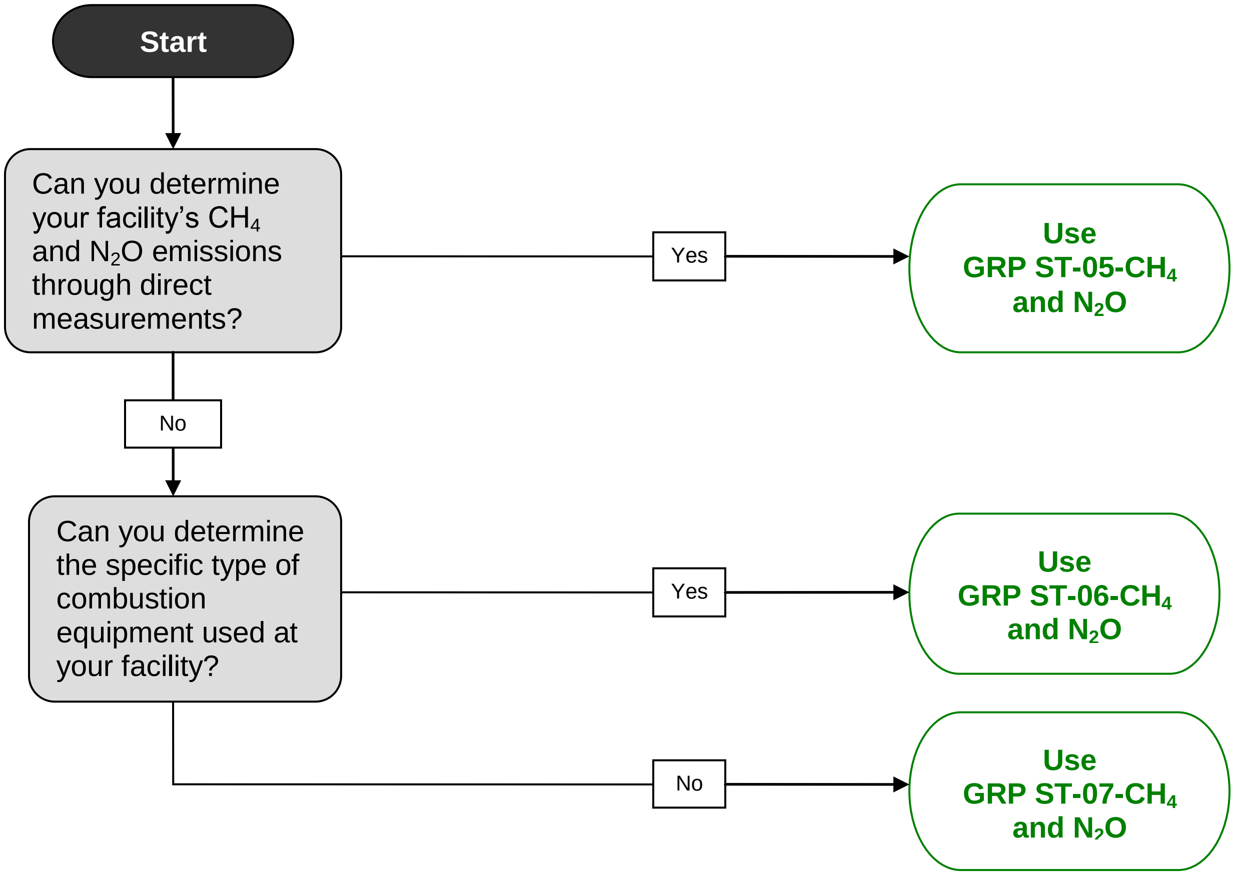


Figure 12.2. Selecting a Methodology: Direct CH_4 and N_2O Emissions from Stationary Combustion



Biofuels, Biofuel Blends Combusted in Units without CEMS, and Biomass Co-Firing in a Unit with CEMS

Biofuels

Biofuels such as landfill gas, ethanol, wood, and wood waste may be combusted in addition to fossil fuels. You must report CO_2 emissions from fossil fuel combustion separately from CO_2 emissions from biomass combustion. CO_2 emissions from fossil fuel combustion are reported in scope 1, while CO_2 emissions from biomass combustion are reported separately from the scopes. The same step-by-step procedure for determining GHG emissions from fossil fuels applies to non-fossil fuels. Note that emissions of CH_4 and N_2O from biomass combustion are included in scope 1 and are not treated differently from CH_4 and N_2O emissions from fossil fuel combustion. This principle also applies to the combustion of liquid biofuels that are received as blends.

Biofuel Blends Combusted in Units without CEMS

For facilities that combust blended fuels such as municipal solid waste (MSW) treatment facilities, you must calculate or monitor CO_2 emissions resulting from the incineration of waste of fossil fuel origin (e.g. plastics, certain textiles, rubber, liquid solvents, and waste oil) and include those emissions as direct CO_2 emissions (scope 1). CO_2 emissions from combusting the biomass portion of the fuel or feedstock (e.g., yard waste, paper products, etc. for MSW) must be separately calculated and reported as biogenic CO_2 emissions (reported separately from the scopes). Information on the biomass portion of fuels and feedstocks are often site-specific. MSW facilities should obtain biomass/fossil fuel breakdown information from a local waste characterization study. You may also use the methodology described in ASTM D6866 (see below for more information).

Biomass Co-Firing in a Unit with CEMS

The Registry requires that participants identify and report biomass CO_2 combustion emissions as “biogenic emissions,” separate from fossil fuel emissions. Thus, if Members combust biomass fuels in any units using CEMS to report CO_2 emissions, you must calculate the emissions associated with the fossil fuels (Equation 12a) and subtract this from the total measured emissions (Equation 12b). You must report these separately from fossil fuel emissions, along with any other biogenic emissions.

The following example illustrates a case where biomass is co-fired and emissions are monitored through a CEMS. An electric utility company reports the CO_2 emissions from its major electric generating facilities using the CEMS already installed on those units. At one of its natural gas-fired units it co-fires with wood; the emissions associated with each combustion activity are mixed in the exhaust stack and measured collectively by the CEMS device. To report its CO_2 emissions from this unit, you must calculate CO_2 from fossil fuel combustion. To do this, multiply fossil fuel consumption by an appropriate fuel-specific emission factor from Tables 12.1 to 12.3 (see Equation 12a and emission factor tables available on The Climate Registry’s website at www.theclimateregistry.org). After deriving total CO_2 from fossil fuel combustion, subtract this value from total CEMS CO_2 emissions to obtain CO_2 from biomass combustion (see Equation 12b).

Equation 12a	**Calculating Fossil Fuel CO_2 Emissions** (Fuel Consumption in MMBtu)				
CO_2 from Fossil Fuel Combustion (metric tons)	=	Fossil Fuel Consumed **x** (MMBtu)	Fossil Fuel Emission Factor **x** (kg CO_2/MMBtu)	0.001 (metric tons/kg)	

Equation 12b	**Backing Out Fossil Fuel CO_2 Emissions from CEMS**		
CO_2 from Biomass Combustion (metric tons)	=	Total CEMS CO_2 Emissions **-** (metric tons)	Total Fossil Fuel CO_2 Emissions (metric tons)

Alternatively, instead of first calculating CO_2 from fossil fuel combustion, you may first calculate the portion of CO_2 emissions from combusting wood, and subtract it from the measurement of total emissions. To do so, you must quantify the amount of biomass consumed by the unit, and multiply that value by the wood-specific CO_2

emission factor from Tables 12.1 to 12.2 (available on The Climate Registry's website at www.theclimateregistry.org) This value is then subtracted from the total CO_2 emissions measured by the CEMS.

As a third option for separately calculating the portion of CO_2 emissions attributable to fossil fuel versus biomass, you may use the methodology described in ASTM D6866-06a, "Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis." For further specifications on using this method, see California Air Resources Board *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, Section 95125(h)(2).

12.2 Calculating Emissions from Stationary Combustion Using Fuel Use Data

Estimating emissions from stationary combustion using fuel use data involves the following six steps:

1. Determine annual consumption of each fuel combusted at your facility;
2. Determine the appropriate CO_2 emission factors for each fuel;
3. Determine the appropriate CH_4 and N_2O emission factors for each fuel;
4. Calculate each fuel's CO_2 emissions;
5. Calculate each fuel's CH_4 and N_2O emissions; and
6. Convert CH_4 and N_2O emissions to CO_2e and determine total emissions.

Step 1: Determine annual consumption of each fuel combusted at the facility.

First identify all fuels combusted at the facility. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Then determine annual fuel use by fuel type, measured in terms of physical units (mass or volume). For stationary combustion sources, the preferred method is to determine the amount of fuel combusted at each combustion unit by reading individual meters located at the fuel input point. Alternatively, you may use fuel receipts or purchase records to calculate total fuel usage. If self-generating fuels, such as biomass, you may rely on internal records.[12] For solid fuels, another acceptable fuel use estimation approach is to back calculate fuel use from steam generation rates (e.g. as indicated in U.S. GHGRP §98.33(a)(2)(iii) corresponding to Tier 2 methodology, Equation C-2c).

Once fuel use is estimated, convert fuel purchase and storage data to estimates of measured fuel use using Equation 12c.

Equation 12c		Accounting for Changes in Fuel Stocks
Total Annual Fuel Consumption	=	Annual Fuel Purchases **-** Annual Fuel Sales **+** Fuel Stock at Beginning of Year **-** Fuel Stock at End of Year

[12] Internal records should identify the methods used, the measurements made, and the calculations performed to quantify fuel usage.

Estimating Tenant Natural Gas Use for Landlords

Members with aggregated data on total building natural gas consumption who act as landlords and wish to allocate proportional scope 1 emissions to a tenant who exercises operational control over its own purchasing and consumption (e.g. by contracting for natural gas directly with the provider) may use the following Registry-approved methodology to deduct tenant natural gas use from their own, provided estimated tenant emissions are less than five percent of the Member's total reported inventory:

Leased Area(s) **x** Natural Gas Intensity Factor = Estimated Tenant Natural Gas Use

Natural Gas Intensity Factors

Principal Building Activity	(ft^3 NG/Area ft^2)
Education	36.9
Food Sales	50.2
Food Service	141.2
Health Care	92.5
Inpatient	109.8
Outpatient	50.2
Lodging	48.9
Mercantile	32.5
Retail (Other Than Mall)	30.9
Enclosed and Strip Malls	33.4
Office	31.8
Public Assembly	36.4
Public Order and Safety	43.7
Religious Worship	30.3
Service	54.1
Warehouse and Storage	23.4
Other	67.6
Vacant	23.0

Source: U.S. Department of Energy, Commercial Buildings Energy Consumption Survey 2003 Table E.8A: Natural Gas Consumption (cubic feet) and Energy Intensities by End Use for All Buildings.

Step 2: Determine the appropriate CO_2 emission factor for each fuel.

GRP ST-02-CO_2: Actual Fuel Characteristics

The preferred method is to derive an emission factor for CO_2 using the measured characteristics of the fuels combusted. This method requires information on the heat content and/or carbon content of the fuels. This information can be determined either through fuel sampling and analysis or from data provided by fuel suppliers. Fuel sampling and analysis should be performed periodically, the frequency depending on the type of fuel. In general, the sampling frequency should be greater for more variable fuels (e.g., coal, wood, solid waste) than for more homogenous fuels (e.g., natural gas, diesel fuel). You should collect and analyze fuel data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation.

For additional resources on sampling rates and methods, refer to:

- 40 CFR Parts 86, 87, 89 et al. Mandatory Reporting of Greenhouse Gases
- 40 CFR Part 75, Appendix G Continuous Emissions Monitoring, Determination of CO_2 Emissions

- California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Section 95125(c)-(e)
- European Union, Monitoring and Reporting Guidelines for the EU Emissions Trading Scheme (2006), Section 13, “Determination of Activity-Specific Data and Factors”
- WRI/WBCSD GHG Protocol Guidance: Direct Emissions from Stationary Combustion, Version 3.0 (July 2005), Annex D (www.ghgprotocol.org)

The carbon content of each fuel can be expressed in mass of carbon per mass of fuel (such as kg C/short ton), mass of carbon per volume of fuel (such as kg C/gallon), or mass of carbon per unit energy of fuel (such as kg C/MMBtu).

The heat content of each fuel is expressed in units of energy per unit mass or volume (such as MMBtu/short ton or MMBtu/gallon) and should be calculated based on higher heating values (HHV). See the box “Estimating Emissions Based on Higher Heating Values” below if you have data based on lower heating values (LHV).

Multiply the heat content per unit mass or volume (such as Btu/ton or Btu/gallon) by the carbon content per unit energy (e.g., kg C/Btu) to determine the mass of carbon per physical unit of fuel (such as kg C/ton or kg C/gallon). If you have measured carbon content data expressed in mass of carbon per mass or volume of fuel, you do not need to multiply by a heat content factor, since your factor is already in physical units.

To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content in physical units by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to units of CO_2, multiply by 44/12, the molecular weight ratio of CO_2 to carbon (see Equation 12d).

Equation 12d	**Calculating CO_2 Emission Factors Using Measured Fuel Characteristics** (Fuel Consumption in Gallons)				
Emission Factor	**=**	Heat Content **x**	Carbon Content **x**	% Oxidized **x**	44/12
(kg CO_2/gallon)		(Btu/gallon)	(kg C/Btu)		(CO_2/C)

GRP ST-03-CO_2: Combining Actual and Default Factors

You should use information on the measured fuel characteristics of combusted fuels whenever possible. In some cases, you may be able to obtain measured heat content information (for example, from the fuel supplier), but be unable to obtain measured carbon content data. Likewise, you may have measured carbon content data but not measured heat content data. In these cases, you should combine the more specific data with default factors from Tables 12.1 to 12.3.[13]

[13] Emission factor tables are available on The Registry’s website at www.theclimateregistry.org.

GRP ST-04-CO_2: Default Emission Factors

If you cannot determine the measured heat content or measured carbon content of specific fuels, use the default emission factors provided by fuel type in Tables 12.1 to 12.3.[14] Emission factors are provided in units of CO_2 per unit energy and CO_2 per unit mass or volume. If combusting a fuel that is not listed in the table, you must derive an emission factor based on the specific properties of the fuel using the GRP ST-02-CO_2 method. For fuels that are combusted in small quantities, it may be acceptable to use SEMs rather than deriving a fuel-specific emission factor. See Chapter 11 for more information on SEMs.

Step 3: Determine the appropriate CH_4 and N_2O emission factors for each fuel.

Estimating CH_4 and N_2O emissions depends not only on fuel characteristics, but also on technology type and combustion characteristics; usage of pollution control equipment; and maintenance and operational practices. Due to this complexity, estimates of CH_4 and N_2O emissions from stationary sources are much more uncertain than estimates of CO_2 emissions. CH_4 and N_2O also account for much smaller quantities of emissions from stationary combustion than CO_2.

GRP ST-05-CH_4 & N_2O: Direct Monitoring

Facilities that use direct monitoring to obtain specific emission factors based on periodic exhaust sampling, should use these emission factors.

GRP ST-06-CH_4 & N_2O: Default Emission Factors by Sector and Technology

If you can determine either the specific type of combustion equipment used at a facility or a facility's specific commercial sector use factors from Tables 12.4 to 12.8[15] based on the specific type of combustion equipment and sector.

[14] Ibid.
[15] Ibid.

Estimating Emissions Based on Higher Heating Values

When calculating CO_2 emissions, all fuel data and factors must be based on the same heating value basis. In the United States and Canada, higher heating values (HHV) are used to measure the heat content of fuels rather than lower heating values (LHV). Therefore, estimates of GHG emissions from fuel combustion should be based on HHV. However, LHV are typically used internationally, so you may be required to convert from LHV to HHV. Note that HHV are also referred to as gross calorific values (GCV) and LHV are also referred to as net calorific values (NCV). Converting from LHV to HHV is inexact and depends on the actual characteristics of fuels, but you can convert from a LHV to a HHV basis using the following "rule of thumb."

Equation 12e	Converting from LHV to HHV
$\textbf{Btu}_{\textbf{HHV}} = \text{Btu}_{\text{LHV}} \div 0.95$ for solid and liquid fuels	
$\textbf{Btu}_{\textbf{HHV}} = \text{Btu}_{\text{LHV}} \div 0.90$ for gaseous fuels	

Where Btu is fuel consumption data on an energy content basis (such as Btu or MMBtu) or a heat content factor (such as Btu/gallon). Note that to convert carbon content factors (such as kg C/Btu) from LHV to HHV, you must multiply by 0.95 or 0.90 rather than divide because the Btu factor is in the denominator.

For example, natural gas has a heat content of 924 Btu/standard cubic feet on an LHV basis and a heat content of 1,027 Btu/standard cubic foot on an HHV basis. Natural gas has a carbon content of 16.08 kg C/MMBtu on a LHV basis and a carbon content of 14.47 kg C/MMBtu on a HHV basis. To calculate a CO_2 emission factor for natural gas on the basis of both LHV and HHV, use Equation 12f.

Equation 12f	Example: Calculating CO_2 Emission Factors Using Measured Fuel Characteristics				
Emission Factor	**=**	Heat Content **x**	Carbon Content **x**	% Oxidized **x**	44/12
(kg CO_2/gallon)		(Btu/gallon)	(kg C/Btu)		(CO_2/C)
LHV Emission Factor	**=**	924 **x**	16.08 ÷	1,000,000 **x**	1.0 **x** 44/12 = 0.05448
(kg CO_2/scf)		(Btu/scf)	(kg C/MMBtu)	(Btu/MMBtu)	(CO_2/C)
HHV Emission Factor	**=**	1027 **x**	14.47 ÷	1,000,000 **x**	1.0 **x** 44/12 = 0.05449
(kg CO_2/scf)		(Btu/scf)	(kg C/MMBtu)	(Btu/MMBtu)	(CO_2/C)

GRP ST-07-CH_4 & N_2O: Default Emission Factors by Sector and Fuel

Use Table 12.9[16] to obtain emission factors by fuel type and sector.

Step 4: Calculate each fuel's CO_2 emissions and convert to metric tons.

To determine CO_2 emissions from stationary combustion, multiply fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 12g). Note that Equation 12g expresses fuel use in gallons. If fuel use is expressed in different units (such as short tons, cubic feet, MMBtu, etc.), replace "gallons" in the equation with the appropriate unit of measure. Be sure that your units of measure for fuel use are the same as those in your emission factor.

[16] Ibid.

Equation 12g	Calculating CO_2 Emissions From Stationary Combustion (Fuel use in gallons)			
Fuel A CO_2 Emissions (metric tons)	=	Fuel Consumed **x** (gallons)	Emission Factor ÷ (kg CO_2/gallon)	1,000 (kg/metric ton)
Fuel B CO_2 Emissions (metric tons)	=	Fuel Consumed **x** (gallons)	Emission Factor ÷ (kg CO_2/gallon)	1,000 (kg/metric ton)
Total CO_2 Emissions (metric tons)	=	CO_2 from Fuel A **+** (metric tons)	CO_2 from Fuel B **+** (metric tons)	… (metric tons)

Step 5: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.

To determine CH_4 emissions from stationary combustion at a facility, multiply the fuel use from Step 1 by the CH_4 emission factor from Step 3, and then convert grams to metric tons. Repeat the calculation for each fuel and technology type, then sum (see Equation 12h). Note that Equation 12h expresses fuel use in MMBtu. If fuel use is expressed in different units (such as gallons, short tons, cubic feet, etc.) you must convert fuel use data to units of MMBtu. If you have measured heat content factors for specific fuels, use them to convert fuel data to energy units. Otherwise, use a default heat content factor by fuel from Tables 12.1 to 12.3.[17] Be sure that your units of measure for fuel use are the same as those in your emission factor. Follow the same procedure, using Equation 12i, to calculate total emissions of N_2O.

Equation 12h	Calculating CH_4 Emissions From Stationary Combustion			
Fuel/Technology Type A CH_4 Emissions (metric tons)	=	Fuel Use **x** (MMBtu)	Emission Factor ÷ (g CH_4/MMBtu)	1,000,000 (g/metric ton)
Fuel/Technology Type B CH_4 Emissions (metric tons)	=	Fuel Use **x** (MMBtu)	Emission Factor ÷ (g CH_4/MMBtu)	1,000,000 (g/metric ton)
Total CH_4 Emissions (metric tons)	=	CH_4 from Type A **+** (metric tons)	CH_4 from Type B **+** (metric tons)	… (metric tons)

Equation 12i	Calculating N_2O Emissions From Stationary Combustion			
Fuel/Technology Type A N_2O Emissions (metric tons)	=	Fuel Use **x** (MMBtu)	Emission Factor ÷ (g N_2O/MMBtu)	1,000,000 (g/metric ton)
Fuel/Technology Type B N_2O Emissions (metric tons)	=	Fuel Use **x** (MMBtu)	Emission Factor ÷ (g N_2O/MMBtu)	1,000,000 (g/metric ton)
Total N_2O Emissions (metric tons)	=	N_2O from Type A **+** (metric tons)	N_2O from Type B **+** (metric tons)	… (metric tons)

[17] Ibid.

Step 6: Convert CH_4 and N_2O emissions to units of CO_2e and determine total emissions from stationary combustion.

Use the IPCC global warming potential (GWP) factors provided in Equation 12j (and Appendix B) to convert CH_4 and N_2O emissions to units of CO_2e. Then sum the emissions of all three gases to determine total facility emissions from stationary combustion (see Equation 12j).

Equation 12j	Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions (metric tons CO_2e)	=	CO_2 Emissions **x** (metric tons)	1 (GWP)	
CH_4 Emissions (metric tons CO_2e)	=	CH_4 Emissions **x** (metric tons)	21 (GWP)	
N_2O Emissions (metric tons CO_2e)	=	N_2O Emissions **x** (metric tons)	310 (GWP)	
Total Emissions (metric tons CO_2e)	=	CO_2 + (metric tons CO_2e)	CH_4 + (metric tons CO_2e)	N_2O (metric tons CO_2e)

12.3 *Optional:* Allocating Emissions from Combined Heat and Power /Cogeneration

Accounting for the GHG emissions from a Combined Heat and Power (CHP) facility is unique because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the GHG emissions between the two different energy streams may be useful.

Note that to comply with Registry reporting guidelines, Members must only determine absolute emissions from a CHP plant using the same procedure for non-CHP plants described in the previous section. However, Members may also allocate emissions according to each final product stream, i.e. electricity or steam, as described in this section.

Note that a CHP facility refers to a system that captures the waste-heat from the primary electricity generating pathway and uses it for non-electricity purposes. In contrast, a combined cycle (or bottoming cycle) power plant that uses waste-heat to generate electricity should be treated no differently from stationary combustion emissions as described in the previous section.

The most consistent approach for allocating GHG emissions in CHP applications is the efficiency method, which allocates emissions of CHP plants between electric and thermal outputs on the basis of the energy input used to produce the separate steam and electricity products. To use this method, you must know the total emissions from the CHP plant, the total steam (or heat) and electricity production, and the steam (or heat) and electricity efficiency of the facility. Use the following steps to determine the share of emissions attributable to steam (or heat) and electricity production.

Step 1: Determine the total direct emissions from the CHP system.

Calculate total direct GHG emissions using the methods described in the previous section. Like the guidance for non-CHP stationary combustion, calculating total emissions from CHP sources is based on either CEMS or fuel input data.

Step 2: Determine the total steam and electricity output for the CHP system.

To determine the total energy output of the CHP plant attributable to steam production, use published tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions (for example, the *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam* published by the International Association for the Properties of Water and Steam (IAPWS)). Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP plant yield energy output values in units of MMBtu. Alternatively, determine net heat (or steam) production (in MMBtu) by subtracting the heat of return condensate (MMBtu) from the heat of steam export (MMBtu). To convert total electricity production from MWh to MMBtu, multiply by 3.412 MMBtu/MWh.

Step 3: Determine the efficiencies of steam and electricity production.

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP plant are not known, use a default value of 80 percent for steam and a default value of 35 percent for electricity. The use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. If the constraints are not satisfied, the efficiencies of the steam and electricity can be modified until constraints are met.

Step 4: Determine the fraction of total emissions allocated to steam and electricity production.

Allocate the emissions from the CHP plant to the steam and electricity product streams by using Equation 12k.

Equation 12k	**Allocating CHP Emissions to Steam and Electricity**

Step 1: $E_H = (H \div e_H) \div [(H \div e_H) + (P \div e_P)] \times E_T$

Step 2: $E_P = E_T - E_H$

Where:

E_H = Emissions allocated to steam production
H = Total steam (or heat) output (MMBtu)
e_H = Efficiency of steam (or heat) production
P = Total electricity output (MMBtu)
e_P = Efficiency of electricity generation
E_T = Total direct emissions of the CHP system
E_P = Emissions allocated to electricity production

Example 12.1. Direct Emissions from Stationary Combustion

Annual Consumption of Fuels

F&M Manufacturing

F&M is a manufacturing facility. It has two 10 MW generating units, one burning natural gas and one coal-fired unit. Neither is equipped with a CEMS device. F&M also has a commercial office building on-site that is heated with distillate fuel. In this example, the entity uses GRP ST-02-CO_2 to quantify CO_2 emissions and GRP ST-07-CH_4 and N_2O to quantify CH_4 and N_2O emissions.

Step 1: Determine annual consumption of each fuel combusted at the facility.

F&M measures fuel used by its plants and purchases its heating fuel for commercial use in bulk by the barrel. Last year it consumed 769,921,800 standard cubic feet (scf) of natural gas and 43,039 short tons of coal. It also purchased 265 barrels of distillate fuel for heating and sold 15 barrels. F&M began the year with 12 barrels in storage and ended the year with 24 barrels in storage. Using Equation 12c, F&M determined distillate fuel consumption. The resulting total in barrels can be converted to gallons by multiplying by 42.

Equation 12c		Example: Accounting for Changes in Fuel Stocks
Annual Distillate Fuel Use	=	265 barrels **-** 15 barrels **+** 12 barrels **-** 24 barrels
	=	238 barrels **x** 42 gallons/barrel
	=	9,996 gallons

Fuel Consumption by Fuel Type and Sector

Fuel Type	Sector	Annual Consumption
Natural Gas	Industrial	769,921,800 scf
Coal	Industrial	43,039 short tons
Distillate Fuel	Commercial	9,996 gallons

Step 2: Determine the appropriate emission factors for each fuel.

F&M calculates CO_2 emission factors for each of the three fuels using measured fuel characteristics it obtained from its fuel suppliers see Equation 12d below. F&M obtains emission factors for CH_4 and N_2O from Table 12.9 because it does not have monitoring data or available data on specific combustion technologies (see below).

Equation 12d		Example: Calculating CO_2 Emission Factors Using Measured Fuel Characteristics				
Natural Gas Emission Factor	=	1,024 **x** (Btu/scf)	14.43 **x** (kg C/MMBtu)	1.0 **x** 44/12 ÷ (CO_2/C)	1,000,000 (Btu/MMBtu)	= **0.054** kg CO_2/scf
Coal Emission Factor	=	21.98 **x** (MMBtu/ short ton)	25.49 **x** (kg C/MMBtu)	1.0 **x** 44/12 (CO_2/C)		= **2,054.32** kg CO_2/ short ton
Distillate Emission Factor	=	5.821 **x** (MMBtu/barrel)	19.94 **x** (kg C/MMBtu)	1.0 **x** 44/12 ÷ (CO_2/C)	42 (gallon/barrel)	= **10.13** kg CO_2/ gallon

Emission Factors by Fuel Type and Sector

Fuel Type	Sector	CO_2 Emission Factor	CH_4 Emission Factor	N_2O Emission Factor
Natural Gas	Industrial	0.054 kg/scf	1 g/MMBtu	0.1 g/MMBtu
Coal	Industrial	2,054.32 kg/short ton	11 g/MMBtu	1.6 g/MMBtu
Distillate Fuel	Commercial	10.13 kg/gallon	11 g/MMBtu	0.6 g/MMBtu

Step 3: Calculate each fuel's CO_2 emissions and convert to metric tons.

See Equation 12g below.

Equation 12g	Example: Calculating CO_2 Emissions From Stationary Combustion				
Natural Gas CO_2 Emissions	=	769,921,800 **x** (scf)	0.054 ÷ (kg CO_2/scf)	1,000 (kg/metric ton)	= 41,575.8 metric tons
Coal CO_2 Emissions	=	43,039 **x** (short tons)	2,054.32 ÷ (kg CO_2/short ton)	1,000 (kg/metric ton)	= 88,415.9 metric tons
Diesel CO_2 Emissions	=	9,996 **x** (gallons)	10.13 ÷ (kg CO_2/gallon)	1,000 (kg/metric ton)	=101.3 metric tons
Total CO_2 Emissions = 41,575.8 **+** 88,415.9 **+** 101.3 = **130,093 metric tons**					

Step 4: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.

F&M first multiplies its fuel consumption in physical units by its fuel-specific heat content values to calculate fuel use in MMBtu for each fuel. See Equations 12h and 12i below.

Equation 12h	Example: Calculating CH_4 Emissions From Stationary Combustion				
NG CH_4 Emissions	=	788,399.92 **x** (MMBtu)	1 ÷	1,000,000 (g/metric ton)	= 0.79 metric tons
Coal CH_4 Emissions	=	951,931.82 **x** (MMBtu)	11 ÷ (g CH_4/MMBtu)	1,000,000 (g/metric ton)	= 10.47 metric tons
Distillate Fuel CH_4 Emissions	=	1,385.40 **x** (MMBtu)	11 ÷ (g CH_4/MMBtu)	1,000,000 (g/metric ton)	= 0.02 metric tons
Total CH_4 Emissions = 0.79 **+** 10.47 **+** 0.02 = **11.3 metric tons**					

Equation 12i	Example: Calculating N_2O Emissions From Stationary Combustion				
NG N_2O Emissions	=	788,399.92 **x** (MMBtu)	0.1 ÷	1,000,000 (g/metric ton)	= 0.08 metric tons
Coal N_2O Emissions	=	951,931.82 **x** (MMBtu)	1.6 ÷ (g CH_4/MMBtu)	1,000,000 (g/metric ton)	= 1.52 metric tons
Distillate Fuel N_2O Emissions	=	1,385.40 **x** (MMBtu)	0.6 ÷ (g CH_4/MMBtu)	1,000,000 (g/metric ton)	= 0.001 metric tons
Total N_2O Emissions = 0.08 **+** 1.52 **+** 0.001 = **1.6 metric tons**					

Step 5: Convert CH_4 and N_2O emissions to units of CO_2e and determine total emissions from stationary combustion.

See Equation 12j below.

Equation 12j	Example: Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions	=	130,231 **x** (metric tons)	1 (GWP)	= 130,231 metric tons CO_2e
CH_4 Emissions	=	11.3 **x** (metric tons)	21 (GWP)	= 237 metric tons CO_2e
N_2O Emissions	=	1.6 **x** (metric tons)	310 (GWP)	= 496 metric tons CO_2e

Total Emissions = CO_2 **+** CH_4 **+** N_2O = **130,964 metric tons CO_2e**

Chapter 13: Direct Emissions from Mobile Combustion

Who should read Chapter 13:

- Chapter 13 applies to all Members that own or operate motor vehicles or other forms of transportation.

What you will find in Chapter 13:

- This chapter provides guidance on calculating direct emissions of CO_2, CH_4, and N_2O from mobile combustion.

Information you will need:

- Types of vehicles, fuel consumption data, and miles traveled for each type of vehicle. Fuel consumption data may be obtained from bulk fuel purchases, fuel receipts, or direct measurements of fuel use. Sources of annual mileage data include odometer readings, trip manifests or maintenance records.

Cross-References:

Refer to Chapter 16 to determine any fugitive emissions from motor vehicle air conditioning units, if applicable.

Direct CO_2 Emissions From Mobile Combustion		
Method	**Type of Method**	**Data Requirements**
GRP MO-01-CO_2	Fuel use	• Measured carbon content (per unit mass) and measured density of fuels, or • Measured carbon content (per unit energy) and measured heat content of fuels
GRP MO-02-CO_2	Fuel use	• Measured heat content of fuels and default carbon content (per unit energy), or • Measured carbon content (per unit energy) and default heat content of fuels
GRP MO-03-CO_2	Fuel use	Default CO_2 emission factors by fuel type
GRP MO-04-CO_2	Fuel use estimated using vehicle miles traveled and vehicle fuel economy	Default CO_2 emission factors by fuel type

Direct CH_4 & N_2O Emissions From Mobile Combustion (Highway Vehicles)		
Method	**Type of Method**	**Data Requirements**
GRP MO-05-CH_4 & N_2O	Miles traveled by vehicle type	Default emission factors by vehicle type based on vehicle technology
GRP MO-06-CH_4 & N_2O	Miles traveled by vehicle type	Default emission factors by vehicle type based on model year
GRP MO-07-CH_4 & N_2O	Distance estimated using fuel use and vehicle fuel economy	Default emission factors by vehicle type based on vehicle technology or model year

Direct CH_4 & N_2O Emissions From Mobile Combustion (Non-Highway Vehicles)		
Method	**Type of Method**	**Data Requirements**
GRP MO-08-CH_4 & N_2O	Fuel use	Default emission factors by vehicle type and fuel type
GRP MO-09-CH_4 & N_2O	Fuel use estimated using vehicle miles traveled and vehicle fuel economy	Default emission factors by vehicle type and fuel type
GRP MO-10-CH_4 & N_2O	Total landing and takeoff (LTO) cycles (*acceptable for jet aircraft only*)	Default emission factors by aircraft type and LTO

Mobile combustion sources include both on-road and non-road vehicles such as automobiles, trucks, buses, trains, ships and other marine vessels, airplanes, tractors, construction equipment, forklifts, ride-on lawn mowers, snowmobiles, snow blowers, chainsaws and lawn care equipment. The combustion of fossil fuels in mobile sources emits carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

Emissions from mobile combustion can be estimated based on vehicle fuel use and miles traveled data. CO_2 emissions, which account for the majority of emissions from mobile sources, are directly related to the quantity of fuel combusted and thus can be calculated using fuel consumption data. CH_4 and N_2O emissions depend more on the emission control technologies employed in the vehicle and distance traveled. Calculating emissions of CH_4 and N_2O requires data on vehicle characteristics (which take into account emission control technologies) and vehicle miles traveled.

Figure 13.1 gives guidance on how to select a particular CO_2 emissions quantification methodology based on available data for direct CO_2 emission from mobile combustion. Figure 13.2 gives similar guidance for direct CH_4 and N_2O emissions from mobile combustion (highway vehicles only).

Mobile sources may also emit hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from mobile air conditioning and transport refrigeration leaks. See Chapter 16 for guidance on estimating these additional mobile source emissions.

Figure 13.1. Selecting a Methodology: Direct CO_2 Emissions from Mobile Combustion

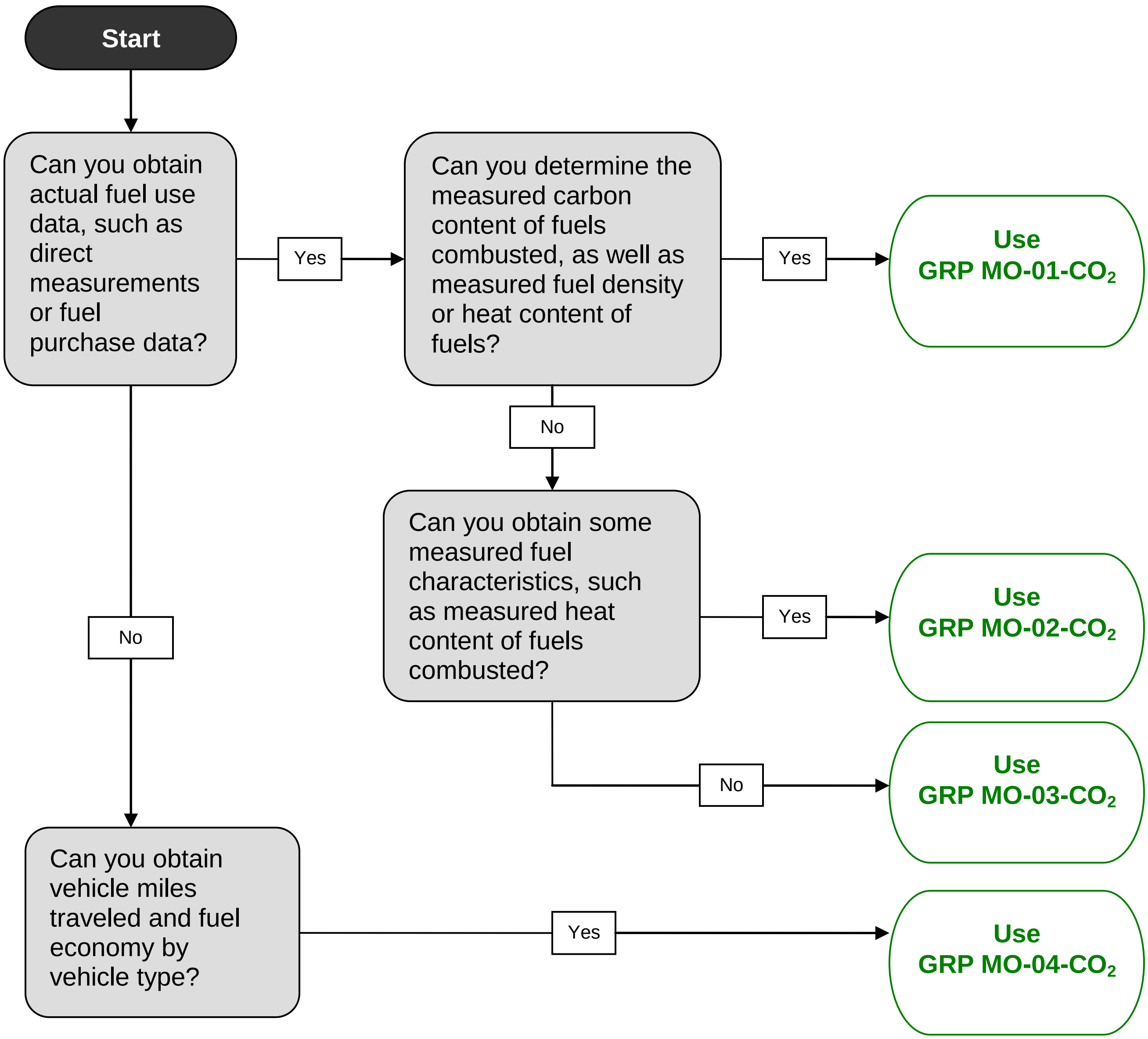
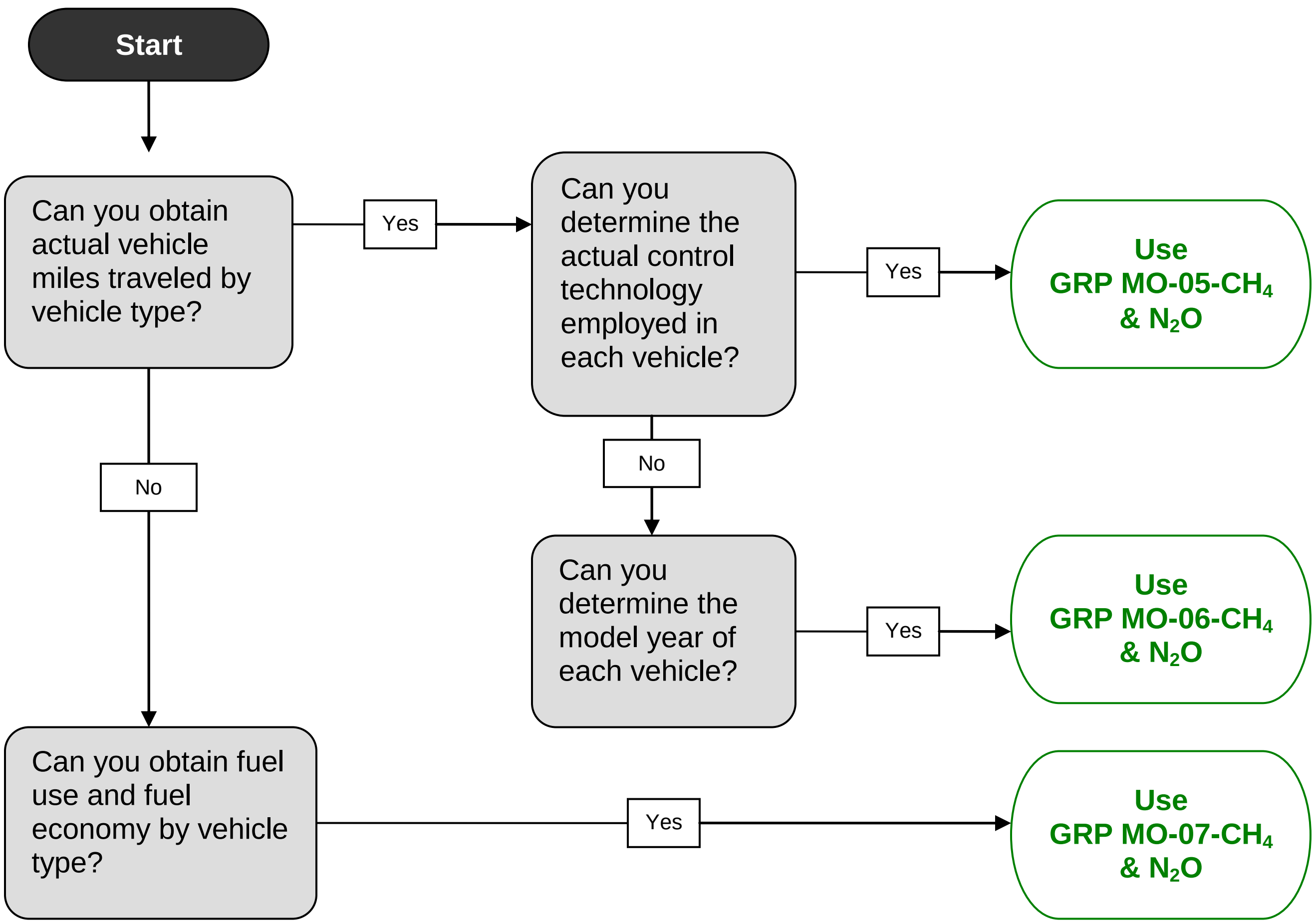


Figure 13.2. Selecting a Methodology: Direct CH_4 and N_2O Emissions from Mobile Combustion (Highway Vehicles Only)



13.1 Calculating CO_2 Emissions from Mobile Combustion

Estimating CO_2 emissions from mobile sources involves three steps:

1. Identify total annual fuel consumption by fuel type;
2. Determine the appropriate emission factor; and
3. Calculate total CO_2 emissions.

