Staff Report Item 14

TO: East Bay Community Energy Board of Directors

FROM: Howard Chang, Chief Operating Officer

SUBJECT: **Carbon emission benchmarking and Accounting Methodology (Informational Item)**

DATE: September 26, 2018

Recommendation

Receive information regarding EBCE's Carbon emissions benchmarking and Accounting methodologies.

Background

EBCE staff is currently evaluating carbon accounting methodologies to measure and disclose EBCE's actual emissions on a backwards looking basis. Staff has engaged with city sustainability staff and informally with independent consultants to research these methodologies. A review of the following methodologies and platforms has been completed.

Accounting methodologies:

- The Climate Registry (TCR) (Voluntary)
    - Includes an electric sector protocol relevant for EBCE electricity supply
    - Certain key commercial customers have requested this platform that aligns with their disclosure methodology
    - Currently utilized by PG&E for annual disclosures and a number of existing CCAs, including MCE, SCP, and SVCE.
- Global Protocol for Communities (GPC) (Voluntary)
    - A methodology developed by WRI, ICLEI, and C40 as part of the Greenhouse Gas Protocol
    - The Global Covenant of Mayors utilizes this protocol
    - There are limitations on scope 2 electricity related emissions with this platform, which is more focused on corporate and city disclosures, limiting the applicability of this for CCAs.
    - The Carbon Disclosure Project and Carbonn are two distinct disclosure platforms that are utilized for information disclosure
    - The GPC currently mandates that member cities utilize a broad regional grid average emission. It does allow for dual reporting to allow cities to disclose emissions based on a grid average emission and a CCA-specific emissions, which

    they deem as a market-based emissions. The disclosure platform is not formalized to allow for dual reporting at this stage however.
    - Currently Berkeley, Emeryville, Fremont, Hayward, Oakland, Piedmont, and San Leandro are part of the Global Covenant of Mayors
- Power Content Label (Mandatory)
    - Power Content Label currently does not incorporate any emissions factors and only shows a % breakdown of the portfolio.
    - AB1110 is an active proceeding that will incorporate changes to require emissions intensities and certain treatment of PCC2 and PCC3 products.
    - AB1110 is expected to come into effect in 2020 for 2019 supply and the exact details of the disclosure changes and accounting methodology are pending
- Clean Net Short GHG calculator used under the IRP (Mandatory)
    - The Clean Net Short methodology was released for the first time as part of this initial IRP requirements for all LSEs.
    - Changes may occur to the current IRP requirements because this was the initial year and CPUC staff is currently soliciting feedback and information

Given pending regulatory changes, it may be advisable to select an accounting methodology at this time to provide some level of transparency and certainty with which staff should operate and make a change at a future date based on regulatory requirements and industry norms. Multiple third-party consultants have informally advised EBCE to utilize the Climate Registry Platform.

In addition to the carbon accounting methodology EBCE staff is researching methodologies to establish a carbon emissions benchmark for the Bright Choice product. Bright Choice is a board approved product set at 85% carbon free. Different energy sources have varying carbon emissions that are important to take into consideration when making procurement decisions. The emissions factor for CAISO unspecified system power is 0.428MT of CO_2e/MWh. Applying this emissions factor to 15% of the Bright Choice product would equate to an emission factor of 0.0642 MT of CO_2e/MWh on the entire portfolio. This equates to 142lbs of CO_2e/MWh. Given a variable energy load relative to a forecast, the emissions benchmark is best provided as a per MWh metric.

For calendar year 2018, Bright Choice would have an emissions factor benchmark of 142 lbs of CO_2e/MWh. For subsequent years EBCE staff would establish new benchmarks with approval from the Board to continue to reach its carbon reduction goals. As a comparison, the latest PG&E published emissions factor was for 2016 power content and was 294 lbs. of CO_2e /MWh1[i], which reflects a 25% reduction from 2015. It is very important to note that the 142 lbs of CO_2e/MWh benchmark is consistent with the carbon accounting methodology under The Climate Registry. Pending changes with the Power Content Label and the Clean Net Short Methodology could materially deviate from this emissions benchmarking process methodology based on different emissions credits for products, such as PCC2 and PCC3 RECs. Unfortunately, those changes are uncertain at this time and difficult to forecast.

By establishing a carbon emissions benchmark, the goal would be to minimize costs while adhering to a cap on the emissions factor. EBCE staff can make objective decisions to procure from various energy sources, which include renewables, large hydro, and from Asset Controlling Suppliers (ACS). In the case of renewable energy certain generation sources, such as geothermal and biomass may contribute carbon emissions compared to zero emissions from solar and wind. In the case of large hydro, power from ACS may provide a low carbon and cost-effective substitute for source specific large hydro. There are currently three approved Asset Controlling Suppliers that may deliver power from a portfolio into CAISO. All three entities reside in the Pacific Northwest and are estimated to be 85-90% large hydro. In the table below, an estimate or emissions factors is provided across several energy sources.

	Carbon Emission lbs. CO2e/MWh
Solar	0
Wind	0
Large Hydro	0
ACS	
Bonneville Power Authority	26
Powerex	56
Tacoma Power	34

	Low Estimate	High Estimate	Avg
Geothermal*	135	240	185
Biomass (wood and landfill gas) *	25	5400	385

*Note emissions are taken from specific units provided in CARB's Import Energy Reporting Data and EPA's egrid data.

Staff is seeking feedback on the evaluated carbon accounting methodologies and carbon emission benchmark and intends to bring this item back to the board in October for approval.

Attachments:

A. Electric Power Sector Protocol_v1.0_TCR;
B. Global Protocol for Community-Scale GHG Emissions; and
C. Power Source Disclosure – AB 1110 Implementation Rulemaking

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[i] http://www.pgecurrents.com/2018/03/26/independent-registry-confirms-record-low-carbon-emissions-for-pge/

Attachment Item 14A

The Climate Registry

Electric Power Sector Protocol for the Voluntary Reporting Program

Annex I to the General Reporting Protocol

June 2009
Version 1.0

FINANCIAL SUPPORT FOR THIS PROTOCOL

The Climate Registry wishes to acknowledge the following organizations for their financial contributions, which in part, made development of this protocol possible.

Xcel Energy®

SMUD
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Attachment Item 14A

Electric Power Sector Protocol
for the Voluntary Reporting Program

The Climate Registry

Annex I to the General Reporting Protocol

June 2009
Version 1.0

ABOUT THIS PROTOCOL

This protocol was developed with substantial input from The Climate Registry's Electric Power Sector Workgroup (see below for a list of workgroup members and organizations) which was composed of a broad range of individuals with expertise in reporting in this sector. The Registry also wishes to acknowledge Ryerson, Master and Associates, Inc. and its staff for their important role in developing this protocol, particularly the leadership of Ivor John. Additionally, the protocol reflects significant contributions from a Technical Expert Panel assembled by The Registry, consisting of over 130 stakeholders and electric power sector greenhouse gas reporting experts. Finally, The Registry's Protocol Committee, its chair Eileen Tutt, and Registry staff members Sam Hitz, Peggy Foran, Adam Regele and Jill Gravender all provided critical input throughout the process.

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ABBREVIATIONS AND ACRONYMS

ASTM	American Society for Testing and Materials
Btu	British thermal unit(s)
CCAR	California Climate Action Registry
CEMS	Continuous Emission Monitoring System
CHP	Combined Heat and Power
DG	Digester Gas
eGRID	Emissions & Generation Resource Integrated Database
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
EPS	Electric Power Sector
EWG	Exempt Wholesale Generator
FERC	United States Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GRP	General Reporting Protocol
GVP	General Verification Protocol
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
ISO	Independent System Operator
J	joule
kg	kilogram(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LDCs	Local Distribution Company
LHV	Lower Heating Value
LSE	Load Serving Entity
MMBtu	million British thermal units
MSW	Municipal Solid Waste
MT	Metric Ton
MW	megawatt
MWh	megawatt-hour
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
PFC	Perfluorocarbon
POD	Point of Delivery
POR	Point of Receipt
RATA	Relative Accuracy Test Audit
RECs	Renewable Energy Certificates
RPS	Renewable Portfolio Standard
T&D	Transmission and Distribution
WDF	Waste Derived Fuel

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PART I: INTRODUCTION

The Climate Registry's (The Registry) General Reporting Protocol (GRP) describes The Registry's voluntary reporting program and provides the basic framework for participating businesses, government agencies, and non-profit organizations to report their emissions of greenhouse gases (GHGs) to The Registry's voluntary program.

The GRP is designed to support the complete, transparent, and accurate reporting of an organization's GHG emissions in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, energy production, and GHG emissions in a quantifiable manner. By joining The Registry, participants agree to report their GHG emissions according to the guidelines in the GRP and its appendices. The reporting requirements of the GRP are the governing requirements for all Members.[1]

In order to support the unique GHG emissions sources of many of the industrial sectors participating in The Registry's reporting program, The Registry develops sector-specific reporting protocols. These protocols address sector-specific issues, and provide methodologies for calculating emissions from unique industry GHG emissions sources. This document (hereafter referred to as the "EPS Protocol") was developed by The Registry as a supplemental annex to the GRP for the electric power sector (EPS). It defines the additional reporting requirements for EPS organizations reporting to The Registry's voluntary program and in some instances provides alternative provisions to those of the GRP. It also provides specific interpretation of the GRP reporting requirements for the EPS' unique operations. As such it is intended to be used in conjunction with the GRP. Members will still need to use the GRP as the primary source document in understanding The Registry's basic reporting requirements and in quantifying and reporting emissions from many of their sources. In order to facilitate coordinated use of the GRP and this protocol, the EPS Protocol structure closely parallels that of the GRP.