Step 1: Identify total annual fuel consumption by fuel type.

GRP MO-01, 02, 03-CO_2 Methods: Actual Use

The preferred approach is to obtain data on actual fuel consumption by fuel type. Methods include direct measurements of fuel use (official logs of vehicle fuel gauges or storage tanks); collected fuel receipts; and purchase records for bulk storage fuel purchases, (in cases fuel for a fleet and is stored at a facility). For bulk purchase records, use Equation 13a to account for changes in fuel stocks when determining annual fuel consumption. Total annual fuel purchases should include both fuel purchased for the bulk fueling facility and fuel purchased for vehicles at other fueling locations.

Equation 13a	Accounting for Changes in Fuel Stocks From Bulk Purchases
Total Annual Consumption =	Total Annual Fuel Purchases + Amount Stored at Beginning of Year – Amount Stored at End of Year

GRP MO-04-CO_2 Method: Estimation Based on Distance

If you cannot obtain fuel use data, but have information on annual mileage and fuel economy, you may estimate your fuel consumption using the following procedure:

1. Identify the vehicle make, model, fuel type, and model years for all operated vehicles;
2. Identify the annual distance traveled by vehicle type;
3. Determine the fuel economy of each vehicle; and
4. Convert annual mileage to fuel consumption using Equation 13b.

Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations. The preferred method for estimating fuel economy is to use company records by specific vehicle, such as the miles per gallon (mpg) values listed on the sticker when the vehicle was purchased, vehicle manufacturer documentation or other company records. If this data is not available, you may obtain fuel economy factors for passenger cars and light trucks from the EPA website www.fueleconomy.gov, which lists city, highway, and combined fuel economy factors by make, model, model year, and specific engine type. If you have accurate information about the driving patterns of the fleet, you should apply a specific mix of city and highway driving, using Equation 13b. Otherwise use the combined fuel economy factor, which assumes 45 percent of a vehicle's mileage is highway driving and 55 percent is city driving.

For heavy-duty trucks, fuel economy data may be available from vehicle suppliers, manufactures, or in company records. If no specific information is available, you should assume fuel economy factors of 8.0 mpg for medium trucks (10,000-26,000 lbs) and 5.8 mpg for heavy trucks (more than 26,000 lbs) (Source: U.S. Department of Energy, *Transportation Energy Data Book*, Ed. 31, 2012, Table 5.4).

Members operating more than one type of vehicle, must calculate the fuel use for each vehicle type and then sum them together.

Equation 13b	Estimating Fuel Use Based on Distance
Fuel Use (gallons) =	Distance (miles) ÷ [(City FE (mpg) × City %) + (Highway FE (mpg) × Hwy %)]
FE = Fuel Economy	

Step 2: Select the appropriate CO_2 emission factor for each fuel.

GRP MO-01-CO_2 Method: Actual Fuel Characteristics

The preferred approach is to measure the fuel characteristics of the specific fuel consumed, or obtain this data from the fuel supplier. Site-specific emission factors can be determined from data on either the fuel density and carbon content of fuels, or heat content and carbon content per unit of energy of fuels.

Fuel Density Approach

Multiply the fuel density (mass/volume) by the carbon content per unit mass (mass C/mass fuel) to determine the mass of carbon per unit of volume of fuel (such as kg C/gallon). To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100 percent oxidation). To convert from units of carbon to CO_2, multiply by 44/12 (see Equation 13c).

Equation 13c	**Calculating CO_2 Emission Factors Using the Fuel Density Approach**				
Emission Factor (kg CO_2/gallon)	=	Fuel Density **x** (kg/gallon)	Carbon Content **x** (kg C/kg fuel)	% Oxidized **x**	44/12 (CO_2/C)

Heat Content Approach

Use this approach if you can obtain the heat content and carbon content of each fuel from the fuel supplier. Multiply the heat content per unit volume (such as Btu/gallon) by the carbon content per unit energy (such as kg C/Btu) to determine the mass of carbon per unit volume (such as kg C/gallon). To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100 percent oxidation). To convert from units of carbon to CO_2, multiply by 44/12 (see Equation 13d).

Equation 13d	**Calculating CO_2 Emission Factors Using the Heat Content Approach**				
Emission Factor (kg CO_2/gallon)	=	Heat Content **x** (Btu/gallon)	Carbon Content **x** (kg C/Btu)	% Oxidized **x**	44/12 (CO_2/C)

If you can obtain measured heat content data but not measured carbon content data, use your own heat content value and a default carbon content factor from Table 13.1 (U.S.) or Table 13.2 (Canada).[18]

GRP MO-02-CO_2 Method: Combining Actual and Default Factors

If you can obtain measured carbon content data but not measured heat content data, use your own carbon content value and a default heat content factor from Table 13.1 (U.S.) or 13.2 (Canada).[19]

[18] Emission factor tables are available on The Registry's website at www.theclimateregistry.org.
[19] Ibid.

GRP MO-03, 04-CO_2 Methods: Default Emission Factors

If you cannot determine the measured fuel density, heat content, or carbon content of specific fuels, use the default CO_2 emission factors by fuel type in Table 13.1 (U.S.) and Table 13.2 (Canada).[20] You are encouraged to use more specific values if available. For example, if you have data that provides information on specific gasoline used in terms of winter or summer grades, oxygenated vs. non-oxygenated fuels or other local fuel characteristics. If possible, you should also obtain specific fuel information for other fuels such as off-road diesel fuel and fuel used for locomotive, rail or marine transport.

Step 3: Calculate total CO_2 emissions and convert to metric tons.

To determine CO_2 emissions from mobile combustion, first multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 13e).

Equation 13e	Calculating CO_2 Emissions From Mobile Combustion			
Fuel A CO_2 Emissions (metric tons)	=	Fuel Consumed **x** (gallons or scf)	Emission Factor ÷ (kg CO_2/gallon or kg CO_2/scf)	1,000 (kg/metric ton)
Fuel B CO_2 Emissions (metric tons)	=	Fuel Consumed **x** (gallons or scf)	Emission Factor ÷ (kg CO_2/gallon or kg CO_2/scf)	1,000 (kg/metric ton)
Total CO_2 Emissions (metric tons)	=	CO_2 from Fuel A **+** (metric tons)	CO_2 from Fuel B **+** (metric tons)	… (metric tons)

13.2 Calculating CH_4 and N_2O Emissions from Mobile Combustion

Estimating emissions of CH_4 and N_2O from mobile sources involves five steps:

1. Identify the vehicle type, fuel type, and technology type or model year of each operated vehicle;
2. Identify the annual mileage by vehicle type;
3. Select the appropriate emission factor for each vehicle type;
4. Calculate CH_4 and N_2O emissions for each vehicle type and sum to obtain total CH_4 and N_2O emissions; and
5. Convert CH_4 and N_2O emissions to units of CO_2e and sum to determine total emissions.

Note that this procedure applies to highway vehicles and alternative fuel vehicles, but not to non-highway vehicles such as ships, locomotives, aircraft, and non-road vehicles. For these vehicles, use the same fuel consumption data used to estimate CO_2 emissions in the previous section. Then follow Steps 3 to 5 below to estimate emissions using default factors provided in Table 13.7.[21]

Figure 13.2 gives guidance on how to select a particular methodology based on the data that is available to you for direct CH_4 and N_2O emissions from highway vehicle mobile combustion.

[20] Ibid.
[21] Ibid.

Members reporting emissions from jet fuel combustion in jet aircraft can also quantify CH_4 and N_2O emissions using the number of landing and takeoff (LTO) cycles by aircraft type.

When mobile emissions of CH_4 and N_2O are sufficiently small, you may want to consider using a SEM to estimate those emissions. This section also includes a SEM that estimates CH_4 and N_2O emissions for on-road vehicles based on the CO_2 emissions quantified in the previous section. If using the SEM method, begin with CO_2 emission totals then follow Steps 4 to 5 below.

Step 1: Identify the vehicle type, fuel type, and technology type or model year of all the vehicles you own and operate.

You must first identify all the vehicles you own and operate, their vehicle type (such as passenger car or heavy-duty truck), their fuel type (such as gasoline or diesel), and either each vehicle's emission control technology or model year.

GRP MO-05-CH_4 & N_2O Method: Vehicle Technology

CH_4 and N_2O emissions depend on the emission control technologies employed. Therefore the preferred approach is to determine the actual control technology employed in each vehicle. Information on the control technology type for each vehicle is posted on an under-the-hood label. See Table 13.4 for a list of control technologies by vehicle type.[22]

GRP MO-06, 07-CH_4 & N_2O Methods: Model Year

If determining the specific technologies of highway vehicles is impossible or too labor intensive, you can estimate vehicle control technologies using each vehicle's model year. Table 13.5 provides emission factors for highway vehicles by model year and vehicle type based on a weighted average of available control technologies for each model year.[23]

Step 2: Identify the annual mileage by vehicle type.

GRP MO-05, 06-CH_4 & N_2O Method: Distance Traveled

CH_4 and N_2O emissions depend more on distance traveled than volume of fuel combusted. Therefore, the preferred approach for highway vehicles is to use vehicle miles traveled data by vehicle type. Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations.

GRP MO-07-CH_4 & N_2O Method: Estimated Distance Traveled

If you do not have mileage data, but you do have fuel consumption data by highway vehicle type, you can estimate the vehicle miles traveled using fuel economy factors by vehicle type. See Step 1 in Section 13.1 for a discussion of determining appropriate fuel economy factors. If more than one type of

[22] Emission factor tables are available on The Registry's website at www.theclimateregistry.org.
[23] Ibid.

vehicle is operated, you must separately calculate the fuel use for each vehicle type. If you have only bulk fuel purchase data, you should allocate consumption across vehicle types and model years in proportion to the fuel consumption distribution among vehicle type and model years, based on your usage data. Then use Equation 13f to estimate distance.

Equation 13f	Estimating Distance Based on Fuel Use		
Distance (miles)	=	Fuel Use **x** (gallons)	[(City FE **x** City %) **+** (Highway FE **x** Hwy %)] (mpg) (mpg)
FE = Fuel Economy			

Step 3: Select the appropriate emission factor for each vehicle type.

GRP MO-05, 08-CH_4 & N_2O Methods: Vehicle Technology

If you have data on vehicles' specific control technologies, obtain emission factors for highway vehicles from Table 13.4. Use Tables 13.6 and 13.7 for alternative fuel and non-highway vehicles.

GRP MO-06, 07, 09-CH_4 & N_2O Methods: Model Year

If you have data on vehicles' model years (rather than control technologies), obtain emission factors for highway vehicles from Table 13.5. Use Tables 13.6 and 13.7 for alternative fuel and non-highway vehicles.[24]

GRP MO-10-CH_4 & N_2O Methods: Aircraft LTO Cycles

If you are reporting emissions associated with jet fuel combustion in jet aircraft, you can use the emission factors based on LTO cycles by aircraft type in Table 13.8 to quantify CH_4 and N_2O emissions.[25] Use these factors to estimate emissions by gas then progress to Step 5 below.

Step 4: Calculate CH_4 and N_2O emissions by vehicle type and sum to obtain total CH_4 and N_2O emissions.

All Registry-Accepted Methods

Use Equation 13g to calculate CH_4 emissions by vehicle type, convert to metric tons, and obtain total CH_4 emissions. Then repeat the procedure using Equation 13h to obtain total N_2O emissions.

[24] Ibid.
[25] Ibid.

Equation 13g	Calculating CH_4 Emissions From Mobile Combustion			
Vehicle Type A CH_4 Emissions (metric tons)	=	Annual Distance **x** (miles)	Emission Factor ÷ (g CH_4/mile)	1,000,000 (g/metric ton)
Vehicle Type B CH_4 Emissions (metric tons)	=	Annual Distance **x** (miles)	Emission Factor ÷ (g CH_4/mile)	1,000,000 (g/metric ton)
Total CH_4 Emissions (metric tons)	=	CH_4 from Type A **+** (metric tons)	CH_4 from Type B **+** (metric tons)	… (metric tons)

Equation 13h	Calculating N_2O Emissions From Mobile Combustion			
Vehicle Type A N_2O Emissions (metric tons)	=	Annual Distance **x** (miles)	Emission Factor ÷ (g N_2O /mile)	1,000,000 (g/metric ton)
Vehicle Type B N_2O Emissions (metric tons)	=	Annual Distance **x** (miles)	Emission Factor ÷ (g N_2O /mile)	1,000,000 (g/metric ton)
Total N_2O Emissions (metric tons)	=	N_2O from Type A **+** (metric tons)	N_2O from Type B **+** (metric tons)	… (metric tons)

Simplified Estimation Method for Mobile CH_4 & N_2O Emissions from Gasoline and Diesel Passenger Cars and Light-Duty Trucks

This method is intended for Members that are only readily able to obtain information on the quantity of gasoline and diesel fuel gallons consumed by their passenger cars and light-duty trucks. This simplified estimation method estimates CH_4 and N_2O emissions by applying an emission factor that describes a default ratio of CH_4 or N_2O to corresponding CO_2 emissions. The default ratio is based on GHG emission trend data reported as part of the U.S. National Inventory of Greenhouse Gas Emissions and Sinks every year to estimate CH_4 and N_2O emissions.

Applying the Simplified Estimation Method

1. Determine the total annual quantity of gasoline and diesel fuel gallons consumed, by fuel-type.
2. Calculate the CO_2 emission totals using the methods in this chapter.
3. Calculate the CH_4 emissions - Multiply the metric tons of CO_2 by the CH_4 emission factor from Table 13.9.[26]
4. Calculate the N_2O emissions - Multiply the metric tons of CO_2 by the N_2O emission factor from Table 13.9.[27]

Step 5: Convert CH_4 and N_2O emissions to units of CO_2e and determine total emissions from mobile combustion.

Use the IPCC global warming potential (GWP) factors in Equation 13i to convert CH_4 and N_2O emissions to units of CO_2e. Then sum the emissions of all three gases to determine total emissions from mobile combustion (see Equation 13i).

[26] Emission factor tables are available on The Registry's website at www.theclimateregistry.org/.
[27] Ibid.

Equation 13i	Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions (metric tons CO_2e)	=	CO_2 Emissions **x** (metric tons)	1 (GWP)	
CH_4 Emissions (metric tons CO_2e)	=	CH_4 Emissions **x** (metric tons)	21 (GWP)	
N_2O Emissions (metric tons CO_2e)	=	N_2O Emissions **x** (metric tons)	310 (GWP)	
Total Emissions (metric tons CO_2e)	=	CO_2 **+** (metric tons CO_2e)	CH_4 **+** (metric tons CO_2e)	N_2O (metric tons CO_2e)

Emissions from Biofuels

Biofuels such as ethanol, biodiesel, and various blends of biofuels and fossil fuels may be combusted in mobile sources. Due to their biogenic origin, you must report CO_2 emissions from the combustion of biofuels separately from fossil fuel CO_2 emissions. For biofuel blends such as E85 (85 percent ethanol and 15 percent gasoline) E10 (10 percent ethanol and 90 percent gasoline) and B20 (20 percent biodiesel and 80 percent diesel), combustion results in emissions of both fossil CO_2 and biomass CO_2. If you know the Member has purchased a blended (biofuel and fossil fuel) fuel product, you may separately report both types of CO_2 emissions for each fuel.

In many cases standard gasoline is blended with some biofuel. However, fuel mixes can vary with location and the time of year. When using default emission factors to quantify CO_2 emissions (see methods: GRP MO-03-CO_2 and GRP MO-04-CO_2), unless you have documentation of specific information about the particular gasoline blend, you should use The Registry's default emission factor for motor gasoline. This will result in all CO_2 emissions being reported in scope 1. Should The Registry recognize default blend emission factors in the future, these will also be acceptable.

Please note, when calculating emissions from mobile combustion, Members are required to account only for emissions resulting from their own activities (i.e., tailpipe emissions from fuel combustion) rather than taking into account life cycle impacts, such as the CO_2 sequestered during the growing of crops or emissions associated with producing the fuels. The life cycle impacts of combusting fuels are scope 3 emissions.

Example 13.1. Direct Emissions from Mobile Combustion

GOFAST Vehicle Rental Agency

GOFAST Vehicle Rental is an independent vehicle renting company in the United States with a fleet of 200 model year 2000 passenger cars, 25 model year 2002 light duty trucks, and two model year 1998 heavy duty diesel powered trucks. GOFAST typically purchases its fuel in bulk.

Last year, GOFAST purchased 235,000 gallons of motor gasoline and 5,000 gallons of diesel fuel. GOFAST began the year with 20,000 gallons of motor gasoline in stock and ended with 10,000 gallons of motor gasoline in stock. GOFAST also began the year with 500 gallons of diesel fuel in stock and ended with 1,000 gallons of diesel fuel in stock. GOFAST keeps odometer readings for each vehicle and determines total mileage by vehicle type as follows: 6,000,000 miles for passenger cars; 550,000 miles for light trucks; and 80,000 miles for heavy duty trucks.

CO_2 Emissions Calculation

Step 1: Identify the total annual fuel consumption by fuel type.

GOFAST uses Equation 13a to determine annual fuel consumption by fuel type.

Equation 13a		Example: Accounting for Changes in Fuel Stocks From Bulk Purchases
Total Annual Consumption	**=**	Total Annual Fuel Purchases **+** Amount Stored at Beginning of Year **–** Amount Stored at End of Year
Total Gasoline Consumption	**=**	235,000 **+** 20,000 **–** 10,000 = 245,000 gallons
Total Diesel Consumption	**=**	5,000 **+** 500 **–** 1,000 = 4,500 gallons

Step 2: Determine the appropriate CO_2 emission factor for each fuel.

GOFAST uses emission factors of 8.81 kilograms CO_2 per gallon of motor gasoline and 10.15 kilograms CO_2 per gallon of diesel fuel.

Step 3: Multiply fuel consumed by the emission factors to calculate total CO_2 emissions.

GOFAST uses Equation 13e to calculate CO_2 emissions for each fuel and then sums to determine total CO_2 emissions.

Equation 13e	Example: Calculating CO_2 Emissions From Mobile Combustion				
Gasoline CO_2 Emissions	=	245,000 **x** (gallons)	8.81 ÷ (kg CO_2/gallon)	1,000 (kg/metric ton)	= 2,158.5 metric tons
Diesel CO_2 Emissions	=	4,500 **x** (gallons)	10.15 ÷ (kg CO_2/gallon)	1,000 (kg/metric ton)	= 45.7 metric tons
Total CO_2 Emissions	=	2,158.5 **+** 45.7 **= 2,204 metric tons**			

Example continued on the next page.

CH_4 and N_2O Emissions Calculation

Step 1: Identify the vehicle type, fuel, and vehicle technology or model year of all the vehicles GOFAST owns and operates.

Step 2: Identify the annual mileage by vehicle type.

Vehicle Type	Fuel	Model Year	No. of Vehicles	Annual Mileage
Passenger Cars	Motor Gasoline	2000	200	6,000,000
Light Duty Trucks	Motor Gasoline	2002	25	550,000
Heavy Duty Trucks	Diesel	1998	2	80,000

GOFAST aggregates its vehicle odometer readings and enters the data in the table above.

Step 3: Select the appropriate emission factor for each vehicle type.

The entity uses Table 13.4 to obtain the emission factors by model year.

Vehicle Type	Fuel	Model Year	g N_2O/ mile	g CH_4/ mile
Passenger Cars	Motor Gasoline	2000	0.0273	0.0178
Light Duty Trucks	Motor Gasoline	2002	0.0228	0.0178
Heavy Duty Trucks	Diesel	1998	0.0048	0.0051

Step 4: Calculate CH_4 and N_2O emissions by vehicle type and sum to obtain total CH_4 and N_2O emissions.

Use Equation 13g to calculate CH_4 emissions by vehicle type, convert to metric tons, and obtain total CH_4 emissions. Then repeat the procedure using Equation 13h to obtain total N_2O emissions.

Equation 13g	**Example: Calculating CH_4 Emissions From Mobile Combustion**				
Passenger Cars CH_4 Emissions	=	6,000,000 **x** (miles)	0.0178 ÷ (g CH_4/mile)	1,000,000 (g/metric ton)	= 0.11 metric tons
Light Duty Trucks CH_4 Emissions	=	550,000 **x** (miles)	0.0178 ÷ (g CH_4/mile)	1,000,000 (g/metric ton)	= 0.01 metric tons
Heavy Duty Trucks CH_4 Emissions	=	80,000 **x** (miles)	0.0051 ÷ (g CH_4/mile)	1,000,000 (g/metric ton)	= 0.0004 metric tons
Total CH_4 Emissions	=	0.11 **+** 0.01 **+** 0.0004 = **0.12 metric tons**			

Example continued on the next page.

Equation 13h	Example: Calculating N_2O Emissions From Mobile Combustion				
Passenger Cars N_2O Emissions	=	6,000,000 **x** (miles)	0.0273 ÷ (g N_2O /mile)	1,000,000 (g/metric ton)	= 0.16 metric tons
Light Duty Trucks N_2O Emissions	=	550,000 **x** (miles)	0.0228 ÷ (g N_2O /mile)	1,000,000 (g/metric ton)	= 0.01 metric tons
Heavy Duty Trucks N_2O Emissions	=	80,000 **x** (miles)	0.0048 ÷ (g N_2O /mile)	1,000,000 (g/metric ton)	= 0.0004 metric tons
Total N_2O Emissions	=	0.16 **+** 0.01 **+** 0.0004 = **0.18 metric tons**			

Step 5: Convert CH_4 and N_2O emissions to units of CO_2e and determine total emissions from mobile combustion.

The entity uses Equation 13i to convert emissions to units of CO_2e and sum to obtain total GHG emissions from mobile combustion.

Equation 13i	Example: Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions	=	2,204 **x** (metric tons)	1 (GWP)	= 2,204 metric tons CO_2e
CH_4 Emissions	=	0.12 **x** (metric tons)	21 (GWP)	= 2.5 metric tons CO_2e
N_2O Emissions	=	0.18 **x** (metric tons)	310 (GWP)	= 55.8 metric tons CO_2e
Total Emissions	=	2,204 **+** 2.5 **+** 55.8 = **2,262 metric tons CO_2e**		

Chapter 14: Indirect Emissions from Electricity Use

Who should read Chapter 14:
- Chapter 14 applies to all Members that purchase and consume electricity.

What you will find in Chapter 14:
- This chapter provides guidance on calculating indirect emissions of CO_2, CH_4, and N_2O from electricity consumption.

Information you will need:
- You will need to refer to monthly electricity bills for information on electricity consumed.

Cross-References:
This chapter may be useful in completing Chapter 15 when quantifying indirect emissions from CHP, steam, or district heating or cooling.

Indirect CO_2, CH_4 & N_2O Emissions From Electricity Use		
Method	**Type of Method**	**Data Requirements**
GRP-IE-01-CO_2, CH_4 & N_2O	Known electricity use (Metered readings or utility bills)	Generator-specific emission factors
GRP-IE-02-CO_2, CH_4 & N_2O	Known electricity use (Metered readings or utility bills)	Generator-specific, utility-specific or third-party developed emission factors
GRP-IE-03-CO_2, CH_4 & N_2O	Estimated electricity use (Area & cost methods)	Generator-specific, utility-specific or third-party developed emission factors
GRP-IE-04-CO_2, CH_4 & N_2O	Estimate electricity use (Average intensity and models)	Generator-specific, utility-specific or third-party developed emission factors

14.1 Calculating Indirect Emissions from Electricity Use

Nearly all entities are likely to have indirect emissions associated with the purchase and use of electricity. In some cases, indirect emissions from electricity use may comprise the majority of an entity's GHG emissions.

The generation of electricity through the combustion of fossil fuels typically yields carbon dioxide (CO_2), and to a smaller extent, nitrous oxide (N_2O) and methane (CH_4). The GRP provides annual emission factors for all three gases. To calculate indirect emissions from electricity use, follow these three steps:

1. Determine annual electricity use from each facility;
2. Select the appropriate emission factors that apply to the electricity used; and
3. Determine total annual emissions in metric tons of CO_2e.

Figure 14.1 gives guidance on how to select a particular quantification methodology based on the data that is available to you.

Step 1: Determine annual electricity consumption.

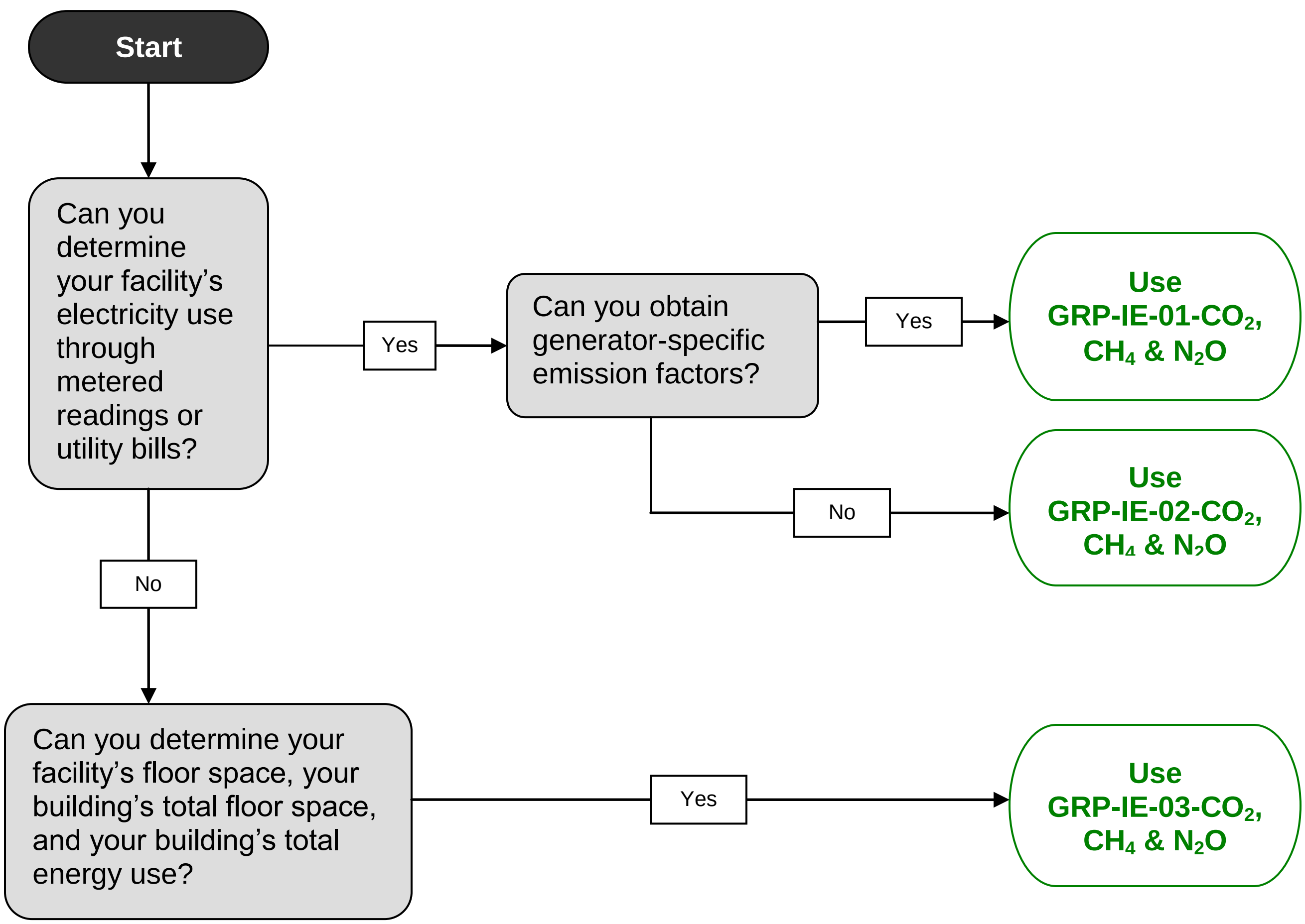
Reporting indirect emissions from electricity consumption begins with determining annual electricity use at each facility.

GRP-IE-01, 02-CO_2, CH_4 & N_2O Method: Known Electricity Use

The preferred sources for determining annual electricity use are monthly electric bills or electric meter records. Both sources provide the number of kilowatt-hours (kWh) or megawatt-hours (MWh) of electricity consumed, giving a measure of the energy used by electric loads, such as lights, office equipment, air conditioning, or machinery.

Record the electricity consumed each month at each facility. Then aggregate monthly bills to determine annual electricity use (in kWh or MWh) for each facility.

Figure 14.1. Selecting a Methodology: Indirect CO_2, CH_4 and N_2O Emissions from Electricity Use



GRP-IE-03-CO_2, CH_4 & N_2O Method: Area and Cost Estimation Methods

If purchase records, electricity bills, or meter readings are not available or applicable, you have several opportunities to estimate electricity consumption:

- The area method
- The cost method (commercial facilities and warehouses only)
- The alternative average electricity intensity method
- The sample data method
- The proxy data method

The Area Method

The area method allows you to estimate energy use based on the entity's share of the building's floor space and total electricity consumption.

This method yields less accurate estimates than the known electricity use method because it is not specific to the particular space in the building used by the Member and assumes that all occupants of the building have similar energy consuming habits. You should first be certain that you are unable to obtain electric bills to determine actual electricity use.

To follow this method, you will need the following information, which should be available from the building's property manager:

- Total building area (square feet);
- Area of entity's space (square feet);
- Total building annual electricity use (kWh); and
- Building occupancy rate (e.g., if 75 percent of the building is occupied, use 0.75)

Use this information and Equation 14a to estimate the Member's share of the building's electricity use.

Equation 14a	Estimating Electricity Consumption Using the Area Method				
Electricity Use (kWh)	=	Entity's Area ÷ (ft^2)	Building Area **x** (ft^2)	Building Electricity Use ÷ (kWh)	Occupancy Rate

As an alternative to Equation 14a, Members with access to a comprehensive energy audit can use the audit findings to apportion total building energy use to the entity's space provided energy use has been consistent since the date of the audit. Members may also use a combination of energy audit findings and the area method to allocate total emissions to different operations.

The Cost Method (Commercial Facilities and Warehouses Only)

Some Members may find it unfeasible to obtain kWh data due to issues such as a lack of robust data management systems or an overwhelming number of utility accounts.

If it is not feasible to obtain kWh data for commercial facilities and warehouses, you can estimate electricity consumption using electricity expenditures and average kWh costs. See Table 14.5 for the average cost figures necessary to estimate commercial facility and warehouse kWh consumption.[28]

Please note this method only qualifies as a Registry-accepted methodology when used to estimate electricity use for commercial facilities and/or warehouses in the U.S. where you do not have feasible access to kWh data. This methodology is not accepted for industrial facilities.

STEP 1: Determine annual electricity expenditures for each facility using utility bills or financial records.

STEP 2: Estimate annual kilowatt hours by dividing the annual facility-level electricity expenditures by the average electricity cost for the appropriate state using Equation 14.b.

Equation 14b	Estimating Electricity Consumption Using the Expenditure Records			
Electricity Use (kWh)	=	Facility Expenditures **x** ($)	100 ÷	Average Kilowatt Hour (¢/kWh)

STEP 3: Calculate the GHG emissions by multiplying the estimated kilowatt hours by the appropriate eGRID factor or Registry-approved utility-specific emissions factor.

GRP-IE-04-CO_2, CH_4 & N_2O Method: Average Intensity and Model Methods

The Alternative Average Electricity Intensity Method

You may use the following alternative estimation methodology to calculate indirect emissions from leased space if:

- The Member does not receive information about electricity usage directly,
- The Member is unable to obtain information about the building's electricity usage from the landlord/property owner/property manager, and
- The Member indicates in its emission report that it has used an estimation methodology to determine your electricity usage.

STEP 1: Determine the leased space's square footage.

To do this, you will need to review the lease which should have the Member's exact usable square footage. Be sure to include square footage for any storage space, if applicable. NOTE: Usable square footage is the space contained within the walls of the office. It does not include other 'rentable' areas such as building bathrooms, common areas, etc.

STEP 2: Determine the average annual electricity intensity for building space.

Select the most appropriate average electricity intensity according the operations of the building space. Use the Canadian Electricity Intensity table (Table 14.6) if you are reporting for Canadian facilities and the U.S. Electricity Intensity table (Table 14.7) if you are reporting for U.S. facilities.[29]

[28] Emission factor tables are available on The Registry's website at www.theclimateregistry.org.
[29] Ibid.

In certain circumstances Members may have sufficient information to develop operation-specific electricity use models for their operations. For example, if a Member has several retail stores where they use a consistent lighting design and lighting makes up the majority of the electricity load, the Member may develop a Member-specific electricity consumption model to estimate electricity use based on square footage. Please contact The Registry if you are interested in developing your own operation-specific electricity use model to estimate electricity use.

Emissions estimated using these approaches will not contribute to the SEMs threshold.

STEP 3: Calculate the office's electricity consumption using Equation 14c below.

Equation 14c	Estimating Annual Electricity Consumption			
Annual Electricity Consumption	**=**	Office Space (useable space) (ft^2) (from landlord)	**x**	Annual Electricity Intensity (kWh/ft^2) (from table)

STEP 4: Calculate the GHG emissions associated with estimated annual electricity consumption.

Use Equation 14d to calculate indirect emissions from electricity use and Equation 14e to convert emissions to CO_2e.

Members with facilities in Mexico who wish to use this methodology should contact The Registry for guidance.

The Sample Data Method

Members who have sampled the power consumption and metered or tracked (logged) the hours of use of the equipment and can demonstrate the equipment is operating continuously (or on a schedule that the Member can account for) at a constant rate, then you can multiply the sample against the amount of time the equipment was in use to estimate the electricity use for the purpose of reporting to The Registry.

The Proxy Data Method

If you can demonstrate that equipment operations where site-specific data is unavailable have the same emissions as identical equipment where site-specific data is available, that the equipment operates on the same schedule and that the same maintenance procedures are followed, then you may assume that emissions associated with electricity use by both pieces of equipment are the same when reporting to The Registry. You may use make and model information, manufacturer specifications or testing to determine that both pieces of equipment consume the same amount of electricity.

Step 2: Select appropriate emission factors.

An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed. It is usually reported in units of pounds of GHG per kilowatt-hour or megawatt-hour.

Registry Members may choose to use the following types of emission factors when quantifying emissions from the use of purchased electricity:

- Off-Grid Generator Emission Factors
- Utility-Developed Emission Factors
- Third-Party Developed Emission Factors

GRP-IE-01-CO_2, CH_4 & N_2O Method: Off-Grid Generator Emission Factors

In some cases, entities may purchase electricity directly from a known “off-grid” electric generation source, that can be specifically identified, rather than from the electric grid. In such a case and if data is available, you should use emission rates specific to the known off-grid generation source as the facility’s emission factors. If a Member consumes power both from a known “off-grid” electric generation source as well as from the grid, you should pro-rate the emissions using the off-grid generator emission factors for the portion of electricity taken from the known “off-grid” sources and the appropriate grid average emission factors for the portion of the electricity consumption taken from the grid. (For purchases from combined heat and power plants, refer to Chapter 15).

GRP-IE-02, 03-CO_2, CH_4 & N_2O Method: Utility or Third-Party Developed Emission Factors

Many Members will either be unable to obtain generator-specific emission factors or will purchase electricity exclusively from the grid. In these cases, you should use either emission factors developed by the utility or third-party developed emission factors based on each facility’s geographic location, corresponding to the average emission rate of electric generators supplying power to the grid over a calendar year.

Utility-Developed Emission Factors

Utility-developed emission factors allow you to quantify indirect emissions associated with electricity in a way that reflects the power products purchased. If Members voluntarily participate in a green power program, this is an excellent way to demonstrate the impact of that participation on the inventory.

The Registry has approved three classes of utility-developed emission factors that may be used to calculate CO_2 emissions from the use of purchased electricity. These are:

1. Electric delivery metrics reported and verified in accordance with The Registry’s Electric Power Sector (EPS) Protocol. The Registry strongly recommends that these factors be used when available.
2. Emission factors reported and verified in accordance with the California Climate Action Registry’s Power Utility Reporting Protocol (PUP).
3. Other emission factors developed by the electricity supplier that are either publicly disclosed or certified by the utility. To demonstrate the validity of these factors, Members must upload as a public document in CRIS either a document identifying where the emission factor is publicly disclosed or the utility’s certification of the emission factor. The utility’s certification must describe the methodology used to develop the emission factor and, as applicable, include references to publicly-available data used in its development.[30]

[30] These emission factors are expected to be compiled in a manner comparable to The Registry’s requirements in the EPS Protocol, Specifically, these factors must reflect purchased power delivered to customers and treatment of RECs should be consistent with the criteria and requirements included in Section 14.2 below.

Members using a utility-specific emission factor must apply that factor to all electricity purchased from the same provider within an inventory.

Third-Party Developed Emission Factors

The Registry accepts the following types of third-party developed emission factors:

1. Registry Default Emission Factors: Regional power pool default factors such as the U.S. EPA eGRID subregion emission rates, which conform to transmission and distribution network infrastructure.
2. Other government agency or industry expert-developed geographic or utility-specific emission factors that are publicly documented and have been through a regulatory or reasonable peer review process.

If you are using third-party developed emission factors, you should be sure to use appropriate region-specific factors for each facility because emission factors vary by location. Facilities in the U.S. using this approach should use emission factors specific to each facility's regional power pool rather than the state it is located in, because transmission and distribution grids do not adhere to state boundaries.

To find the appropriate emission factors for a facility in the U.S., determine the eGRID subregion from the U.S. EPA Power Profiler tool, available at: www.epa.gov/cleanenergy/powerprofiler.html. Then, based on the subregion, find the appropriate emission factors for each gas in Table 14.1.[31]

For Canadian and Mexican facilities, use emission factors from Tables 14.2[32] and 14.3[33] for your emissions year (or the most recent year if no data are available).

If you are reporting emissions from facilities outside of North America, you can opt to use The Registry's default non-North American emission factors for electricity and heat generation in Table 14.4.[34]

Emission Factor Updates

Electricity emission factors vary over time due to the nature of the electric system. Members must use either the corresponding generator-specific, utility-developed or third-party developed (e.g. eGRID) emission factor closest to the emissions year reported that does not post-date the emissions year. Generator-specific or utility-developed emission factors corresponding to data that is less recent than the data underlying The Registry's default third-party developed emission factors, may not be used.

For example, if, in 2012, a company is compiling inventories for emissions years 2008-2011 *and* there is a Registry-accepted utility-developed emission factor based on 2008 data, the company may report as described in the following table:

Year	Emission Factor
EY 2008	Utility-developed
EY 2009	eGRID 2012 (2009 data)
EY 2010	eGRID 2012 (2009 data)
EY 2011	eGRID 2012 (2009 data)

Please note that if a new emission factor closer to the emissions year reported becomes available after the emissions year report has been verified, it is not necessary to go back and update calculations.

[31] Emission factor tables are available on The Registry's website at www.theclimateregistry.org.
[32] Ibid.
[33] Ibid.
[34] Ibid.

Step 3: Determine total annual emissions and convert to metric tons of CO_2e.

To determine annual emissions, multiply annual electricity use (in MWh) from Step 1 by the emission factors for CO_2, CH_4, and N_2O (in pounds per MWh) from Step 2.[35] Then convert pounds into metric tons by dividing the total by 2,204.62 lbs/metric ton. To convert kilograms into metric tons, divide by 1,000 kg/metric ton (see Equation 14d). Repeat this step for each gas.

Equation 14d	Calculating Indirect Emissions from Electricity Use			
CO_2 Emissions (metric tons)	=	Electricity Use **x** (MWh)	Emission Factor ÷ (lbs CO_2/MWh)	2,204.62 (lbs/metric ton)
CH_4 Emissions (metric tons)	=	Electricity Use **x** (MWh)	Emission Factor ÷ (lbs CH_4 /MWh)	2,204.62 (lbs/metric ton)
N_2O Emissions (metric tons)	=	Electricity Use **x** (MWh)	Emission Factor ÷ (lbs N_2O /MWh)	2,204.62 (lbs/metric ton)

To convert CH_4 and N_2O into units of CO_2e, multiply total emissions of each gas (in metric tons) by its IPCC global warming potential (GWP) factor provided in Equation 14e. Then sum the emissions of each of the three gases in units of CO_2e to obtain total GHG emissions (see Equation 14e).

Equation 14e	Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions (metric tons CO_2e)	=	CO_2 Emissions **x** (metric tons)	1 (GWP)	
CH_4 Emissions (metric tons CO_2e)	=	CH_4 Emissions **x** (metric tons)	21 (GWP)	
N_2O Emissions (metric tons CO_2e)	=	N_2O Emissions **x** (metric tons)	310 (GWP)	
Total Emissions (metric tons CO_2e)	=	CO_2 **+** (metric tons CO_2e)	CH_4 **+** (metric tons CO_2e)	N_2O (metric tons CO_2e)

14.2 Calculating Indirect Emissions Associated with Renewable Energy Products

Renewable energy products result in the generation of Renewable Energy Certificates (RECs), which provide proof of renewable electricity generation from a recognized renewable energy source and represent the rights to the environmental, social and other non-power qualities of that renewable electricity generation. RECs can be bundled with the renewable electricity or sold separately (unbundled) to customers interested in supporting renewable energy.[36] In both cases, ownership and retirement of RECs are required in order to include the GHG impact of the renewable energy product in a GHG inventory.

Members who voluntarily purchase green power from an electric service provider, should quantify scope 2 emissions using the electric utility's special power emission factor for that program in order to reflect the

[35] If your electricity use data is in units of kWh, divide by 1,000 to convert to MWh.
[36] Once the RECs are unbundled the underlying energy is considered null (non-renewable) power and no green claims can be made for use or ownership of this null electricity.

RECs the utility retires on the Member's behalf.[37] See Section 14.1 for more information on utility-developed emission factors.

If Members control renewable power generation (e.g. from an on-site system owned and operated by the Member) and maintain ownership of RECs associated with that generation, Members must still account for any emissions associated with that power as scope 1 or biogenic emissions as appropriate.[38]

Members who choose to sell RECs from electricity that they have generated and consumed, must apply the utility or third-party developed system average emission factor(s) to the power consumed and report those emissions as scope 2.

Members who participate in a net metering program[39] where excess production is sent to the grid and any purchases from the grid are netted out, emissions associated with power produced must be reported as scope 1 and any *net* grid purchases[40] must be reported as scope 2. It is recommended that total grid purchases and any netting-out procedures be reported as supplemental information.

Members can also account for the purchase and retirement of unbundled RECs in scope 2.[41] If RECs are part of a green power product purchased from an electric utility, the electric utility's special power emission factor should be used. See the section below on quantifying emissions associated with RECs for more information on how to account for independently purchased RECs. Unbundled REC purchases that are applied to scope 2 must be Registry-recognized products. Members disclosing REC purchases as an additional information item and are not applying those RECs to an inventory, are not required to use Registry-recognized products or The Registry's quantification requirements.

Registry-Recognized RECs

In order for bundled or unbundled REC products to be recognized by The Registry, they must meet certain quality and eligibility criteria.

REC quality criteria:

- **Whole/fully-aggregated:** Each REC must include all renewable and environmental attributes, including GHG emissions attributes (emission factor of the generating facility and any avoided emissions on the grid), associated with the production of electricity from the renewable energy resource.
- **Not double counted:** All RECs must have either undergone third-party verification that includes a chain of custody audit, or have documentation of permanent retirement in an electronic tracking system in a dedicated, named retirement subaccount for a particular Registry emission year, so that ownership is clear and explicit.
- **Surplus to regulatory requirements:** Voluntary RECs applied to an inventory cannot have been used to comply with a regulatory mandate such as a renewable portfolio standard or otherwise counted toward such a mandate.

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[37] This factor can be developed through The Registry's EPS Protocol or through another equivalent process as described in Section 14.1.
[38] Members may disclose the MWhs of electricity that are consumed and sold as optional information to illuminate the combustion total reported in scope 1.
[39] Net metering enables customers to use their own generation from on-site energy systems to reduce their electricity purchase over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand.
[40] The electricity purchased from the provider in excess of the energy the system produces.
[41] Unbundled RECs can either be purchased and retired directly or be retired on a purchaser's behalf.

REC eligibility criteria:

The Registry defines certain eligibility criteria that are designed to ensure that the REC products incorporated in corporate inventories are consistent with GHG accounting best practices.

- **Resource type:** RECs must be generated using Registry-recognized resources and technologies. See The Registry's website (www.theclimateregistry.org) for a full list of eligible resources and technologies.
- **Separate from offsets:** In instances where a renewable project is receiving carbon offsets, for example for the capture and destruction of biogenic methane, the carbon offset quantity generated by the project must not include the carbon benefit of the generation of renewable electricity. If the project is receiving carbon offsets for renewable energy generation, RECs associated with MWhs of generation that are being credited for GHG reductions (carbon offsets) are not eligible, since they must be retired on behalf of the carbon offset owner.
- **Product vintage:** RECs applied to an inventory in any year must have been generated within a period of six months before the emissions year to up to three months after the emissions year.
- **Facility vintage:** RECs must come from renewable facilities that began operations within 15 years of the emissions year.

Members purchasing unbundled RECs are encouraged to seek out certified REC products that will inherently meet The Registry's REC eligibility requirements. The Registry accepts certified RECs from the following certification programs:

- Green-e Energy
- EcoLogo
- Other programs or RECs meeting equivalent standards upon Registry staff evaluation.[42]

To demonstrate the validity of REC products claimed in an inventory, Members must upload a public document identifying the REC certification program(s) or other documentation that demonstrates clear and explicit ownership and Registry eligibility in CRIS.

Quantifying Emissions Associated with RECs

RECs are measured in units of energy such that one REC is equal to one MWh of renewable electricity.

Accounting for Registry-recognized RECs in scope 2 follows the same process as for other electricity products. To determine annual emissions, multiply REC purchases by emission factors for CO_2, CH_4, and N_2O as in Equation 14d. Most RECs will have an emission factor of zero. However, depending on the renewable resource employed, some may have non-biogenic emissions that must be reflected in scope 2.[43]

Members seeking to enhance the transparency of RECs in their inventory are encouraged to disclose additional activity data such as MWh consumed, purchased, generated or sold as supplemental information.

[42] Contact The Registry at info@theclimateregistry.org to request evaluation of an additional REC product or program.
[43] Facility-specific non-biogenic emissions should be reported to the tracking system and be disclosed with the REC. If facility-specific emissions are not reported to the tracking system, Members can use industry best practice information such as tracking system rules around assigning emission factors to report these emissions.

Prorating Monthly Electricity Use

When an electric bill does not begin exactly on January 1 or end on December 31, Members must prorate January and December electricity bills (for those two months only) to determine annual electricity use. To calculate emissions for January from an electric bill spanning part of December and part of January, first divide total kWh used in the period by the number of days in the billing cycle. Then, determine the number of days from the bill that fall in January. Multiply the electricity use per day by the number of days in January. Add this amount to any other electric bill that includes days in January.

Accounting for Electricity Transmission and Distribution Losses

Some electricity is lost during the transmission and distribution (T&D) of power from electric generators to end users. T&D losses are the scope 2 emissions of the entity that owns or controls the T&D lines. Members who do not own or control a T&D system, should not account for T&D losses in scope 2. Emission factors presented in this chapter do not account for T&D losses and are therefore appropriate for utility customers who do not own or operate T&D lines. Utility customers who are interested in reporting emissions associated with T&D losses can report those emissions in scope 3.

Members who own or control the T&D system but generates (rather than purchases) the electricity transmitted through the system, should not report the emissions associated with T&D losses in scope 2, as they would already be accounted for under scope 1. This is the case when generation, transmission, and distribution systems are vertically integrated and owned or controlled by the same entity.

However, if Members purchase (rather than generate) electricity and transport it through a T&D system that it owns or controls, the Member should report the emissions associated with T&D losses in scope 2. To estimate these emissions, follow the same procedure described in Section 14.1 of this chapter for estimating indirect emissions from electricity use. In Step 1, use the electricity consumed in the T&D system (T&D losses) as the quantity of electricity consumed. In Step 2, use either a generator-specific, utility-developed or third-party developed emission factor.

Primary and Secondary REC Attributes

The attributes of renewable energy that are included in a REC can be divided into two categories, the primary attributes and the secondary attributes. The primary attributes include the identifying characteristics of the electricity generation, such as the energy source, the project location, and the direct emissions of generation, which are zero for most renewable energy technologies. The secondary attributes, also known as the derived attributes, include the emissions from fossil fuel facilities that are displaced by the renewable generation.

When accounting for RECs in an inventory, whether through the use of a utility-specific emission factor or through adjustments to scope 2 emissions, Members must account for RECs using the primary emission rate reflecting the actual emissions resulting from renewable electricity generation. This emissions rate will typically be zero.

While RECs also carry an avoided emissions value, this is a secondary attribute that can be optionally reported as supplemental information.

Example 14.1. Indirect Emissions from Electricity Use

Cost-lo Clothing Distributors

Cost-lo is a discount retail clothing chain with one outlet in Los Angeles, California, one in Portland, Oregon, and one in Tucson, Arizona.

Step 1: Determine annual electricity consumption.

Cost-lo records its annual electricity purchases in megawatt-hours (MWh): 1,600 MWh at its Los Angeles store, 600 MWh at its Portland store, and 800 MWh at its Tucson store.

Step 2: Select electricity emission factors that apply to the electricity purchased.

The company finds the appropriate emission factors for CO_2, CH_4, and N_2O from Table 14.1 for each facility and records them in the table below.

Step 3: Determine total annual emissions and convert to metric tons of CO_2e.

See Equations14d and 14e below.

Annual Electricity Use and Emission Factors

Facility	eGRID Subregion	Annual Electricity Purchases (MWh)	CO_2 (lbs / MWh)	CH_4 (lbs / MWh)	N_2O (lbs / MWh)
Los Angeles, CA	CAMX	1,600	878.71	0.036	0.008
Portland, OR	NWPP	600	921.10	0.022	0.014
Tucson, AZ	AZNM	800	1,254.02	0.018	0.015

Example continued on next page.

Example 14.1 Continued.

Equations 14d and 14e			
Facility	**Calculating Indirect Emissions from Electricity Use**		**Converting to CO_2e**
Los Angeles	CO_2 Emissions	1,600 (MWh) × 878.71 (lbs CO_2/MWh) ÷ 2,204.62 (lbs/mt) = 637.72 (mt CO_2)	× 1 (GWP) = 637.72 (metric tons CO_2e)
	CH_4 Emissions	1,600 (MWh) × 0.036 (lbs CH_4/MWh) ÷ 2,204.62 (lbs/mt) = 0.026 (mt CH_4)	× 21 (GWP) = 0.55 (metric tons CO_2e)
	N_2O Emissions	1,600 (MWh) × 0.008 (lbs N_2O/MWh) ÷ 2,204.62 (lbs/mt) = 0.006 (mt N_2O)	× 310 (GWP) = 1.80 (metric tons CO_2e)
	Total Los Angeles Emissions		**= 640.07 metric tons CO_2e**
Portland	CO_2 Emissions	600 (MWh) × 921.10 (lbs CO_2/MWh) ÷ 2,204.62 (lbs/mt) = 250.68 (mt CO_2)	× 1 (GWP) = 250.68 (metric tons CO_2e)
	CH_4 Emissions	600 (MWh) × 0.022 (lbs CH_4/MWh) ÷ 2,204.62 (lbs/mt) = 0.006 (mt CH_4)	× 21 (GWP) = 0.13 (metric tons CO_2e)
	N_2O Emissions	600 (MWh) × 0.014 (lbs N_2O/MWh) ÷ 2,204.62 (lbs/mt) = 0.004 (mt N_2O)	× 310 (GWP) = 1.18 (metric tons CO_2e)
	Total Portland Emissions		**= 251.99 metric tons CO_2e**
Tucson	CO_2 Emissions	800 (MWh) × 1,254.02 (lbs CO_2/MWh) ÷ 2,204.62 (lbs/mt) = 455.05 (mt CO_2)	× 1 (GWP) = 455.05 (metric tons CO_2e)
	CH_4 Emissions	800 (MWh) × 0.018 (lbs CH_4/MWh) ÷ 2,204.62 (lbs/mt) = 0.007 (mt CH_4)	× 21 (GWP) = 0.14 (metric tons CO_2e)
	N_2O Emissions	800 (MWh) × 0.015 (lbs N_2O/MWh) ÷ 2,204.62 (lbs/mt) = 0.005 (mt N_2O)	× 310 (GWP) = 1.69 (metric tons CO_2e)
	Total Tucson Emissions		**= 456.88 metric tons CO_2e**
Total Indirect Emissions From Electricity Use = 640.07 + 251.99 + 456.88 = **1,348.94 metric tons CO_2e**			

Chapter 15: Indirect Emissions from Imported Steam, District Heating, Cooling, and Electricity from a CHP Plant

Who should read Chapter 15:

- Chapter 15 applies to organizations that purchase steam, district heat, cooling or electricity, from a CHP plant or import steam, heating, or cooling from a conventional boiler that they do not control.

What you will find in Chapter 15:

- This chapter provides guidance on estimating indirect emissions from a CHP facility, imported steam, and district heating or cooling. The chapter includes the quantification methodology for CHP and an example addressing indirect emissions from district heating.

Information you will need:

- You will need information about the type of CHP, imported steam and heat, and imported cooling used, and the types and amounts of fuel consumed by the plant to generate that electricity, heating, or cooling. For example, for heat or electricity from a CHP facility, you will need information about the plant's net heat production and net electricity production, in addition to the organization's own consumption of that power.

Cross-References:

Refer to Chapter 14 for guidance on calculating indirect emissions from electricity use and Chapter 12 for guidance on calculating direct emissions from fuel combustion from a CHP or conventional boiler plant.

Indirect Emissions From Combined Heat and Power	
Method	**Type of Method**
GRP-CHP-01- CO_2, CH_4 & N_2O	CHP plant emissions calculated using GRP ST-01 or 02-CO_2 and GRP ST-05-CH_4 & N_2O from Chapter 12 (Stationary Combustion)
GRP-CHP-02- CO_2, CH_4 & N_2O	CHP plant emissions calculated using GRP ST-03-CO_2 and GRP ST-06-CH_4 & N_2O from Chapter 12 (Stationary Combustion)
GRP-CHP-03- CO_2, CH_4 & N_2O	CHP plant emissions calculated using GRP ST-04-CO_2 and GRP ST-07-CH_4 & N_2O from Chapter 12 (Stationary Combustion)

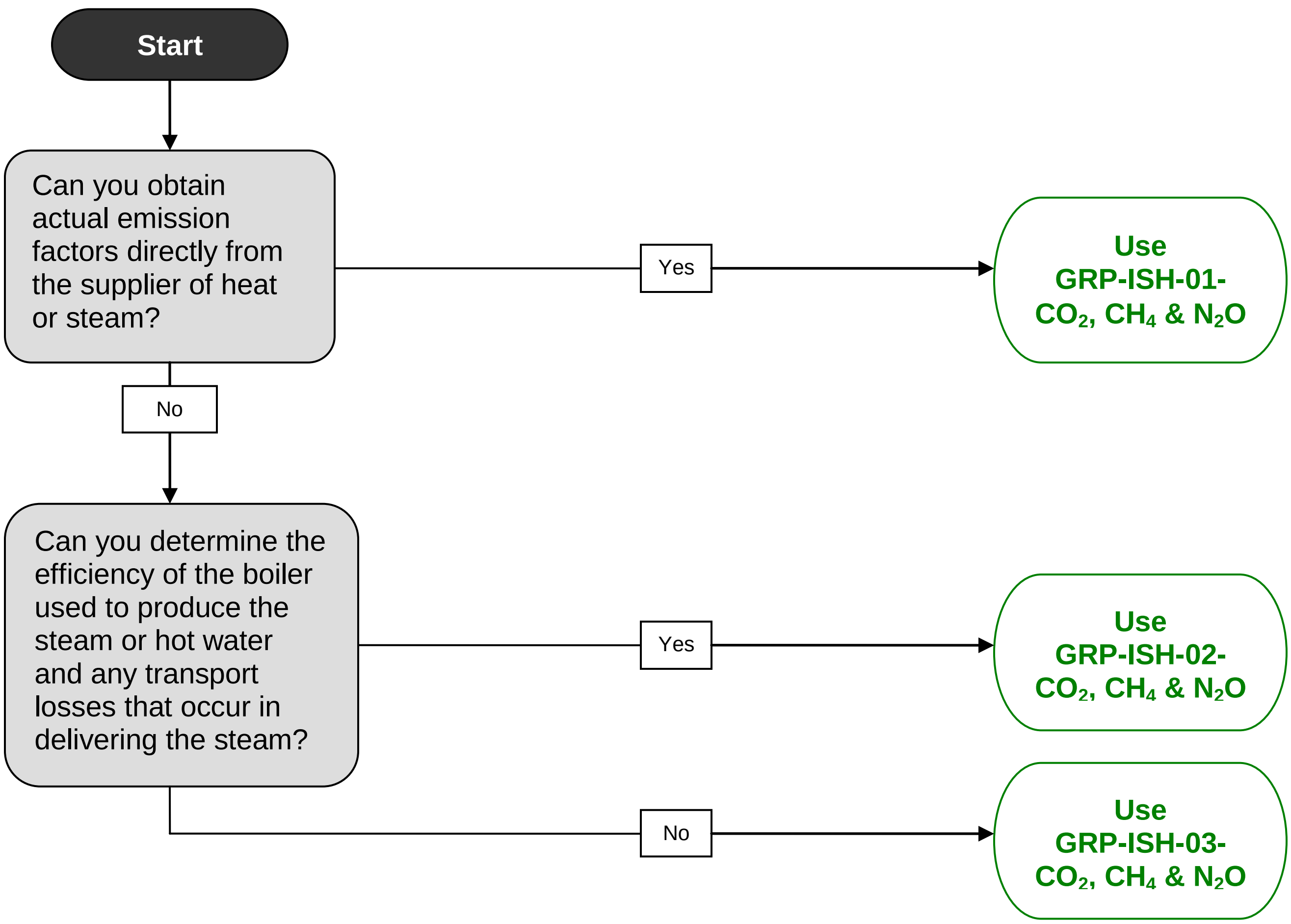
Indirect Emissions From Imported Steam or Heat	
Method	**Type of Method**
GRP-ISH-01- CO_2, CH_4 & N_2O	Measured emission factors obtained directly from the supplier
GRP-ISH-02- CO_2, CH_4 & N_2O	Efficiency approach using source-specific efficiency factor
GRP-ISH-03- CO_2, CH_4 & N_2O	Efficiency approach using default efficiency factor (75 percent)

Indirect Emissions From District Cooling	
Method	**Type of Method**
GRP-IDC-01- CO_2, CH_4 & N_2O	Detailed approach
GRP-IDC-02- CO_2, CH_4 & N_2O	Simplified approach with source-specific Coefficient of Performance
GRP-IDC-03- CO_2, CH_4 & N_2O	Simplified approach with default Coefficient of Performance (See Table 15.1)

15.1 Calculating Indirect Emissions from Heat and Power Produced at a CHP Facility

Emissions from CHP facilities represent a special case for estimating indirect emissions. Because CHP simultaneously produces electricity and heat (or steam), attributing total GHG emissions to each product stream would result in double counting. Thus, when two or more parties receive the energy streams from CHP plants, GHG emissions must be determined and allocated separately for heat production and electricity production.

Figure 15.1. Selecting a Methodology: Indirect CO_2, CH_4, and N_2O Emissions from Imported Steam or Heat



Since the output from CHP results simultaneously in heat and electricity, you can determine what “share” of the total emissions is a result of electricity and heat by using a ratio based on the Btu content of heat and/or electricity relative to the CHP plant’s total output.

The process for estimating indirect emissions from heat and power produced at a CHP facility involves the following four steps:

1. Obtain total emissions and power and heat generation information from CHP facility;

2. Determine emissions attributable to net heat production and electricity production;
3. Calculate emissions attributable to the portion of heat and electricity consumed;
4. Convert to units of CO_2e and determine total emissions.

Step 1: Obtain emissions and power and heat information from the CHP facility.

You will need to obtain the following information from the CHP plant owner or operator to estimate indirect GHG emissions:

- Total emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) from the CHP facility, based on fuel input information;
- Total electricity production from the CHP plant, based on generation meter readings; and
- Net heat production from the CHP plant.

Net heat production refers to the useful heat that is produced in CHP, minus whatever heat returns to the boiler as steam condensate, as shown in Equation 15a. (Alternatively, refer to Step 2 in Section 12.3 for guidance on determining net heat production from steam temperature and pressure data.)

Equation 15a	**Calculating Net Heat Production**		
Net Heat Production (MMBtu)	**=**	Heat of Steam Export **-** (MMBtu)	Heat of Return Condensate (MMBtu)

Step 2: Determine emissions attributable to net heat production and electricity production for the CHP plant.

Refer to Section 12.3 to calculate emissions attributable to net heat and electricity production.

Step 3: Calculate emissions attributable to the portion of heat and electricity consumed.

Once you have determined total emissions attributable to heat (or steam) and electricity production, you will need to determine the portion of heat or electricity consumed, and thus your indirect GHG emissions associated with heat or electricity use. First, obtain electricity and heat (or steam) consumption information, then use Equations 15b and 15c to calculate the share of emissions, as appropriate.

Equation 15b	**Calculating Indirect Emissions Attributable To Electricity Consumption**	
Indirect Emissions Attributable to Electricity Consumption (metric tons)	=	Total CHP Emissions Attributable to Electricity Production (metric tons) **x** (Your Electricity Consumption (kWh) ÷ Total CHP Electricity Production (kWh))

Equation 15c	**Calculating Indirect Emissions Attributable To Heat (or Steam) Consumption**	
Indirect Emissions Attributable to Heat Consumption (metric tons)	=	Total CHP Emissions Attributable to Heat Production (metric tons) **x** (Your Heat Consumption (MMBtu) ÷ CHP Net Heat Production (MMBtu))

Step 4: Convert to units of CO_2e and determine total emissions.

Finally, use the IPCC global warming potential (GWP) factors provided in Equation 15d to convert CH_4 and N_2O emissions to units of CO_2e. Then sum your emissions of all three gases to determine your total emissions from stationary combustion (see Equation 15d).

Equation 15d	Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions (metric tons CO_2e)	=	CO_2 Emissions **x** (metric tons)	1 (GWP)	
CH_4 Emissions (metric tons CO_2e)	=	CH_4 Emissions **x** (metric tons)	21 (GWP)	
N_2O Emissions (metric tons CO_2e)	=	N_2O Emissions **x** (metric tons)	310 (GWP)	
Total Emissions (metric tons CO_2e)	=	CO_2 **+** (metric tons CO_2e)	CH_4 **+** (metric tons CO_2e)	N_2O (metric tons CO_2e)

15.2 Calculating Indirect GHG Emissions from Imported Steam or District Heating from a Conventional Boiler Plant

Some facilities purchase steam or district heating, for example to provide space heating in the commercial sector or process heating in the industrial sector. This section provides guidance on calculating emissions from imported steam or district heating that is produced at a conventional boiler plant (i.e., not a CHP facility).

To estimate a facility's GHG emissions from imported steam or district heating, follow these four steps:

1. Determine energy obtained from steam or district heating;
2. Determine appropriate emission factors for the steam or district heating;
3. Calculate emissions from imported steam or district heating; and
4. Convert to units of CO_2e, and determine total emissions.

Figure 15.1 gives guidance on how to select a particular emissions quantification methodology based on the data that is available to you.

Step 1: Determine energy obtained from steam or district heating.

First, determine the quantity of acquired steam or district heating. You may use metered records of energy use, purchase records, or utility/supplier energy bills to determine annual consumption. Monthly energy bills must be summed over the year to give annual consumption.

Consumption data should be expressed in units of million British thermal units (MMBtu). If consumption data is expressed in therms, you can convert the values to units of MMBtu by multiplying by 0.1, as shown in Equation 15e.

Equation 15e	Converting Steam Consumption from Therms to MMBtu		
Energy Consumption (MMBtu)	=	Energy Consumption **x** (therms)	0.1 (MMBtu/therm)

If steam consumption is measured in pounds (lbs), you either need to monitor the temperature and pressure of the steam received, or request it from the steam supplier. This information can be used with standard steam tables to calculate the steam's energy content.

Calculate the thermal energy of the steam using saturated water at 212°F as the reference (Source: American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, 2001). The thermal energy consumption is calculated as the difference between the enthalpy of the steam at the delivered conditions and the enthalpy (or heat content) of the saturated water at the reference conditions (or heat content).

The enthalpy of the steam can be found in standard steam tables (for example, the *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam* published by the International Association for the Properties of Water and Steam (IAPWS)). The enthalpy of saturated water at the reference conditions is 180 Btus per pound. The thermal energy consumption for the steam can then be calculated as shown in Equation 15f.

Equation 15f	Converting Steam Consumption from Pounds to MMBtu			
Energy Consumption (MMBtu)	=	[Enthalpy of Delivered Steam **-** 180] **x** (Btu/lb)	Steam Consumed ÷ (lbs)	1,000,000 (Btu/MMBtu)

Step 2: Determine the appropriate emission factors for the steam or district heating.

GRP-ISH-01 CO_2, CH_4 & N_2O Method: Measured Emission Factors

Supplied steam or heat is usually generated from direct, known sources of energy. In this case, you should obtain measured emission factors directly from the supplier of heat or steam. Emission factors should be in units of mass per unit of energy (such as tons of CO_2 emitted per MMBtu of heat generated). See Chapter 12, Section 12.2, for information on deriving CO_2 emission factors.

GRP-ISH-02 CO_2, CH_4 & N_2O Method: Efficiency Approach Using Source-Specific Efficiency Factor

If you cannot obtain emission factors directly from suppliers of heat or steam, you can estimate emission factors based on boiler efficiency, fuel mix, and fuel-specific emission factors.

Because emissions vary with fuel type, you must know the type of fuels that are burned in the plant supplying the steam or hot water. You can obtain this information from the plant's energy supplier. Once you know the fuels combusted to generate the steam or hot water, determine the appropriate emission factors for each fuel combusted. The preferred approach is to obtain CO_2 emission factors based on measured characteristics of the fuels combusted, including measured heat content and measured carbon content, from the supplier. If this data is not available, use default emission factors for CO_2, CH_4, and N_2O from Tables 12.1 to 12.9.[44]

Next, you must determine the efficiency of the boiler used to produce the steam or hot water and any transport losses that occur in delivering the steam, and calculate a total efficiency factor using Equation 15g. Boiler efficiency is the ratio of steam output to fuel input, in units of energy, which you should obtain from the steam or heat supplier. If transport losses or boiler efficiency vary seasonally, these factors should be calculated on a monthly or seasonal basis and summed to yield total annual factors.

Equation 15g	**Calculating System Efficiency**		
Total Efficiency Factor (%)	=	Boiler Efficiency **x** (%)	(100% - Transport Losses) (%)

Calculate CO_2, CH_4, and N_2O emission factors that reflect the efficiency and fuel mix of the boiler employed to generate your steam or hot water using Equation 15h.

Equation 15h	**Calculating Emission Factors**		
CO_2 Emission Factor (kg CO_2 / MMBtu)	=	Fuel-Specific Emission Factor ÷ (kg CO_2 / MMBtu)	Total Efficiency Factor (%)
CH_4 Emission Factor (kg CH_4 / MMBtu)	=	Fuel-Specific Emission Factor ÷ (kg CH_4 / MMBtu)	Total Efficiency Factor (%)
N_2O Emission Factor (kg N_2O / MMBtu)	=	Fuel-Specific Emission Factor ÷ (kg N_2O / MMBtu)	Total Efficiency Factor (%)

GRP-ISH-03 CO_2, CH_4 & N_2O Method: Efficiency Approach Using Default Efficiency Factor (75%)

If you are unable to obtain the specific system efficiency of the boiler that generated the steam or heat, apply a default total efficiency factor—boiler efficiency and transport losses combined—of 75 percent in Equation 15h.

Step 3: Calculate emissions from imported steam or district heating.

Once you have both the value of total energy consumed from Step 1 and the appropriate emission factors from Step 2, use Equation 15i to calculate GHG emissions from imported steam or hot water.

Equation 15i	**Calculating Emissions From Imported Steam or Heat**			
Total CO_2 Emissions (metric tons)	=	Energy Consumed **x** (MMBtu)	Emission Factor **x** (kg CO_2 / MMBtu)	0.001 (metric tons/kg)
Total CH_4 Emissions (metric tons)	=	Energy Consumed **x** (MMBtu)	Emission Factor **x** (kg CH_4 / MMBtu)	0.001 (metric tons/kg)
Total N_2O Emissions (metric tons)	=	Energy Consumed **x** (MMBtu)	Emission Factor **x** (kg N_2O / MMBtu)	0.001 (metric tons/kg)

[44] Emission factor tables are available on The Registry's website at www.theclimateregistry.org/.

Step 4: Convert to units of CO_2e and determine total emissions.

Use the IPCC global warming potential factors provided in Equation 15d to convert CH_4 and N_2O emissions to units of CO_2e. Then sum emissions of all three gases to determine total indirect emissions from imported heat or steam (see Equation 15d).

Calculating Indirect GHG Emissions from Imported Steam or District Heating in Leased Spaces
In many cases, organizations that lease space (such as office space) use heat or steam that is generated within the facility they are located in where the heat generation unit is outside of their organizational boundary. For example, if a firm leases office space on the third floor of a 24 story building with a central heating system consisting of a series of boilers in the basement and the firm does not contract for heating fuel directly from the utility, the boilers are in the same facility but outside of the firm's organizational boundary. Members who lease space with heating units that are located within their leased space, as well as Members who pay their own gas bill directly to the utility (assuming operational control) are required to report the emissions from such heating units as scope 1 (stationary combustion) emissions. Members who lease space that is heated by units located in the building they occupy but that are outside of their organizational boundaries may report emissions from the resulting heating unit(s) as optional scope 2 emissions (imported heat). This emission source is part of scope 2 as defined by the GHG Protocol Corporate Standard, but in The Registry's voluntary program, this emission source is not required to be reported. Members who opt to report the scope 2 emissions associated with imported heat under these circumstances must report those emissions in the Scope 2 (Optional) category in CRIS. Often in leased spaces, tenants do not separately contract for imported heat and are unable to obtain that information from their landlords. In these cases, Members optionally reporting these emissions can utilize default consumption rates such as these natural gas consumption defaults from the U.S. Energy Information Administration Commercial Building Energy Consumption Survey: http://www.eia.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/2003set16/2003html/c24a.html or the Natural Resources Canada Commercial and Institutional Building Energy Use Survey: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/Cibeus/tables/cibeus_12_1_1.cfm?attr=0 to determine the energy used to generate the heat they consume.

15.3 Calculating Indirect GHG Emissions from District Cooling

Some facilities purchase cooling, such as chilled water, for either cooling or refrigeration when they do not operate cooling compressors on-site. Conceptually, purchased chilled water is similar to purchased heat or steam, with the primary difference being the process used to generate the chilled water. When Members purchase cooling services using district cooling, the compressor system that produces the cooling is driven by either electricity or fossil fuel combustion. Indirect emissions from district cooling represent the Member's share of the total cooling demand from the cooling plant, multiplied by the total GHG emissions generated by that plant.

Calculating Indirect GHG Emissions from District Cooling in Leased Spaces

In many cases, organizations that lease space (such as office space) use cooling that is generated within the facility they are located in where the cooling generation unit is outside of their organizational boundary.

Members who lease space with cooling units that are located within their organizational boundaries are required to report the emissions from such cooling units as scope 1 (fugitive) emissions and scope 2 (electricity use).

Members who lease space that is cooled by units located in the building they occupy but that are outside of their organizational boundaries may report indirect fugitive and indirect electricity emissions associated with the power used to run the cooling unit(s) as scope 3.

You must first determine the total cooling use by summing the total cooling from monthly cooling bills. Once you have determined total cooling, you can use either the detailed approach (GRP-IDC-01- CO_2, CH_4 & N_2O) or simplified approaches (GRP-IDC-02 or 03- CO_2, CH_4 & N_2O) to estimate GHG emissions from district cooling. Figure 15.2 gives guidance on how to select a particular approach based on the data that is available to you.

GRP-IDC-01- CO_2, CH_4 & N_2O: Detailed Approach

The detailed approach allows you to determine the total cooling-related emissions from the district cooling plant and the facility's fraction of total cooling demand.

Step 1: Determine total cooling-related emissions from the district cooling plant.

District cooling plants take a variety of forms and may produce electricity, hot water, or steam for sale in addition to cooling.

Where Cooling Plant Produces Only Cooling. In the simplest case, all of the fuel consumed by the plant is used to provide cooling. In that case, you will be able to determine total cooling emissions based on (1) total indirect emissions from cooling plant electricity and heat consumption (metric tons), and (2) total direct emissions from cooling plant fuel combustion (metric tons).

The process for calculating direct and indirect emissions from cooling plants is described in Chapters 12 and 14. You will need to obtain the emission values from the district cooling plant, or calculate the emissions based on the fuel consumption, as well as electricity and steam consumption information, provided by the plant.

Where Cooling Plant Produces More Than Cooling. In many cases, the simple situation described above will not apply. Instead, the cooling plant will be integrated into a combined heat and power plant, where some of the steam and electricity produced by the plant may be used for cooling, and some may be used for other purposes. In this case, the emissions from the combined heat and power plant will need to be allocated between heating and electricity production (or shaft work in the case of internal combustion engines), and these emissions will have to be scaled by the fraction of the heat or electricity that is used for cooling, as shown in Equation 15k. This equation assumes 90 percent efficiency for boiler emissions and allocates all other waste heat to electrical efficiency.

Step 2: Determine fraction of cooling emissions attributable to your operations.

The next step in calculating GHG emissions from cooling is to scale the total plant cooling emissions by the percentage share of the cooling load. Equation 15j demonstrates how the total cooling load on the plant is scaled to determine cooling emissions.