The EPS involves all aspects of the electricity supply system, including power generation, transmission, and distribution.

The text box at the end of this introduction (Applicability: Who Must Use the EPS Protocol) gives a description of the operations included in the EPS Protocol, and the types of organizations that are required to use the EPS Protocol.

[1] *The Registry changed its nomenclature from "Reporters" to "Members" in the fall of 2008 to reflect the leadership Members demonstrate by reporting their emissions to The Registry and to highlight that its Members are part of a community of organizations committed to the application of best practices in GHG reporting.*

The EPS Protocol must be used by Members that own or control:

- electric power generating facilities;
- transmission systems that convey electricity from a generation facility to a distribution system; or
- distribution systems that convey electric power received from a generation facility or a transmission system to the final consumer.

These entities usually have facilities with the following root code in the North American Industry Classification System (NAICS):

2211 Electric Power Generation, Transmission and Distribution

This industry group is comprised of entities primarily engaged in generating, transmitting, and/or distributing electric power.

However more generally, the protocol applies to two main groups of entities – those involved with **power generation** and those involved with **power delivery** (transmission and/or distribution of electricity). As such the applicability of the protocol extends to the following types of entities:[2]

Power Generation

- Electric Utilities that operate generating facilities – including Investor-Owned Utilities (IOUs), federally-owned utilities, and other publicly-owned utilities.
- Electricity Power Generators – including Independent Power Producers (IPPs), Qualifying Facilities (QFs), Exempt Wholesale Generators (EWGs), and Non-Utility Generators (NUGs).
- Electric Cooperatives with generating facilities.

Power Delivery

- Transmission and Distribution (T&D) System Operators – including utilities, distribution cooperatives, and other Local Distribution Companies (LDCs).
- Bulk Power Transmission Operators – including utilities, Transmission Companies (or "Transcos"), Balancing Authorities, Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), and transmission cooperatives.
- Power Marketers, Energy Service Companies, or Retail Electricity Providers that do not own or operate power generation, transmission or distribution facilities. (These entities have the option report power deliveries metrics.)

A single entity –such as a vertically integrated utility – may have operations that are represented in more than one of the above categories. These entities will need to meet the reporting requirements for all of the categories in which they have operations. Refer to Figure 10.1 to identify the components of your operations covered by the EPS Protocol.

The EPS Protocol also extends to Members that deliver power to the grid in any amount that may not be covered by the 2211 classification, including renewable and other low or zero-emissions generation.[3] Certain sections of this protocol apply to Members that own or control power generating facilities that have no anthropogenic GHG emissions. This is because Members are required to calculate and report emissions metrics for all power generating facilities that deliver electricity to the grid. The data required for these facilities is primarily net power generated.

Entities that generate electricity, heat or steam for their own use and even for sale to outside entities whose facilities are not classified under 2211 and do not deliver electricity to the grid are not required to use the EPS Protocol. These entities should report using the GRP.

The EPS Protocol does not have any specific Scope 1 or Scope 2 reporting requirements for Power Marketers, Energy Service Companies or Retail Electricity Providers that do not own or control power generation, transmission or distribution facilities or systems. If these entities choose to develop power deliveries metrics for the electricity they provide to others (Chapter 19), then they must also calculate Scope 3 emissions for the electricity they deliver. (Refer to Section 5.5 for more details.)

The EPS Protocol does not contain guidance for reporting emissions from natural gas transmission and distribution operations, thus it does not provide a complete reporting methodology for electric utilities that also have natural gas operations.

The glossary included at the end of the EPS Protocol includes definitions and descriptions for many of the entities that participate in the EPS.

[2] *Note that a single entity may operate and report as both a power generator and as a power deliverer.*

[3] *For those entities that export relatively small amounts of electricity, the burden of reporting under this protocol is expected to be minimal, consisting mainly of reporting emissions associated with energy generation and data related to power exported to the grid.*

PART II: DETERMINING WHAT YOU SHOULD REPORT

Chapter 1: Introduction

1.1 GHG Accounting and Reporting Principles

REFER TO GRP.

1.2 Origin of The Registry's GRP

REFER TO GRP.

1.3 Reporting Requirements

REFER TO GRP.

1.4 Annual Emissions Reporting

You must report your emissions in The Registry's reporting software by **June 30th** of the year following the emissions year. You must successfully verify your emissions by **December 15th** of that same year. These dates are consistent with those in the GRP.

Chapter 2: Geographic Boundaries

2.1 Required Geographic Boundaries

REFER TO GRP.

The EPS Protocol requires Members to conform to the geographic boundary requirements articulated in the GRP (i.e. you must report all emissions sources in all Canadian provinces and territories, Mexican states, and U.S. states and dependent areas as well as indicate if any of your facilities are located in lands designated as Native Sovereign Nations).

Geographic boundary considerations for this sector within regional cap and trade systems can be complex, if those systems attempt to account for emissions associated with power imports that may be generated beyond the state or provincial borders of the region. For The Registry however, the relevant geographic region is North America and therefore boundary considerations are relatively straightforward. Where the EPS Protocol focuses on power purchases (Chapter 14), the frame of reference is the reporting entity's organizational boundaries, regardless of geographic boundaries, national or otherwise.

2.2 Optional Reporting: Worldwide Emissions

REFER TO GRP.

Chapter 3: Gases to Be Reported

3.1 Required Reporting of All Six Internationally-Recognized Greenhouse Gases

REFER TO GRP.

3.2 Optional Reporting: Additional Greenhouse Gases

REFER TO GRP.

Chapter 4: Organizational Boundaries

4.1 Two Approaches to Organizational Boundaries: Control and Equity Share

Section 4.1 of the GRP describes two approaches that can be employed to define the organizational boundaries of an entity for the purposes of emissions reporting:

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

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

The GRP requires that if a Member selects Option 2 and is a publicly traded corporation, it must also submit a list of its equity investment as part of its emissions report. (More information on this requirement is presented in the GRP, Section 4.3). The GRP also provides a discussion of some considerations to bear in mind when setting organizational boundaries.

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

If GRP Option 1 is selected, the entire entity's emissions must be reported on both an equity share and control basis. In using the equity share consolidation approach, it should be recognized that the EPS is characterized by complex organizational structures and assets that are shared in a variety of ways, including but not limited to equity positions, long-term purchase agreements, transmission rights, etc. In applying the equity share consolidation approach, it is important to distinguish a bona fide equity share from other kinds of joint financing or asset sharing.[4] In the CRIS reporting tool, separate entity-level emission totals will be consolidated using both methods. Members should refer to the GRP (Section 4.2 and Table 4.3) for more information, and consult The Registry's Member Services Department at (866) 523-0764 ext. 3 or help@theclimateregistry.org to further discuss the requirements for reporting according to equity share.

4.3 Option 2: Reporting Using the Control Consolidation

Section 4.3 of the GRP provides instructions on how Members generally apply GRP Option 2 for organizational boundaries. The EPS Protocol places one additional requirement on Members selecting GRP Option 2 – emissions from any electric generating facilities that the Member has an equity share in must be reported, whether they control the facility or not.[5] This supplemental requirement applies only to emissions associated with electric generation units at the facility (i.e. combustion emissions and related process and fugitive emissions) and not to other types of ancillary operations (e.g. associated mobile sources or

4 Reporting indirect emissions for transmission systems and for transmission and distribution systems can be complex, especially when there are multiple owners involved. EPS Members are advised to consider this carefully before selecting Option 1 with complete equity share reporting.
5 The requirement to report emissions associated with equity share in generating facilities is additional to the organizational boundary requirements of Option 2. However, this additional information will not be consolidated into the organization's overall emissions totals if Option 2 is selected.

indirect emissions from electricity consumption).

This additional equity share information allows The Registry to compile a complete and comparable inventory of power generation emissions, the most significant source of emissions within this sector. This supplemental requirement is largely consistent with industry practice and it provides a way for vertically integrated utilities to report the equity share of their power generation facilities while still reporting emissions for transmission and distribution systems solely on a control basis.[6]

Emission reports of Members that select GRP Option 2 for organizational boundaries will be aggregated to the entity level using control as the consolidation approach. While the supplemental equity share emissions for power generation will not be aggregated as part of an entity's total emissions, The Registry's reporting software will generate an emissions report that separately shows these equity share emissions for each electric generating facility.

6 Without this provision, Members wishing to provide power generation emissions according to the equity share consolidation approach would be required to report all other emission sources according to equity share. This is especially challenging for transmission systems, which are often characterized by complex ownership arrangements.

4.4 Examples: Applying Organizatonal Boundaries to Power Generating Operations

4.1

EXAMPLE 4.1

A power plant operated by Company A has four electric generating units. The first three units are owned by Company A, and the fourth Unit is owned by Company B. Each unit has 100,000 metric tons of emissions (CO_2e). The facility also has a fleet of three vehicles with an aggregate of 100 metric tons of CO_2e emissions, a facility-wide fire suppression system (10 metric tons, CO_2e), and a central control room with an HVAC unit (five metric tons CO_2e). How are the direct (Scope 1) emissions divided up between the two entities?