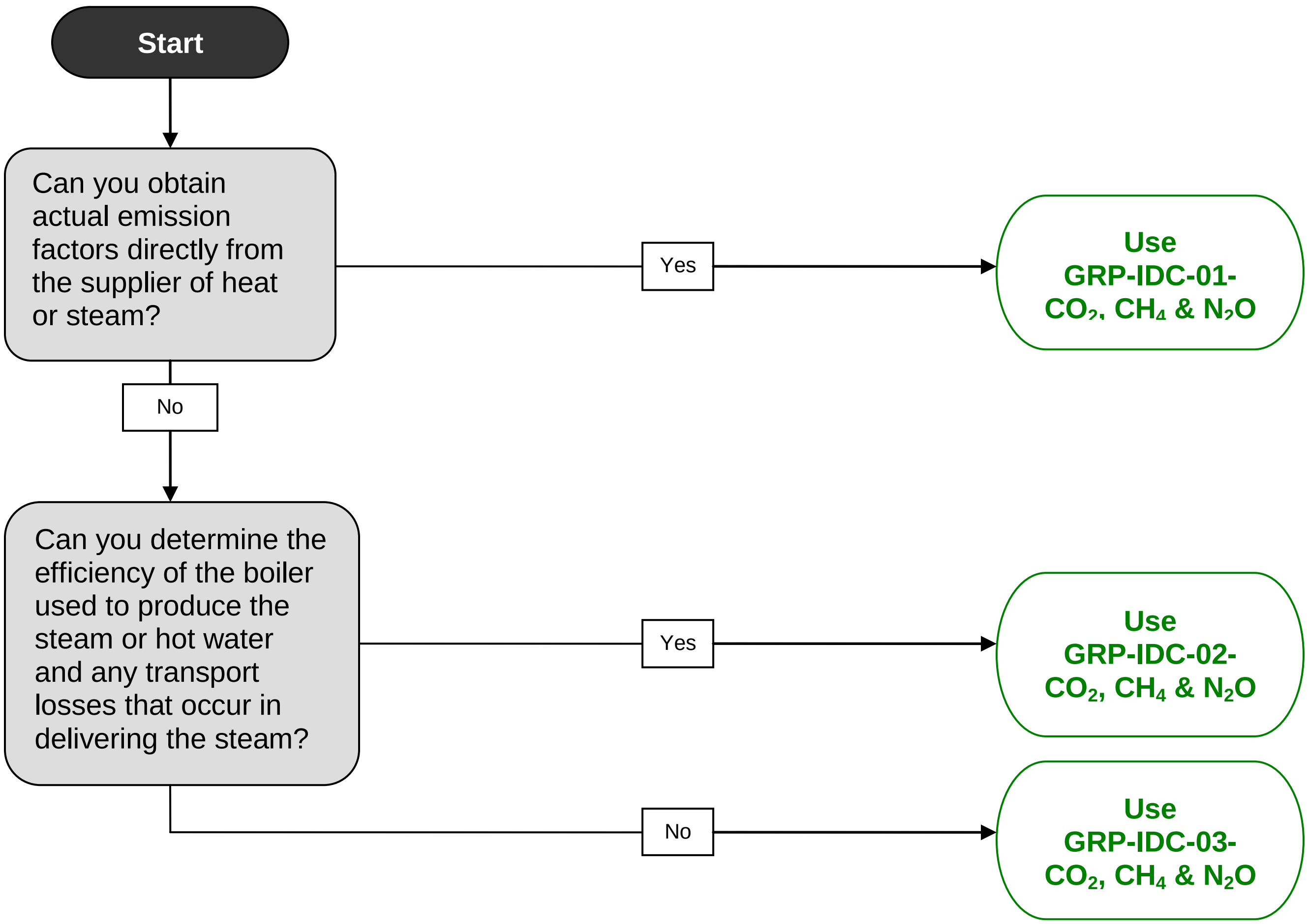
Equation 15j	Calculating Annual Cooling Emissions		
Cooling Emissions (metric tons)	=	Total Plant Cooling Emissions **x** (metric tons)	[Cooling Load ÷ Total Cooling Load] (ton-hour)

Step 3: Determine total annual emissions.

For each month (or longer period) of the year, cooling emissions should be calculated as described in Steps 1 and 2, above. The duration of the periods for which the emissions are calculated will depend on the data available. Ideally, calculations would be made monthly for cooling plants integrated with CHPs, as emissions associated with cooling will depend on how the CHP outputs are distributed. If data for making these calculations are not available on a monthly basis, then longer periods will need to be used. In either case, the emissions for each period must be summed over the year to obtain the annual total.

Equation 15k	Calculating Cooling Emissions From Plant with Multiple Product Streams	
Total Cooling Emissions (metric tons)	=	[% of CHP Electricity Prod. Used for Cooling **x** {(Total Fuel Heat Input (MMBtu) **-** Net Heat Production (MMBtu)) ÷ 0.9} ÷ Total Fuel Heat Input (MMBtu)] **+** [% of CHP Heat Prod. Used for Cooling **x** (Net Heat Production (MMBtu) ÷ (0.9 **x** Total Fuel Heat Input (MMBtu)))] **x** Total CHP Emissions (metric tons)

Figure 15.2. Selecting a Methodology: Indirect CO_2, CH_4, and N_2O Emissions from District Cooling



GRP-IDC-02 and 03- CO_2, CH_4 & N_2O Methods: Simplified Approaches

The simplified approaches uses an estimated value for the ratio of cooling demand to energy input for the cooling plant, known as the "coefficient of performance" (COP). Thus, these approaches allow you to estimate the portion of energy used at the district cooling plant directly attributable to the Member's cooling.

Step 1: Determine your annual cooling demand.

While cooling bills may be reported in terms of million Btu (MMBtu), it will typically report cooling demand in ton-hours. You can convert ton-hours of cooling demand to MMBtu using Equation 15l. If Members are billed monthly, sum together monthly cooling demand to yield an annual total.

Equation 15l	Calculating Annual Cooling Demand			
Cooling Demand (MMBtu)	=	Cooling Demand **x** (ton-hour)	12,000 ÷ (Btu/ton-hour)	1,000,000 (MMBtu/Btu)

Step 2: Estimate COP for the plant's cooling system.

GRP-IDC-02- CO_2, CH_4 & N_2O: Source-Specific COP

The preferred approach is to obtain the source-specific COP for the cooling plant. This method is designated as GRP-IDC-02- CO_2, CH_4 & N_2O. If you can obtain the COP for the cooling plant, proceed to Step 3.

GRP-IDC-03- CO_2, CH_4 & N_2O: Default COP

If you cannot obtain the COP for the plant itself, determine the type of chiller used by the district cooling plant. With that information, a rough estimate of the COP may be selected from the default values shown in Table 15.1.

Table 15.1. Typical Chiller Coefficients of Performance

Chiller Type	COP	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas
Electric-Driven Compressor	4.2	Electricity

Source: California Climate Action Registry General Reporting Protocol Version 3.1, January 2009.

Step 3: Determine energy input.

To determine the energy input to the system resulting from cooling demand, use Equation 15m. For an electric driven compressor, convert the energy input in MMBtu into kWh by multiplying by 293.1.

Equation 15m	Calculating Energy Input		
Energy Input	=	Cooling Demand ÷ (MMBtu)	COP (MMBtu)

Step 4: Calculate GHG emissions resulting from cooling, convert to units of CO_2e, and determine total emissions.

Where Cooling Plant Uses Absorption Chillers or Combustion Engine-Driven Compressors. In this case, calculate the compressor's emissions using the stationary combustion methods outlined in Chapter 12. If you can determine what type of fuel is being used, multiply the energy input by source-specific or default emission factors for CO_2, CH_4, and N_2O from Tables 12.1 to 12.9.[45] If the fuel type cannot be determined, assume the fuel used is natural gas. Use Equation 15n to calculate emissions.

[45] Emission factor tables are available on The Registry's website at www.theclimateregistry.org.

Equation 15n	Calculating Total Cooling Emissions			
Total CO_2 Emissions (metric tons)	=	Energy Input **x** (MMBtu)	Emission Factor **x** (kg CO_2 / MMBtu)	0.001 (metric tons/kg)
Total CH_4 Emissions (metric tons)	=	Energy Input **x** (MMBtu)	Emission Factor **x** (kg CH_4 / MMBtu)	0.001 (metric tons/kg)
Total N_2O Emissions (metric tons)	=	Energy Input **x** (MMBtu)	Emission Factor **x** (kg N_2O / MMBtu)	0.001 (metric tons/kg)

Where Cooling Plant Uses Electric-Driven Compressors. In this case, calculate emissions using the procedures for estimating indirect emissions from electricity use described in Chapter 14.

Finally, convert emissions to units of CO_2e using Equation 15d and sum to determine total emissions from cooling.

Example 15.1. Indirect Emissions from District Heating

Socal Manufacturing Company

The Socal Manufacturing Company imports steam at its California facility. The steam is imported from a conventional natural gas-fired boiler. The boiler efficiency is 85 percent and the loss factor is six percent.

Step 1: Determine energy obtained from steam or district heating.

Since its energy consumption is provided in therms on its monthly billing, Socal uses Equation 15e to determine energy consumption. Socal consumed 6,000 therms in the past year.

Equation 15e	Example: Converting Steam Consumption from Therms to MMBtu			
Steam Energy Consumption	=	6,000 **x** (therms)	0.1 (MMBtu/therm)	= 600 MMBtu

Step 2: Determine appropriate emission factors.

Socal cannot obtain emission factors directly from the supplier of steam. However, the entity can obtain source-specific efficiency factors from the supplier, namely a boiler efficiency of 85 percent and a loss factor of six percent. It also knows that the boiler combusts natural gas. The entity uses Equation 15g to calculate a total efficiency factor and Equation 15h to calculate emission factors for CO_2, CH_4, and N_2O, using emission factors for natural gas (represented in the table below).

Emission Factors for Natural Gas

Fuel	Gas Emitted	Emission Factor
Natural Gas	CO_2	53.06 kg/MMBtu
Natural Gas	CH_4	0.001 kg/MMBtu
Natural Gas	N_2O	0.0001 kg/MMBtu

Equation 15g	Example: Calculating System Efficiency			
Total Efficiency Factor	=	85% **x**	(100% - 6%)	= 0.799

Example continued on next page.

Equation 15h	Example: Calculating Emission Factors			
CO_2 Emission Factor	=	53.06 ÷ (kg CO_2 / MMBtu)	0.799	= 66.4 kg CO_2 / MMBtu
CH_4 Emission Factor	=	0.001 ÷ (kg CH_4 / MMBtu)	0.799	= 0.001 kg CH_4 / MMBtu
N_2O Emission Factor	=	0.0001 ÷ (kg N_2O / MMBtu)	0.799	= 0.0001 kg N_2O / MMBtu

Step 3: Calculate Total Emissions.

Socal uses the steam consumption from Step 1, the emission factors from Step 2, and Equation 15i to calculate emissions from steam consumption. Then the entity converts to units of CO_2e using Equation 15d and sums to determine total emissions.

Equation 15i	Example: Calculating Emissions From Imported Steam or Heat				
Total CO_2 Emissions	=	600 **x** (MMBtu)	66.4 **x** (kg CO_2 / MMBtu)	0.001 (metric tons/kg)	= 39.8 metric tons
Total CH_4 Emissions	=	600 **x** (MMBtu)	0.001 **x** (kg CH_4 / MMBtu)	0.001 (metric tons/kg)	= 0.0006 metric tons
Total N_2O Emissions	=	600 **x** (MMBtu)	0.0001 **x** (kg N_2O / MMBtu)	0.001 (metric tons/kg)	= 0.00006 metric tons

Equation 15d	Example: Converting to CO_2e and Determining Total Emissions			
CO_2 Emissions	=	39.8 **x** (metric tons)	1 (GWP)	= 39.8 metric tons CO_2e
CH_4 Emissions)	=	0.0006 **x** (metric tons)	21 (GWP)	= 0.01 metric tons CO_2e
N_2O Emissions	=	0.00006 **x** (metric tons)	310 (GWP)	= 0.02 metric tons CO_2e
Total Emissions	=	39.8 **+** 0.01 **+** 0.02 = **39.8 metric tons CO_2e**		

Chapter 16: Direct Fugitive Emissions from the Use of Refrigeration and Air Conditioning Equipment

Who should read Chapter 16:

- Chapter 16 applies to organizations that use refrigeration and air conditioning equipment, including household, commercial, industrial, and motor vehicle refrigeration and air conditioning systems.

What you will find in Chapter 16:

- This chapter provides guidance on determining direct fugitive emissions of HFCs and PFCs from refrigeration and air conditioning systems.

Information you will need:

- To complete this chapter you will need information on the types and quantities of air conditioning equipment, total refrigerant charge, annual leak rates, and the types of refrigerant, as applicable.

Cross-References:

See Chapter 13 for guidance on calculating combustion emissions from motor vehicles and see Appendix D.10 for calculating emissions from the manufacturing of refrigeration and air conditioning equipment.

Direct Fugitive Emissions From the Use of Refrigeration and Air Conditioning Equipment	
Method	**Type of Method**
GRP FG-01	Mass balance method
GRP FG-02	Simplified mass balance method

16.1 Calculating Direct Fugitive Emissions from Refrigeration Systems

Leakage from refrigeration systems, such as air conditioners and refrigerators, is common across a wide range of entities. Refrigeration and air conditioning systems include household refrigeration, domestic air conditioning and heat pumps, motor vehicle air conditioning, chillers, retail food refrigeration, cold storage warehouses, refrigerated transport, industrial process refrigeration, and commercial air conditioning systems.

Emissions of hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration and air conditioning equipment result from the manufacturing process, leakage over the operational life of the equipment, and disposal at the end of the useful life of the equipment. This chapter addresses emissions from use of equipment only (including installation, use, and disposal). For guidance on calculating emissions from the manufacturing of refrigeration and air condition equipment, see Section D.10 of Appendix D.

Please note, common refrigerants R-22, R-12 and R-11 are not part of the GHGs required to be reported to The Registry because they are either HCFCs or CFCs. The production of HCFCs and CFCs is being phased out under the Montreal Protocol and as a result, HCFCs and CFCs are not defined as GHGs under the Kyoto Protocol. Emissions of non-Kyoto-defined GHGs must not be reported as emission sources or part of a facility totals grid in CRIS, regardless of the global warming potential of the gas. Members that opt to disclose emissions of these refrigerants must include that information in a supplemental document. The Registry encourages Members to optionally disclose these gases in a supplemental public document.

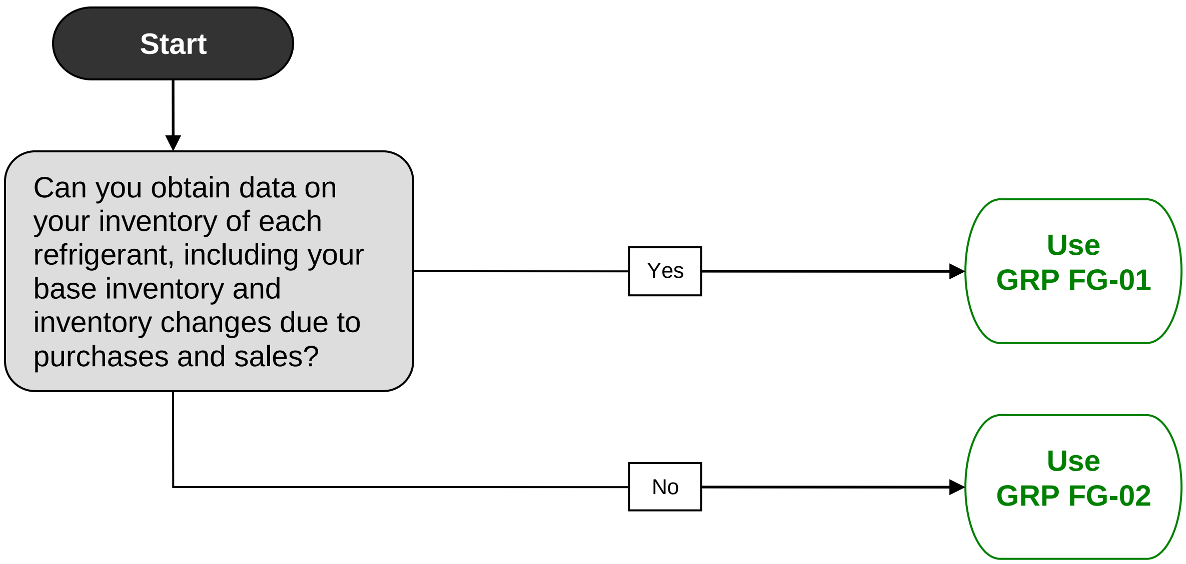
There are three methods for estimating emissions of HFCs and PFCs from refrigeration and air conditioning equipment:

1. Mass balance approach (GRP FG-01);
2. Simplified mass balance approach (GRP FG-02); and
3. Screening method, which can only be used to determine whether emissions fall below five percent of a Member's total entity-wide emissions, and if so, may be used as a simplified estimation method (see Chapter 11). The screening method cannot be used as a method for quantifying and reporting emissions if these emissions sources exceed five percent of total emissions.

Figure 16.1 gives guidance on how to select a particular emissions quantification methodology based on the data that is available to you.

Emissions from refrigeration and air conditioning equipment should be calculated and reported separately for each facility.

Figure 16.1. Selecting a Methodology: Fugitive Emissions from the Use of Refrigeration and Air Conditioning Equipment



GRP FG-01: Mass Balance Approach

The mass balance approach is the most accurate method for determining HFC and PFC emissions. This method is particularly recommended for equipment manufacturers and for equipment users who service their own equipment. To calculate HFC and PFC emissions using the mass balance approach, follow these three steps:

1. Determine the base inventory for each refrigerant in use at each facility;
2. Calculate changes to the base inventory for each refrigerant based on purchases and sales of refrigerants and changes in total capacity of the equipment; and
3. Calculate annual emissions of each type of refrigerant, convert to units of CO_2e, and determine total HFC and PFC emissions for each facility.

Step 1: Determine the base inventory for each HFC and PFC.

For each facility, first determine the quantity of the refrigerant in storage at the beginning of the year **(A)** and the quantity in storage at the end of the year **(B)**, as shown in Table 16.1. Refrigerant in storage (or in inventory) is the total stored on site in cylinders or other storage containers and does not include refrigerants contained within equipment.

Step 2: Calculate changes to the base inventory.

Next, include any purchases or acquisitions of each refrigerant, sales or disbursements of each refrigerant, and any changes in capacity of refrigeration equipment. Additions and subtractions refer to refrigerants placed in or removed from the stored inventory, respectively.

Purchases/Acquisitions of Refrigerant. This is the sum of all the refrigerants acquired during the year either in storage containers or in equipment (item **C** in Table 16.1). Purchases and other acquisitions may include refrigerant:

- Purchased from producers or distributors,
- Provided by manufactures or inside equipment,
- Added to equipment by contractors or other service personnel (but not if that refrigerant is from the Member's inventory), and
- Returned after off-site recycling or reclamation.

Sales/Disbursements of Refrigerant. This is the sum of all the refrigerants sold or otherwise disbursed during the year either in storage containers or in equipment (item **D** in Table 16.1). Sales and disbursements may include refrigerant:

- In containers or left in equipment that is sold,
- Returned to suppliers, and
- Sent off-site for recycling, reclamation, or destruction.

Net Increase in Total Full Charge of Equipment. This is the net change to the total equipment volume for a given refrigerant during the year (item **E** in Table 16.1). Note that the net increase in total full charge of equipment refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. It accounts for the fact that if new equipment is purchased, the refrigerant that is used to charge that new equipment should not be counted as an emission.

It also accounts for the fact that if the amount of refrigerant recovered from retiring equipment is less than the full charge, then the difference between the full charge and the recovered amount has been emitted. Note that this quantity will be negative if the retiring equipment has a total full charge larger than the total full charge of the new equipment.

If the beginning and ending total capacity values are not known, this factor can be calculated based on known changes in equipment. The total full charge of new equipment (including equipment retrofitted to use the refrigerant in question) minus the full charge of equipment that is retired or sold (including full charge of refrigerant in question from equipment that is retrofit to use a different refrigerant) also provides the change in total capacity.

Step 3: Calculate annual emissions of each type of HFC and PFC, convert to units of CO_2e, and determine total HFC and PFC emissions.

For each type of refrigerant or refrigerant blend, use Equation 16a and data from Table 16.1 to calculate total annual emissions of each type of HFC and PFC at each facility.

Equation 16a	Calculating Emissions of Each Type of HFC and PFC Using the Mass Balance Method		
Total Annual Emissions (metric tons HFC or PFC)	=	(A **-** B **+** C **-** D **-** E) ÷ (kg)	1,000 (kg/metric tons)

Please note, some refrigerant blends include both HFCs and PFCs. To report the emissions from these blends, you must multiply the amount of each refrigerant used by the percent composition of HFC and PFC listed in Appendix B. When reporting emissions associated with these blends, the HFC and PFC components must be reported by gas. Next, use Equation 16b and the appropriate GWP factors from Appendix B to convert each HFC and PFC to units of CO_2e.

Equation 16b	Converting to CO_2e		
HFC Type A Emissions (metric tons CO_2e)	=	HFC Type A Emissions **x** (metric tons HFC Type A)	GWP (HFC A)
PFC Type A Emissions (metric tons CO_2e)	=	PFC Type A Emissions **x** (metric tons PFC Type A)	GWP (PFC A)

Finally, sum the totals of each type of HFC, in units of CO_2e, to determine total HFC emissions (see Equation 16c) at each facility. Likewise, sum the totals of each type of PFC to determine total PFC emissions.

Equation 16c	Determining Total HFC and PFC Emissions		
Total HFC Emissions (metric tons CO_2e)	=	HFC Type A **+** (metric tons CO_2e)	HFC Type B **+** … (metric tons CO_2e)
Total PFC Emissions (metric tons CO_2e)	=	PFC Type A **+** (metric tons CO_2e)	PFC Type B **+** … (metric tons CO_2e)

Table 16.1. Base Inventory and Inventory Changes

Inventory		Amount (kg)
Base Inventory		
A	Refrigerant in inventory (storage) at the beginning of the year	
B	Refrigerant in inventory (storage) at the end of the year	
Additions to Inventory		
1	Purchases of refrigerant (including refrigerant in new equipment)	
2	Refrigerant returned to the site after off-site recycling	
→ C	Total Additions (1+2)	
Subtractions from Inventory		
3	Returns to supplier	
4	HFCs taken from storage and/or equipment and disposed of	
5	HFCs taken from storage and/or equipment and sent off-site for recycling or reclamation	
→ D	Total Subtractions (3+4+5)	
Net Increase in Full Charge/Nameplate Capacity		
6	Total full charge of new equipment	
7	Total full charge of retiring equipment	
→ E	Change to nameplate capacity (6-7)	

GRP FG-02: Simplified Mass Balance Approach

If you do not have the necessary data to use the mass balance approach outlined above, you should use the simplified mass balance approach. This method may be used either by entities that service their own equipment or by entities that have contractors service their equipment. This method requires information on the quantity of refrigerant used to charge new equipment during installation, the quantity of refrigerant used to service equipment, the quantity of refrigerant recovered from retiring equipment, and the total full charges of new and retiring equipment.

To calculate HFC and PFC emissions using the simplified mass balance approach, follow these three steps:

1. Determine the types and quantities of refrigerants used at each facility;
2. Calculate annual emissions of each type of HFC and PFC; and
3. Convert to units of CO_2e and determine total HFC and PFC emissions at each facility.

Step 1: Determine the types and quantities of refrigerants used.

For each type of refrigerant used, determine the following quantities used or recovered during the reporting year, if applicable:

- Quantity of refrigerant used to charge new equipment during installation (if new equipment was installed that was not pre-charged by the manufacturer)
- Total full charge (capacity) of new equipment using this refrigerant (if new equipment was installed that was not pre-charged by the manufacturer)

- Quantity of refrigerant used to service equipment.
- Total full charge (capacity) of retiring equipment (if equipment was disposed during the reporting year)
- Quantity of refrigerant recovered from retiring equipment (if equipment was disposed during the reporting year)

Members who have contractors that service refrigeration equipment, obtain the required information from the contractor. Always track and maintain the required information carefully in order to obtain accurate estimates of emissions.

Note that "total full charge" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. For more information, see the description of "Net Increase in Total Full Charge of Equipment" from Step 2 in the Mass Balance Approach above.

Step 2: Calculate annual emissions of each type of HFC and PFC.

Next, use Equation 16d to calculate emissions for each type of refrigerant used. Repeat Equation 16d for each type of refrigerant used.

Equation 16d	Calculating Emissions of Each Type of Refrigerant		
Total Annual Emissions (metric tons)	**=**	$(P_N - C_N + P_S - P_R + C_D - R_D) \div$ (kg)	1,000 (kg/metric tons)

Where:
P_N = Purchases of refrigerant used to charge new equipment *
C_N = Total full charge of the new equipment *
P_S = Quantity of refrigerant used to service equipment
P_R = Quantity of refrigerant recycled
C_D = Total full charge of retiring equipment
R_D = Refrigerant recovered from retiring equipment

* Omitted if the equipment has been pre-charged by the manufacturer

Step 3: Convert to units of CO_2e and determine total annual HFC and PFC emissions.

Use Equation 16b and the appropriate GWP factors from Appendix B to convert each HFC and PFC to units of CO_2e.

Finally, sum the totals of each type of HFC, in units of CO_2e, to determine total HFC emissions at each facility (see Equation 16c). Likewise, sum the totals of each type of PFC to determine total PFC emissions.

Screening Method

Consistent with The Registry's voluntary reporting requirements, any combination of emissions that total less than or equal to five percent of a Member's total entity-wide emissions may be estimated with Simplified Estimation Methods (and reported to The Registry). The Screening Method is intended to help roughly estimate these emissions and determine whether HFC and PFC emissions from refrigeration and air conditioning systems may be estimated SEMs.

If the Screening Method determines that emissions from refrigeration and air conditioning systems represent less than five percent of total entity-wide emissions, you may use the Screening Method to estimate and report these emissions. Note that you may only use SEMs to estimate up to five percent of total entity-wide emissions. If emissions from refrigeration and air conditioning represent five percent of total emissions and you use the Screening Method to estimate those emissions, you are not eligible to use simplified methods to estimate other sources within the inventory. See Chapter 11 for more information.

If the Screening Method determines that emissions from refrigeration and air conditioning are greater than five percent of total entity-wide emissions, you must use either the Mass Balance Approach or Simplified Mass Balance Approach outlined above to accurately quantify and report your emissions. In this case, you may not use the Screening Method to report these emissions.

The Screening Method estimates emissions by multiplying the quantity of refrigerants used by default emission factors. Because default emission factors are highly uncertain, the resulting emissions estimates are not considered accurate.

To estimate emissions using the Screening Method, follow these three steps:

1. Determine the types and quantities of refrigerants used;
2. Estimate annual emissions of each type of HFC and PFC; and
3. Convert to units of CO_2e and determine total HFC and PFC emissions.

Step 1: Determine the types and quantities of refrigerants used.

To estimate emissions, you must determine the number and types of refrigeration and air conditioning equipment, by equipment category; the types of refrigerant used; and the refrigerant charge capacity of each piece of equipment (see Table 16.2). If you do not know the refrigerant charge capacity of each piece of equipment, use the upper bound of the range provided by equipment type in Table 16.2.

Step 2: Estimate annual emissions of each type of refrigerant.

For each type of refrigerant, use Equation 16e to estimate annual emissions. Default emission factors are provided in Table 16.2 by equipment type. The equation includes emissions from installation, operation, and disposal of equipment. Members who did not install or dispose of equipment during the reporting year, should not include emissions from these activities in the estimation.

Please note some refrigerant blends include both HFCs and PFCs. To report the emissions from these blends, you must multiply the amount of each refrigerant used by the percent composition of HFC and PFC listed in Appendix B. When reporting emissions associated with these blends, the HFC and PFC components must be reported by gas category.

Equation 16e	Estimating Emissions of Each Type of Refrigerant using the Screening Method

For each type of refrigerant:

Total Annual Emissions (metric tons) **=** [(C_N **x** k) **+** (C **x** x **x** T) **+** (C_D **x** y **x** (1 **–** z))] ÷ 1,000
(kg) (kg/metric tons)

Where:
C_N = Quantity of refrigerant charged into the new equipment [1]
C = Total full charge (capacity) of the equipment
T = Time in years equipment was in use (e.g., 0.5 if used only during half the year and then disposed)
C_D = Total full charge (capacity) of equipment being disposed of [2]
k = Installation emission factor [1]
x = Operating emission factor
y = Refrigerant remaining at disposal [2]
z = Recovery efficiency [2]

[1] Omitted if no equipment was installed during the reporting year or the installed equipment was pre-charged by the manufacturer
[2] Omitted if no equipment was disposed of during the reporting year

Step 3: Convert to units of CO_2e and determine total HFC and PFC emissions.

Use Equation 16b and the appropriate GWP factors from Appendix B to convert each type of refrigerant to units of CO_2e.

Finally, sum the totals of each type of HFC, in units of CO_2e, to determine total HFC emissions (see Equation 16c). Likewise, sum the totals of each type of PFC to determine total PFC emissions.

If the sum of HFC and PFC emissions, in units of CO_2e, is less than five percent of total entity-wide emissions, you may use these estimates to report HFC and PFC emissions from refrigeration and air conditioning use, provided you estimate no more than five percent of total emissions using a SEM such as this screening method. If you determine HFC and PFC emissions to be more than five percent of total emissions (or you are using simplified estimation methods to estimate other sources that together constitute five percent of total emissions), you must use one of the other methods outlined in this chapter to estimate these emissions.

Example of Mass Balance Approach: Direct Fugitive Emissions from Refrigeration Systems

Produce Chillers, Inc.

Produce Chillers, Inc. operates five large commercial chillers to refrigerate vegetable produce shortly after harvest, using HFC-23. During the reporting year, Produce Chillers, Inc. increased its total vegetable produce refrigeration capacity by 18 percent with new equipment, decommissioned one refrigeration unit for recycling, and recharged several of its refrigeration units. Its inventory at the beginning of the year is 412.6 kg and at the end of the year it is 405.1 kg.

Step 1: Determine the base inventory for each refrigerant.

Produce Chillers records its base inventory for HFC-23 in the table below.

Step 2: Calculate changes to the base inventory.

The entity records its additions, subtractions, and changes to full charge in the table below and calculates the values C, D, and E.

Inventory for HFC-23 from Commercial Chillers		Amount (kg)
Base Inventory		
A	Beginning of year	412.6
B	End of year	405.1
Additions to Inventory		
1	Purchases of HFCs (including HFCs in new equipment)	197.5
2	HFCs returned to the site after off-site recycling	0
→ C	Total Additions (1+2)	197.5
Subtractions from Inventory		
3	Returns to supplier	0
4	HFCs taken from storage and/or equipment and disposed of	0
5	HFCs taken from storage and/or equipment and sent off-site for recycling or reclamation	53.3
→ D	Total Subtractions (3+4+5)	53.3
Net Increase in Full Charge/Nameplate Capacity		
6	Total full charge of new equipment	100
7	Total full charge of retiring equipment	10
→ E	Change to nameplate capacity (6-7)	90

Step 3: Calculate annual emissions of each type of HFC and PFC, convert to units of CO_2e, and determine total HFC and PFC emissions.

The entity uses Equation 16a and the data from the table above to calculate emissions of HFC-23, and then converts the total to units of CO_2e using Equation 16b and the appropriate global warming potential value from Appendix B1. Because Produce Chillers uses only one type of HFC, it does not need to sum emissions for multiple HFCs using Equation 16c. Instead, the entity's total emissions of HFCs result from Equation 16b.

Equation 16a	**Example: Calculating Emissions of Each Type of HFC and PFC**			
HFC-23 Emissions	=	(412.6 **-** 405.1 **+** 197.5 **–** 53.3 **-** 90) ÷ (kg)	1,000 (kg/metric tons)	= 0.062 metric tons HFC-23

Equation 16b	**Example: Converting to CO_2e**			
HFC-23 Emissions	=	0.062 **x** (metric tons HFC-23)	11,700 (HFC-23 GWP)	= 725.4 metric tons CO_2e

Example of Screening Method: Direct Fugitive Emissions from Refrigeration Systems

GHG Inc.

GHG Inc. is a small consulting firm with an office in Phoenix, AZ. To create their inventory, GHG Inc. has determined that they own the following items which use HFCs: five passenger cars, one window air-conditioning unit, and two kitchen refrigerators. GHG Inc. leases an office and therefore is not required to report fugitive emissions from the building's central Heating, Ventilating, and Air Conditioning (HVAC) system. However, to fully estimate their operations emissions, GHG Inc. will also include fugitive emissions from the building's central HVAC (district cooling), as a part of their optional emissions.

GHG Inc. has obtained the following information for each piece of equipment:

Type of Equipment	Number of Units	Capacity (kg)	Refrigerant Used	GWP
Toyota Corolla 2000	3	0.8	HFC-134a	1,300
Ford Escort 2002	2	1.0	HFC-134a	1,300
Kenmore 75101 Window AC Unit	1	5.0	R-407c	1,526
GE® ENERGY STAR® 17.9 Cu. Ft. Top-Freezer Refrigerator	2	0.1	HFC-152a	140
Building HVAC (Chiller)	1	50	HFC-134a	1,300

GHG Inc. has not had any of the above equipment serviced in the last year, but is fairly confident that these fugitive emissions represent less than 5 percent of their total entity-wide emissions. Given this assumption, GHG Inc. begins with the *screening method* to determine if the *simplified estimation method* is appropriate.

Given the above information, GHG Inc. determines their entity's fugitive emissions using default emission factors from Table 16.2 and Equation 16e by refrigerant type.
NOTE: no piece of equipment was installed, serviced, or retired during the reporting year.

a) HFC-134a (Vehicles)

HFC-134a = [((0.8 x 3) x 20% EF x 1 year) + ((1.0 x 2) x 20% EF x 1 year)] / 1,000
HFC-134a emissions = 0.00088 metric tons
CO_2e emissions = 0.00088 metric tons x 1,300 GWP **= 1.144 metric tons CO_2e**

b) HFC-152a (Refrigerators)

HFC-152a = [((0.1 x 2) x 0.5% EF x 1 year)] / 1,000
HFC-152a emissions = 0.000001 metric tons
CO_2e emissions = 0.000001 metric tons x 140 GWP **= 0.00014 metric tons CO_2e**

c) R-407a (Window AC)
R-407a = [((5.0 x 1) x 10% EF x 1 year)] / 1,000
R-407a emissions = 0.0005 metric tons
CO_2e emissions = 0.0005 metric tons x 1,526 GWP **= 0. 763 metric tons CO_2e**

Total Required Fugitive Emissions = 1.144 + 0.00014 + 0.763 **= 1.90714 metric tons CO_2e**

GHG Inc.'s entity-wide emissions, excluding fugitive emissions equals 573 metric tons CO_2e, therefore the inventory fraction comprised by their HFCs is equal to 0.33 percent.

(1.90714 / [573+1.90714]) * 100 = **0.33% of total inventory**

GHG Inc.'s total entity-wide emissions are equal to 574.91 metric tons CO_2e. Their fugitive emissions represent less than 5 percent of their total inventory so the simplified estimation method is appropriate.

d) Optional Scope 2: HFC-134a (Building HVAC)
HFC-134a = [((50 x 1) x 15% EF x 1 year)] / 1,000
HFC-134a emissions = 0.0075 metric tons
CO_2e emissions = 0.0075 metric tons x 1,300 GWP **= 9.75 metric tons CO_2e**

Optional emissions must be reported separately from required emissions.

PART IV: REPORTING YOUR EMISSIONS

About Part IV

All entities that report to The Climate Registry's voluntary reporting program should read Part IV in its entirety. This section sets forth the procedures that all Members must follow once they have completed their emissions calculations. Specifically, Part IV provides information on how to report data using The Registry's software, the supplemental information you need to report (or may report optionally), and how to have the inventory verified.

Chapter 17: Completing the Annual Emissions Inventory

Issue	Requirements		Optional
	Transitional	Complete	
Performance Metrics	• There is no requirement to report performance metrics, unless reporting in conformance with the Electric Power Sector (EPS) Protocol.		• May report chosen performance metrics to show relevant, comparable data that enables tracking of emissions relative to indicators of performance (e.g., output).

Now that you have defined and calculated the GHG emissions, you are ready to complete the annual emissions inventory. In addition to quantifying emissions, you must also provide The Registry with some information about the entity. You have the ability to also include optional information in the emission report to better illustrate Member goals and achievements. Members may keep optional information private to use for internal purposes, or it can be disclosed to stakeholders via the public emission report.

As you compile the emission report, please adhere to the following reporting and verification deadlines:

- **Reporting Deadline** (Data must be submitted into CRIS): **June 30th**
- **Verification Deadline** (Data must be successfully verified by a Registry-recognized Verification Body): **December 15th**
- **Batch Reporting and Verification:** Deadlines are announced at the beginning of each year.

17.1 Additional Reporting Requirements

The primary information that Members must report to The Registry is the GHG emissions data. However, The Registry also requires that Members provide the following additional information:

- Information about the entity (address, key contacts, etc.)
- Whether the inventory is Transitional or Complete
- The consolidation approach(es) employed (i.e., operational control, financial control, equity share)
- If the Member is reporting as a subsidiary and the parent company is also reporting, the identity of the parent company as it appears in CRIS.

17.2 Optional Data

The Registry encourages Members to exceed its reporting requirements by providing optional data in addition to the required data and information described above. Reporting optional data will enhance the value of the inventory to stakeholders and demonstrates both the transparency of the emission report and the Member's environmental leadership. Members may include whatever additional data or information would be helpful for stakeholders to review with the emission report. Members may either enter this data or information in text boxes in CRIS designated for optional data, or documents may be uploaded to the Member's document library within CRIS (for either internal purposes or public disclosure).

Members may submit a wide array of optional data to The Registry, however The Registry encourages Members to consider including the following:

- Worldwide emissions (in addition to North American emissions)
- Unit-level emissions (for stationary combustion units)
- Historical emissions
- Emissions based on more than one of the consolidation approaches described in Chapter 4 (e.g., report emissions on both an equity share and operational control basis, or both an equity share and financial control basis)
- Scope 3 emissions
- Information on any GHG management or reduction programs or strategies, including green power purchases (e.g., RECs) and purchases of offsets (including information on whether they are verified or certified)
- Descriptions of unique environmental practices

17.3 Offsets

Offsets represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for (i.e., offset) GHG emissions occurring elsewhere, for example to meet a voluntary GHG target.

Offsets that are applied to an inventory must meet The Registry's eligibility requirements. Members who are disclosing offsets purchases as an additional information item and are not applying those offsets to their inventories are not required to demonstrate conformance with The Registry's eligibility requirements.

Registry-recognized offsets must demonstrate that their associated GHG reductions meet six key accounting criteria:

- **Real:** GHG reductions must represent actual emission reductions quantified using comprehensive accounting methods.

- **Additional:** GHG reductions or removals must be surplus to regulation and beyond what would have happened in the absence of the incentive provided by the offset credit. Offsets quantified using a project vs. performance standard methodology may establish slightly different requirements for demonstrating additionally.

- **Permanent:** The GHG reductions must be permanent or have guarantees to ensure that any losses are replaced in the future.

- **Transparent:** Offsets must be publicly and transparently registered to clearly document offset generation, transfers and ownership.

- **Verified:** The GHG reductions must result from projects whose performance has been appropriately validated and verified to a standard that ensures reproducible results by an independent third party that is subject to a viable and trustworthy accreditation system.

- **Owned Unambiguously:** No parties other than the project developer, must be able to reasonably claim ownership of the GHG reductions.

Offsets that are applied to an adjusted inventory summary can be used once and only once and must be retired prior to the date they are reported to The Registry.

The Registry recognizes offset credits that are issued by and retired under the following offset programs:

- State, province or federal regulatory agencies in North America
- American Carbon Registry
- Clean Development Mechanism
- Climate Action Reserve
- Climate Leaders
- Gold Standard
- Joint Implementation
- Pacific Carbon Standard
- Verified Carbon Standard
- Other programs meeting equivalent standards upon Registry staff evaluation.[46]

Members purchasing carbon offsets in the retail market can gain assurance about the validity of their purchases by seeking out retail offset product certification. One such certification program is Green-e Climate.[47]

Offsets must be reported separately from inventory totals and can be disclosed as a GHG management practice for scope 1, scope 2 or scope 3 emissions.

17.4 Performance Metrics for Your Entity

Performance metrics provide information about an entity's direct and indirect emissions relative to a unit of business activity, input, or output. Members may use performance metrics to serve a range of objectives, including:

- Evaluation of emissions over time in relation to targets or industry benchmarks;
- Facilitation of comparisons between similar businesses, process or products; and
- Improving public understanding of the emissions profile over time, even as business activity changes, expands or decreases.

Many companies track environmental performance with intensity ratios. Intensity ratios measure GHG emissions per unit of physical activity or economic unit. For example, an electricity generating company

[46] Contact The Registry at info@theclimateregistry.org to request evaluation of additional offset programs.
[47] Please contact The Registry if you have questions about offset product certification.

may use a GHG intensity indicator that specifically measures pounds of emissions per total megawatt-hour generated (lbs/MWh). In the power sector, some examples of performance metrics include generation emission intensity (e.g., tons of CO_2 emissions per unit of electricity consumed); and sales emissions intensity (e.g., emissions per unit of electricity sold).

Registry Performance Metrics

The Registry currently has standards for several performance metrics specific to different sectors.

Electric Power Generation and Delivery Metrics

The Electric Power Sector (EPS) Protocol contains requirements for developing both electricity generation and delivery metrics, which provide helpful information for other Members working to better quantify scope 2 emissions. Electric power utilities reporting to The Registry are required to quantify and report generation metrics and may opt to develop delivery metrics for their customers. See the EPS Protocol, which can be found on The Registry's website (www.theclimateregistry.org), for more information on these metrics.

Transit Agency Performance Metrics

The Registry has developed a set of transit agency performance metrics that provide transit agencies with a reliable, transparent, and clear communication tool that can be used to explain carbon efficiency to policy makers, funders, and the public. Transit agencies reporting to The Registry are not required to develop these metrics, however The Registry strongly encourages they be disclosed. For more information on the transit agency performance metrics, please see The Registry's website (www.theclimateregistry.org).

Chapter 18: Reporting Data Using CRIS

18.1 CRIS Overview

The Climate Registry Information System (CRIS) provides multiple options to calculate and report GHG emissions annually, and produces user-friendly reports for both the Member and the public. Since Members have different approaches for collecting and reporting GHG emissions data, CRIS provides a number different methodologies that allow Members to follow an approach that aligns best with their own internal process.

In order to report their GHG inventory to CRIS, Members define the facilities that identify the plants, industrial processes, buildings and fleets that contribute to their total footprint. This information is available from one year to the next so it only needs to be entered once. Members are then able to report their emissions for any year they plan to submit a report to The Climate Registry.

The sections that follow describe the different approaches that Members can follow when reporting emissions to CRIS. Please refer to the CRIS section of The Climate Registry's website for resources and documentation that provide detailed guidance on using CRIS.

Entity-Level Reporting

Members that decide to report emissions at the entity level will submit pre-calculated data for one or more facilities in CRIS. If the entity consolidation methodology is operational or financial control with equity share, they will need to set up additional facilities to allow accurate equity share reporting. Verification of entity level reports will rely on supporting documentation supplied by the Member to their verifier. Public reports will only contain aggregated entity level data.

Facility-Level Reporting

Members also have the option of reporting pre-calculated data at the facility level. In this case the Member is expected to define all of the facilities in their inventory following the facility-level reporting requirements in Chapter 6. This provides more transparency to public stakeholders than entity level reporting. As with entity level reporting, facility reporting requires that members provide supporting documentation to their Verifier offline. Public reports will contain an emissions summary for each facility, but Private reports that are available only to the Member will show detail for all emissions by activity type.

Source-Level Reporting

CRIS has a sophisticated source-level calculation engine that allows members to perform all GHG emission calculations according to the policy defined in this protocol. Member can define emitting sources for each facility including the activity type (e.g. scope 1 stationary combustion, scope 2, purchased electricity) and the fuel consumed. Activity data (e.g. fuel quantity, unit of measure) are defined for each year of reporting to complete the calculations. There are multiple calculation methodologies available with source-level reporting:

- The most common methodology is to use the *default emissions factor* supplied by the CRIS calculator. Emission factors can be customized if members have a factor which is more specific for their fuel.
- *Pre-calculated* data may also be submitted at the source level if the member prefers to perform some calculations offline.
- *Lastly* there are options for *CEMS, PART 70 CEMS, and PART 60 CEMS* to identify the type of monitoring used for relevant sources of pre-calculated data.

Public reports will contain an emissions summary for each facility, but private reports that are available only to the Members will show all source calculation details.

Contact The Registry's helpline (866-523-0764 ext. 3) to discuss your best option for entering data into CRIS.

18.2 Electronic Submissions to CRIS

Many members have custom applications or use third-party software tools to manage their emissions data. It may be simpler for these members to upload data to CRIS electronically, rather than entering the data into CRIS manually.

Using GHG Sync to Upload Data to CRIS

The CRIS application has a built in service that enables Members to upload data using an XML schema which is called GHG Sync. Members may develop the ability to generate the schema independently, but may also work with their software provider or consulting partner to develop this capability. A number of software vendors and consultants have developed this capability already. GHG Sync can save time and reduce errors for members with many facilities.

Using the CRIS Data Upload Service to Upload Data from a Spreadsheet

For members that would like to upload data electronically but prefer not to adopt GHG Sync, The Registry offers a low cost service to upload member data from a spreadsheet template called *the CRIS Data Upload Service*. Registry staff will send the member a pre-populated spreadsheet and the Member will complete the data and submit it for upload.

18.3 Help with CRIS

The Registry's technical staff is available to help you with any questions you may have about using CRIS to calculate, report, or verify your emissions. Please call **866-523-0764 ext. 3** if you need technical support.

Reporting Deadline Reminder

The deadline for reporting your emissions is June 30th of the year following your emissions year.

Chapter 19: Third-Party Verification

Issue	Requirements		Optional
	Transitional	Complete	
Verification	• Third-party verification is required.		• If the following information is optionally reported, it must be third-party verified: a) Worldwide scope 1 and 2 emissions; b) Equity share GHG inventory; c) Adjustment to base year; and, d) Transit and power delivery metrics. • The following information is not subject to verification: d) Scope 3 emissions; e) Optional scope 1 and 2 emissions; and, f) Non-combustion biogenic CO_2 emissions.

This chapter provides an overview of The Registry's verification process, focusing primarily on those aspects that are a Member's responsibilities. As such, it is designed to provide you with a comprehensive, yet concise, overview of the steps in the verification process that require your direct participation. If you are interested in reading a more detailed description of the verification process, including the responsibilities and activities of the Verification Bodies, Accreditation Bodies, The Registry's Verification Advisory Group, please refer to The Registry's *General Verification Protocol*.

19.1 Background: The Purpose of The Registry's Verification Process

One of The Registry's guiding principles is to establish a high level of environmental integrity in the GHG data it collects. In part, the measurement, estimation, and reporting requirements articulated in this GRP will assure the quality and integrity of the data. Equally important, however, is the independent evaluation of the accuracy of emission reports and their conformity with the GRP's requirements. Third-party verification is defined as an independent expert assessment of the accuracy and conformity of a Member's emission report based on the reporting requirements contained in this GRP and the verification requirements described in The Registry's *General Verification Protocol.*

The purpose of third-party verification is to provide confidence to users (state regulatory agencies, tribal authorities, investors, suppliers, customers, local governments, The Registry, the public, etc.) that your emission report represents a faithful, true, and fair account of your emissions—free of material misstatements and conforming to The Registry's accounting and reporting rules.

Third-party verification is a widely accepted practice for ensuring accurate emissions data. Verification has been employed in the context of a number of voluntary and mandatory GHG reporting programs. In the U.S., the Environmental Protection Agency (EPA) does not require third-party verification of GHG emissions reported under its mandatory reporting rule; however, third-party verification is relied upon by several GHG regulatory programs, including the California Air Resources Board (CARB), the Western Climate Initiative (WCI), Massachusetts Department of Environmental Protection (MassDEP), the European Union's Emissions Trading System (EU ETS), the United Kingdom's GHG Emissions Trading System, Alberta's Specified Gas Emitters Program, and British Columbia's Greenhouse Gas Reduction Act.

19.2 Activities to Be Completed by the Member in Preparation for Verification

The remaining sections of this chapter walk you through the steps that you must take to initiate and complete The Registry's verification process.

Selecting a Verification Body

Each year, once you have completed compiling the emissions inventory and have entered this information into CRIS, you must have the emissions report verified. The Registry has adopted a rigorous verification process to ensure the accuracy and credibility of the reported emissions data. To initiate this process, Members must select a Verification Body from the list of Registry-recognized Verification Bodies available on The Registry's website (www.theclimateregistry.org).

To select a Verification Body, The Registry recommends that Members discuss the type and scope of your emissions with at least two Verification Bodies and request that they submit a verification proposal including cost and time estimate.

To do so, Members should first review the list of Registry-recognized Verification Bodies and select some as prospective bidders. Due to the possibility of access to proprietary information, Members may want to send each prospective bidder a non-disclosure agreement.

In order to help selected Verification Bodies prepare accurate verification proposals, Members may want to provide them with the following information:

1. The expected contract duration;
2. A general description of the organization and operations;
3. Whether or not the Member is reporting a transitional inventory;
4. The geographic boundaries of the emissions report;
5. A description of the GHG data management system; and
6. A copy of the private CRIS report.

Once Members have chosen a preferred Verification Body, they may *begin* negotiating contract terms. However, The Registry requires the selected Verification Body to submit a Case Specific Conflict of Interest (COI) Assessment Form to The Registry, and await The Registry's confirmation of this Assessment prior to finalizing a verification contract.

The COI Assessment Form evaluates the potential conflicts between a Member's organization and the Verification Body. Verification contracts may **not** be finalized until The Registry authorizes a Verification Body to proceed.

The Registry screens all COI Assessments, and will periodically conduct a more thorough review of COI. If The Registry chooses a Member's COI Assessment to review, that Member may not proceed with its verification contract until The Registry authorizes the Verification Body to do so.

If a Verification Body or The Registry finds that the risk of COI between the Member and the Verification Body is high, we will inform the Member. At this point, the Member will either need to select a different Verification Body to work with (where the risk for COI is lower), or direct the Verification Body to submit a Mitigation Plan to The Registry demonstrating how they have reduced the COI risk to an acceptable level. The process and criteria used by Verification Bodies to assess COI is described in Part 3 of the *General Verification Protocol.*

Finalizing the Verification Contract

Assuming that there is no finding of a high risk COI, Members may finalize a contract with a Verification Body once they receive confirmation from The Registry. This contract is exclusively between the Member and the Verification Body. The particulars of any given contract are at the discretion of the two parties. However, contracts for verification services typically include the following components:

- **Scope of the Verification Process.** This component of the contract should outline the exact geographic and organizational boundaries of the emissions inventory. In addition, Members should clarify the type of emissions reported (e.g. specific industry sectors) and confirm that the Verification Body is approved to verify such types of emission activity. Finally, Members must define the total scope of the Verification Body's activities. The scope will likely be the emissions required to be reported by The Registry, however, it may also include additional boundaries or activities (e.g. GHG reports submitted to federal or state mandatory programs, historical emissions years, updated base year) as well.

- **Confirmation of Accredited Verification Body.** This is a simple statement that the Verification Body has been recognized by The Registry to verify emission reports covering the scope listed above.

- **Verification Standard.** Verification Bodies must verify emission reports against The Registry's requirements (defined in this GRP) using the process outlined in The Registry's *General Verification Protocol*. ISO 14064-3 should also be indicated as a standard for verification. However in cases where its requirements could prohibit the Verification Body from complying with the *General Verification Protocol*, the latter will take precedence. Members planning to use emissions reports for additional purposes such as submitting data to another registry, satisfying mandatory reporting requirements, participating in emissions trading schemes, etc., may want to add additional verification standards to the contract.

- **Non-disclosure Terms.** Members should reach agreement with a Verification Body in advance on methods for identifying and protecting proprietary and confidential business data that may be revealed during verification.

- **Facility Access.** Members should reach agreement in advance to the conditions of the Verification Body's facility visits.

- **Documentation and Data Requirements.** Members should reach agreement in advance on how and when they will provide activity and emissions data to the Verification Body. The range of required documentation will largely be determined by the size and complexity of the Member's operations, and whether the Member has used the online calculation tools available through CRIS.

- **Period of Performance.** The period of performance for verification services may be up to six years. However, Members have discretion as to whether they sign a one- or multi-year contract.

- **Performance Schedule.** Members may wish to reach agreement on a schedule to complete the verification process and for the Verification Body to deliver a Verification Report and Verification Statement by the deadline of **December 15** of the year following the emissions year.

- **Payment Terms.** Typical payment terms include total value, schedule of payments, and method of payment (e.g., electronic funds transfer).

- **Re-verification Terms.** If the Verification Body identifies material misstatements in an emission report, the Member must revise the report. Upon completion of revisions, the Member may ask the Verification Body to re-verify the portions of the emission report that was corrected. Contracts should also specify the length of time Members will have to correct misstatements. *It is important to note that Verification Bodies may **not** provide guidance, technical assistance, or implementation work on the remediation of misstatements, as this constitutes consulting services, which The Registry prohibits.*

- **Liability.** All Registry-recognized Verification Bodies are required to have professional indemnity insurance to the level of at least U.S. $1,000,000. Members may require, and the Verification Body may agree to, additional liability under the contract.

- **Contacts.** Members should identify technical leads for their organization and the Verification Body, as well as responsible corporate officials of both parties.

- **Dispute Resolution.** Both parties must state their consent to submit irreconcilable differences for review to the appropriate Accreditation Body.

- **Acknowledgement of Registry Personnel and Registry-Authorized Representative Site Visits.** Both the Member and its Verification Body must sign an acknowledgement that Registry/Accreditation Body personnel and/or Registry-authorized representatives may occasionally accompany the verification team on visits to facilities for purposes of monitoring the verification process.

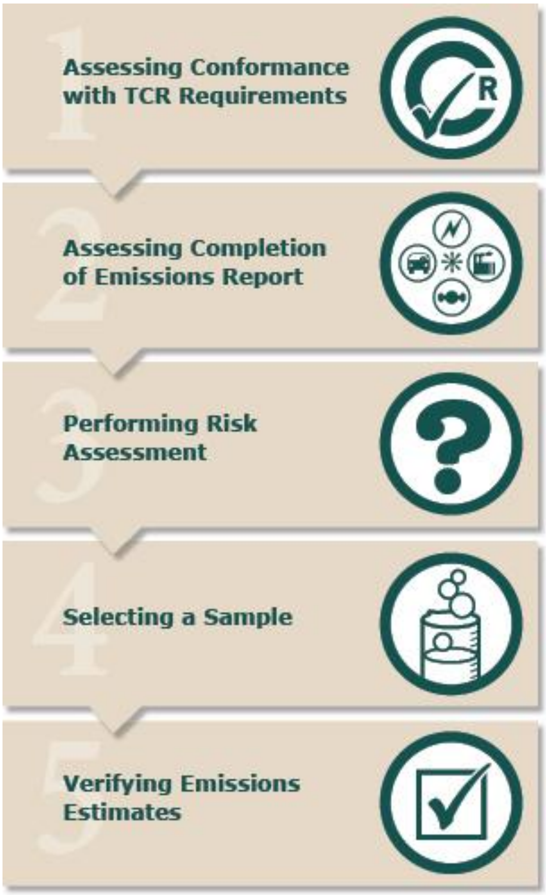
Kickoff Meeting with the Verification Body

Once the verification contract is in place, the verification team will meet with the Member to discuss the planned verification activities. At a minimum, the agenda for this meeting should include:

1. Introduction of the verification team;
2. Review of verification activities and scope;
3. Transfer of background information; and
4. Review and confirmation of the verification process schedule.

Although the specific needs of the verification team will vary from Member to Member, Members will typically be asked to provide access to documents and data related to the emission report (supporting data, information about control systems, management plans, etc.) as well as to individual employees involved in the preparation of your report. In addition, most Members will be asked to provide verification team members with physical access to a sample of facilities selected by the Verification Body. Occasionally Registry personnel and/or Registry-authorized representatives may accompany verification team members on site visits, in order to monitor the verification team's efforts.

Following the initial kickoff meeting, the Verification Body will begin the technical work involved in verifying emissions, and will contact the Member on an as needed basis to obtain documents and other materials, contacts, site access permissions, etc.



19.3 Batch Verification Option

To reduce the transaction costs associated with the verification of small office-based organizations, The Registry offers a modified version of its standard verification process.[48] The Registry refers to this modified process as "batch verification." The Registry offers batch verification options to Members that have:

- Not more than 1000 tonnes total CO_2e emissions per emissions year,
- No process emissions; and
- Fugitive emissions that comprise less than five percent of the entity's total emissions.

In addition, scope 1 and scope 2 emissions must originate from only the following sources:

- Indirect emissions from electricity consumption;
- Direct emissions from stationary combustion for heating, cooling, or emergency electricity generation;
- Direct emissions from mobile combustion; and,
- Fugitive emissions from refrigeration, air conditioning, and/or fire suppression.

[48] Please note that Members going through batch verification are eligible to achieve Climate Registered status.

For Members whose emissions are just outside of these parameters, the Batch Verification Body will determine eligibility on a case by case basis.

The Registry negotiates a standard contract and fixed price with a Verification Body (the “Batch Verification Body”) on behalf of qualifying Members (“Batch Participants”) to help streamline the process and minimize the costs of completing verification.

At the beginning of each year, The Registry will publish as schedule for batch verification, including deadlines for submittal of the application and for submittal of data in CRIS. The verification deadline for Batch Verification may be accelerated (e.g. Members may be required to upload the final Verification Statements in CRIS by the beginning of July).

Members interested in batch verification must submit an application to the Batch Verification Body prior to the specified application deadline. The Batch Verification Body is responsible for determining the eligibility of Members.

To facilitate the batch verification, each Batch Participant will be required to submit supporting information in the format requested by the Batch Verification Body and adhere to the schedule for batch verification activities. The Registry will also provide Members with a standard verification contract template. Members will sign their own contracts with the Batch Verification Body. If a Member requires non-standard contract language, it may not be able to participate in batch verification.

Once the standard contract is signed, the batch verification process is essentially the same as the standard (non-batch) verification process. However, facility visits, which are conducted as part of the standard verification process, are not required or expected for batch verifications.

19.4 Overview of Verification Process

1. **Member submits CRIS report for verification:** Once the report is submitted for verification, data is “read-only” to the Member.

2. **Member selects a Verification Body (VB):** Member contacts one or more Registry-recognized VBs to request a proposal for verification services. Member selects a VB and begins to negotiate contract terms.

3. **VB submits Case-Specific Conflict of Interest (COI) Assessment Form:** After a Member chooses a VB, the VB must submit a Case-Specific COI Assessment Form to The Registry. The Registry reviews the COI assessment and notifies the VB of its determination within 15 business days.

4. **VB and Member finalize contract:** Once The Registry has determined that the potential for COI between a Member and VB is low, the VB may finalize its contract with the Member.

5. **VB develops a verification plan:** VB develops a sampling plan, identifies facilities to be visited, and submits a Notification of Planned Facility Visits form to The Registry at least 10 business days before the scheduled visits.

6. **VB conducts verification activities:** VB follows the guidance in the General Verification Protocol to evaluate a Member’s annual GHG emission report and conducts core verification activities.

7. **VB informs Member of reporting errors:** The VB prepares a detailed summary (e.g. Draft Verification Report, corrective action request) of the verification activities and misstatements (both material and immaterial) and reviews it with the Member.

8. **Member implements corrective action:** The Member corrects all material misstatements and as many immaterial misstatements as possible.

9. **VB prepares final Verification Report and Verification Statement:** The VB prepares a final Verification Report and Verification Statement and reviews these documents with the Member.

10. **Member and VB Sign Verification Statement:** The Member returns the signed Verification Statement to the Verification Body.

11. **Verification Body Completes Verification Module in CRIS:** The Verification Body uploads the fully-executed Verification Statement (as *.pdf file) and submits the verification in CRIS.

12. **Member Accepts Verification in CRIS:** The Member logs into CRIS to click the "Accept Verification" button.

13. **Registry reviews verification documentation:** The Registry reviews the Verification Statement and evaluates the Member's emission report. Once accepted by The Registry, the Member's emission report and the Verification Statement become available to the public through CRIS.

19.5 Verification Concepts

Materiality

Verification Bodies use the concept of materiality to determine if omitted or misstated GHG emissions information will lead to significant misrepresentation of your emissions, thereby influencing conclusions or decisions made on the basis of those emissions by intended users. A material misstatement is the aggregate of errors, omissions, non-compliance with program requirements, and/or misrepresentations that could affect the decisions of intended users.

The Registry sets this threshold at five percent (on an absolute value basis) of a Member's direct (scope 1), indirect (scope 2) and biogenic emissions from stationary and mobile combustion emissions. Thus, The Registry requires Verification Bodies to assess the accuracy of your direct and indirect emissions separately. Members' direct and indirect emissions must both be deemed as accurate (within five percent) for a Verification Body to issue a successful Verification Statement.

> **Material Misstatement:** A discrepancy is considered to be material if the collective magnitude of compliance and reporting errors in a Member's emission report alters a Member's direct or indirect emissions by plus or minus five percent.

As illustrated in Figure 19.1, The Registry requires Verification Bodies to assess the positive and negative errors outside of an inherent uncertainty band surrounding the true value of a Member's emissions. Due to the inherent uncertainty associated with CEMs and other metering equipment, emission factors, and some of The Registry's approved emission calculation methodologies, a

Member's emissions will more than likely deviate to some extent from the "true" emissions. The Registry recognizes and accepts the inherent uncertainty surrounding reported emissions.[49]

The Registry defines inherent uncertainty as the uncertainty associated with:

1. The inexact nature of measuring and calculating GHG emissions (rounding errors, default emission factors, significant digits, etc.), and
2. The inexact nature of the calculations associated with The Registry's permitted use of simplified estimation methods (for up to five percent of the sum of a Member's scope 1, scope 2, and biogenic emissions from stationary and mobile combustion).

Mitigating Misstatements

If during the course of conducting the verification activities, a Verification Body discovers a discrepancy (either material or not), it must inform the Member of the error in a timely fashion, so that the Member may work to correct the error or discrepancy. The Registry requires Members to correct as many misstatements as is possible; however, it realizes that some misstatements may not be able to be corrected in a timely manner or at all (missing data, etc.).

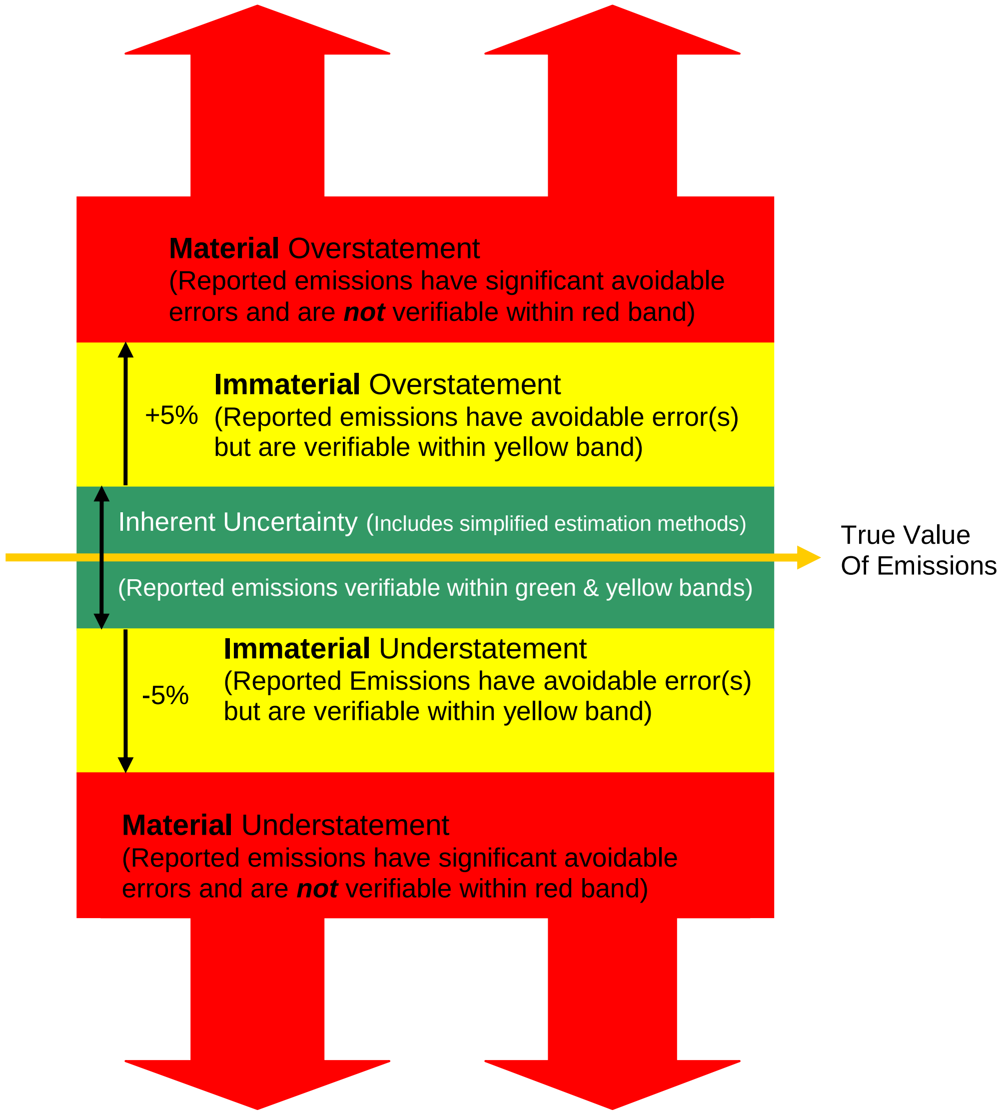
The application of a materiality threshold involves qualitative as well as quantitative considerations (refer to the General Verification Protocol for examples). The Registry requires that Verification Bodies follow a hierarchical assessment when evaluating material misstatements. First, a Verification Body must confirm that a Member meets all of The Registry's reporting and programmatic requirements (qualitative assessment). Then, a Verification Body must conduct a risk assessment to sample for reporting errors (quantitative assessment). If a Verification Body discovers that a Member has not complied with The Registry's program requirements (e.g. has not reported for one of its facilities) then it must inform the Member, and cease further verification activities until the Member can correct the error.

Verification Bodies must communicate with the Member to determine how much time the Member will require to correct any discovered misstatements, so that they can plan another assessment of the corrected misstatements accordingly.

While The Registry requires Verification Bodies to inform Members of discrepancies and encourages the correction of errors before completing a final Verification Statement, The Registry strictly prohibits Verification Bodies from providing any consulting activities to Members to help correct the discovered error or discrepancy. In summary, Verification Bodies must clearly explain the error, but cannot help Members correct the error. Verification Bodies should agree to a typical and reasonable response that will allow for ample time for Members to correct discrepancies before completing the Verification Statement.

[49] Verification Bodies exclude inherent uncertainty from their assessment of material misstatements.

Figure 19.1. Conceptual Application of the Materiality Threshold



Risk-Based Approach to Verification

Given the impossibility of assessing and confirming the accuracy of every piece of GHG information that goes into an emission report, The Registry has adopted ISO 14064-3's risk-based approach to verification. This approach directs Verification Bodies to focus their attention on those data systems, processes, emissions sources, and calculations that pose the greatest risk of generating a material discrepancy in an effort to locate systemic reporting errors.

The main objective of the verification effort is to confirm that reported emissions comply with The Registry's materiality threshold of five percent (on an absolute value basis). Thus, a Verification Body's risk assessment will focus on those reporting errors that might materially affect Members' reported emissions.

Verification Bodies must perform risk assessments at the entity-level. This means that Verification Bodies must survey emission sources, facilities, GHG gases, processes, policies, and operations and identify those that pose the greatest threat to causing material misstatements in the emission report. From this entity-level risk assessment, Verification Bodies will identify certain facilities, sources, policies, etc. to sample for errors. Thus, a Verification Body will visit some individual facilities and they will be assessing the overall entity-level risk of each Member's emissions.

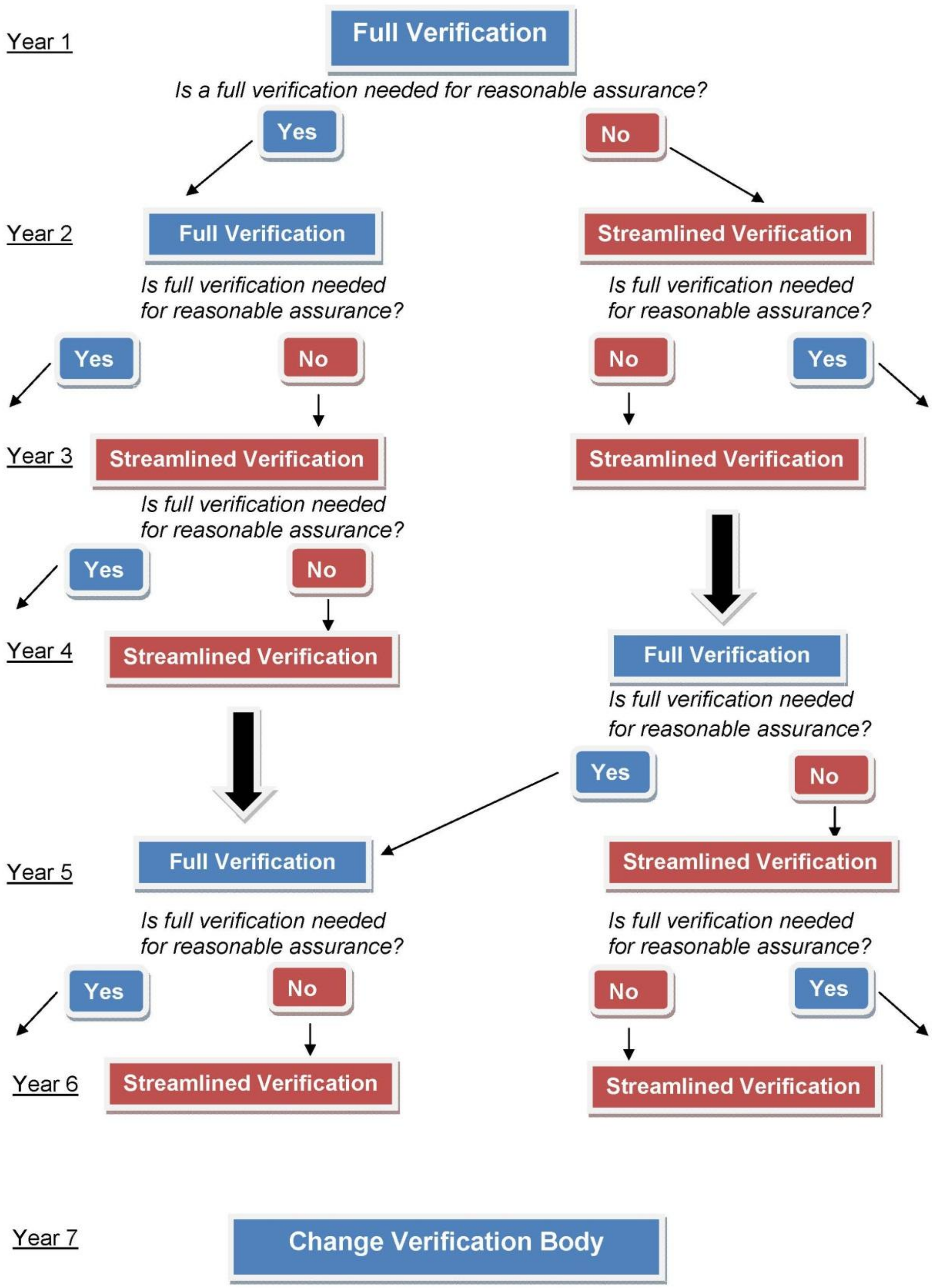
19.6 Verification Cycle

The Registry requires annual verification of all GHG data and allows Members to contract with the same Verification Body for up to six consecutive years. The verification cycle starts anew each time a Member retains a new Verification Body, even if the Member switches Verification Bodies before six years.

Members must have their GHG data verified every year; however, if management systems and/or emissions sources do not change from year to year, then The Registry allows Verification Bodies to use their professional judgment to determine the appropriate level of a verification assessment in order to issue a Verification Statement with reasonable assurance of a Member's reported emissions. At a minimum, each year a Verification Body must conduct an entity-wide risk assessment and check for reporting errors and misstatements.

The Registry allows Verification Bodies to streamline verification activities in the years following a successful comprehensive verification process in order to minimize verification costs whenever this is possible without compromising the integrity and credibility of the reported GHG data. To this end, The Registry allows for a three-year verification cycle, which permits a streamlined verification process in the second and third years of the cycle, assuming that the Member has not experienced any significant changes to their organizational structure or GHG emissions (see Figure 19.2 below).

Figure 19.2. Three-Year Verification Cycle



In Year 1 of the three-year cycle, a Verification Body must comprehensively assess the emission report and its compliance with Registry requirements; confirm the Member's emissions sources and GHGs; review management policies and systems; and sample data for calculation and reporting errors in order to gain a detailed understanding of Member operations and resulting GHG emissions. For full verifications (e.g. Years 1 and 4), the Verification Body must visit a sample of the Member's facilities in accordance with the methodologies set forth in the General Verification Protocol.

If the organizational structure and GHG emissions have not changed significantly, and a Member asks the same Verification Body to verify its emissions the next year, then a Verification Body may choose to streamline their verification activities, as long as the Verification Body can still provide reasonable assurance that the Member has accurately reported its emissions within five percent.

While The Registry largely defers to a Verification Body's professional judgment to assess if a Member's organizational structure or emissions have changed significantly after the first year of the verification cycle, The Registry deems the following changes as being material, and therefore as triggering a review on the part of the Verification Body as to whether more comprehensive (or more substantial) verification activities might be required:

- The Member becomes a "complete" reporter (no longer a Transitional Reporter)
- Emissions change by more than five percent from the previous year's emissions
- Changes to GHG data collection, management, and/or reporting systems and/or the key persons responsible
- Misstatements identified through the course of verification activities
- Other issues as deemed appropriate by the Verification Body

While some of the above changes might necessitate a full verification, other changes may still be addressed as part of a streamlined process, depending on the professional judgment of the Verification Body. A full verification, including one or more facility visits, is required if:

- The Member selects a new Verification Body;
- Overall scope 1 emissions increase or decrease by more than 10 percent on a CO_2e basis as a result of:
    - Acquired or new facilities and/or operations;
    - Changes in the nature of emissions sources, emissions control technology, and/or emissions monitoring equipment.

Changes in the quantity of emissions generated as a result of the following are exempt from this analysis: increased or decreased energy use due to increases or decreases of previously existing production operations, divestiture of facilities, and cessation of operations. If a full verification is trigged, at least one facility visit must be conducted. The minimum number and selection of facilities to be visited shall be based on the Verification Body's risk assessment and the methodologies provided in the General Verification Protocol.

The specific activities that constitute streamlined verification will vary depending on the circumstances, but in all cases the Verification Body must perform the minimum set of activities that will allow it to conduct a risk-based assessment of materiality and to attain reasonable assurance in the findings presented in its Verification Statement. The minimum required activities include the risk-based assessment and the verification of emission estimates against the verification criteria. Beyond these required activities, the Verification Body should use its professional judgment to determine the set of verification activities that will be required to meet the reasonable assurance goal.

In short, The Registry does not prescribe the specific activities that should constitute a streamlined verification (beyond the activities noted above), but rather encourages Verification Bodies to use professional judgment in tailoring a verification process appropriate to your specific circumstances. This latitude to tailor the verification process to the circumstances applies only to streamlined verifications; not to the full verification that the Verification Body must conduct at least once every three years.

NOTE: The Registry articulates this process to serve as guidance for ways to streamline the verification process. Verification Bodies are not required to follow this three-year cycle, but are allowed to do so, as long as they can meet the intent of the verification process, appropriately manage their own risks, and thus are able to provide reasonable assurance that a Member's emissions contain no material errors, omissions or misrepresentations.

Verifying Multiple Years of Data

If a Member needs to correct a previously reported and verified year of data, a Verification Body may verify this information together with the current emission report. This will count as one year in the three-year verification cycle. If a Member requests that its Verification Body verify multiple years of historical data along with the current emission report, they may do so. There is no limit to the number of years of historical data that can be verified during the three-year verification cycle. In other words, historical years of data are not counted toward the three-year verification cycle. For example, if in 2012 a Verification Body verifies the current (2011) emission report in addition to four consecutive years of historic data (2007 through 2010), the Verification Body will have completed only one year of the six-year relationship and will be eligible to serve as the Member's Verification Body for another five years.

Previous Verification Body- Member Relationships

Members who have a previous relationship with a Verification Body through a different registry or program (e.g. CCAR, Chicago Climate Exchange, CARB or other mandatory programs, etc.) must count the prior GHG verification work toward The Registry's six-year limit on the Verification Body/Member relationship. The six-year limit begins at the time the Member retains the Verification Body for verification services, whether for The Registry or another program. The Verification Body-Member relationship must not exceed verification of six (current) emissions years. The Registry does not limit the number of past years of data that a Verification Body can verify for you during this six-year period.

19.7 Conducting Verification Activities

The heart of the verification process lies in conducting the verification activities. While this process is customized for each Member, Verification Bodies will take the following actions to complete the verification process. They will:

- Develop a Verification Plan
- Implement the Verification Plan
- Conduct the Core Verification Activities

The five core verification activities involved in the verification effort are:

1. Assessing conformance with The Registry's requirements
2. Assessing completeness of emission report
3. Performing risk assessment based on review of information systems and controls

4. Selecting a sample/developing a sampling plan
5. Evaluating GHG information systems and controls and emission estimates against verification criteria

Following the completion of the verification activities, the Verification Body will complete the required verification documentation and discuss their findings with the Member.