It is determined that Company A has operational control of the facility, and as such, all emissions are assigned to this entity under the control option (400,115 metric tons CO_2e). The emissions associated with power generation (400,000 metric tons CO_2e) are identified as such and reported separately from the non-generation emissions (115 metric tons CO_2e). Company B reports zero emissions under the control approach.

The EPS Protocol also requires supplemental equity share emissions reporting for power generation. In this example, the equity share of power generation emissions for Company A would be 300,000 metric tons CO_2e, and 100,000 metric tons CO_2e for Company B. The vehicle, fire suppressions system and HVAC unit emissions are not included in the supplemental equity reporting of emissions because they are not associated directly with power generation.

The allocation of power generation emissions is summarized below for both consolidation approaches.

	Ownership	Control Consolidation		Equity Share Consolidation	
		Company A	Company B	Company A	Company B
Unit 1	Company A (100%)	100,000 MT	0 MT	100,000 MT	0 MT
Unit 2	Company A (100%)	100,000 MT	0 MT	100,000 MT	0 MT
Unit 3	Company A (100%)	100,000 MT	0 MT	100,000 MT	0 MT
Unit 4	Company B (100%)	100,000 MT	0 MT	0 MT	100,000 MT
Total Power Generation	**Company A (75%), Company B (25%)**	**400,000 MT**	**0 MT**	**300,000 MT**	**100,000 MT**

4.2

EXAMPLE 4.2
Entity Aggregation of CO_2 Emissions from Power Generating Facilities

An entity has an ownership interest in five power plants that emit CO_2 emissions as shown in the table below. The entity consolidation of emissions for control and equity share based reporting are also shown in this table.

	CO_2 Emissions (MT)	Equity Share	Control (Y/N)	Control-Based Report CO_2 Emissions (MT)	Equity Share Report CO_2 Emissions (MT)
Plant 1	5,000,000	100%	Y	5,000,000	5,000,000
Plant 2	3,600,000	33%	N	0	1,200,000
Plant 3	160,000	75%	Y	160,000	120,000
Plant 4	500,000	50%	Y	500,000	250,000
Plant 5	250,000	20%	N	0	50,000
Total	**9,510,000**			**5,660,000**	**6,620,000**

4.5 Corporate Reporting: Parent Companies & Subsidiaries

In cases where a parent company reports to The Registry, the EPS Protocol requires the holding/parent company to disaggregate emissions by subsidiary (i.e. apply this protocol separately to each subsidiary), for any subsidiary that operates a distinct retail electricity provision business (i.e. a Local Distribution Company).[7] Emissions from these key subsidiaries will ultimately be consolidated at the parent level in entity-level reports, but reporting in this disaggregated fashion will allow for the calculation of emissions (and metrics, if applicable) that are meaningful at the local subsidiary level.

While the GRP encourages entities to report at the highest level, it is recognized that in some cases a subsidiary chooses to join The Registry, and its parent company (or holding company) chooses not to report. If a parent company reports to The Registry using the GRP, the separate emissions for each subsidiary would not typically be reported separately.

In the EPS, parent companies often have subsidiaries that are distinct retail providers of electricity and some parent companies may deem it important for their subsidiaries to be able to report separately. Because of this, The Registry recognizes that a parent company may decide not to report, but instead encourage or require its subsidiaries to report as distinct entities. This may be another transparent way to coordinate reporting to The Registry.

4.6 Government Agency Reporting

Most Municipal Utilities and many other local, state, and federal utilities are affiliated in some way with a city, county or other general-purpose local government that has operations in addition to electricity power supply. For the municipalities that own or control these utilities, The Registry has adopted the Local Government Operations (LGO) Protocol, which provides guidance on how to report all of a local government's emissions at the facility level. All local governments will need to use the LGO Protocol as their principle reporting protocol. However, the LGO Protocol instructs public electric utilities that are part of a larger local government entity to report their EPS emissions using this EPS Protocol and indicate which emissions sources are associated with their electric utility within CRIS. This public utility data will be aggregated separately from the rest of the local government's operations. Requiring the public or municipal utility component of a local government to report using the EPS protocol will facilitate comparison between public and private electric utility entities. However, a public utility's emissions will also be aggregated into the emissions report corresponding to the larger local government of which it is a part.

[7] The Registry permits holding companies to choose to disaggregate their reporting in an even more detailed manner by choosing to apply the EPS Protocol to other subsidiaries such as wholesale electricity supply subsidiaries. However, disaggregation to the subsidiary level is required only for the subsidiaries which are Local Distribution Companies. In such cases, The Registry's requirements for material accuracy (GVP) and limitation, on the use of simplified methodologies (Chapter 11) will be applied at the subsidiary level as well as the entity level.

4.7 Reporting Emissions Associated with Bulk Power Transmission Losses

When applying an organizational boundary approach consistent with GRP Option 1, Members should treat the emissions associated with bulk transmission system losses as they would any other source (i.e. report emissions associated with your equity share of the source).

With GRP Option 2, the responsibility for reporting the indirect emissions associated with losses on bulk power transmission systems belongs with the entity that controls the system. Consequently, the entity responsible for reporting depends on the selected control consolidation methodology (operational or financial).

With financial control, it is likely that the primary owner of the asset will be the controlling party. This entity will have the most at stake when financial decisions are made concerning capital improvements and maintenance.

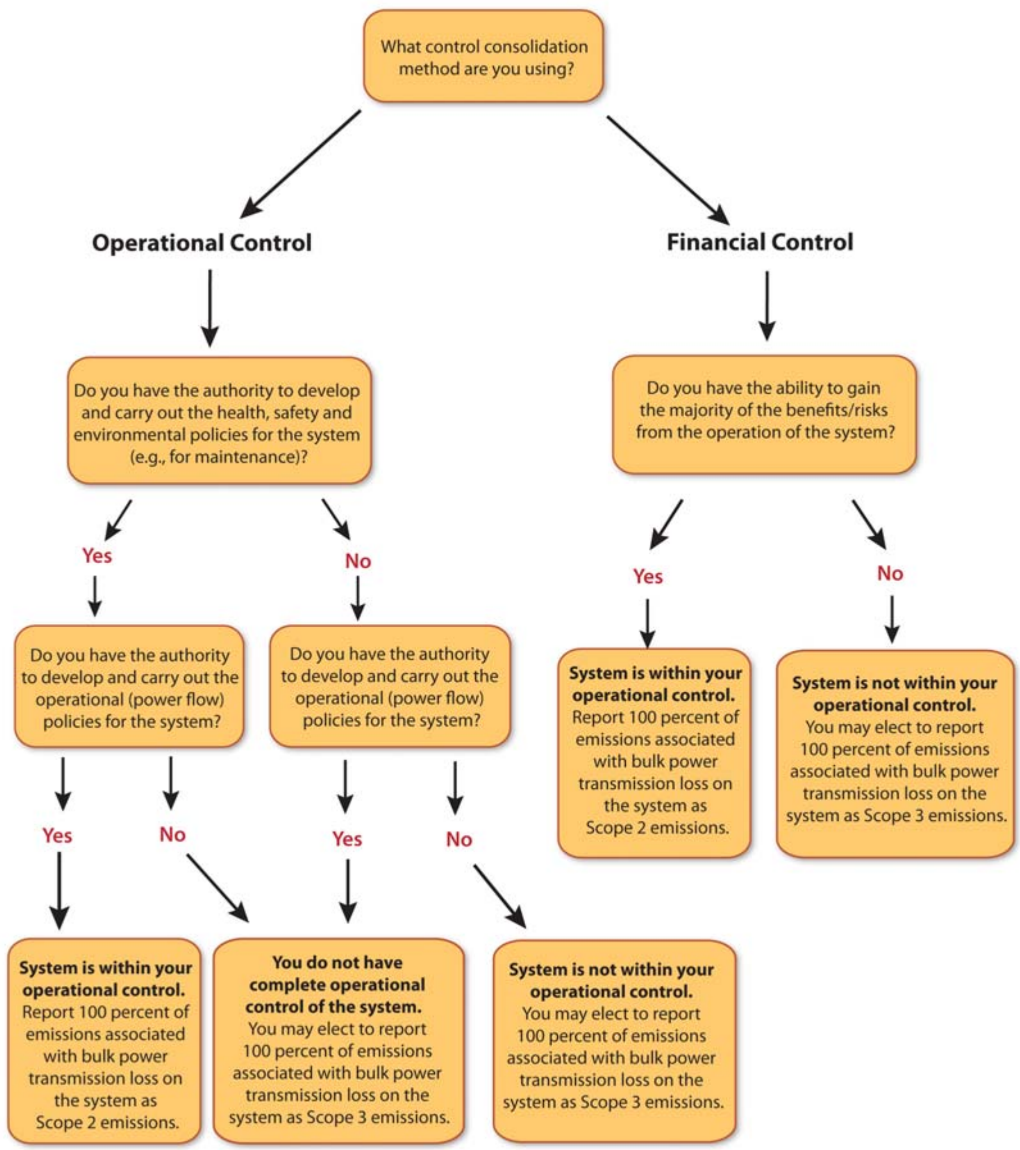
However, when a Member selects the operational control approach, bulk power transmission systems can raise unique challenges. The complex arrangements in place for managing the day-to-day operation of these transmission systems often make it difficult for Members to understand their control responsibilities. For example, transmission systems are often co-owned by a number of entities, and the lines can be operated by one entity and maintained by another.