19.8 Activities to Be Completed After the Verification Body Reports Its Findings

Upon completion of the verification activities, the Verification Body will provide the Member with a Verification Report and Verification Statement that document its findings. At a minimum, the Verification Report should include the following elements:

- The scope, objectives, criteria, and level of assurance of the verification process undertaken and description of the verification plan employed;
- The standard used to verify emissions (this is The Registry's GRP, but may also include other protocols or methodologies for those sources for which The Registry has yet to provide detailed guidance);
- A description of the verification activities, based on the size and complexity of the Member's operations;
- A list of facilities and emissions sources identified, including sources estimated using simplified methods not prescribed in the GRP;
- A description of the sampling plan as well as techniques and risk assessment methodologies employed for each source identified to be sampled;
- An evaluation of whether the annual GHG report is in compliance with the GRP;
- A comparison of the Member's overall emission estimates with the Verification Body's overall emission estimates;
- A list of misstatements, if any; and
- A Verification Statement that contains its overall findings, which the Member must sign and return to the Verification Body for submittal to The Registry.

The Verification Report is typically shared only between the Member and its the Verification Body. In some cases Registry personnel or Registry-authorized representatives may request to review the Verification Report. In these cases, the Verification Report will be treated as a confidential document. No part of it will be made available to the public or to any person or organization outside of The Registry and its authorized representatives.

The Verification Statement is an official documentation of the outcome of the verification activities. The Registry makes this document available to the public upon completion of the verification process. The standard format used for the Verification Statement is shown in Figure 19.3.

Exit Meeting with your Verification Body

The Verification Body must prepare a brief summary presentation of its verification findings and provide this presentation during an Exit Meeting with the Member. This meeting may be conducted in person, or via phone.

At a minimum, the goals of this meeting should be:

- The Member's acceptance of the Verification Report and Verification Statement
- The Member's authorization for the Verification Body to communicate its findings to The Registry via CRIS
- If the same Verification Body is under contract for verification activities in future years, the establishment of a schedule for the next year's verification activities
- In addition, the exchange of lessons learned about the verification process. Please also consider sharing these thoughts with The Registry to improve the verification process in the future.

19.9 Unverified Emission Reports

If the Verification Body determines theemission report is not verifiable due to material misstatements, the Member must correct the report and have it re-verified.

The Registry will retain a Member's unverified emission report in The Registry database for up to one year pending correction and re-verification. Upon completion of a successful re-verification, The Registry will formally accept the revised report into CRIS.

Dispute Resolution Process

There may be instances where a Member and its Verification Body cannot agree on the findings expressed in the Verification Report or Verification Statement. In such instances, the Member should attempt to reach a resolution with the Verification Body, relying first on the Verification Body's internal dispute resolution process. In the event that the Member cannot reach a resolution, either party can initiate a dispute resolution process by submitting a request to the Accreditation Body. Additionally, Members or Verification Bodies may e-mail The Registry directly (verification@theclimateregistry.org) if they have any questions regarding resolving disputes.

The Accreditation Body will review the dispute and reach a unanimous, binding decision concerning verifiability. In doing so it may interview the Member and the Verification Body and/or request documentation related to the dispute. The Accreditation Body will notify the Member and the Verification Body of its decision.

In the event that the Accreditation Body overturns the Verification Body's original Verification Statement, the reasons for this finding will be discussed with the Member and the Verification Body. If, at the conclusion of this discussion, the Verification Body indicates that it is in agreement with the Accreditation Body, it will be provided with an opportunity to issue a new Verification Statement reversing the original Verification Statement.

The decision to issue a new Verification Statement is up to the Verification Body. If for any reason the Verification Body chooses not to issue a new Verification Statement, the Accreditation Body will complete the "Dispute Resolution" addendum to the Verification Statement, indicating that the original finding of the Verification Body has been overturned upon review by the Accreditation Body.

Verification Bodies are free to disagree with the findings of the Accreditation Body, and will not be instructed or in any way pressured to issue a new Verification Statement. The purpose of the above-outlined procedure is merely to provide a Verification Body with an opportunity to revise its Verification Statement during the dispute resolution process if, on the basis of the evidence and reasons cited by the Accreditation Body, the Verification Body changes its original judgment and wishes to issue a new judgment. However, while the Verification Body (or the Member) is free to disagree with the findings of the Accreditation Body, those findings are nonetheless binding on both parties once the dispute resolution process has been completed.

In the event that the Accreditation Body finds that the original Verification Statement was correct, they will complete the "Dispute Resolution" addendum to the Verification Statement to indicate that the original Verification Statement has been upheld upon review by the Accreditation Body.

Errors Discovered After the Completion of Verification

In some cases, errors in an emission report may be discovered after the completion of the verification process, either by the Member, the Verification Body, The Registry, or another party (e.g., a user of the data).

If such errors result in a cumulative change in total reported emissions of less than five percent, The Registry encourages Members to correct the error. However, if the reporting errors cause a material misstatement of more than five percent, The Registry requires Members to correct the error and re-verify the emission report.

If The Registry determines that a material misstatement exists in a Member's previously verified emission report, The Registry will change the verification status of the emission report to "unverified," and will notify the Member of the change in status. The Registry provides Members with one year to correct the report and have the report re-verified (either by the original Verification Body or a new Verification Body).

Members must successfully complete the re-verification process within a year to remain an active Member in The Registry. Upon completion of a successful re-verification, The Registry will formally accept the revised emission report into CRIS.

Verification Deadline Reminder

The deadline for verifying your emissions is December 15th of the year following your emissions year.

Figure 19.3. Verification Statement

The Climate Registry

Name of Verification Body: [Verification Body]

This Verification Statement documents that [Verification Body] has conducted verification activities in compliance with ISO 14064-3 and The Registry's General Verification Protocol. This statement also attests to the fact that [Verification Body] [provides/cannot provide reasonable/limited assurance that] OR [was unable to obtain sufficient evidence to verify whether] [Member] reported greenhouse gas emissions from January 1, [Year] through December 31, [Year] [are verifiable and] meet the requirements of The Climate Registry's voluntary program.

Reporting Classification: ☐ Transitional ☐ Complete ☐ Historical

Type of Verification: ☐ Batch ☐ Streamlined ☐ Full

GHG Reporting Protocols against which Verification was Conducted:

☐ The Climate Registry's *General Reporting Protocol Version [1.1 / 2.0]*, dated [Month Year]

☐ The Climate Registry's GRP Updates and Clarifications document dated [Month Day, Year]

☐ Others (specify): _____

GHG Verification Protocols used to Conduct the Verification:

☐ The Climate Registry's *General Verification Protocol Version* 2.0, dated June 2010

☐ The Climate Registry's GVP Updates and Clarifications document dated [Month Day, Year]

☐ Others (specify): _____

Member's Organizational Boundaries:

☐ Control Only: (☐ Financial **or** ☐ Operational)

☐ Equity Share and Control (☐ Financial **or** ☐ Operational)

Scope of Verification:

☐ Transitional or Historical, specify operational boundary:_____; GHGs (specify): _____

☐ North American ☐ Worldwide (including North America) ☐ Worldwide (non-North America)

Total Entity-Wide Emissions Verified (Control Criteria):

Total Scope 1 Emissions: _____ tonnes CO_2e, consisting of tonnes of each GHG as follows:

_____ CO_2 _____ CH_4 _____ N_2O _____ HFCs (CO_2e) _____ PFCs (CO_2e) _____ SF_6

Total Scope 2 Emissions: _____ tonnes CO_2e, consisting of tonnes of each GHG as follows:

_____ CO_2 _____ CH_4 _____ N_2O

Biogenic CO_2 (stationary & mobile combustion only): _____ tonnes CO_2

Total Entity-Wide Emissions Verified (Equity Share Criteria, if applicable):

Total Scope 1 Emissions: _____ tonnes CO_2e, consisting of tonnes of each GHG as follows:

_____ CO_2 _____ CH_4 _____ N_2O _____ HFCs (CO_2e) _____ PFCs (CO_2e) _____ SF_6

Total Scope 2 Emissions: _____ tonnes CO_2e, consisting of tonnes of each GHG as follows:

_____ CO_2 _____ CH_4 _____ N_2O

Biogenic CO_2 (stationary & mobile combustion only): _____ tonnes CO_2

Verification Statement:

☐ Verified

☐ Unable to verify conformance (include reason, e.g., "unable to obtain sufficient evidence", "due to data errors" or "due to non-compliance with The Registry's reporting requirements): _____

Comment: _____

Attestation:

[Insert Name], Lead Verifier	Date	☐ Digital Signature Acknowledgement*
[Insert Name], Independent Peer Reviewer	Date	☐ Digital Signature Acknowledgement*

Authorization:

I [Name of Member Representative] accept the findings in this Verification Statement and authorize the submission of this Verification Statement to The Climate Registry on behalf of [Name of Member].

Member Representative Signature	Date	☐ Digital Signature Acknowledgement*

*For digital signature: By checking the "Digital Signature Acknowledgement" box, I agree that this Verification Statement shall be deemed to be "in writing" and to have been "signed" for all purposes and that any electronic record will be deemed to be in "writing." I will not contest the legally binding nature, validity, or enforceability of this Verification Statement and any corresponding documents based on the fact that they were entered and executed electronically, and expressly waive any and all rights I may have to assert any such claim.

Chapter 20: Public Emission Reports

20.1 Required Public Disclosure

Verified annual emission reports are accessible to the public through The Registry's website. These reports describe Member's annual emissions and serve as useful tools for various stakeholders, such as shareholders, regulators, non-governmental organizations, and the general public, to better understand Registry Members' GHG emissions (and reductions).

The Registry requires Climate Registered Members to disclose GHG emission reports to the public. Specifically, The Registry requires that the following information be disclosed annually to the public for each Member:

- **Entity-level emissions, by gas and emissions category**
- **Facility-level emissions, by gas and emissions category** (if reporting at the facility-level)

Stakeholders can query CRIS via The Registry's website to access public emission reports for each Member with verified emissions data. A Member's public annual entity emission report contains the following information:

- Direct emissions of each GHG by source type (stationary combustion, mobile combustion, process, and fugitive emissions) with CO_2 emissions from biomass combustion reported separately
- Indirect emissions of each GHG (scope 2)
- Consolidation approach employed
- Base year (if applicable) and description of any structural changes in the reporting entity (mergers, acquisitions, divestitures, etc.)
- Information on parent companies for reporting entities that are subsidiaries
- Information about a Member's third-party Verification Body
- Indication of historical, transitional or imported data when applicable
- Optional data, if provided (performance metrics, GHG reduction goals, etc.)

A Member's facility-level emission report will include the same information listed above, for each facility.

In addition, the public may query CRIS to produce emission reports that describe emissions data:

- By geographic area, including worldwide (*optional*), North America, and non-North America
- Over multiple years

20.2 Confidential Business Information

If the release of facility-level emissions data will jeopardize an entity's confidential business information (CBI), then the Member may apply to The Registry for an exemption from this reporting requirement. Members submitting the Public Disclosure Exemption Request Form are still required to conform to The Registry's facility-level reporting requirements in CRIS.

To do so, please download the Public Disclosure Exemption Request Form from The Registry's website: www.theclimateregistry.org, and email the completed form to The Registry at help@theclimateregistry.org.

All Members that submit the Public Disclosure Exemption Request Form for reasons of CBI will be granted an exemption unless their form is incomplete.

The Registry will honor any CBI classification granted by a regulatory agency. However, the Member must communicate such classification to The Registry on the Public Disclosure Exemption Request Form.

Once a complete Public Disclosure Exemption Request Form is submitted, all future inventory reports for that Member will display only entity-level emissions by gas and emission category.

The Registry will review exemption requests within 14 business days of their submittal. Members will be notified by email regarding the status of the exemption request and instructions for how to proceed with emission reporting in CRIS.

Members interested in reporting entity-level information only in CRIS can take advantage of The Registry's entity-level reporting option. See Chapter 6 for more information on entity-level reporting.

Members with questions regarding the public release of data, should contact The Registry at 1-866-523-0764 ext. 3 or help@theclimateregistry.org.

GLOSSARY OF TERMS

Activity Data	Data on the magnitude of a human activity resulting in emissions or reductions taking place during a given period of time. Data on energy use, miles traveled, input material flow, and product output are all examples of activity data that might be used to compute GHG emissions.
Base Year	A benchmark against which an entity's emissions are compared over time.
Base Year Emissions	GHG emissions in the base year.
Biofuel	Fuel made from biomass, including wood and wood waste, sulphite lyes (black liquor), vegetal waste (straw, hay, grass, leaves, roots, bark, crops), animal materials/waste (fish and food meal, manure, sewage sludge, fat, oil and tallow), turpentine, charcoal, landfill gas, sludge gas, and other biogas, bioethanol, biomethanol, bioETBE, bioMTBE, biodiesel, biodimethylether, fischer tropsch, bio oil, and all other liquid biofuels which are added to, blended with, or used straight as transportation diesel fuel. Biomass also includes the plant or animal fraction of flotsam from water body management, mixed residues from food and beverage production, composites containing wood, textile wastes, paper, cardboard and pasteboard, municipal and industrial waste, and processed municipal and industrial wastes.
Biogenic Emissions	Carbon dioxide (CO_2) generated during the combustion or decomposition of biologically-based material. The Registry requires that CO_2 resulting from the combustion of biofuels be reported as part of a complete inventory.
Biomass	Non-fossilized and biodegradable organic material originating from plants, animals, and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.
Boundaries	GHG accounting and reporting boundaries can have several dimensions, i.e., organizational, operational and geographic. These boundaries determine which emissions are accounted for and reported by the entity.
Calculation-Based	Any of various emission quantification methodologies that involve the calculation of emissions based on emission factors and activity data such as input material flow, fuel consumption, or product output.
Capital Lease	A lease which transfers substantially all the risks and rewards of ownership to the lessee and is accounted for as an asset on the balance sheet of the lessee. Also known as a finance lease or financial lease. Leases other than capital or finance leases are operating leases. Consult an accountant for further detail as definitions of lease types differ between various accepted financial standards.
Climate Registered	Registry Membership option that involves a publicly reported and verified inventory. Climate Registered Members can report transitionally or completely.
CO_2e	The universal unit for comparing emissions of different GHGs expressed in terms of the GWP of one unit of carbon dioxide.

Cogeneration	An energy conversion process in which more than one useful product (e.g., electricity and heat or steam) is generated from the same energy input stream. Also referred to as combined heat and power (CHP).
Combined Heat and Power	(CHP) Same as cogeneration.

Commercial Buildings	Office-based or retail facilities that do not conduct industrial operations and for which emission sources are limited to:
	• Purchased or acquired electricity, heating or cooling
	• Stationary combustion of fuel for building heating
	    o Refrigerants for building and vehicle air conditioning;
	    o Standard fire extinguishers (as opposed to more complex PFC systems);
	    o Non-commercial refrigeration;
	    o Commercial refrigeration operations when an organization centrally manages refrigerant stocks
	    o Emergency generators; and,
	    o Automobiles and on-road trucks
	• Off-road equipment limited to building and landscape maintenance.
	
	The Registry will consider allowing the aggregation of non-commercial facilities where non-commercial activities are sufficiently small on a case-by-case basis. Members and Verification Bodies may contact The Registry at help@theclimateregistry.org to propose a special case.

Complete Inventory	Includes all Kyoto-defined GHG emissions (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, NF_3), except where exclusion of miniscule sources is disclosed, from a Member's operations in Canadian provinces and territories, Mexican states, and U.S. states and dependent areas.
Continuous Emission Monitoring System	(CEMS) Monitors installed in energy and industrial operations to continuously collect, record, and report emissions data.
Control Approach	An emissions accounting approach for defining organizational boundaries in which an entity reports 100 percent of the GHG emissions from operations under its financial or operational control.
Direct Emissions	Emissions from sources within the reporting entity's organizational boundaries that are owned or controlled by the reporting entity, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions.
Emission Factor	GHG emissions expressed on a per unit activity basis (for example, metric tons of CO_2 emitted per million Btus of coal combusted, or metric tons of CO_2 emitted per kWh of electricity consumed).
Emissions Year	The calendar year in which the emissions occurred.
Entity	Any business, corporation, institution, organization, government agency, etc., recognized under U.S., Canadian, or Mexican law. A reporting entity is comprised of all the facilities and emission sources delimited by the organizational boundary developed by the entity, taken in their entirety.

Equity Share Approach	An emissions accounting approach for defining organizational boundaries in which an entity accounts for GHG emissions from each operation according to its share of economic interest in the operation, which is the extent of rights an entity has to the risks and rewards flowing from an operation.
Facility	Any installation or establishment located on a single site or on contiguous or adjacent sites in actual physical contact or separated solely by a public roadway or other public right-of way that are owned or operated by an entity. A facility includes not only all of the stationary installations and equipment located at the site, but all mobile equipment that is under the control of the reporting entity and operates exclusively on a particular facility's premises. Examples of such site-specific mobile equipment include forklifts, front-end loaders, off-road trucks, mobile cranes, etc. Mobile sources that beyond the confines of a single facility (e.g., automobiles and on-road trucks), may also be reported as part of a facility. Pipelines, pipeline systems, and electricity transmission and distribution systems are considered discrete facilities for reporting purposes.
Finance Lease	Same as capital lease.
Financial Control	The ability to direct the financial and operating policies of an operation with an interest in gaining economic benefits from its activities. Financial control is one of two ways to define the control approach.
Fugitive Emissions	Intentional or unintentional releases from the production, processing, transmission, storage, and use of fuels and other substances, that do not pass through a stack, chimney, vent, exhaust pipe or other functionally-equivalent opening (such as releases of sulfur hexafluoride from electrical equipment; hydrofluorocarbon releases during the use of refrigeration and air conditioning equipment; landfill gas emissions; and methane leakage from natural gas transport).
Full Verification	A comprehensive assessment of an emissions report including its conformance with Registry requirements, confirmation of emission sources and GHGs, review of management policies and systems, and the sampling of data to evaluate calculation and reporting errors. This assessment must include site visits to a sample of facilities in accordance with the methodologies set forth in the General Verification Protocol. Full verifications are required in Years 1 and 4 of The Registry's 6-year verification cycle.
Geographic Boundary	The physical boundary within which emissions are included in an inventory. This is generally defined as a sub-national or national boundary. The Registry requires that complete inventories include all emissions occurring within North America. Members may elect to report worldwide emissions.
Global Warming Potential	(GWP) The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of carbon dioxide (CO_2).
Greenhouse Gases	(GHG) For the purposes of The Registry, GHGs are the internationally recognized gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6) and nitrogen trifluoride (NF_3).

Historical Emissions	Data that has been previously calculated and verified to another standard (e.g. EPA Climate Leaders, Carbon Disclosure Project, ICLEI), but may not meet The Registry's reporting and verification requirements. Historical data must consist of calendar-year data with transparently defined inventory boundaries that has been third-party verified.
Hydrofluorocarbons	(HFC) A group of manmade chemicals with various commercial uses (e.g., refrigerants) composed of one or two carbon atoms and varying numbers of hydrogen and fluorine atoms. Most HFCs are highly potent GHGs with 100-year GWPs in the thousands.
Indirect Emissions	Emissions that are a consequence of activities that take place within the organizational boundaries of the reporting entity, but that occur at sources owned or controlled by another entity. For example, emissions of electricity used by a manufacturing entity that occur at a power plant represent the manufacturer's indirect emissions.
Industry Best Practice	Calculation and measurement methodologies or factors that are documented and have been through a reasonable peer review process conducted by industry experts.
Insourcing	The administration of ancillary business activities, formally performed outside of the company, using resources within a company.
Intergovernmental Panel on Climate Change	(IPCC) International body of climate change scientists. The role of the IPCC is to assess the scientific, technical and socio-economic information relevant to the understanding of the risk of human-induced climate change (www.ipcc.ch).
Inventory	A comprehensive, quantified list of an organization's GHG emissions and sources.
Inventory Boundary	An imaginary line that encompasses the direct and indirect emissions included in the inventory. It results from the chosen organizational and operational boundaries.
Inventory Report	The summary of emissions information reported as part of an inventory.
Measurement-Based	Any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.
Member	An entity that submits an emissions inventory based on the requirements in the General Reporting Protocol to The Registry.

Miniscule Sources	Emissions sources listed on The Registry's *Exclusion of Miniscule Sources Form* which The Registry has deemed may be excluded from an inventory without: • Compromising the relevance of the reported inventory; • Significantly reducing the combined quantity of scope 1, scope 2, and biogenic CO_2e emissions reported; • Impacting ability to identify the Member's viable opportunities for emissions reductions projects; • Impacting the ability to ascertain whether the Member has achieved a reduction (of five percent or greater) in total entity emissions from one year to the next; • Impacting ability to assess the Member's climate change related risk exposure; or, • Impacting the decision-making needs of users.
Mobile Emissions	Emissions from the combustion of fuels and refrigerant leaks in transportation sources (e.g., cars, trucks, buses, trains, airplanes, and marine vessels), emissions from non-road equipment such as equipment used in construction, agriculture, and forestry and other mobile sources.
Mobile Source	Emissions sources designed and capable of emitting GHGs while moving from one location to another. An emissions source is not a mobile source if it is a piece of equipment that is designed and capable of being moved from one location to another but does not combust fuel while it is being moved (e.g., an emergency generator).
Nitrogen Trifluoride	NF3 is used as a replacement for PFCs (mostly C_2F_6) and SF_6 in the electronics industry. It is typically used in plasma etching and chamber cleaning during the manufacture of semi-conductors and LCD panels (Liquid Crystal Display). NF3 is broken down into nitrogen and fluorine gases in situ, and the resulting fluorine radicals are the active cleaning agents that attack the poly-silicon. NF3 is also used in the photovoltaic industry (thin-film solar cells) for "texturing, phosphorus silicate glass (PSG) removal, edge isolation and reactor cleaning after deposition of silicon nitrate or film silicon." NF3 is further used in hydrogen fluoride and deuterium fluoride lasers, which are types of chemical lasers.
Non-Commercial Buildings	Stationary facilities that have significant stationary combustion, fugitive or process emission sources such as industrial facilities, manufacturing facilities, mills and power plants.
Offsets	Offsets represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for (i.e., offset) GHG emissions occurring elsewhere.
Operating Lease	A lease which does not transfer the risks and rewards of ownership to the lessee and is not recorded as an asset in the balance sheet of the lessee. Leases other than operating leases are capital, finance, or financial leases. Consult an accountant for further detail as definitions of lease types differ between various accepted financial standards.
Operational Boundaries	The boundaries that determine the direct and indirect emissions associated with operations within the Member's organizational boundaries.

Operational Control	Full authority to introduce and implement operating policies at an operation. Operational control is one of two ways to define the control approach.
Organic Growth (or Decline)	Increases or decreases in GHG emissions as a result of changes in production output, product mix, plant closures, and the opening of new plants.
Organizational Boundaries	The boundaries that determine the operations owned or controlled by the reporting entity, depending on the consolidation approach taken (either the equity share or control approach).
Outsourcing	The contracting out of activities to other businesses.
Perfluorocarbons	(PFC) A group of man-made chemicals composed of one or two carbon atoms and four to six fluorine atoms, containing no chlorine. PFCs have no commercial uses and are emitted as a byproduct of aluminum smelting and semiconductor manufacturing. PFCs have very high GWPs and are very long-lived in the atmosphere.
Process Emissions	Emissions resulting from physical or chemical processes other than from fuel combustion. Examples include emissions from manufacturing cement, aluminum, adipic acid, ammonia, etc.
Renewable Energy Certificate (REC)	Represents the property rights to the environmental, social and other non-power qualities of renewable electricity generation.
Scope 1 Emissions	All direct GHG emissions, with the exception of direct CO_2 emissions from biogenic sources.
Scope 2 Emissions	Indirect GHG emissions associated with the consumption of purchased or acquired electricity, heating, cooling, or steam.
Scope 3 Emissions	All indirect emissions not covered in Scope 2. Examples include upstream and downstream emissions, emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity, use of sold products and services, outsourced activities, recycling of used products, waste disposal, etc.
Simplified Estimation Methods	Rough, upper-bound methods for estimating emissions. Approved methodologies in the GRP that are not found in Part III, Appendix D or annexes of the GRP or those that meet The Registry's definition of Industry Best Practices are not Simplified Estimation Methods (SEMs). SEMs may be used to calculate emissions from one or more sources, for one or more gases, that, when aggregated, equal no more than five percent of the sum of an entity's scope 1, scope 2 and biogenic emissions from stationary combustion, as determined on a CO_2e basis. SEMs include Registry-approved calculations where non-accepted activity data is used as an input. Where emission sources are small enough to be included within the five percent SEMs threshold, Members may elect to use non-registry approved methods that are more accurate than the simplified upper bounds methods generally used to estimate very small sources without submitting a Member Derived Methodology Form, as long as the emissions are designated as SEMs.

Stationary Combustion Emissions	Emissions from the combustion of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.
Stationary Source	An emissions source that is confined to a distinct geographic location and is not designed to operate while in motion.
Streamlined Verification	Verification services provided in interim years between full verifications. The Verification Body must perform the minimum set of activities that will allow it to conduct a risk-based assessment of materiality and to attain reasonable assurance in the findings presented in its Verification Statement. The minimum required activities include the risk-based assessment and the verification of emission estimates against the verification criteria.
Structural Change	A change in the organizational or operational boundaries of a company that result from a transfer of ownership or control of emissions from one company to another. Structural changes usually result from a transfer of ownership of emissions, such as mergers, acquisitions, divestitures, but can also include insourcing and outsourcing.
Submitting Year	The year in which you are submitting your emission report. For example, when submitting a report in 2015 for emissions that occurred in 2014, your submitting year would be 2015. The submitting year is always the year following the reporting year.
Transitional Inventory	The reporting boundary of a transitional inventory is self-defined by the Member based on the following parameters: • Scopes • Gases • Activity Types (stationary combustion, etc.) • Geographic/operational boundaries (country, state, business units, facility, etc.) The transitional reporting option is available only during a Member's first five emissions years, after which time a waiver is required to continue to report on a transitional basis. The waiver must set a target date for complete reporting, provide justification for the requested extension, identifies the steps being taken to achieve a complete inventory (such as an inventory management plan) and identify any obstacles or limitations prohibiting you from reporting completely to The Registry after five years.
Verification	The process used to ensure that a given Member's greenhouse gas emissions inventory has met a minimum quality standard and complied with The Registry's procedures and protocols for calculating and reporting GHG emissions.

Appendix A: Managing Inventory Quality

Note: The guidance in this appendix is taken directly from the WRI/WBCSD *GHG Protocol Corporate Standard* (Revised Edition), Chapter 7.

A corporate GHG inventory program includes all institutional, managerial, and technical arrangements made for the collection of data, preparation of the inventory, and implementation of steps to manage the quality of the inventory. The guidance in this appendix is intended to help companies develop and implement a quality management system for their inventory.

Given an uncertain future, high quality information will have greater value and more uses, while low quality information may have little or no value or use and may even incur penalties. For example, a company may currently be focusing on a voluntary GHG program but also want its inventory data to meet the anticipated requirements of a future when emissions may have monetary value. A quality management system is essential to ensuring that an inventory continues to meet the principles of the *GHG Protocol Corporate Standard* and anticipates the requirements of potential future GHG emissions programs.

Even if a company is not anticipating a future regulatory mechanism, internal and external stakeholders will demand high quality inventory information. Therefore, the implementation of some type of quality management system is important. However, the *GHG Protocol Corporate Standard* recognizes that companies do not have unlimited resources, and, unlike financial accounting, corporate GHG inventories involve a level of scientific and engineering complexity. Therefore, companies should develop their inventory program and quality management system as a cumulative effort in keeping with their resources, the broader evolution of policy, and their own corporate vision.

A quality management system provides a systematic process for preventing and correcting errors, and identifies areas where investments will likely lead to the greatest improvement in overall inventory quality. However, the primary objective of quality management is ensuring the credibility of a company's GHG inventory information. The first step towards achieving this objective is defining inventory quality.

Defining Inventory Quality

The *GHG Protocol Corporate Standard* outlines five accounting principles that set an implicit standard for the faithful representation of a company's GHG emission through its technical, accounting, and reporting efforts (Chapter 1). Putting these principles into practice will result in a credible and unbiased treatment and presentation of issues and data. For a company to follow these principles, quality management needs to be an integral part of its corporate inventory program. The goal of a quality management system is to ensure that these principles are put into practice.

An Inventory Program Framework

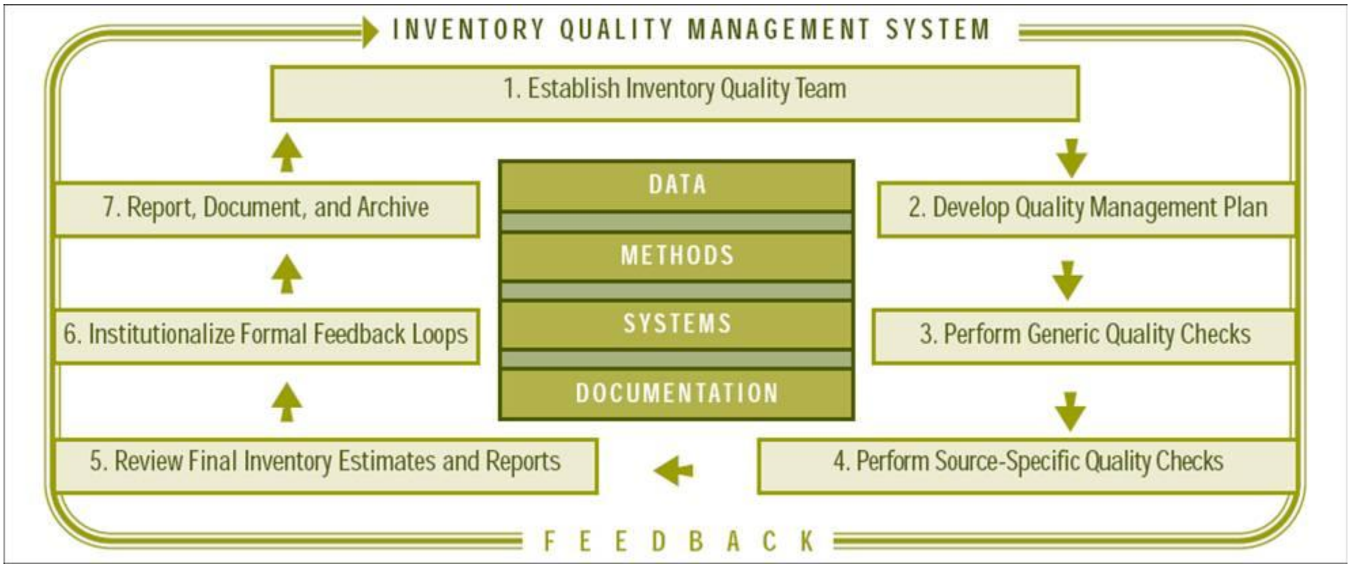
A practical framework is needed to help companies conceptualize and design an integrated corporate inventory program and quality management system and to help plan for future improvements (Figure A.1). This framework focuses on the following institutional, managerial, and technical components of an inventory:

Methods: These are the technical aspects of inventory preparation. Companies should select or develop methodologies for estimating emissions that accurately represent the characteristics of their source categories. The *GHG Protocol* provides many default methods and calculation tools to help with this effort. The design of an inventory program and quality management system should provide for the selection, application, and updating of inventory methodologies as new research becomes available, changes are made to business operations, or the importance of inventory reporting is elevated.

Data: This is the basic information on activity levels, emission factors, processes, and operations. Although methodologies need to be appropriately rigorous and detailed, data quality is more important. No methodology can compensate for poor quality input data. The design of a corporate inventory program should facilitate the collection of high quality inventory data and the maintenance and improvement of collection procedures.

Inventory processes and systems: These are the institutional, managerial, and technical procedures for preparing GHG inventories. They include the team and processes charged with the goal of producing a high quality inventory. To streamline GHG inventory quality management, these processes and systems may be integrated, where appropriate, with other corporate processes related to quality.

Figure A.1. Inventory Quality Management System



Documentation: This is the record of methods, data, processes, systems, assumptions, and estimates used to prepare an inventory. It includes everything employees need to prepare and improve a company's inventory. Since estimating GHG emissions is inherently technical (involving engineering and science), high quality, transparent documentation is particularly important to credibility. If information is not credible, or fails to be effectively communicated to either internal or external stakeholders, it will not have value.

Companies should seek to ensure the quality of these components at every level of their inventory design.

Implementing an Inventory Quality Management System

A quality management system for a company's inventory program should address all four of the inventory components described above. To implement the system, a company should take the following steps:

1. *Establish an inventory quality team. This team should be responsible for the company's GHG inventory program, implementing a quality management system, and continually improving inventory quality.* This team or manager should coordinate interactions between relevant business units, facilities and external entities such as government agency programs, research institutions, verifiers, or consulting firms.

2. *Develop a quality management plan.* This plan describes the steps a company is taking to implement its quality management system, which should be incorporated into the design of its inventory program from the beginning, although further rigor and coverage of certain procedures may be phased in over multiple years. The plan should include procedures for all organizational levels and inventory development processes—from initial data collection to final reporting of accounts. For efficiency and comprehensiveness, companies should integrate (and extend as appropriate) existing quality systems to cover GHG management and reporting, such as any ISO procedures. To ensure accuracy, the bulk of the plan should focus on practical measures for implementing the quality management system, as described in steps three and four.

3. *Perform generic quality checks*. These apply to data and processes across the entire inventory, focusing on appropriately rigorous quality checks on data handling, documentation, and emission calculation activities (e.g., ensuring that correct unit conversions are used). Guidance on quality checking procedures is provided in the section on implementation below.

4. *Perform source-category-specific quality checks*. This includes more rigorous investigations into the appropriate application of boundaries, adjustment procedures, and adherence to accounting and reporting principles for specific source categories, as well as the quality of the data input used (e.g., whether electricity bills or meter readings are the best source of consumption data) and a qualitative description of the major causes of uncertainty in the data. The information from these investigations can also be used to support a quantitative assessment of uncertainty. Guidance on these investigations is provided in the section on implementation below.

5. *Review final inventory estimates and reports.* After the inventory is completed, an internal technical review should focus on its engineering, scientific, and other technical aspects. Subsequently, an internal managerial review should focus on securing official corporate approval of and support for the inventory.

6. *Institutionalize formal feedback loops*. The results of the reviews in step five, as well as the results of every other component of a company's quality management system, should be fed back via formal feedback procedures to the person or team identified in step one. Errors should be corrected and improvements implemented based on this feedback.

7. *Establish reporting, documentation, and archiving procedures*. The system should contain record keeping procedures that specify what information will be documented for internal purposes, how that information should be archived, and what information is to be reported for external stakeholders. Like internal and external reviews, these record keeping procedures include formal feedback mechanisms.

A company's quality management system and overall inventory program should be treated as evolving, in keeping with a company's reasons for preparing an inventory. The plan should address the company's strategy for a multi-year implementation (i.e., recognize that inventories are a long-term effort), including steps to ensure that all quality control findings from previous years are adequately addressed.

Practical Measures for Implementation

Although principles and broad program design guidelines are important, any guidance on quality management would be incomplete without a discussion of practical inventory quality measures. A company should implement these measures at multiple levels within the company, from the point of primary data collection to the final corporate inventory approval process. It is important to implement these measures at points in the inventory program where errors are mostly likely to occur, such as the initial data collection phase and during calculation and data aggregation. While corporate-level inventory quality may initially be emphasized, it is important to ensure quality measures are implemented at all levels of disaggregation (e.g., facility, process, geographical, according to a particular scope, etc.) to be better prepared for possible GHG markets or regulatory rules in the future.

Companies also need to ensure the quality of their historical emission estimates and trend data. They can achieve time series consistency by employing inventory quality measures to minimize biases that can arise from changes in the characteristics of the data or methods used to calculate historical emission estimates and by following the standards and guidance of Chapter 7.

The third step of a quality management system, as described above, is to implement generic quality checking measures. These measures apply to all source categories and all levels of inventory preparation. Table A.1 provides a sample list of such measures.

The fourth step of a quality management system is source category-specific data quality investigations. The information gathered from these investigations can also be used for the quantitative and qualitative assessment of data uncertainty (see section on uncertainty). Addressed below are the types of source-specific quality measures that can be employed for emission factors, activity data, and emission estimates.

Emission Factors and Other Parameters. For a particular source category, emissions calculations will generally rely on emission factors and other parameters (e.g., utilization factors, oxidation rates, methane conversion factors). These factors and parameters may be published or default factors, based on company-specific data, site-specific data, or direct emission or other measurements. For fuel consumption, published emission factors based on fuel energy content are generally more accurate than those based on mass or volume, except when mass or volume based factors have been measured at the company- or site-specific level. Quality investigations need to assess the representativeness and applicability of emission factors and other parameters to the specific characteristics of a company. Differences between measured and default values need to be qualitatively explained and justified based upon the company's operational characteristics.

Activity Data. The collection of high quality activity data will often be the most significant limitation for corporate GHG inventories. Therefore, establishing robust data collection procedures needs to be a priority in the design of any company's inventory program. The following are useful measures for ensuring the quality of activity data:

- Develop data collection procedures that allow the same data to be efficiently collected in future years.
- Convert fuel consumption data to energy units before applying carbon content emission factors, which may be better correlated to a fuel's energy content than its mass.
- Compare current year data with historical trends. If data do not exhibit relatively consistent changes from year to year then the causes for these patterns should be investigated (e.g., changes of over 10 percent from year to year may warrant further investigation).
- Compare activity data from multiple reference sources (e.g., government survey data or data compiled by trade associations) with corporate data when possible. Such checks can ensure that consistent data is being reported to all parties. Data can also be compared among facilities within a company.
- Investigate activity data that is generated for purposes other than preparing a GHG inventory. In doing so, companies will need to check the applicability of this data to inventory purposes, including completeness, consistency with the source category definition, and consistency with the emission factors used. For example, data from different facilities may be examined for inconsistent measurement techniques, operating conditions, or technologies. Quality control measures (e.g., ISO) may have already been conducted during the data's original preparation. These measures can be integrated with the company's inventory quality management system.
- Check that base year adjustment procedures have been followed consistently and correctly (see Chapter 7).
- Check that operational and organizational boundary decisions have been applied correctly and consistently to the collection of activity data (see Chapters 4 and 5).
- Investigate whether biases or other characteristics that could affect data quality have been previously identified (e.g., by communicating with experts at a particular facility or elsewhere). For example, a bias could be the unintentional exclusion of operations at smaller facilities or data that do not correspond exactly with the company's organizational boundaries.
- Extend quality management measures to cover any additional data (sales, production, etc.) used to estimate emission intensities or other ratios.

Emission Estimates. Estimated emissions for a source category can be compared with historical data or other estimates to ensure they fall within a reasonable range. Potentially unreasonable estimates provide cause for checking emission factors or activity data and determining whether changes in methodology, market forces, or other events are sufficient reasons for the change. In situations where actual emission monitoring occurs (e.g., power plant CO_2 emissions), the data from monitors can be compared with calculated emissions using activity data and emission factors.

If any of the above emission factor, activity data, emission estimate, or other parameter checks indicate a problem, more detailed investigations into the accuracy of the data or appropriateness of the methods may be required. These more detailed investigations can also be utilized to better assess the quality of data. One potential measure of data quality is a quantitative and qualitative assessment of their uncertainty.