In applying a standard sense of operational control, it is possible that more than one entity could be deemed responsible for reporting emissions associated with bulk power transmission losses. The entity that has the authority to implement the environmental, health and safety policies related to a system – typically the entity that manages the physical aspects (lines, substations, etc.) of the transmission system – could be deemed to have partial operational control and hence the responsibility to report the emissions associated with losses on that system. In other cases, a different entity may have partial operational control by virtue of managing the day-to-day power flows through the system; while they may not control the physical aspects of the system itself, they often control the amount of power transmitted across the system, affecting the associated emissions of the line losses.

A Registry Member reporting under the operational control approach that has control of both the implementation of environmental, health and safety standards as well as the day-to-day power flows traveling across the system is deemed to have complete operational control of the bulk power transmission system and is required to report 100 percent of the emissions associated with bulk power transmission losses as Scope 2 emissions. Entities that have only partial control however are not required to report bulk power transmission losses.

Figure 4.1 is a decision tree designed to provide guidance to Members when determining whether emissions associated with bulk power transmission losses are within their organizational boundary. Methodologies for calculating the indirect emissions associated with bulk power transmission system losses are included in Section 14.3 of the EPS Protocol.

Figure 4.1 Decision Tree for Determining Reporting Requirements for Emissions Associated with Bulk Power Transmission Loss



Chapter 5: Operational Boundaries

5.1 Required Emission Reporting

The GRP includes methodologies for reporting emissions for Scope 1 and Scope 2 emission sources that are not unique to the EPS, including stationary combustion sources, mobile sources, common fugitive sources, and indirect emissions from purchased electricity. As with the GRP, the EPS Protocol requires Members to report all Scope 1 and Scope 2 emissions.

The EPS Protocol includes methodologies for reporting Scope 1 emissions associated with electric power generation and Scope 2 emissions associated with losses that occur through electric power transmission and distribution and with consumption of purchased electricity by the reporting Member. Some Members will, as part of the process of reporting emissions associated with transmission and distribution losses, also report emissions associated with power purchases that ultimately are delivered to customers.[8] This protocol also includes direction for calculating these Scope 3 emissions.

Members with power generation operations are also required to report some non-emissions data (e.g. generation output) that are needed to calculate power generation metrics. The EPS Protocol also provides an option for Members to calculate and report power deliveries metrics. Members that choose to report power deliveries metrics must follow the methods provided in Chapter 19.

Subsequent sections of the EPS Protocol provide detailed guidance on reporting sources of emissions that are related directly to power generation and power delivery, including Scope 1, 2, and 3 emissions and metrics. Table 5.1 provides a matrix of likely emission source categories for a range of EPS entity types. Some Members will have more than one operational activity within their organizational boundaries, in which case their emissions inventory will include emissions from all categories applicable to those operations. For example, a vertically integrated utility will have emissions associated with power generation, power transmission and power distribution.[9] Table 5.1 should not be interpreted as an exhaustive list of emissions categories for your entity, as the operations undertaken by entities within each of these headings can be different; however it does provide an indication of the likely sources for each type of EPS entity.

8 Only Members that are required to report emissions from transmission and distribution, and choose to use a particular energy balance methodology described in Chapter 14 will report these emissions.

9 Most Members will also have other direct sources of emissions from non-generation stationary combustion, such as mobile combustion, fugitive and process emissions. Methods for calculating and reporting these emissions are provided in the GRP and are not indicated in Table 5.1.

5.1 TABLE 5.1
Expected Emissions Categories for Various EPS Organizations

EPS Report Entity Type

	Fossil Generator[1]	Other Generator[2]	Transmission Company, Balancing Authority, ISO[3]	Local Distribution Company[4]	Marketer/ Intermediary/ Retail Provider[5]
Direct Emissions (Scope 1)					
Stationary Combustion	√	√			
Process Emissions	√	√			
Fugitive Emissions	√	√			
Direct Emissions (Biogenic)					
Stationary Combustion		√			
Process		√			
Indirect Emissions (Scope 2)					
Bulk Power Transmission Losses			√		
Wheeled Power			√		
Local T&D Losses				√	√
Purchased and Consumed Electricity	√	√	√	√	√
Other Indirect Emmisions (Scope 3)[6]					
Specified Purchases			√	√	√
Other Purchases			√	√	√
Direct Access			√	√	
Power Exchanges			√	√	
Wheeled Power			√		

Notes:

1. Fossil Generator is an entity that owns, controls or shares ownership in a facility that uses fossil fuels for power generation, including coal, oil, waste oil fuel or waste tires. These entities will report emissions and power output for these facilities.

2. Other Generator is any entity that generates power at facilities using fuels and technologies that are not fossil fuels. Relevant facilities include nuclear, hydro, geothermal, biomass, biogas, and other renewable power generation. These entities will report anthropogenic and biogenic emissions, if applicable, and power output by facility.

3. Transmission companies, Balancing Authorities and Independent System Operators are required to report indirect emissions if they control the bulk power transmission systems they oversee.

4. Local Distribution Companies are required to report indirect emissions if they control a local transmission and distribution system.

5. Power Marketers, intermediaries and retail service providers that do not own or control physical assets (such as generation facilities or transmission or distribution systems) are not responsible for reporting Scope 1 emissions. The only Scope 2 emissions these entities are expected to have are those associated with purchased and consumed electricity. These entities may opt to report emissions associated with the power they purchase for resale (Scope 3). This is a necessary step for marketers, intermediaries or retail service providers that choose to report power deliveries metrics and do not already report their purchases as part of a T&D loss calculation.

5.2 Direct Emissions: Scope 1

The EPS Protocol provides specific methods to address the following types of Scope 1 emission sources involved in power generation and power delivery:

1. **Stationary combustion emissions.** These are emissions from the production of electricity at facilities owned or controlled by your organization.[10,11] (Chapter 12)
2. **Fugitive emissions.** These are the emissions of: (a) SF_6 from high voltage equipment used in electricity transmission and distribution systems, (b) HFCs from power generation air intake chillers, and (c) CH_4 emissions from coal piles (Chapter 16).
3. **Process emissions.** These are emissions from acid gas/SO_2 scrubbers, geothermal facilities, and other small sources associated with electric power generation (Chapter 17).

Scope 1 emissions not directly related to power generation or power delivery, such as emissions from vehicles and buildings, should be reported following the requirements of the GRP.

5.3 Indirect Emissions: Scope 2

The EPS Protocol provides specific methods to address the following types of Scope 2 emission sources:

1. **Indirect emissions associated with T&D system losses.** These are the emissions associated with the portion of purchased electricity that is consumed (i.e. lost) in the T&D system (Section 14.2).
2. **Indirect emissions associated with losses in the bulk power transmission system.** These are the emissions associated with (1) the portion of purchased electricity consumed in the transmission system prior to delivery to a T&D system, and (2) the portion of wheeled electricity that is consumed in the transmission system prior to delivery to another transmission system (Section 14.3).
3. **Purchased or acquired electricity, steam, or heat for own consumption.** These are the emissions associated with purchased electricity, steam/heating/cooling consumed in owned equipment or facilities (e.g., office buildings and maintenance facilities) (Section 14.4).

10 Combustion emissions from mobile generators that produce electricity (for example for demand response) must also be included as an EPS source of Scope 1 emissions if the electricity is delivered to the grid.

11 The EPS Protocol also has methodologies for calculating biogenic CO_2 emissions; however, these emissions are reported separately from the scopes.

5.4 Reporting Emissions from Biomass Combustion

The GRP includes direction for quantifying and reporting biogenic emissions from the combustion of biomass separately from any anthropogenic emissions. This approach is consistent with the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories. This approach also supports The Registry's goal to uphold policy-neutral reporting, which allows groups analyzing the data to make their own determinations about the carbon neutrality of emissions from biomass combustion.

The EPS Protocol requires that Members report certain biogenic process emissions in addition to the stationary and mobile biogenic emissions required to be reported in the GRP. These required biogenic process emissions are necessary to determine accurate power generation and power deliveries metrics (Chapter 18).

Chapter 12 of the EPS Protocol includes further guidance to allow power generators to estimate emissions from a wider range of biogenic sources used for power generation, and for fuels (such as Municipal Solid Waste) that consist of a mixture of fossil and biogenic source material.

5.5 Scope 3 Emissions

The Registry requires that Members use the following sources of Scope 3 emissions to calculate the indirect emissions described in section 5.3 when they own or control transmission and/or distribution systems (Chapter 14):

1. *Emissions associated with power purchased and delivered to wholesale customers or end users (in scenarios where the Member is an LSE).* These Scope 3 emissions are important for calculating the Scope 2 emissions associated with Transmission and Distribution losses (Chapter 14), and the power deliveries metrics (Chapter 19) if you choose to calculate and report these metrics.
2. *Emissions associated with power wheeled across your transmission lines.* These emissions are important for determining losses associated with the transmission or distribution of wheeled power (Chapter 14).

Members may report Scope 3 emissions as optional data. These include GHG emissions that occur upstream (and outside of your organizational boundaries) of the generation of electricity (e.g. mining of coal or nuclear fuels, refining of fuel oil, extraction of natural gas, emissions from fuel cell reformers, emissions from the manufacture of solar panels, and emissions from the production of biofuels). Members are encouraged but not required to report these emissions when they fall outside of a Member's organizational boundary.

Emission sources commonly found in the EPS are summarized in Table 5.2.

5.2 TABLE 5.2
Overview of EPS Emissions Sources and Gases

DIRECT EMISSIONS		
Technology/Segment	**Source Type**	**Greenhouse Gases**
Boilers	Natural Gas Boilers Residual or Distillate Oil Boilers Coal-fired Boilers (pulverized coal, fluidized bed, spreader stoker, tangentially fired, wall fired, etc.) Biomass-fired Boilers Dual-fuel Fired Boilers Auxiliary Boilers	CO_2, CH_4, N_2O
Turbines	Combined Cycle Gas Simple Cycle Gas Combined Heat and Power Microturbines Steam Turbines Integrated Gasification Combined Cycle, etc.	CO_2, CH_4, N_2O
Internal Combustion Engines	Emergency and Backup Generators Reciprocating Engines Compressors Firewater Pumps Black Start Engines, etc.	CO_2, CH_4, N_2O
Other Electricity Generation	Fuel Cells Geothermal Anaerobic Digesters Refuse-derived Fuels, etc.	CO_2, CH_4, N_2O
Electricity Transmission and Distribution	Circuit Breakers and Other Equipment with SF_6	SF_6
Reservoirs Used for Hydroelectric Power Generation	Fugitive emissions from decomposing organic matter	CO_2, CH_4
Electricity Generation, Fuel Storage	Coal Piles, Biomass Piles	CH_4
Electricity Generation	Air Intake Chiller – Power Generation	HFCs
Electricity Generation	Fire Extinguishers	CO_2, HFCs, PFCs
INDIRECT EMISSIONS		
Technology/Segment	**Source Type**	**Greenhouse Gases**
Electricity Transmission	Transmission Line Losses	CO_2, CH_4, N_2O
Electricity Distribution	Transmission & Distribution Losses	CO_2, CH_4, N_2O
Electricity Consumption	Buildings and Offices[12]	CO_2, CH_4, N_2O
Electricity Generation	Imported steam or heat for power generation	CO_2, CH_4, N_2O

12 This source is not unique to EPS, but the methodology for estimating emissions is unique for many Members where the electricity consumed includes self-generated power (Chapter 14).

Chapter 6: Facility-Level Reporting

6.1 Required Facility-Level Reporting

REFER TO GRP.

6.2 Defining Facility Boundaries

REFER TO GRP.

6.3 Optional Aggregation of Emissions from Certain Types of Facilities

In general, the GRP provisions in Section 6.3 that allow for aggregation of certain types of sources and facilities also apply to the EPS.

Additionally, Members in the EPS may choose to aggregate the emissions (if any) and net power generation by generation type for zero or low emitting electric generating facilities (e.g. hydro, wind, solar, etc) that may be geographically distributed.

Members may also select to aggregate all lines in a T&D system or for selected subsets of the T&D system. Substations and their equipment (breakers, transformers, etc.) may be considered part of the T&D system for estimating T&D losses and fugitive emissions of SF_6.

If a T&D system crosses state or national borders, the system should be reported at the most appropriate geographical level. For example, if a T&D system crosses state or provincial lines but does not cross national borders, it should be reported as a country-level facility. If a T&D system crosses national borders, it should be reported as a North American facility.

In many cases, the control and operation of bulk power transmission pathways (including interconnections from one control area to another) are managed in a different way than the T&D lines used to deliver power to retail consumers within a utility's service area. As such, it is acceptable to treat the T&D system within the service area as one reporting facility, and to treat the bulk power transmission lines as a distinct facility. Chapter 14 provides further guidance about how to establish reporting boundaries for this type of situation.

6.4 Categorizing Mobile Source Emissions

REFER TO GRP.

6.5 Unit Level Data

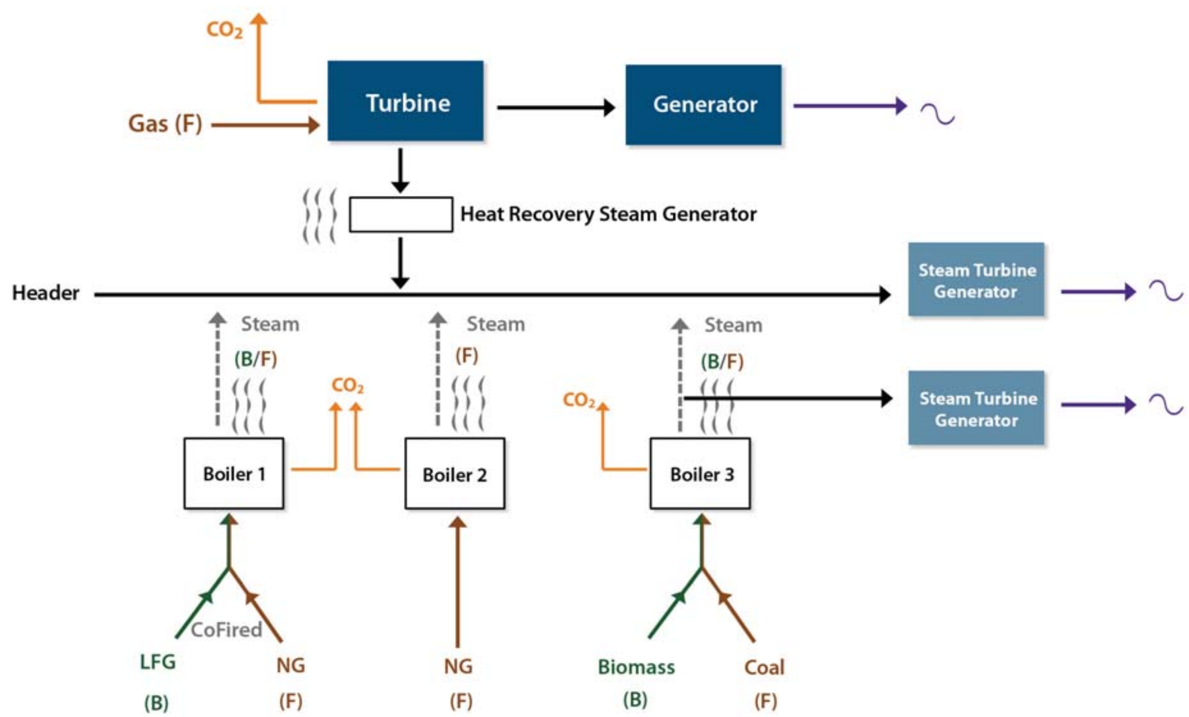
Members in the EPS must follow the basic GRP requirements for facility level reporting. However, many large electric generation facilities are comprised of multiple combustion and generation devices. In some instances, the ownership of these devices within a single facility may vary from one to the next (i.e. ownership of the overall facility does not mirror the ownership of the individual devices that comprise the facility). This creates challenges when trying to determine overall facility emissions on an equity share basis (either as part of Option 1 for organizational boundaries or for the supplemental requirement to report any equity share emissions from electric generation facilities that is part of Option 2).

When ownership of devices within a facility varies, output and GHG emissions must be reported at a sub-facility level. Depending on the particular configuration of combustion devices and generating units this might require separate reporting for each combustion device, generating device or effluent stack, together with the equity share the reporting Member has in each device or unit. When combustion devices are owned by more than one entity, the emissions must be pro-rated between owners based on the equity share. This additional requirement for reporting equity share emissions at the sub-facility level ensures that emissions can be consolidated in a way that reflects the Member's selected organizational boundary approach, and to ensure that power generation metrics are calculated properly (Chapter 18).

Unit level reporting is only required when there is shared ownership of the combustion devices or generating units at a single facility, and the ownership structure varies from device to device. If this does not occur, no unit level reporting is required. It should be noted that even when unit level reporting is required, the total facility emissions will still be reported by one entity under the control consolidation method.

Figure 6.1 depicts a hypothetical facility in which there are multiple combustion devices including boilers, a combustion turbine, and shared generating units. When the combustion devices and/or generators are owned by different entities, the emissions and output need to be accurately attributed to each owner. This must be done by pro-rating emissions based on heat input or steam production for each combustion device, and/or electricity generation. How this is done in practice will depend on what operational variables are being measured and the degree of accuracy associated with each. Example 6.1 provides a hypothetical ownership scenario based on Figure 6.1.

Figure 6.1 Generation Facility with Multiple Units



Notes:

B	– Biofuel with biogenic CO_2 emissions	LFG	– Landfill Gas
F	– Fossil fuel with anthropogenic emissions	NG	– Natural Gas

6.5.1 Example: Reporting Unit Level Data

6.1

EXAMPLE 6.1
Reporting Responsibilities for Facilities where there is a Shared Ownership of Generating Units and Non-Generating Equipment

Company A and Company B are both reporting to The Registry according to GRP Option 2. A power plant operated by Company A has four combustion devices. The first three are boilers owned by Company A, and the fourth unit is a turbine owned by Company B (see Figure 6.1). Each of these four combustion devices has 100,000 metric tons of emissions (CO_2e). The facility also has a fleet of three vehicles with an aggregate of 100 metric tons of CO_2e emissions, a facility-wide fire suppression system (10 metric tons, CO_2e), and a central control room with an HVAC unit (five metric tons CO_2e).

Company A has operational control of the facility, and as such, all emissions are assigned to this entity under the control option (400,115 metric tons CO_2e). The emissions associated with power generation (400,000 metric tons CO_2e) are tagged as such and reported separately in CRIS from the non-generation emissions (115 metric tons CO_2e). Company B reports zero emissions with this option.

The EPS Protocol also requires equity share consolidation for power generation. In this example, the equity share of power generation emissions for Company A would be 300,000 metric tons CO_2e and 100,000 metric tons CO_2e for Company B. The vehicle, fire suppressions system and HVAC unit emissions are not included in the equity reporting of emissions because they are not associated directly with power generation.