Inventory Quality and Inventory Uncertainty

Preparing a GHG inventory is inherently both an accounting and a scientific exercise. Most applications for company-level emissions and removal estimates require that these data be reported in a format similar to financial accounting data. In financial accounting, it is standard practice to report individual point estimates (i.e., single value versus a range of possible values). In contrast, the standard practice for most scientific studies of GHG and other emissions is to report quantitative data with estimated error bounds (i.e., uncertainty). Just like financial figures in a profit and loss or bank account statement, point estimates in a corporate emission inventory have obvious uses. However, how would or should the addition of some quantitative measure of uncertainty to an emission inventory be used?

In an ideal situation, in which a company had perfect quantitative information on the uncertainty of its emission estimates at all levels, the primary use of this information would almost certainly be comparative. Such comparisons might be made across companies, across business units, across source categories, or through time. In this situation, inventory estimates could even be rated or discounted based on their quality before they were used, with uncertainty being the objective quantitative metric for quality. Unfortunately, such objective uncertainty estimates rarely exist.

Types of Uncertainties. Uncertainties associated with GHG inventories can be broadly categorized into scientific uncertainty and estimation uncertainty. Scientific uncertainty arises when the science of the actual emission and/or removal process is not completely understood. For example, many direct and indirect factors associated with GWP values that are used to combine emission estimates for various GHGs involve significant scientific uncertainty. Analyzing and quantifying such scientific uncertainty is extremely problematic and is likely to be beyond the capacity of most company inventory programs.

Estimation uncertainty arises any time GHG emissions are quantified. Therefore all emissions or removal estimates are associated with estimation uncertainty. Estimation uncertainty can be further classified into two types: *model* uncertainty and *parameter* uncertainty.

Model uncertainty refers to the uncertainty associated with the mathematical equations (i.e., models) used to characterize the relationships between various parameters and emission processes. For example, model uncertainty may arise either due to the use of an incorrect mathematical model or inappropriate input into the model. As with scientific uncertainty, estimating model uncertainty is likely to be beyond most company's inventory efforts; however, some companies may wish to utilize their unique scientific and engineering expertise to evaluate the uncertainty in their emission estimation models.

Parameter uncertainty refers to the uncertainty associated with quantifying the parameters used as inputs (e.g., activity data and emission factors) into estimation models. Parameter uncertainties can be evaluated through statistical analysis, measurement equipment precision determinations, and expert judgment. Quantifying parameter uncertainties and then estimating source category uncertainties based on these parameter uncertainties will be the primary focus of companies that choose to investigate the uncertainty in their emission inventories.

Limitations of Uncertainty Estimates. Given that only parameter uncertainties are within the feasible scope of most companies, uncertainty estimates for corporate GHG inventories will, of necessity, be imperfect. Complete and robust sample data will not always be available to assess the statistical uncertainty in every parameter. For most parameters (e.g., liters of gasoline purchased or metric tons of limestone consumed), only a single data point may be available. In some cases, companies can utilize instrument precision or calibration information to inform their assessment of statistical uncertainty. However, to quantify some of the systematic uncertainties associated with parameters and to supplement statistical uncertainty estimates, companies will usually have to rely on expert judgment. The problem with expert judgment, though, is that it is difficult to obtain in a comparable (i.e., unbiased) and consistent manner across parameters, source categories, or companies.

For these reasons, almost all comprehensive estimates of uncertainty for GHG inventories will be not only imperfect but also have a *subjective* component and, despite the most thorough efforts, are themselves considered highly uncertain. In most cases, uncertainty estimates cannot be interpreted as an objective measure of quality. Nor can they be used to compare the quality of emission estimates between source categories or companies.

Exceptions to this include the following cases, in which it is assumed that either statistical or instrument precision data are available to objectively estimate each parameter's statistical uncertainty (i.e., expert judgment is not needed):

- When two operationally similar facilities use identical emission estimation methodologies, the differences in scientific or model uncertainties can, for the most part, be ignored. Then quantified estimates of statistical uncertainty can be treated as being comparable between facilities. This type of comparability is what is aimed for in some trading programs that prescribe specific monitoring, estimation, and measurement requirements. However, even in this situation, the degree of comparability depends on the flexibility that participants are given for estimating emissions, the homogeneity across facilities, as well as the level of enforcement and review of the methodologies used.

- Similarly, when a single facility uses the same estimation methodology each year, the systematic parameter uncertainties—in addition to scientific and model uncertainties—in a source's emission estimates for two years are, for the most part, identical. Because the systematic parameter uncertainties then cancel out, the uncertainty in an emission trend (e.g., the difference between the estimates for two years) is generally less than the uncertainty in total emissions for a single year. In such a situation, quantified uncertainty estimates can be treated as being comparable over time and used to track relative changes in the quality of a facility's emission estimates for that source category. Such estimates of uncertainty in emission trends can also be used as a guide to setting a facility's emissions reduction target. Trend uncertainty estimates are likely to be less useful for setting broader (e.g., company-wide) targets (see Chapter 11) because of the general problems with comparability between uncertainty estimates across gases, sources, and facilities.

Given these limitations, the role of qualitative and quantitative uncertainty assessments in developing GHG inventories include:

- Promoting a broader learning and quality feedback process.

- Supporting efforts to qualitatively understand and document the causes of uncertainty and help identify ways of improving inventory quality. For example, collecting the information needed to determine the statistical properties of activity data and emission factors forces one to ask hard questions and to carefully and systematically investigate data quality.

- Establishing lines of communication and feedback with data suppliers to identify specific opportunities to improve quality of the data and methods used.

- Providing valuable information to reviewers, verifiers, and managers for setting priorities for investments into improving data sources and methodologies.

The *GHG Protocol Corporate Standard* has developed a supplementary guidance document on uncertainty assessments ("Guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty") along with an uncertainty calculation tool, both of which are available on the GHG Protocol website. The guidance document describes how to use the calculation tool in aggregating uncertainties. It also discusses in more depth different types of uncertainties, the limitations of quantitative uncertainty assessment, and how uncertainty estimates should be properly interpreted.

Additional guidance and information on assessing uncertainty—including optional approaches to developing quantitative uncertainty estimates and eliciting judgments from experts—can also be found in EPA's *Procedures Manual for Quality Assurance/Quality Control and Uncertainty Analysis* and in Chapter 6 of the IPCC's *Good Practice Guidance*.

Table A.1. Generic Quality Checking Measures

Data Gathering, Input, and Handling Activities
✔ Check a sample of input data for transcription errors
✔ Identify spreadsheet modifications that could provide additional controls or checks on quality
✔ Ensure that adequate version control procedures for electronic files have been implemented
✔ Others
Data Documentation
✔ Confirm that bibliographical data references are included in spreadsheets for all primary data
✔ Check that copies of cited references have been archived
✔ Check that assumptions and criteria for selection of boundaries, base years, methods, activity data, emission factors, and other parameters are documented
✔ Check that changes in data or methodology are documented
✔ Others
Calculating Emissions and Checking Calculations
✔ Check whether emission units, parameters, and conversion factors are appropriately labeled
✔ Check if units are properly labeled and correctly carried through from beginning to end of
✔ Check that conversion factors are correct
✔ Check the data processing steps (e.g., equations) in the spreadsheets
✔ Check that spreadsheet input data and calculated data are clearly differentiated
✔ Check a representative sample of calculations, by hand or electronically
✔ Check some calculations with abbreviated calculations (i.e., back of the envelope checks)
✔ Check the aggregation of data across source categories, business units, etc.
✔ Check consistency of time series inputs and calculations
✔ Others

Inventory Management Plan Template

The Inventory Management Plan Template (IMP) will help you to coordinate and document the decisions you make about your organization's GHG inventory, which will enable you to keep all information in one place and track decisions and changes over time. Managing your inventory through an IMP will facilitate building your inventory in CRIS, provide an audit trail for your Verifier and create institutional memory within your organization.

This IMP is a template. Feel free to modify it to better meet your organization's inventory management needs. The italicized text in the sections below offers instruction and examples. Please delete this text as you complete the IMP.

Last updated:

Organizational Information
Organization:
Address:

Technical contact:
Phone number:
Email address:

Organization description:

Reporting Boundaries & Annual Summary of GHG Reporting
Record pertinent data about each reporting year in this at-a-glance table. For more information on each category, please see the associated chapter in the General Reporting Protocol (GRP).

Emissions Year (EY)	Reporter Type (GRP Ch. 8)	GHGs Reported (GRP Ch. 3)	Geographic Boundary (GRP Ch. 2)	Organizational Boundary (GRP Ch. 4)	Operational Boundary (GRP Ch. 5)	Total CO_2e Emissions
e.g. 2008	*Transitional*	*CO_2*	*North America*	*Operational control*	*Scope 1 & 2*	*400,000*

The Green Team
Identify staff members who are/were involved in the GHG reporting and inventory management process and provide their contact information.

Responsibility	Staff Member (name, phone number, and email address)
• **Manage GHG reporting**	
• **Collect emissions data**	
• **Internally review and certify CRIS report**	
• **Manage contracts with consultants or the verification body**	

Facilities and Associated Emissions
This section is designed to track all facilities and related pertinent information that fall within the organizational boundaries of your GHG inventory.

Facility	Address	Percent Ownership / Control	Emissions Scopes	Emissions Activities	Emissions Sources	Documentation
e.g. Mobile fleet	*100 N Spring St., Los Angeles, CA 90014*	*100%*	*Scope 1*	*Mobile combustion*	*Toyota Prius (x5)*	*Fuel bills & mileage records*

Emissions Management and Reporting Methodologies
This section details the systems and methodologies you used to develop your organization's GHG inventory. Pertinent information includes:

- *Rationale for chosen geographic, organizational & operational boundaries*
- *Methods for identifying GHG emissions sources & gathering data*
- *Registry protocols, methodologies, emissions factors & resources (e.g. CRIS) used to calculate GHG emissions*
- *NAICS codes*
- *Internal auditing procedures, including process, timeline and documentation of findings*
- *External auditing procedures, including process, timeline and documentation of findings*
- *Process for undergoing & implementing corrective action*
- *Systems & procedures used to track GHG emissions data (e.g. CRIS)*
- *Procedures for document management*
- *Integration of GHG data management with other management systems (i.e. ISO 14001: EMS, ISO 9001: QMS, etc.)*

Auditing
<u>Internal Auditing</u>
Describe quality assurance and internal auditing procedures, timelines, and documentation of findings.

<u>External Auditing</u>
Describe the external audit (i.e. third-party verification) process and timeline.

<u>Corrective Action</u>
Describe the process for implementing and documenting corrective action for all internal and external reviews.

<u>Record Keeping</u>
Review procedure for record keeping and document retention.

Additional Information

Other useful information includes:

- *Information on how you determined your organization's reporting boundaries*
- *Review of procedures for maintenance and calibration of measurement equipment (if applicable)*
- *Resources used for scope 3 calculation guidance*

Members reporting for two or more years should:

- *Track changes over time in emission quantification methodologies*
- *Divulge process for tracking structural changes (e.g. acquisitions, divestitures, outsourcing, etc.) and evaluating the necessity to update base year emissions*
- *Identify procedures for documenting updates to your base year emissions*

Appendix B: Global Warming Potentials

If you report emissions of non-CO_2 gases, CRIS will convert the mass estimates of these gases to a CO_2e basis. Converting emissions of non-CO_2 gases to units of CO_2e allows GHGs to be compared on a common basis, i.e., on the ability of each greenhouse gas to trap heat in the atmosphere. Global Warming Potential (GWP) factors represent the ratio of the heat-trapping ability of each GHG relative to that of carbon dioxide. For example, the GWP of methane is 21 because one metric ton of methane has 21 times more ability to trap heat in the atmosphere than one metric ton of carbon dioxide. To convert emissions of non-CO_2 gases to units of CO_2e, multiply the emissions of each gas in units of mass (e.g., metric tons) by the appropriate GWP factors in the following table.

Table B.1. Global Warming Potential Factors for Required Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Nitrogen trifluoride	NF_3		10,800*
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23 (R-23)	CHF_3	trifluoromethane	11,700
HFC-32 (R-32)	CH_2F_2	difluoromethane	650
HFC-41 (R-41)	CH_3F	fluoromethane	150
HFC-43-10mee (R-4310)	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125 (R-125)	C_2HF_5	pentafluoroethane	2,800
HFC-134 (R-134)	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a (R-134a)	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143 (R-143)	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a (R-143a)	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152 (R-152)	$C_2H_4F_2$	1,2-difluoroethane	43*
HFC-152a (R-152a)	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161 (R-161)	C_2H_5F	fluoroethane	12*
HFC-227ea (R-227ea)	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb (R-236cb)	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300*
HFC-236ea (R-236ea)	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200*
HFC-236fa (R-236fa)	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca (R-245ca)	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa (R-245fa)	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950*
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890*
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	c-C_4F_8	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report published in 1995, unless no value was assigned in the document. In that case, the GWP values are from the IPCC Third Assessment Report published in 2001 (those marked with *). GWP values are from the Second Assessment Report (unless otherwise noted) to be consistent with international practices. Values are 100-year GWP values.

Example Calculation	Convert 10 metric tons of HFC-134a to CO_2e	
10 **x**	1,300	**=** 13,000
(metric tons HFC-134a)	(GWP HFC-134a)	(metric tons CO_2e)

Note: Since the Second Assessment Report (SAR) was published in 1995, the Intergovernmental Panel on Climate Change (IPCC) has published updated GWP values in its Third Assessment Report (TAR) and Fourth Assessment Report (AR4) that reflect new information on atmospheric lifetimes of greenhouse gases and an improved calculation of the radiative forcing of CO_2. However, GWP values from the SAR are still used by international convention to maintain consistency in GHG reporting, including by the United States and Canada when reporting under the United Nations Framework Convention on Climate Change. TAR GWP values are often used for gases that were not reported in the SAR. To maintain consistency with international practices, The Registry requires participants to use the GWP values in Table B.1. If more recent GWP values are adopted as standard practice by the international community, The Registry will likewise update its GWP requirements to reflect international practices.

Table B.2. Global Warming Potentials of Refrigerant Blends

Refrigerant Blend	Global Warming Potential
R-401A	18
R-401B	15
R-401C	21
R-402A	1,680
R-402B	1,064
R-403A	1,400
R-403B	2,730
R-404A	3,260
R-407A	1,770
R-407B	2,285
R-407C	1,526
R-407D	1,428
R-407E	1,363
R-408A	1,944
R-410A	1,725
R-410B	1,833
R-411A	15
R-411B	4
R-412A	350
R-413A	1,774
R-415A	25
R-415B	105
R-416A	767
R-417A	1,955
R-418A	4
R-419A	2,403
R-420A	1,144
R-500	37
R-503	4,692
R-504	313
R-507 or R-507A	3,300
R-508A	10,175
R-508B	10,350
R-509 or R-509A	3,920

Source: ASHRAE Standard 34

Table B.3. Refrigerant Blends (Contain HFCs and PFCs)

Blend	Constituents	Composition (%)
R-405A	HCFC-22/HFC-152a/HCFC-142b/PFC-318	(45.0/7.0/5.5/42.5)
R-413A	PFC-218/HFC-134a/HC-600a	(9.0/88.0/3.0)
R-508A	HFC-23/PFC-116	(39.0/61.0)
R-508B	HFC-23/PFC-116	(46.0/54.0)

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Table 7.8, page 7.44.

Appendix C: Standard Conversion Factors

Table C.1. Conversion Factors

Mass			
1 pound (lb) =	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons (tonnes)
1 kilogram (kg) =	1,000 grams (g)	2.2046 pounds (lb)	0.001 metric tons (tonnes)
1 short ton (ton) =	2,000 pounds (lb)	907.18 kilograms (kg)	0.9072 metric tons (tonnes)
1 metric ton (tonne) =	2,204.62 pounds (lb)	1,000 kilograms (kg)	1.1023 short tons (tons)
Volume			
1 cubic foot (ft^3) =	7.4805 U.S. gallons (gal)	0.1781 barrels (bbl)	
1 cubic foot (ft^3) =	28.32 liters (L)	0.02832 cubic meters (m^3)	
1 U.S. gallon (gal) =	0.0238 barrels (bbl)	3.785 liters (L)	0.003785 cubic meters (m^3)
1 barrel (bbl) =	42 U.S. gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m^3)
1 liter (L) =	0.001 cubic meters (m^3)	0.2642 U.S. gallons (gal)	0.0063 barrels (bbl)
1 cubic meter (m^3) =	6.2897 barrels (bbl)	264.17 U.S. gallons (gal)	1,000 liters (L)
Energy			
1 kilowatt hour (kWh) =	3,412 Btu (Btu)	3,600 kilojoules (KJ)	
1 megajoule (MJ) =	0.001 gigajoules (GJ)		
1 gigajoule (GJ) =	0.9478 million Btu (MMBtu)	277.8 kilowatt hours (kWh)	
1 British thermal unit (Btu) =	1,055 joules (J)	1.055 kilojoules (KJ)	
1 million Btu (MMBtu) =	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm =	100,000 Btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)
Other			
kilo =	1,000		
mega =	1,000,000		
giga =	1,000,000,000		
tera =	1,000,000,000,000		
peta =	1,000,000,000,000,000		
1 mile =	1.609 kilometers		
1 metric ton carbon (C) =	$^{44}/_{12}$ metric tons CO_2		

Example Calculation	**Convert 1,000 lb C/kWh into metric tons CO_2 /GJ**			
1,000 **x**	277.8 **x**	0.0004536 **x**	44/12	**=** 462.04 metric tons CO_2/GJ
(lb C/kWh)	(kWh/GJ)	(metric tons/lb)	(CO_2/C)	

Appendix D: Direct Emissions from Sector-Specific Sources

Who should read Appendix D:

- Appendix D applies to Members that have direct process or fugitive emissions from industry-specific emission sources.

What you will find in Appendix D:

- Appendix D provides a framework for determining direct process or fugitive emissions from selected sector-specific sources. Each section in this chapter provides the methods, and default emission factors to be used for quantifying emissions for each source type.

Information you will need:

- To complete this chapter you will need information pertaining to the relevant industry-specific processes outlined in each section.

Cross-References:

See Part III: Chapters 12 to 16 for guidance on calculating emissions from sources that are not specific to your industry, such as stationary combustion, mobile combustion, electricity use, imported steam, and refrigeration systems.

Appendix D contains a framework for quantifying emissions from the following sources:

- Adipic acid production (Section D.1)
- Aluminum production (Section D.2)
- Ammonia production (Section D.3)
- Cement production (Section D.4)
- HCFC-22 production (Section D.5)
- Iron and steel production (Section D.6)
- Lime production (Section D.7)
- Nitric acid production (Section D.8)
- Pulp and paper production (Section D.9)
- Refrigeration and air condition equipment manufacturing (Section D.10)
- Semiconductor manufacturing (Section D.11).

D.1 Adipic Acid Production (N_2O Emissions)

Direct Process N_2O Emissions from Adipic Acid Production

Method	Emission Factors
Continuous emissions monitoring	n/a
Mass Balance	Plant-specific factors: • Measured destruction and utilization factors for an abatement technology • Measured N_2O emissions factor based on direct measurements
Mass Balance	Mix of default and plant-specific factors
Mass Balance	Default factors: • Default destruction and utilization factors for an abatement technology • Default N_2O emissions factor

Mass Balance Method

N_2O Emissions = (Adipic Acid Production x N_2O Emission Factor) x (1 - Destruction factor x Abatement system utilization factor)

Where:

			Units
N_2O emissions	=	N_2O emissions	metric tons
N_2O emission factor	=	N_2O emission factor by technology type	metric tons N_2O /metric ton adipic acid produced
N_2O destruction factor	=	Fraction of emissions abated by reduction technologies	
Abatement system utilization factor	=	Fraction of time the abatement system was in use	

Source: WRI/WBCSD, *Calculating N_2O Emissions from the Production of Adipic Acid*, 2001 (Consistent with IPCC 2006, Equation 3.8, N_2O Emissions from Adipic Acid Production, Tier 2)

Default Emission Factors

TABLE 3.4
DEFAULT FACTORS FOR ADIPIC ACID PRODUCTION

Production Process	N_2O Generation Factor[a,d]	Uncertainty Estimate
Nitric Acid Oxidation	300 kg/tonne adipic acid (uncontrolled)	± 10% (based on expert judgement). The range of 300 kg ± 10% encompasses the variability from pure ketone to pure alcohol feedstocks, with most manufacturers somewhere in the middle.[a]
Abatement Technology	**N_2O Destruction Factor[b]**	**Uncertainty Estimate**
Catalytic Destruction	92.5%	90-95% (based on expert judgement). Manufacturers known to employ this technology include: BASF (Scott, 1998), and DuPont (Reimer, 1999b).
Thermal Destruction	98.5%	98-99% (based on expert judgement). Manufacturers known to employ this technology include: Asahi, DuPont, Bayer, and Solutia (Scott, 1998).
Recycle to Nitric Acid	98.5%	98-99% (based on expert judgement). Manufacturers known to employ this technology include: Alsachemie (Scott, 1998).
Recycle to feedstock for Adipic Acid	94%	90-98% (based on expert judgement). Solutia implemented this technology around 2002.
Abatement System	**Utilisation Factor[d]**	**Uncertainty Estimate**
Catalytic Destruction	89%	80-98% (based on expert judgement)[c].
Thermal Destruction	97%	95-99% (based on expert judgement)[c].
Recycle to Nitric Acid	94%	90-98% (based on expert judgement)[c].
Recycle to Adipic Acid	89%	80-98% (based on expert judgement)[c].

Source: IPCC 2006

D.2 Aluminum Production (CO_2 and PFC Emissions)

Direct Process CO_2 Emissions from Aluminum Production

Method	Emission Factors
Process-Specific Mass Balance	Plant-specific factors • For each applicable parameter listed in IPCC Tables 4.11 – 4.14
Process-Specific Mass Balance	Default factors: • Industry-typical values in IPCC Tables 4.11 – 4.14 (Tier 2 column)

Process-Specific Mass Balance Method

CO_2 EMISSIONS FROM PREBAKED ANODE CONSUMPTION

$$E_{CO2} = NAC \bullet MP \bullet \frac{100 - S_a - Ash_a}{100} \bullet \frac{44}{12}$$

Where:			**Units**
E_{CO2}	=	CO_2 emissions from prebaked anode consumption	metric tons
MP	=	Total metal production	metric tons Al
NAC	=	Net prebaked anode consumption per metric ton of aluminum	metric tons C / metric ton Al
S_a	=	Sulfur content in baked anodes	wt %
Ash_a	=	Ash content in baked anodes	wt %
44/12	=	CO_2 molecular mass: carbon atomic mass ratio	

Source: IPCC 2006 Equations 4.21 – 4.24 (Tier 2/3 Methods)

CO_2 EMISSIONS FROM PITCH VOLATILES COMBUSTION

$$E_{CO2} = \left(GA - H_w - BA - WT\right) \bullet \frac{44}{12}$$

Where:			**Units**
E_{CO2}	=	CO_2 emissions from pitch volatiles combustion	metric tons
GA	=	Initial weight of green anodes	metric tons
H_w	=	Hydrogen content in green anodes	metric tons
BA	=	Baked anode production	metric tons
WT	=	Waste tar collected	metric tons
44/12	=	CO_2 molecular mass: carbon atomic mass ratio	

Source: IPCC 2006 Equations 4.21 – 4.24 (Tier 2/3 Methods)

CO_2 EMISSIONS FROM BAKE FURNACE PACKING MATERIAL

$$E_{CO2} = PCC \bullet BA \bullet \frac{100 - S_{pc} - Ash_{pc}}{100} \bullet \frac{44}{12}$$

Where:			**Units**
E_{CO2}	=	CO_2 emissions from bake furnace packing material	metric tons
PCC	=	Packing coke consumption	metric tons / metric ton BA
BA	=	Baked anode production	metric tons
S_{pc}	=	Sulfur content in packing coke	wt %
Ash_{pc}	=	Ash content in packing coke	wt %

Source: IPCC 2006 Equations 4.21 – 4.24 (Tier 2/3 Methods)

CO_2 EMISSIONS FROM PASTE CONSUMPTION (for Søderberg cells (VSS and HSS))

$$E_{CO2} = \left(PC \bullet MP - \frac{CSM \bullet MP}{1000} - \frac{BC}{100} \bullet PC \bullet MP \bullet \frac{S_p + Ash_p + H_p}{100} - \frac{100 - BC}{100} \bullet PC \bullet MP \bullet \frac{S_c + Ash_c}{100} - MP \bullet CD \right) \bullet \frac{44}{12}$$

Where:			**Units**
E_{CO2}	=	CO_2 emissions from paste consumption	metric tons
PC	=	Paste consumption	metric tons / metric ton Al
MP	=	Total metal production	metric tons Al
CSM	=	Emissions of cyclohexane soluble matter	kg/ metric ton Al
BC	=	Binder content in paste	wt %
S_p	=	Sulfur content in pitch	wt %
Ash_p	=	Ash content in pitch	wt %
H_p	=	Hydrogen content in pitch	wt %
S_c	=	Sulfur content in calcined coke	wt %
Ash_c	=	Ash content in calcined coke	wt %
CD	=	Carbon in skimmed dust from Søderberg cells	metric tons C/ metric ton Al
44/12	=	CO_2 molecular mass: carbon atomic mass ratio	

Source: IPCC 2006 Equations 4.21 – 4.24 (Tier 2/3 Methods)

Default Emission Factors

TABLE 4.11
DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM PREBAKE CELLS (CWPB AND SWPB), SEE EQUATION 4.21

Parameter	Tier 2 Method		Tier 3 Method	
	Data Source	Uncertainty (+/-%)	Data Source	Uncertainty (+/-%)
MP: total metal production (tonnes aluminium per year)	Individual facility records	2	Individual facility records	2
NAC: net anode consumption per tonne of aluminium (tonnes per tonne Al)	Individual facility records	5	Individual facility records	5
S_a: sulphur content in baked anodes (wt %)	Use industry typical value, 2	50	Individual facility records	10
Ash_a: ash content in baked anodes (wt %)	Use industry typical value, 0.4	85	Individual facility records	10

Source: IAI (2005b).

Source: IPCC 2006

TABLE 4.12 DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM PITCH VOLATILES COMBUSTION (CWPB AND SWPB), SEE EQUATION 4.22				
Parameter	**Tier 2 Method**		**Tier 3 Method**	
	Data Source	**Uncertainty (+/-%)**	**Data Source**	**Uncertainty (+/-%)**
GA: initial weight of green anodes processed (tonnes green anode per year)	Individual facility records	2	Individual facility records	2
H_w: Hydrogen content in green anodes (tonnes)	Use industry typical value, 0.005 • GA	50	Individual facility records	10
BA: Baked anode production (tonnes per year)	Individual facility records	2	Individual facility records	2
WT: Waste tar collected (tonnes) a) Riedhammer furnaces b) All other furnaces	Use industry typical value, a) 0.005 • GA b) insignificant	50	Individual facility records	20
Source: IAI (2005b).				

Source: IPCC 2006

TABLE 4.13 DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM BAKE FURNACE PACKING MATERIAL (CWPB AND SWPB), SEE EQUATION 4.23				
Parameter	**Tier 2 Method**		**Tier 3 Method**	
	Data Source	**Uncertainty (+/-%)**	**Data Source**	**Uncertainty (+/-%)**
PCC: Packing coke consumption (tonnes per tonne BA)	Use industry typical value, 0.015	25	Individual facility records	2
BA: Baked anode production (tonnes per year)	Individual facility records	2	Individual facility records	2
S_{pc}: Sulphur content in packing coke (wt %)	Use industry typical value, 2	50	Individual facility records	10
Ash_{pc}: Ash content in packing coke (wt %)	Use industry typical value, 2.5	95	Individual facility records	10
Source: IAI (2005b).				

Source: IPCC 2006

TABLE 4.14 DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM SØDERBERG CELLS (VSS AND HSS)				
Parameter	**Tier 2 Method**		**Tier 3 Method**	
	Data Source	**Data Uncertainty (+/-%)**	**Data Source**	**Data Uncertainty (+/-%)**
MP: total metal production (tonnes Al/year)	Individual facility records	2	Individual facility records	2
PC : paste consumption (tonnes per tonne Al)	Individual facility records	2-5	Individual facility records	2-5
CSM: emissions of cyclohexane soluble matter (kg per tonne Al)	Use industry typical value, HSS – 4.0 VSS – 0.5	30	Individual facility records	15
BC: binder content in paste (wt %)	Use industry typical value, Dry Paste – 24 Wet Paste – 27	25	Individual facility records	5
S_p: sulphur content in pitch (wt %)	Use industry typical value, 0.6	20	Individual facility records	10
Ash_p: ash content in pitch (wt %)	Use industry typical value, 0.2	20	Individual facility records	10
H_p: hydrogen content in pitch (wt %)	Use industry typical value, 3.3	50	Individual facility records	10
S_c: sulphur content in calcined coke (wt %)	Use industry typical value, 1.9	20	Individual facility records	10
Ash_c: ash content in calcined coke (wt %)	Use industry typical value, 0.2	50	Individual facility records	10
CD: carbon in dust from anode (tonnes of carbon in skim per tonne Al)	Use industry typical value, 0.01	99	Individual facility records	30

Source: IPCC 2006

Direct Process PFC Emissions from Aluminum Production

Method	Emission Factors
Slope method or Overvoltage method	Plant-specific factors • Plant-specific Slope or Overvoltage coefficients based on representative measurements • Plant-specific weight fraction
Slope method or Overvoltage method	Default factors: • Default Slope or Overvoltage coefficients by technology type from IPCC Table 4.16 • Default weight fraction from IPCC Table 4.16
Simplified method	Default factors: • Default factors by technology type from IPCC Table 4.15

Slope Method

$$E_{CF4} = S_{CF4} \bullet AEM \bullet MP$$
$$and$$
$$E_{C2F6} = E_{CF4} \bullet F_{C2F6/CF4}$$

Where:			**Units**
E_{CF4}	=	Emissions of CF_4 from aluminum production	kg CF_4
S_{CF4}	=	Slope coefficient for CF_4	(kg CF_4 /tonne Al)/(AE-Mins/cell-day)
AEM	=	Anode effect minutes per cell-day	AE-Mins/cell-day
MP	=	Metal production	metric tons Al
E_{C2F6}	=	Emissions of C_2F_6 from aluminum production	kg C_2F_6
$F_{C2F6/CF4}$	=	Weight fraction of C_2F_6 / CF_4	kg C_2F_6 /kg CF_4

Source: IPCC 2006 Equation 4.26 (PFC Emissions by Slope Method, Tier 2 and 3 Methods)

Overvoltage Method

$$E_{CF4} = OVC \bullet \frac{AEO}{CE/100} \bullet MP$$
$$and$$
$$E_{C2F6} = E_{CF4} \bullet F_{C2F6/CF4}$$

Where:			**Units**
E_{CF4}	=	Emissions of CF_4 from aluminum production	kg CF_4
OVC	=	Overvoltage coefficient for CF_4	(kg CF_4/tonne Al)/mV
AEO	=	Anode effect overvoltage	mV
CE	=	Aluminum production process current efficiency expressed	Percent (e.g., 95%)
MP	=	Metal production	metric tons Al
E_{C2F6}	=	Emissions of C_2F_6 from aluminum production	kg C_2F_6
$F_{C2F6/CF4}$	=	Weight fraction of C_2F_6 / CF_4	kg C_2F_6 /kg CF_4

Source: IPCC 2006 Equation 4.27 (PFC Emissions by Overvoltage Method, Tier 2 and 3 Methods)

Simplified Method

$$E_{CF4} = \sum_i \left(EF_{CF4,i} \bullet MP_i\right)$$
$$and$$
$$E_{C2F6} = \sum_i \left(EF_{C2F6,i} \bullet MP_i\right)$$

Where:			**Units**
E_{CF4}	=	Emissions of CF_4 from aluminum production	kg CF_4
$EF_{CF4,i}$	=	Default emission factor by cell technology type i for CF_4	kg CF_4/ metric ton Al
MP_i	=	Metal production by cell technology type i	metric tons Al
E_{C2F6}	=	Emissions of C_2F_6 from aluminum production	kg C_2F_6
$EF_{C2F6,i}$	=	Default emission factor by cell technology type i for C_2F_6	kg C_2F_6 / metric ton Al

Source: IPCC 2006 Equation 4.25 (PFC Emissions, Tier 1 Method)

Default Emission Factors

TABLE 4.15
DEFAULT EMISSION FACTORS AND UNCERTAINTY RANGES FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINIUM PRODUCTION BY CELL TECHNOLOGY TYPE (TIER 1 METHOD)

Technology	CF_4		C_2F_6	
	EF_{CF4} (kg/tonne Al)[a]	Uncertainty Range (%)[b]	EF_{C2F6} (kg/tonne Al)[c]	Uncertainty Range (%)[d]
CWPB	0.4	-99/+380	0.04	-99/+380
SWPB	1.6	-40/+150	0.4	-40/+150
VSS	0.8	-70/+260	0.04	-70/+260
HSS	0.4	-80/+180	0.03	-80/+180

[a] Default CF_4 values calculated from median anode effect performance from 1990 IAI survey data (IAI, 2001).
[b] Uncertainty based on the range of calculated CF_4 specific emissions by technology from 1990 IAI anode effect survey data (IAI, 2001).
[c] Default C_2F_6 values calculated from global average C_2F_6:CF_4 ratios by technology, multiplied by the default CF_4 emission factor.
[d] Uncertainty range based on global average C_2F_6:CF_4 ratios by technology, multiplied by calculated minimum and maximum specific CF_4 emissions from 1990 IAI survey data (IAI, 2001).
Note: These default emission factors should only be used in the absence of Tier 2 or Tier 3 data.

Source: IPCC 2006

TABLE 4.16
TECHNOLOGY SPECIFIC SLOPE AND OVERVOLTAGE COEFFICIENTS FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINIUM PRODUCTION (TIER 2 METHOD)

Technology[a]	Slope Coefficient[b, c] [(kg $_{PFC}$/t$_{Al}$) / (AE-Mins/cell-day)]		Overvoltage Coefficient[b, c, d] [(kg $_{CF4}$/t$_{Al}$) / (mV)]		Weight Fraction C_2F_6 / CF_4	
	CF_4	Uncertainty (+/-%)	CF_4	Uncertainty (+/-%)	C_2F_6/CF_4	Uncertainty (+/-%)
CWPB	0.143	6	1.16	24	0.121	11
SWPB	0.272	15	3.65	43	0.252	23
VSS	0.092	17	NR	NR	0.053	15
HSS	0.099	44	NR	NR	0.085	48

[a] Centre Worked Prebake (CWPB), Side Worked Prebake (SWPB), Vertical Stud Søderberg (VSS), Horizontal Stud Søderberg (HSS).
[b] Source: Measurements reported to IAI, US EPA sponsored measurements and multiple site measurements (U.S. EPA and IAI, 2003).
[c] Embedded in each Slope and Overvoltage coefficient is an assumed emissions collection efficiency as follows: CWPB 98%, SWPB 90%, VSS 85%, HSS 90%. These collection efficiencies have been assumed based on measured PFC collection fractions, measured fluoride gas collection efficiencies and expert opinion.
[d] The noted coefficients reflect measurements made at some facilities recording positive overvoltage and others recording algebraic overvoltage. No robust relationship has yet been established between positive and algebraic overvoltage. Positive overvoltage should provide a better correlation with PFC emissions than algebraic overvoltage. Overvoltage coefficients are not relevant (NR) to VSS and HSS technologies.

Source: IPCC 2006

D.3 Ammonia Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Ammonia Production

Method	Emission Factors
Direct measurement, either continuous emissions monitoring or periodic direct measurements	n/a
Mass Balance	Plant-specific carbon content of feedstock fuels
Mass Balance	Default carbon content of feedstock fuels by fuel type

Mass Balance Method

$$CO_2\ Emissions = \sum_i (FC_i \times CC_i \times OF_i \times 44/12) - R_{CO2}$$

Where:

			Units
CO_2 Emissions	=	Emissions of CO_2	kg
FC_i	=	Total feedstock fuel consumption of fuel type i	MMBtu
CC_i	=	Carbon content factor of the fuel type i	kg C/MMBtu
OF_i	=	Carbon oxidation factor of the fuel type i	Fraction
R_{CO2}	=	CO_2 recovered for downstream use (urea production, CO_2 capture and storage)	kg

Source: Adapted from IPCC 2006 Equation 3.3 (CO_2 Emissions from Ammonia Production, Tier 2 and 3)

Default Emission Factors

Carbon content and oxidation factors are provided for U.S. natural gas below by heat content. For other fuels, refer to Tables 12.1 to 12.4 in Chapter 12 (*Direct Emissions from Stationary Combustion*).

Heat Content (HHV Btu per Standard Cubic Foot)	Carbon Content (kg C / MMBtu)	Oxidation Factor
975 – 1,000	14.73	1.0
1,000 – 1,025	14.43	1.0
1,025 – 1,050	14.47	1.0
1,050 – 1,075	14.58	1.0
1,075 – 1,100	14.65	1.0
Greater than 1,100	14.92	1.0
Unspecified (Weighted U.S. Average)	14.47	1.0

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, A-35.

D.4 Cement Production (CO_2 Emissions)

Direct Process CO_2 Emissions Using Clinker Method

Method	Emission Factors
Process CO_2 emissions from Clinker Calcination	
Clinker Method	Plant-specific clinker emission factor: • Measured CaO- and MgO content of a plant's clinker • Measured non-carbonate fractions of CaO and MgO
Clinker Method	Default clinker emission factor: • Default clinker EF = 525 kg CO_2/ metric tons clinker
Process CO_2 emissions from Discarded Cement Kiln Dust	
Direct Measurement	n/a
Mass Balance	Plant-specific CKD emission factor: • Plant-specific clinker emission factor • Plant-specific CKD calcination rate
Mass Balance	Default CKD emission factor: • CKD calcination rate (d) = 1 • Default clinker EF = 525 kg CO_2/ metric tons clinker
Process CO_2 emissions from Organic Carbon in Raw Meal	
Mass Balance	Measured organic carbon content
Mass Balance	Default organic carbon content = 0.2%

Direct Process CO_2 Emissions Using Carbonate Input Method

Method	Emission Factors
Carbonate Input Method	Plant-specific factors
Carbonate Input Method	Default factors: • F_i = 1.00 • F_d = 1.00 • C_d = the calcium carbonate ratio in the raw material feed to the kiln • EF_d = the emission factor for calcium carbonate • CO_2 emissions from non-carbonate carbon in the non-fuel raw materials can be ignored (set $M_k \bullet X_k \bullet EF_k = 0$) if the heat contribution from the non-carbonate carbon is < 5% of total heat (from fuels).