Chapter 7: Establishing and Updating the Base Year

7.1 Required Base Year

Section 7.1 of the GRP outlines The Registry's requirement for Members to set, and under certain circumstances, adjust base year emissions. Setting a base year serves the specific purpose of allowing Members to normalize their emissions in terms of their organizational structure within The Registry's database. Base year emissions are then adjusted when there are significant and relevant changes (changes can include mergers, acquisitions, or divestments of sources that existed in the base year—see Section 7.1 of the GRP for a description of relevant changes) in the Member's organizational structure. A Member's base year is defined as the earliest reporting year to The Registry in which a complete emission report is submitted (i.e. a non-transitional report—see GRP Chapter 8: Transitional Reporting). Significant changes are defined as those changes to organizational structure that result in a cumulative change of five percent or more in your entity's total base year emissions (Scope 1 plus Scope 2, and Scope 3 if reported).

7.2 Updating Your Base Year Emissions

A Member within the EPS can have large swings between Scope 1 (owned or controlled generation) and Scope 3 (power purchases) and concomitant variation in Scope 2 emissions (T&D losses), due to year-to-year operational decisions to purchase versus generate electricity.[13] Although these swings may be significant, they do not represent swings that are due to changes in the actual organizational structure of the entity. Consequently, Members should not adjust their base year in response to such changes. Please see the GRP's base year discussion of emitting activities that are "insourced" or "outsourced" for more information (GRP Chapter 7).

Members that anticipate dramatic swings between the different categories of their emissions (i.e. Scope 1, 2 or 3) from year to year are encouraged to upload additional public documents in The registry's reporting software (see GRP Chapter 19) to add explanatory notes for any such emissions swings.

7.3 Optional Reporting: Updating Intervening Years

REFER TO GRP.

[13]This may be particularly true for utilities that own or control significant hydropower operations. For example, a dry year may necessitate the purchase of significant quantities of power from other generation sources.

Chapter 8: Transitional Reporting (Optional)

8.1 Reporting Transitional Data

REFER TO GRP.

8.2 Minimum Reporting Requirements for Transitional Reporting

The GRP indicates that the minimum requirements for transitional reporting are as follows:

- A transitional reporter must report at a minimum all CO_2 emissions from stationary combustion for all of its operations in at least one state, province or territory

- All transitional emission reports must be third-party verified by a Registry-recognized Verification Body

These minimum requirements for transitional reporting remain unmodified for the EPS Protocol. However, while the GRP encourages Members reporting transitionally to exceed the minimum requirements in their report and to report as comprehensively as possible, the EPS Protocol recognizes that in many instances, these Members may not be able to report the supplemental information required by the EPS Protocol, until they report completely.

For instance, it is difficult and of limited meaning to report Scope 2 line loss emissions associated with a T&D system that spans multiple states, provinces, territories or Native Sovereign Nations, if a Member is not yet reporting on a complete geographic basis.

Consequently, the EPS Protocol strongly recommends that Members who are reporting transitionally not report the following emissions categories until they report completely:

- Scope 2 emissions associated with T&D line losses
- Scope 3 emissions from power purchases and wheeled power
- Power deliveries metrics (optional)

8.3 Public Disclosure of Transitional Data

REFER TO GRP.

Chapter 9: Historical Reporting (Optional)

9.1 Reporting Historical Data

REFER TO GRP.

9.2 Minimum Reporting Requirements for Historical Data

REFER TO GRP.

9.3 Importing Historical Data

REFER TO GRP.

9.4 Public Disclosure of Historical Data

REFER TO GRP.

PART III: QUANTIFYING YOUR EMISSIONS

Chapter 10: Introduction to Quantifying Your Emissions

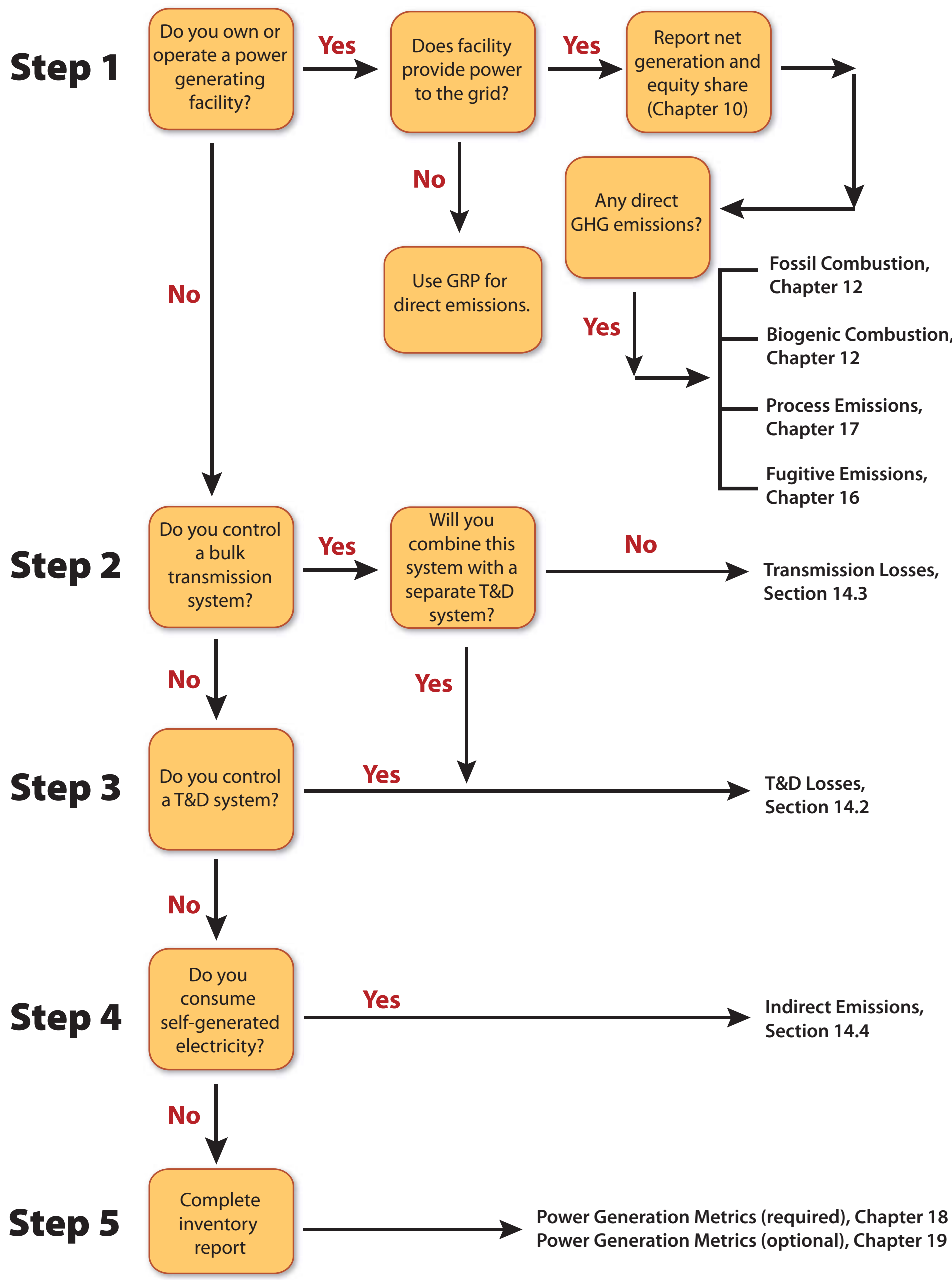
Part III of the EPS Protocol includes detailed methods for calculating emissions associated with electric power generation, transmission and distribution (Chapters 10 through 17).

The following summary indicates the chapters where Part III of the protocol provides additional direction for the EPS:

Chapter 10	Introduction to Quantifying Your Emissions
Chapter 11	Simplified Estimation Methods (no change from GRP)
Chapter 12	Direct Emissions from Stationary Combustion (includes specific methods unique to EPS)
Chapter 13	Direct Emissions from Mobile Combustion (no change from GRP)
Chapter 14	Indirect Emissions from Electricity Use (includes specific methods unique to EPS)
Chapter 15	Indirect Emissions from Imported Steam, District Heating, Cooling and Electricity from a CHP Plant (no change from GRP)
Chapter 16	Direct Fugitive Emissions (includes specific methods unique to EPS)
Chapter 17	Direct Process Emissions (includes specific methods unique to EPS)

Figure 10.1 is a flow chart that you should use to identify your reporting requirements. The specific chapters and methodologies that apply to your entity will depend on your organizational and operational boundaries.

Figure 10.1 Flow Chart Showing Reporting Requirements and Relevant Quantification Chapter for EPS Members



Chapter 11: Simplified Estimation Methods

REFER TO GRP.

Chapter 12: Direct Emissions from Stationary Combustion

This chapter applies to Members that own or control any combustion facilities or devices used for electricity generation and it supplements the guidance provided for general stationary combustion included in the GRP. Members must report power generation and non-power generation stationary combustion sources separately. This chapter applies only to the power generating sources.

The data elements you will need for reporting stationary combustion emissions associated with electricity generation are as follows:

- Facility (or combustion device) name
- Control of facility (or combustion device) (Y/N)
- Equity share (percent) of facility (or combustion device)
- Fuel types per facility (or combustion device)
- Fuel use (MMBtu or J) per facility (or combustion device)
- Emissions for each GHG (metric tons) per facility (or combustion device)

It should be noted that this information is required at the combustion device level only when needed to address shared ownership relationships or equity share reporting (Chapter 6.5).

Emissions from auxiliary boilers used to supplement the prime mover heat source upon startup and any engines used for startup assistance should be considered to be directly associated with power generation and must be reported according to the requirements in this chapter. However, auxiliary boilers used for building heat or used solely to provide steam to another customer are not part of the power generation system, and should be treated in the same way as any other GRP emission source. Similarly, the emissions from portable generators should only be included with other power generation emissions if they are specifically used for grid power generation.

Additionally, the following sources (even when associated with a power plant) are not part of power generation and should be reported using the GRP: mobile sources, fire suppression equipment, and air conditioning or refrigeration units for power plant office buildings and in vehicles.

Members may calculate stationary combustion emissions using a Continuous Emissions Monitoring System (CEMS) or based on fuel use and heat input or carbon content. The methods provided in the EPS Protocol to calculate stationary combustion emissions for power generation are summarized in Table 12.1.[14,15]

[14] *Methods EPS ST-01 through EPS ST-07 have been adapted from the State of California's mandatory reporting regulations (California Code of Regulations Title 17, Subchapter 10, Article 2, Sections 95110 to 95115).*

[15] *When using EPS ST-02, EPS ST-03 or EPS ST-04, refer to the GRP for guidance on using oxidation factors and the current emission factors.*

12.1 TABLE 12.1 Summary of Calculation Methods for Stationary Combustion Emissions

Direct CO_2 Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
EPS ST-01-CO_2	Direct Monitoring	Continuous emissions monitoring (CEMS)
EPS ST-02-CO_2	Calculation Based on Fuel Use	Measured fuel consumption, measured carbon content of fuel (per unit mass or volume)
EPS ST-03-CO_2	Calculation Based on Fuel Use	Measured fuel consumption, measured heat content of fuels and default emission factor
EPS ST-04-CO_2	Calculation Based on Fuel Use	Measured fuel consumption, default heat content, default emission factor

Biogenic CO_2 Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
EPS ST-05-CO_2	Calculation Based on Heat Input	Imputed heat input and default carbon content
EPS ST-06-Partioning anthropogenic and biogenic CO_2	Direct Measurement or default (MSW and WDF)	Sample analysis or waste characterization study (MSW and WDF)
EPS ST-07-CO_2 Biogas	Calculation Based on Fuel Use	Measured fuel consumption and measured carbon or, measured or default heat content

Direct CH_4 and N_2O Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
EPS ST-08-CH_4 and N_2O	Calculation Based on Fuel Use	Source test based emissions factors; Measured fuel consumption and measured or default heat content

Once a calculation methodology has been chosen, in most cases the same methodology should be used for reporting emissions in all subsequent years. This does not preclude a Member from changing to an alternative method if doing so will lead to more accurate or comprehensive reporting. However, changing calculation methodologies may trigger a base year adjustment review as described in Chapter 7 of the GRP.

12.1 Measurement of Carbon Dioxide Using Continuous Emissions Monitoring System Data

This section discusses the provisions for reporting your CO_2 emissions using CEMS data. This section applies to the use of CEMS data for anthropogenic emissions (fossil fuel combustion) and biogenic emissions (biomass or biogas combustion).

In the U.S., many of the power generators reporting under the EPS Protocol must use Continuous Emissions Monitoring Systems (CEMS) as required under the U.S. Environmental Protection Agency's (EPA) acid rain regulation (40 CFR Part 75). Others generating power from landfill gas, municipal solid waste, and other waste derived fuels are subject to similar monitoring requirements under 40 CFR Part 60.

In Canada, the following documents from Environment Canada outline specifications for the design, installation, certification, and operation of CEMS used for fossil fuel-fired steam and electric generating facilities in Canada. They include procedures used to determine the standards for CEMS measurements during initial certification testing as well as subsequent long-term operation of the monitoring system.

- From Environment Canada's Website: http://www.ec.gc.ca/cleanair-airpur/Pollution_Sources/Electricity_Generation/Guidelines_and_Codes_of_Practice-WS047445FC-0_En.htm
- Environment Canada's "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation, Report EPS 1/PG/7 (revised)," originally published in 1993 and updated in November 2005.

CO_2 emissions data compiled using systems that meet the specifications in these federal procedures (U.S. or Canada) will be acceptable for reporting to The Registry. If you are reporting CO_2 emissions to the U.S. EPA or Environment Canada under these CEMS programs, you are encouraged to report those same emissions values to The Registry. The specific method for compiling and reporting emissions is presented below (EPS ST-01).[16]

If you are not required to report under any of the aforementioned regulations, but operate a CEMS device comparable with EPA or Environment Canada provisions, you may also use this method to report to The Registry.

Members are strongly encouraged to consider reporting both CEMS data and emissions data calculated using fuel-based methodologies, if the data are available. Doing so will provide a more comprehensive picture of your emissions from power generation and it is unclear whether future mandatory reporting schemes will require CEMS data or fuel-based calculations. The Registry's reporting software can accommodate both data sets, though only one (as designated by the Member) will be used for the purposes of public reporting.

16 *It is important to convert from short tons to metric tons when using the EPA CEMS data to report to The Registry. (Conversion factor: 1 metric ton = 1.1023 short tons)*

— EPS ST-01: CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS)

If your facility combusts fossil fuels or biomass and operates Continuous Emissions Monitoring Systems (CEMS) in response to federal, state, or local air agency regulations, you may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions. You should report CO_2 emissions in metric tons based on the sum of hourly CO_2 mass emissions over the year. This procedure is consistent with the CEMS methodology required by 40 CFR Part 75 in the U.S.[17]

If your facility combusts biomass, and you use O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

If your facility combusts municipal solid waste or other waste-derived fuels and you operate a CEMS in response to federal, state, or local agency regulations, you may use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. Alternatively, if your CEMS measures CO_2 and steam flow, but not flue gas flow, then you may use the method provided in 40 CFR 60, Method 19 (see text box below). You should report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year.

If your facility combusts municipal solid waste or other waste-derived fuels and you choose to calculate CO_2 emissions using CEMS measurements, determine the portion of emissions associated with the combustion of biomass-derived fuels using EPS ST-06, if applicable.

If you choose to use CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass, determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using EPS ST-06, if applicable. Alternatively, if your facility co-fires biomass with fossil fuels, you may calculate CO_2 emissions for the fossil fuels using EPS ST-02, EPS ST-03 or EPS ST-04, and then subtract the fossil fuel related emissions from the total CO_2 emissions measured by CEMS to derive the biogenic CO_2 emissions.

If you choose to report CO_2 emissions using CEMS data, this data will include process emissions associated with scrubbers. You are not required to separately report these process emissions. Similarly when reporting using CEMS, you do not need to report emissions separately for different fossil fuels when fossil fuels are co-fired.

[17] For power generation sources that report CO_2 emissions to a federal, state, or provincial agency based on the measurement of natural gas fuel flow and heat input, refer to the provisions included in EPS ST-03 for reporting those emissions into The Registry. While these emissions are not measured CEMS data, they are often reported for compliance purposes in the same way as CEMS data. For example, U.S. EPA allows this alternative for reporting as part of their Acid Rain regulations (40 CFR Part 75, Appendices F and G).

Report CO_2 emissions in metric tons based on the sum of hourly CO_2 mass emissions over the year.

For each monitoring system, report CO_2 emissions for the year, total fuel used, and any other parameter required to determine CO_2 mass emissions and heat input in accordance with 40 CFR 75. The quarterly reports submitted to the U.S. EPA showing CO_2 mass emissions data and heat input data for the CO_2 emissions unit (and U.S. EPA's confirmation correspondence) will be used as evidence that the emissions data have been accepted by the U.S. EPA.

CALCULATING BOILER FLUE GAS FLOW RATE USING STEAM GENERATION RATE

If you have a CEMS that provides the CO_2 or O_2 concentration in the flue gas and steam generation rate from a boiler, you can use this method to calculate flue gas flow using the measured steam rate, the design steam and waste heat content specifications for the boiler.

In this method[18] CO_2 or oxygen O_2 concentrations and appropriate F factors are used to calculate pollutant emission rates from pollutant concentrations. The F factor is the volume of combustion components per unit of heat content, scm/J or scf/ million Btu.

Using this method with measured CO_2 concentrations, the relevant equation for hourly flow rate is:

$$\text{Flow} = F_c * (H_d / \text{Steam}_d) * \text{Steam}_a / (CO_2\%/100)$$

where **Flow** = stack flow, dscfh
F_c = CO_2 based factor from 40 Cfr 60 Method 19 Table 19-2 (dscf/MMBtu)
H_d = design heat input rate (MMBtu/hr)
Steam_d = design steam rate (lbs steam/hr)
Steam_a = CEMS-measured steam rate (lbs steam/hr)
$CO_2\%$ = measured CO_2 concentration from CEMS, percent

Refer to 40 CFR 60, Method 19 for details of how to conduct this calculation using measured O_2 concentrations in the flue gas in place of CO_2.

Typically the CEMS data are provided on an hourly basis for each day. The CO_2 emissions are then calculated for each hour using:

$$E = MW_{CO2} * (CO_2\%/100) / V_m * \text{Flow}$$

where **E** = CO_2 emissions (lbs/hr)
MW_{CO2} = molecular weight CO_2 (44 lb/lbmol)
$CO_2\%$ = concentration of CO_2 in percent
V_m = standard molar volume of gas at 68°F (385.286 dscf/lbmol)
Flow = stack flow rate, dscfh

The hourly results are then summed to determine the annual total CO_2 emissions.