Clinker Method

Process CO_2 Emissions = $CO_{2\,(clinker)}$ + $CO_{2\,(cement\ kiln\ dust)}$ + $CO_{2\,(non\text{-}carbonate\ carbon)}$ = $(Cli \times EF_{Cli}) + (CKD \times EF_{CKD}) + (TOC_{RM} \times RM \times 44/12)$			
Where:			**Units**
Cli	=	Quantity of clinker produced	metric tons
EF_{Cli}	=	Clinker emission factor	metric tons CO_2/metric tons clinker
CKD	=	Quantity CKD discarded	
EF_{CKD}	=	CKD emission factor	
TOC_{RM}	=	Organic carbon content of raw material	percent
RM	=	Amount of raw material consumed	metric tons/year
44/12	=	CO_2 to carbon molar ratio	

Source: Cement Sustainability Initiative, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* (2005) Version 2.0, consistent with California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007, and the California Climate Action Registry's *Cement Reporting Protocol*, 2005

Clinker Emission Factor

EF_{Cli} = [(CaO content – non-carbonate CaO) x Molecular ratio of CO_2/CaO] + [(MgO content – non-carbonate MgO x Molecular ratio of CO_2/MgO]

Where:			**Units**
CaO Content (by weight)	=	CaO content of clinker	%
MgO Content (by weight)	=	MgO content of clinker	%
Molecular Ratio of CO_2/CaO	=	44g/56g	0.785
Molecular Ratio of CO_2/MgO	=	44g/40g	1.092

Source: Cement Sustainability Initiative, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* (2005) Version 2.0, consistent with California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007, and the California Climate Action Registry's *Cement Reporting Protocol*, 2005

CKD Emission Factor

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1+EF_{Cli}} \times d}{1 - \frac{EF_{Cli}}{1+EF_{Cli}} \times d}$$

Where:

EF_{CKD}	=	CKD emission factor
EF_{Cli}	=	Clinker emission factor
d	=	CKD calcination rate

$$d = 1 - \frac{fCO_{2\,CKD} \times (1 - fCO_{2\,RM})}{(1 - fCO_{2\,CKD}) \times fCO_{2\,RM}}$$

Where:

$fCO_{2\,CKD}$	=	Weight fraction of carbonate CO_2 in the CKD
$fCO_{2\,RM}$	=	Weight fraction of carbonate CO_2 in the raw meal

Source: Cement Sustainability Initiative, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* (2005) Version 2.0, consistent with California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007, and the California Climate Action Registry's *Cement Reporting Protocol*, 2005

Carbonate Input Method

EQUATION 2.3

TIER 3: EMISSIONS BASED ON CARBONATE RAW MATERIAL INPUTS TO THE KILN

$$CO_2\ Emissions = \underbrace{\sum_i (EF_i \bullet M_i \bullet F_i)}_{\text{Emissions from carbonates}} - \underbrace{M_d \bullet C_d \bullet (1 - F_d) \bullet EF_d}_{\text{Emissions from uncalcined CKD not recycled to the kiln}} + \underbrace{\sum_k (M_k \bullet X_k \bullet EF_k)}_{\text{Emissions from carbon-bearing non-fuel materials}}$$

Where:

			Units
CO_2 Emissions	=	Emissions of CO_2 from cement production	metric tons
EF_i	=	Emission factor for the particular carbonate i	metric tons CO_2 /tonne carbonate
M_i	=	Weight or mass of carbonate i consumed in the kiln	metric tons
F_i	=	Fraction calcination achieved for carbonate i	fraction
M_d	=	Weight or mass of CKD not recycled to the kiln (= 'lost' CKD)	metric tons
C_d	=	Weight fraction of original carbonate in the CKD not recycled to the kiln	fraction
F_d	=	Fraction calcination achieved for CKD not recycled to kiln	fraction
EF_d	=	Emission factor for the uncalcined carbonate in CKD not recycled to the kiln	metric tons CO_2/tonne carbonate
M_k	=	Weight or mass of organic or other carbon-bearing nonfuel raw material k	metric tons
X_k	=	Fraction of total organic or other carbon in specific nonfuel raw material k	fraction
EF_k	=	Emission factor for kerogen (or other carbon)-bearing nonfuel raw material k	metric tons CO_2/ metric ton carbonate

Source: IPCC 2006 (Tier 3 Method)

Default CO_2 Emission Factors for Carbonate Inputs

TABLE 2.1
FORMULAE, FORMULA WEIGHTS, AND CARBON DIOXIDE CONTENTS OF COMMON CARBONATE SPECIES*

Carbonate	Mineral Name(s)	Formula Weight	Emission Factor (tonnes CO_2/tonne carbonate)**
$CaCO_3$	Calcite*** or aragonite	100.0869	0.43971
$MgCO_3$	Magnesite	84.3139	0.52197
$CaMg(CO_3)_2$	Dolomite***	184.4008	0.47732
$FeCO_3$	Siderite	115.8539	0.37987
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite****	185.0225–215.6160	0.40822–0.47572
$MnCO_3$	Rhodochrosite	114.9470	0.38286
Na_2CO_3	Sodium carbonate or soda ash	106.0685	0.41492

Source: CRC Handbook of Chemistry and Physics (2004)

* Final results (i.e., emission estimates) using these data should be rounded to no more than two significant figures.

** The fraction of emitted CO_2 assuming 100 percent calcination; e.g., 1 tonne calcite, if fully calcined, would yield 0.43971 tonnes of CO_2.

*** Calcite is the principal mineral in limestone. Terms like high-magnesium or dolomitic limestones refer to a relatively small substitution of Mg for Ca in the general $CaCO_3$ formula commonly shown for limestone.

**** Formulae weight range shown for ankerite assumes that Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

Source: IPCC 2006

D.5 HCFC-22 Production (HFC-23 Emissions)

Direct Process HFC-23 Emissions from HCFC-22 Production

Method	Emission Factors
Direct measurement, either continuous emissions monitoring or periodic direct measurements	n/a
Mass Balance based on process efficiencies	Plant-specific factors
Mass Balance based on production data	Default HFC-23 emission factor

Mass Balance Based on Process Efficiencies

$$E_{HFC-23} = EF_{calculated} \bullet P_{HCFC-22} \bullet F_{released}$$

Where: **Units**

E_{HFC-23}	=	By-product HFC-23 emissions from HCFC-22 production	kg
$EF_{calculated}$	=	HFC-23 calculated emission factor	kg HFC-23/kg HCFC-22
$P_{HCFC-22}$	=	Total HCFC-22 production	kg
$F_{released}$	=	Fraction of the year that this stream was released to atmosphere untreated	fraction

Source: IPCC 2006, Equations 3.31 – 3.33 (Tier 2 Method)

The calculated emission factor can be calculated from both the carbon efficiency and the fluorine efficiency (equations below). The value used in the above equation should be the average of these two values.

$$EF_{carbon\_balance} = \frac{(100 - CBE)}{100} \bullet F_{efficiency\ loss} \bullet FCC$$

Where: **Units**

$EF_{carbon\_balance}$	=	HFC-23 emission factor calculated from carbon balance efficiency	kg HFC-23/kg HCFC-22
CBE	=	Carbon balance efficiency	percent
$F_{efficiency\ loss}$	=	Factor to assign efficiency loss to HFC-23	fraction
FCC	=	Factor for the carbon content of this component (= 0.81)	kg HFC-23/kg HCFC-22

Source: IPCC 2006, Equations 3.31 – 3.33 (Tier 2 Method)

$$EF_{fluorine\_balance} = \frac{(100 - FBE)}{100} \bullet F_{efficiency\ loss} \bullet FFC$$

Where: **Units**

$EF_{fluorine\_balance}$	=	HFC-23 emission factor calculated from fluorine balance efficiency	kg HFC-23/kg HCFC-22
FBE	=	Fluorine balance efficiency	percent
$F_{efficiency\ loss}$	=	Factor to assign efficiency loss to HFC-23	fraction
FFC	=	Factor for the fluorine content of this component (= 0.54)	kg HFC-23/kg HCFC-22

Source: IPCC 2006, Equations 3.31 – 3.33 (Tier 2 Method)

Mass Balance Based on Production Data

HFC-23 Emissions = (HCFC-22 Production x HFC-23 Emission Factor) x (1 – Fraction Abated x Utilization Factor)			
Where:			**Units**
HCFC-22 Production	=	Total amount of HCFC-22 produced by the facility	metric tons
HFC-23 Emission Factor	=	EF from HCFC-22 production	metric tons HFC-23/metric ton HCFC-22 produced
Fraction Abated	=	Percent of emissions abated by reduction technologies and practices (if applicable)	percent
Utilization Factor	=	Percent of time the abatement technology was in use (if applicable)	percent

Source: WRI/WBCSD, *Calculating HFC-23 Emissions from the Production of HCFC-22*, 2001.

Default Emission Factors

HFC-23 Emission Factor (kg HFC-23/kg HCFC-22 produced) by Type	
Old, un-optimized plants (e.g., 1940s to 1995)	0.04
Plants of recent design, not specifically optimized	0.03

Source: IPCC 2006, Table 3.28

D.6 Iron and Steel Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Iron and Steel Production

Method	Emission Factors
Mass Balance	Plant-specific carbon content factors
Mass Balance	Default carbon content factors (IPCC Table 4.3)

Mass Balance Method

Process CO_2 Emissions = $CO_{2\ (Iron\ \&\ Steel\ Prod)}$ + $CO_{2\ (Sinter\ Prod)}$ + $CO_{2\ (Direct\ Reduced\ Iron\ Prod)}$

EQUATION 4.9
CO_2 EMISSIONS FROM IRON & STEEL PRODUCTION (TIER 2)

$$E_{CO2,non-energy} = \left[PC \bullet C_{PC} + \sum_a (COB_a \bullet C_a) + CI \bullet C_{CI} + L \bullet C_L + D \bullet C_D + CE \bullet C_{CE} + \sum_b (O_b \bullet C_b) + COG \bullet C_{COG} - S \bullet C_S - IP \bullet C_{IP} - BG \bullet C_{BG} \right] \bullet \frac{44}{12}$$

Where:			Units
$E_{CO2,non-energy}$	=	Process emissions of CO_2	metric tons
PC	=	Quantity of coke consumed in iron and steel production (not including sinter production)	metric tons
COB_a	=	Quantity of onsite coke oven by-product a, consumed in blast furnace	metric tons
CI	=	Quantity of coal directly injected into blast furnace	metric tons
L	=	Quantity of limestone consumed in iron and steel production	metric tons
D	=	Quantity of dolomite consumed in iron and steel production	metric tons
CE	=	Quantity of carbon electrodes consumed in EAFs	metric tons
O_b	=	Quantity of other carbonaceous and process material b, consumed in iron and steel production, such as sinter or waste plastic	metric tons
COG	=	Quantity of coke oven gas consumed in blast furnace in iron and steel production	m^3 (or other unit such as metric tons or GJ)
S	=	Quantity of steel produced	metric tons
IP	=	Quantity of iron production not converted to steel	metric tons
BG	=	Quantity of blast furnace gas transferred offsite	m^3 (or other unit such as metric tons or GJ)
44/12	=	CO_2 to carbon molar ratio	
C_{PC}, C_a, C_{CI}, etc.	=	Carbon content of material input or output: PC, a, CI, etc.	metric tons C/(unit for material)

Source: IPCC 2006 Equations 4.9 – 4.11 (Tier 2/3 Method)

EQUATION 4.10
CO_2 EMISSIONS FROM SINTER PRODUCTION (TIER 2)

$$E_{CO2,non-energy} = \left[CBR \bullet C_{CBR} + COG \bullet C_{COG} + BG \bullet C_{BG} + \sum_a (PM_a \bullet C_a) - SOG \bullet C_{SOG} \right] \bullet \frac{44}{12}$$

Where:			**Units**
$E_{CO2,non-energy}$	=	Process emissions of CO_2	metric tons
CBR	=	Quantity of purchased and onsite produced coke breeze used for sinter production	metric tons
COG	=	Quantity of coke oven gas consumed in blast furnace in sinter production	m^3 (or other unit such as metric tons or GJ)
BG	=	Quantity of blast furnace gas consumed in sinter production	m^3 (or other unit such as metric tons or GJ)
PM_a	=	Quantity of other process material a, other than those listed as separate terms, such as natural gas and fuel oil, consumed for coke and sinter production in integrated coke production and iron and steel production facilities	metric tons
SOG	=	Quantity of sinter off gas transferred offsite either to iron and steel production facilities or other facilities	m^3 (or other unit such as metric tons or GJ)
44/12	=	CO_2 to carbon molar ratio	
C_{CBR}, C_{COG}, C_{BG}, etc.	=	Carbon content of material input or output: CBR, COG, etc.	metric tons C/(unit for material)

Source: IPCC 2006 Equations 4.9 – 4.11 (Tier 2/3 Method)

EQUATION 4.11
CO_2 EMISSIONS FROM DIRECT REDUCED IRON PRODUCTION (TIER 2)

$$E_{CO2,non-energy} = (DRI_{NG} \bullet C_{NG} + DRI_{BZ} \bullet C_{BZ} + DRI_{CK} \bullet C_{CK}) \bullet \frac{44}{12}$$

Where:			**Units**
$E_{CO2,non-energy}$	=	Process emissions of CO_2	metric tons
DRI_{NG}	=	Amount of natural gas used in direct reduced iron production	GJ
C_{NG}	=	Carbon content of natural gas	metric tons C/GJ
DRI_{BZ}	=	amount of coke breeze used in direct reduced iron production	GJ
C_{BZ}	=	Carbon content of coke breeze	metric tons C/GJ
DRI_{CK}	=	amount of metallurgical coke used in direct reduced iron production	GJ
C_{CK}	=	Carbon content of metallurgical coke	metric tons C/GJ
44/12	=	CO_2 to carbon molar ratio	

Source: IPCC 2006 Equations 4.9 – 4.11 (Tier 2/3 Method)

Default Emission Factors

TABLE 4.3
TIER 2 MATERIAL-SPECIFIC CARBON CONTENTS FOR IRON & STEEL AND COKE PRODUCTION (kg C/kg)

Process Materials	Carbon Content
Blast Furnace Gas	0.17
Charcoal*	0.91
Coal[1]	0.67
Coal Tar	0.62
Coke	0.83
Coke Oven Gas	0.47
Coking Coal	0.73
Direct Reduced Iron (DRI)	0.02
Dolomite	0.13
EAF Carbon Electrodes[2]	0.82
EAF Charge Carbon[3]	0.83
Fuel Oil[4]	0.86
Gas Coke	0.83
Hot Briquetted Iron	0.02
Limestone	0.12
Natural Gas	0.73
Oxygen Steel Furnace Gas	0.35
Petroleum Coke	0.87
Purchased Pig Iron	0.04
Scrap Iron	0.04
Steel	0.01

Source: Default values are consistent with the those provided in Vol 2 and have been calculated with the assumptions below. Complete references for carbon content data are included in Table 1.2 and 1.3 in Volume 2, Chapter 1.

Notes:

[1] Assumed other bituminous coal

[2] Assumed 80 percent petroleum coke and 20 percent coal tar

[3] Assumed coke oven coke

[4] Assumed gas/diesel fuel

* The amount of CO_2 emissions from charcoal can be calculated by using this carbon content value, but it should be reported as zero in national greenhouse gas inventories. (See Section 1.2 of Volume 1.)

Source: IPCC 2006

D.7 Lime Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Lime Production

Method	Emission Factors
Mass balance based on carbonate inputs	Plant-specific factors
Mass balance based on production	Plant-specific factors • Measured CaO and MgO content factors • Measured correction factor for LKD • Measured correction factor for hydrated lime
Mass balance based on carbonate inputs	Default factors • Fi = 1.00 • Fd = 1.00 • EFd = emission factor for calcium carbonate • Cd = the calcium carbonate ratio in the raw material feed to the kiln
Mass balance based on production	Default factors • Default CaO and MgO content factors • Default inputs to correction factor for LKD • Default correction factor for hydrated lime, 0.97

Mass Balance Based on Carbonate Inputs

$$CO_2\ Emissions = \sum_i (EF_i \bullet M_i \bullet F_i) - M_d \bullet C_d \bullet (1 - F_d) \bullet EF_d$$

Where:			**Units**
CO_2 Emissions	=	Emissions of CO_2 from lime production	metric tons
EF_i	=	Emission factor for carbonate I (see Table 2.1)	metric tons CO_2/ metric ton carbonate
M_i	=	Weight or mass of carbonate i consumed	metric tons
F_i	=	Fraction calcination achieved for carbonate i	fraction
M_d	=	Weight or mass of LKD	metric tons
C_d	=	Weight fraction of original carbonate in the LKD. Can be accounted for in a similar way as CKD from cement manufacturing	fraction
F_d	=	Fraction calcination achieved for LKD	fraction
EF_d	=	Emission factor for the uncalcined carbonate in LKD	metric tons CO_2/metric ton carbonate

IPCC 2006 Equation 2.7 (Tier 3: Emissions Based on Carbonate Inputs)

Mass Balance Based on Production

$$CO_2\ Emissions = \sum_i (EF_{lime,i} \bullet M_{l,i} \bullet CF_{lkd,i} \bullet C_{h,i})$$

Where: **Units**

CO_2 Emissions	=	Emissions of CO_2 from lime production	metric tons
$EF_{lime,i}$	=	Emission factor for lime of type i,	metric tons CO_2/ metric ton lime
$M_{l,i}$	=	Lime production of type i	metric tons
$CF_{lkd,i}$	=	Correction factor for LKD for lime of type i	
$C_{h,i}$	=	Correction factor for hydrated lime of the type i of lime	

(Calculated as 1 – (x • y) where x is the proportion of hydrated lime and y is the water content in it. Since the vast majority of hydrated lime produced is high-calcium (90 percent), the default values are x=0.10 and y = 0.28 (default water content), resulting in a default correction factor of 0.97)

i = Each of the specific lime types listed in Table 2.4

IPCC 2006 Equations 2.6 (Tier 2: Emissions Based on National Lime Production Data by Type), 2.9 (Tier 2 Emission Factors for Lime Production), and 2.5 (Correction Factor for CKD Not Recycled to the Kiln). IPCC Equation 2.5 has been modified to be applicable to lime production, following the recommendation of the 2006 IPCC guidelines.

$$EF_{lime,a} = SR_{CaO} \bullet CaO\ Content$$

$$EF_{lime,b} = SR_{CaO \cdot MgO} \bullet CaO \cdot MgO\ Content$$

$$EF_{lime,c} = SR_{CaO} \bullet CaO\ Content$$

Where: **Units**

$EF_{lime,a}$	=	Emission factor for quicklime (high-calcium lime)	metric tons CO_2/ metric ton lime
SR_{CaO}	=	Stoichiometric ratio of CO_2 and CaO (see Table 2.4)	metric tons CO_2/ metric ton CaO
CaO Content	=	CaO content (see Table 2.4 for default factors)	metric tons CaO/ metric ton lime
$EF_{lime,b}$	=	Emission factor for dolomitic lime	metric tons CO_2/ metric ton lime
$SR_{CaO\ MgO}$	=	Stoichiometric ratio of CO_2 and CaO·MgO (see Table 2.4)	metric tons CO_2/metric ton CaO·MgO
CaO MgO Content	=	CaO·MgO content (see Table 2.4 for default factors)	metric tons CaO·MgO/ metric ton lime
$EF_{lime,c}$	=	Emission factor for hydraulic lime	metric tons CO_2/ metric ton lime

IPCC 2006 Equations 2.6 (Tier 2: Emissions Based on National Lime Production Data by Type), 2.9 (Tier 2 Emission Factors for Lime Production), and 2.5 (Correction Factor for CKD Not Recycled to the Kiln). IPCC Equation 2.5 has been modified to be applicable to lime production, following the recommendation of the 2006 IPCC guidelines.

$CF_{lkd} = 1 + (M_d / M_l) \times C_d \times F_d$

Where:			Units
CF_{lkd}	=	Emissions correction factor for LKD	
M_d	=	Weight of LKD not recycled to the kiln	metric tons
M_l	=	Weight of lime produced	metric tons
C_d	=	Fraction of original carbonate in the LKD (i.e., before calcination)	fraction
F_d	=	Fraction calcination of the original carbonate in the LKD	fraction*

* Default values: Assume that the original carbonate is all $CaCO_3$ and that the proportion of original carbonate in the LKD is the same as that in the raw mix kiln feed.

IPCC 2006 Equations 2.6 (Tier 2: Emissions Based on National Lime Production Data by Type), 2.9 (Tier 2 Emission Factors for Lime Production), and 2.5 (Correction Factor for CKD Not Recycled to the Kiln). IPCC Equation 2.5 has been modified to be applicable to lime production, following the recommendation of the 2006 IPCC guidelines.

Default Emission Factors

TABLE 2.4
BASIC PARAMETERS FOR THE CALCULATION OF EMISSION FACTORS FOR LIME PRODUCTION

Lime Type	Stoichiometric Ratio [tonnes CO_2 per tonne CaO or CaO·MgO] (1)	Range of CaO Content [%]	Range of MgO Content[d] [%]	Default Value for CaO or CaO·MgO Content [fraction] (2)	Default Emission Factor [tonnes CO_2 per tonne lime] (1) • (2)
High-calcium lime[a]	0.785	93-98	0.3-2.5	0.95	0.75
Dolomitic lime[b]	0.913	55-57	38-41	0.95 or 0.85[c]	0.86 or 0.77[c]
Hydraulic lime[b]	0.785	65-92[e]	NA	0.75[e]	0.59

Source:

[a] Miller (1999b) based on ASTM (1996) and Schwarzkopf (1995).

[b] Miller (1999a) based on Boynton (1980).

[c] This value depends on technology used for lime production. The higher value is suggested for developed countries, the lower for developing ones.

[d] There is no exact chemical formula for each type of lime because the chemistry of the lime product is determined by the chemistry of the limestone or dolomite used to manufacture the lime.

[e] Total CaO content (including that in silicate phases).

Source: IPCC 2006

TABLE 2.1
FORMULAE, FORMULA WEIGHTS, AND CARBON DIOXIDE CONTENTS OF COMMON CARBONATE SPECIES*

Carbonate	Mineral Name(s)	Formula Weight	Emission Factor (tonnes CO_2/tonne carbonate)**
$CaCO_3$	Calcite*** or aragonite	100.0869	0.43971
$MgCO_3$	Magnesite	84.3139	0.52197
$CaMg(CO_3)_2$	Dolomite***	184.4008	0.47732
$FeCO_3$	Siderite	115.8539	0.37987
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite****	185.0225–215.6160	0.40822–0.47572
$MnCO_3$	Rhodochrosite	114.9470	0.38286
Na_2CO_3	Sodium carbonate or soda ash	106.0685	0.41492

Source: CRC Handbook of Chemistry and Physics (2004)

* Final results (i.e., emission estimates) using these data should be rounded to no more than two significant figures.

** The fraction of emitted CO_2 assuming 100 percent calcination; e.g., 1 tonne calcite, if fully calcined, would yield 0.43971 tonnes of CO_2.

*** Calcite is the principal mineral in limestone. Terms like high-magnesium or dolomitic limestones refer to a relatively small substitution of Mg for Ca in the general $CaCO_3$ formula commonly shown for limestone.

**** Formulae weight range shown for ankerite assumes that Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

Source: IPCC 2006

D.8 Nitric Acid Production (N_2O Emissions)

Direct Process N_2O Emissions from Nitric Acid Production

Method	Emission Factors
Continuous emissions monitoring	n/a
Mass Balance	Plant-specific factors: • Measured destruction and utilization factors for an abatement technology • Measured N_2O emission factor based on direct measurements
Mass Balance	Default N_2O emission factor by technology type from Table 3.3

Mass Balance Method

N_2O Emissions = Nitric Acid Production x N_2O Emission Factor
x (1 – N_2O Destruction factor x Abatement system utilization factor)

Where:

N_2O emission factor = Metric tons of N_2O / metric tons of nitric acid produced
N_2O destruction factor = Fraction of emissions abated by reduction technologies
Abatement system utilization factor = Fraction of time the abatement system was in use

Source: WRI/WBCSD, *Calculating N_2O Emissions from the Production of Nitric Acid*, 2001 (Consistent with IPCC 2006 Equation 3.6: N_2O Emissions from Nitric Acid Production, Tier 2)

Default Emission Factors

Note: The default emission factors in Table 3.3 include the impact on emissions of abatement technology where relevant (i.e. for plants with NSCR and plants with process-integrated or tail gas N_2O destruction). If you are using default emission factors from Table 3.3 for plants with these abatement technologies (NSCR or process-integrated or tail gas N_2O destruction), you should use a simplified version of the Mass Balance method that does include the N_2O destruction factor or abatement system utilization factor. In this case, use the equation:

N_2O Emissions = Nitric Acid Production x N_2O Emission Factor

For plants without abatement technologies (e.g. atmospheric pressure plants (low pressure), medium pressure combustion plants, and high pressure plants), use the full Mass Balance equation above, incorporating an N_2O destruction factor and abatement system utilization factor if applicable.

TABLE 3.3
DEFAULT FACTORS FOR NITRIC ACID PRODUCTION

Production Process	N_2O Emission Factor (relating to 100 percent pure acid)
Plants with NSCR[a] (all processes)	2 kg N_2O/tonne nitric acid ±10%
Plants with process-integrated or tailgas N_2O destruction	2.5 kg N_2O/tonne nitric acid ±10%
Atmospheric pressure plants (low pressure)	5 kg N_2O/tonne nitric acid ±10%
Medium pressure combustion plants	7 kg N_2O/tonne nitric acid ±20%
High pressure plants	9 kg N_2O/tonne nitric acid ±40%

[a] Non-Selective Catalytic Reduction (NSCR).
Source: van Balken (2005).

Source: IPCC 2006

D.9 Pulp and Paper Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Make-Up Carbonates Used in the Pulp Mill

Method	Emission Factors
Mass Balance	Default stoichiometric emission factors

Mass Balance Method

CO_2 emissions = $\sum_i$ (Carbonate Used $_i$ × Emission Factor $_i$)			
Where:			**Units**
Carbonate Used$_i$	=	Amount of carbonate i ($CaCO_3$ and Na_2CO_3) used in the pulp mill	metric tons
Emission Factor$_i$	=	Stoichiometric ratio for make-up carbonate i	metric tons CO/metric tons $CaCO_3$ and metric tons CO_2/metric tons Na_2CO_3

Source: IPCC 2006, Section 2.5 (Consistent with International Council of Forest and Paper Associations (ICFPA), *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*, Version 1.1, 2005, and European Union, *Guidelines for the monitoring and reporting of greenhouse gas emissions*, 2006, Annex XI).

Direct Process CO_2 Emissions from Limestone or Dolomite Used in Flue Gas Desulfurization Systems

Method	Emission Factors
Mass Balance	Default stoichiometric emission factors

Mass Balance Method

CO_2 emissions = $\sum_i$ (Carbonate Used $_i$ × Emission Factor $_i$)			
Where:			**Units**
Carbonate Used$_i$	=	Amount of carbonate i (limestone or dolomite) consumed in the flue gas desulfurization system	metric tons
Emission Factor$_i$	=	Stoichiometric ratio for carbonate i	metric tons CO_2/metric ton limestone and metric tons CO_2/metric ton dolomite

Source: IPCC 2006, Section 2.5

Default Emission Factors for Pulp and Paper Production

TABLE 2.1
FORMULAE, FORMULA WEIGHTS, AND CARBON DIOXIDE CONTENTS OF COMMON CARBONATE SPECIES*

Carbonate	Mineral Name(s)	Formula Weight	Emission Factor (tonnes CO_2/tonne carbonate)**
$CaCO_3$	Calcite*** or aragonite	100.0869	0.43971
$MgCO_3$	Magnesite	84.3139	0.52197
$CaMg(CO_3)_2$	Dolomite***	184.4008	0.47732
$FeCO_3$	Siderite	115.8539	0.37987
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite****	185.0225–215.6160	0.40822–0.47572
$MnCO_3$	Rhodochrosite	114.9470	0.38286
Na_2CO_3	Sodium carbonate or soda ash	106.0685	0.41492

Source: CRC Handbook of Chemistry and Physics (2004)

* Final results (i.e., emission estimates) using these data should be rounded to no more than two significant figures.

** The fraction of emitted CO_2 assuming 100 percent calcination; e.g., 1 tonne calcite, if fully calcined, would yield 0.43971 tonnes of CO_2.

*** Calcite is the principal mineral in limestone. Terms like high-magnesium or dolomitic limestones refer to a relatively small substitution of Mg for Ca in the general $CaCO_3$ formula commonly shown for limestone.

**** Formulae weight range shown for ankerite assumes that Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

Source: IPCC 2006

D.10 Refrigeration and A/C Equipment Manufacturing (HFC and PFC Emissions)

Direct Process HFC and PFC Emissions from Manufacturing Refrigeration and A/C Equipment

Method	Emission Factors
Mass Balance using measured refrigerant data	n/a

Mass Balance Method

$$\textbf{Emissions} = \sum_i [(I_{Bi} - I_{Ei} + P_i - S_i) \times GWP_i]$$

Where:

Emissions	=	Total HFC and PFC emissions (in CO_2e) from manufacturing refrigeration and A/C equipment
I_{Bi}	=	Amount of refrigerant i in inventory at the beginning of reporting period (in storage, not equipment)
I_{Ei}	=	Amount of refrigerant i in inventory at the end of reporting period (in storage, not equipment)
P_i	=	Purchases/acquisitions of refrigerant i. This is the sum of all the refrigerant acquired from other entities during the year, including refrigerant purchased from producers/distributors; refrigerant acquired in either storage containers or equipment; refrigerant returned after off-site reclamation or recycling; and refrigerant returned by equipment users
Si	=	Sales/disbursements of refrigerant i. This is the sum of all the refrigerant sold or otherwise disbursed to other entities during the year, including refrigerant sold, delivered, or disbursed in storage containers or charged into equipment; refrigerant recovered and sent off-site for recycling, reclamation, or destruction; and refrigerant returned to refrigerant producers
GWP_i	=	Global warming potential factor for refrigerant i from IPCC Second Assessment Report

Source: WRI/WBCSD, *Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration & Air-conditioning Equipment* (Version 1.0) 2005, consistent with U.S. EPA Climate Leaders, *Direct HFC and PFC Emissions from Manufacturing Refrigeration and Air Conditioning Units*, 2003

D.11 Semiconductor Manufacturing (PFC, SF_6 and NF_3 Emissions)

Direct Process PFC, SF_6, and NF_3 Emissions from Plasma Etching and Chemical Vapor Deposition (CVD)

Method	Emission Factors
Mass Balance Using Process-Specific Parameters	Plant-specific factors: • For each parameter used in Equations 6.7 – 6.11 for each individual process • 'p' in the equations is a specific 'process' (e.g., silicon nitride etching or plasma enhanced chemical vapor deposition (PECVD) tool chamber cleaning), not a 'process type' (e.g. etching vs. CVD chamber cleaning)
Mass Balance Using Process Type-Specific Parameters	Plant-specific factors: • For each parameter used in Equations 6.7 – 6.11 for each process type • 'p' in the equations is a 'process type' (etching vs. CVD chamber cleaning)
Mass Balance Using Process Type-Specific Parameters	Default factors: Industry-wide default values used for any or all of the following parameters: • h = 0.10 • Ui,p (IPCC Table 6.3, Tier 2b) • BCF4,i,p, BC2F6,i,p, BC3F8,i,p (IPCC Table 6.3, Tier 2b) • di,p, dCF4,p, dC2F6,p, dCHF3,p and dC3F8,p (IPCC Table 6.6) • ai,p = 0 (unless emission control technologies are installed)

Mass Balance Method

Total Emissions of Gas i = $E_i + BPE_{CF4,i} + BPE_{C2F6,i} + BPE_{CHF3,i} + BPE_{C3F8,i}$

Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

EQUATION 6.7
TIER 2b METHOD FOR ESTIMATION OF FC EMISSIONS

$$E_i = (1-h)\bullet\sum_p\left[FC_{i,p}\bullet(1-U_{i,p})\bullet(1-a_{i,p}\bullet d_{i,p})\right]$$

Where: **Units**

			Units
E_i	=	Emissions of gas i	kg
h	=	Fraction of gas remaining in shipping container (heel) after use	fraction
p	=	Process or process type	
$FC_{i,p}$	=	Mass of gas i fed into process or process type p (e.g., CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6)	kg
$U_{i,p}$	=	Use rate for each gas i and process or process type p (fraction destroyed or transformed)	fraction
$a_{i,p}$	=	Fraction of gas i volume fed into process or process type p with emission control technologies	fraction
$d_{i,p}$	=	Fraction of gas i destroyed by the emission control technology used in process or process type p. (If more than one emission control technology is used in process or process type p, this is the average of the fraction destroyed by those emission control technologies, where each fraction is weighted by the quantity of gas fed into tools using that technology)	fraction

Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

EQUATION 6.8
BY-PRODUCT EMISSIONS OF CF_4

$$BPE_{CF4,i} = (1-h) \bullet \sum_p \left[B_{CF4,i,p} \bullet FC_{i,p} \bullet (1 - a_{i,p} \bullet d_{CF4,p})\right]$$

Where:			Units
$BPE_{CF4,i}$	=	By-product emissions of CF_4 converted from the gas i used	kg
$B_{CF4,i,p}$	=	Emission factor for by-product emissions of CF_4 converted from gas i in process or process type p	kg CF_4 created/ kg gas i used
$d_{CF4,p}$	=	Fraction of CF_4 by-product destroyed by the emission control technology used in process or process type p (e.g., control technology type listed in Table 6.6)	fraction

Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

EQUATION 6.9
BY-PRODUCT EMISSIONS OF C_2F_6

$$BPE_{C2F6,i} = (1-h) \bullet \sum_p \left[B_{C2F6,i,p} \bullet FC_{i,p} \bullet (1 - a_{i,p} \bullet d_{C2F6,p})\right]$$

Where:			Units
$BPE_{C2F6,i}$	=	By-product emissions of C_2F_6 converted from the gas i used	kg
$B_{C2F6,i,p}$	=	Emission factor for by-product emissions of C_2F_6 converted from gas i in process or process type p	kg C_2F_6 created/ kg gas i used
$d_{C2F6,p}$	=	Fraction of C_2F_6 by-product destroyed by the emission control technology used in process or process type p (e.g., control technology type listed in Table 6.6)	fraction

Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

EQUATION 6.10
BY-PRODUCT EMISSIONS OF CHF_3

$$BPE_{CHF3,i} = (1-h) \bullet \sum_p \left[B_{CHF3,i,p} \bullet FC_{i,p} \bullet (1 - a_{i,p} \bullet d_{CHF3,p})\right]$$

Where:			Units
$BPE_{CHF3,i}$	=	By-product emissions of CHF_3 converted from the gas i used	kg
$B_{CHF3,i,p}$	=	Emission factor for by-product emissions of CHF_3 converted from gas i in process or process type p	kg CHF_3 created/ kg gas i used
$d_{CHF3,p}$	=	Fraction of CHF_3 by-product destroyed by the emission control technology used in process or process type p (e.g., control technology type listed in Table 6.6)	fraction

Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

EQUATION 6.11
BY-PRODUCT EMISSIONS OF C_3F_8

$$BPE_{C3F8,i} = (1-h) \bullet \sum_p \left[B_{C3F8,i,p} \bullet FC_{i,p} \bullet \left(1 - a_{i,p} \bullet d_{C3F8,p}\right)\right]$$

Where:			**Units**
$BPE_{C3F8,i}$	=	By-product emissions of C_3F_8 converted from the gas i used	kg
$B_{C3F8,i,p}$	=	Emission factor for by-product emissions of C_3F_8 converted from gas i in process or process type p	kg C_3F_8 created/ kg gas i used
$d_{C3F8,p}$	=	Fraction of C_3F_8 by-product destroyed by the emission control technology used in process or process type p (e.g., control technology type listed in Table 6.6)	fraction

Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

Default Emission Factors

TABLE 6.6
TIER 2a & 2b DEFAULT EFFICIENCY PARAMETERS FOR ELECTRONICS INDUSTRY FC EMISSION REDUCTION TECHNOLOGIES[a,b,e]

Emission Control Technology	CF_4	C_2F_6	CHF_3	C_3F_8	$c\text{-}C_4F_8$	NF_3[f]	SF_6
Destruction[c]	0.9	0.9	0.9	0.9	0.9	0.95	0.9
Capture/Recovery[d]	0.75	0.9	0.9	NT	NT	NT	0.9

[a] Values are simple (unweighted) averages of destruction efficiencies for all abatement technologies. Emission factors do not apply to emission control technologies which cannot abate CF_4 at destruction or removal efficiency (DRE) ≥ 85 percent when CF_4 is present as an input gas or by-product and all other FC gases at DRE ≥ 90 percent. If manufacturers use any other type of emission control technology, its destruction efficiency is 0 percent when using the Tier 2 methods.

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

- are specifically designed to abate FCs,
- are used within the manufacturer's specified process window and in accordance with specified maintenance schedules and
- have been measured and has been confirmed under actual process conditions, using a technically sound protocol, which accounts for known measurement errors including, for example, CF_4 by-product formation during C_2F_6 as well as the effect of dilution, the use of oxygen or both in combustion abatement systems

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

[d] Average values for cryogenic and membrane capture and recovery technologies.

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

[f] Use of NF_3 in the etch process is typically small compared to CVD. The aggregate emissions of NF_3 from etch and CVD under Tier 2b will usually not be greater than estimates made with Tier 2a or Tier 1 methods.

NT = not tested.

Source: IPCC 2006

TABLE 6.3
TIER 2 DEFAULT EMISSION FACTORS FOR FC EMISSIONS FROM SEMICONDUCTOR MANUFACTURING

	Greenhouse Gases with TAR GWP									Greenhouse Gases without TAR GWP			Non-GHGs Producing FC By-products‡	
Process Gas (i)	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O	F_2	COF_2
Tier 2a														
1-Ui	0.9	0.6	0.4	0.1	0.4	0.1	0.02	0.2	0.2	0.1	0.1	0.1	NA	NA
B_{CF4}	NA	0.2	0.07	0.08	0.1	0.1	0.02†	0.09	NA	0.3	0.1	0.1	0.02†	0.02†
B_{C2F6}	NA	NA	NA	NA	NA	0.1	NA	NA	NA	0.2	0.04	NA	NA	NA
B_{C3F8}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.04	NA	NA
Tier 2b														
Etch 1-Ui	0.7*	0.4*	0.4*	0.06*	NA	0.2*	NA	0.2	0.2	0.1	0.2	NA	NA	NA
CVD 1-Ui	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1	NA	NA
Etch B_{CF4}	NA	0.4*	0.07*	0.08*	NA	0.2	NA	NA	NA	0.3*	0.2	NA	NA	NA
Etch B_{C2F6}	NA	NA	NA	NA	NA	0.2	NA	NA	NA	0.2*	0.2	NA	NA	NA
CVD B_{CF4}	NA	0.1	NA	NA	0.1	0.1	0.02†	0.1†	NA	NA	0.1	0.1	0.02†	0.02†
CVD B_{C2F6}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CVD B_{C3F8}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.04	NA	NA

Notes: NA denotes not applicable based on currently available information

‡ The default emission factors for F_2 and COF_2 may be applied to cleaning low-k CVD reactors with ClF_3.

* Estimate includes multi-gas etch processes

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

Source: IPCC 2006

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