18 Methodology adapted from the U.S. 40 CFR 60, Method 19.

12.2 Calculating Anthropogenic Carbon Dioxide Emissions Using Fuel Use Data

This section includes several methods for calculating CO_2 emissions using fuel use data, including methods that involve the use of measured values and default emission factors. For fossil fuels, you must select one of the methods from those included below (EPS ST-02 through EPS ST-04). For biomass fuels (including biomass, municipal solid waste, or waste derived fuels with biomass), you should use the methods provided in Section 12.3.

In all cases where emissions are calculated using fuel use data, values for the applicable emission factors (and carbon content of fuels) can be found in the GRP, Tables 12.1 through 12.5. For EPS ST-02 through EPS ST-08, it is acceptable to substitute heat input units from Btu to joules using a conversion factor of 1055 J/Btu.

— EPS ST-02: Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Carbon Content of the Fuel

For each type of fuel combusted at your facility, calculate CO_2 emissions using the appropriate method below:

If combusting solid fuels, use the following equation to calculate CO_2 emissions:

Equation 12a	Solid Fuels

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664$$

Where:

CO_2 = carbon dioxide emissions, metric tons per year

$Fuel_n$ = mass of fuel combusted in month “n,” metric tons

CC_n = carbon content from fuel analysis for month “n,” percent (e.g. 95 percent expressed as 0.95)

3.664 = CO_2 to carbon molar ratio

When reporting emissions from the combustion of solid fuels for power generation, measure and record the carbon content monthly. The monthly solid fuel sample should be a composite sample of weekly sub-samples. The solid fuel should be sampled weekly at a location after all fuel treatment operations, and the sub-samples should be representative of the fuel chemical characteristics combusted during the sub-sample week. Collect each weekly sub-sample at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Combine weekly sub-samples of equal mass to form the monthly composite sample. The monthly composite sample should be homogenized and well mixed prior to withdrawal of a sample for analysis. Randomly select one in twelve composite samples for additional analysis of its discreet constituent samples. Use this information to monitor the homogeneity of the composite.

Determine carbon content coal and coke, solid biomass-derived fuels, and waste-derived fuels using ASTM 5373.[19]

If your facility combusts liquid fuels, use the following equation to calculate CO_2 emissions:

Equation 12b	Liquid Fuels

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tons per year

$Fuel_n$ = volume of fuel combusted in month “n”, gallons

CC_n = carbon content from fuel analysis for month “n”, kg carbon per gallon fuel

3.664 = mass conversion factor from carbon to carbon dioxide

0.001 = factor to convert kg to metric tons

[19] *ASTM 5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.*

Measure and record carbon content monthly or for each new delivery of fuel. When measured by you or a fuel supplier, determine carbon content as follows:

- For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291, ultimate analysis of oil or computations based on ASTM D3238-95 (reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (reapproved 2002).[20]

- For gaseous fuels, use the following equation to calculate CO_2 emissions:

Equation 12c	Gaseous Fuels
$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 1/MVC * 3.664 * 0.001$$ **Where:** **CO_2** = carbon dioxide emissions, metric tons per year **$Fuel_n$** = volume of gaseous fuel combusted in month "n," scf **CC_n** = carbon content from fuel analysis for month "n," kg C per kg-mole fuel **MVC** = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere) **3.664** = mass conversion factor from carbon to carbon dioxide **0.001** = factor to convert kg to metric tons	

[20] *ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants. ASTM D3238 – Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils. ASTM D2502 – Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements ASTM D2503 – Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.*

When measured by you or a fuel supplier, determine carbon content using the method in ASTM D1945.[21] Measure and record the carbon content monthly.

If your facility combusts waste-derived fuels that are partly but not pure biomass and if you determine CO_2 emissions using EPS ST-04, determine the biomass-derived portion of CO_2 emissions using EPS ST-06, if applicable.

— EPS ST-03: Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Fuel Flow, Heating Value for the Fuel and Default Emission Factor

Use the following equation to calculate fuel combustion CO_2 emissions by fuel type using the measured heat content of the fuel combusted:

Equation 12d

$$CO_2 = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CO_2 = combustion emissions from specific fuel type, metric tons CO_2 per year

n = period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = high heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = default carbon dioxide emission factor provided in Chapter 12 of the GRP, kg CO_2 per MMBtu

0.001 = factor to convert kg to metric tons

21 *ASTM D1945 – Standard Test Method for Analysis of Natural Gas by Gas Chromatography.*

Measure and record fuel consumption and the fuel's high heat value at frequencies specified by fuel type below. You may use the high heat values provided by the fuel supplier if they are calculated using an applicable method approved in the EPS Protocol. The required frequencies for measurements and recordings are as follows:

1. At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and Liquefied Petroleum Gas (ethane, propane, isobutene, n-Butane, unspecified Liquefied Petroleum Gas).
2. Monthly for natural gas, associated gas, and mixtures of low Btu gas excluding refinery fuel gas. If combusting gases with high heat value (<975 or >1100 Btu per scf) including natural gas, associated gas, and mixtures of low Btu gas and natural gas, use EPS ST-04 to calculate CO_2 emissions.
3. Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
4. Monthly for the heat content of all solid fuels. Monthly solid fuel sample should be a composite sample of weekly sub-samples. The solid fuel should be sampled at a location after all fuel treatment operations and the sub-samples should be representative of the fuel chemical and physical characteristics immediately prior to combustion. Collect each weekly sub-sample at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Combine weekly sub-samples of equal mass to form the monthly composite sample. The monthly composite sample should be homogenized and well mixed prior to withdrawal of a sample for analysis.

The method described above is a detailed method that will provide accurate data. However, if other sampling and analysis methods are used that provide equal or better accuracy, they may be used for EPS reporting to The Registry.

High heat values must be determined using one of the following methods when measured by you or the fuel supplier for:

1. Gases, use ASTM D1826, ASTM D3588, ASTM D4891, GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." You may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value convert the value to high heating value as specified in EPS ST-03.
2. Middle distillates and oil, or liquid waste-derived fuels, use ASTM D240, ASTM D4809.
3. Solid biomass-derived fuels use ASTM D5865.
4. Waste-derived fuels use ASTM D5865 or ASTM D5468. If your facility combusts waste-derived fuels that are partly but not pure biomass, determine the biomass-derived portion of CO_2 emissions using EPS ST-06, if applicable.

If yours is a facility where currently installed on-line instrumentation provides a measure of lower heating value (LHV) but not higher heating value (HHV), convert LHVs (Btu/scf) to HHVs (Btu/scf) in the following manner.

Equation 12e

HHV = LHV * CF

Where:

HHV = fuel or fuel mixture higher heating value (Btu/scf)

LHV = fuel or fuel mixture lower heating value (Btu/scf)

CF = conversion factor

For natural gas, use a CF of 1.11.

For refinery fuel gas and mixtures of refinery fuel gas, derive a fuel system specific conversion factor. Determine a weekly average conversion factor from either concurrent LHV instrumentation measurements and HHV determined as part of the daily carbon content determination (by on-line instrumentation or laboratory analysis), or by the HHV/LHV ratio obtained from your laboratory analysis of the daily samples.

For power generation sources that report CO_2 emissions to a federal, state or provincial agency based on the measurement of natural gas fuel flow and heat input, those emissions may be used for reporting to The Registry in place of this method if they are based on fuel measurement, fuel heating value measurement and a default emission factor for CO_2 stipulated by the regulation. No changes to those data are required for reporting to The Registry.[22]

[22] *For example, this alternative applies to facilities in the United States reporting to U.S. EPA under the Acid Rain regulations (40 CFR Part 75, Appendices F and G).*

— EPS ST-04: Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content

This method should be used and repeated for each type of fuel combusted in power generating units you control.

Calculate each fuel's CO_2 emissions and report them in metric tons using the following equation:

Equation 12f

$$CO_2 = Fuel * HHV_D * EF_{CO2} * 0.001$$

Where:

CO_2 = CO_2 emissions from a specific fuel type, metric tons CO_2 per year

Fuel = mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = default high heat value specified by fuel type, MMBtu per unit of mass or volume

EF_{CO2} = default CO_2 emission factor selected from Chapter 12 of the GRP (kg CO_2 per MMBtu), based on fuel type.[23]

0.001 = factor to convert kg to metric tons

12.3 Calculating Biogenic Carbon Dioxide Emissions

This section includes three methods for calculating biogenic emissions from stationary combustion of biomass, wood waste, Municipal Solid Waste (MSW), Waste-Derived Fuel (WDF), and/or biogas – the term used to collectively describe Landfill Gas (LFG) and Digester Gas (DG).

— EPS ST-05: Method for Calculating CO_2 Emissions from Biogenic Sources

Use the following method to calculate CO_2 emissions from combustion of biogenic sources including the combustion of biomass, municipal solid waste, waste or biomass derived fuels, and/or biodiesel. This method does not apply for biogas combustion where the heating value of the gas can be used to calculate emissions using EPS ST-03 or EPS ST-04.

23 *The Registry updates the emission factors in Chapter 12 of the GRP on a regular basis, including those for Canada and Mexico.*

Calculate CO_2 emissions from combusting biomass or MSW using the following equation:

Equation 12g
CO_2 = Heat * CC_{EF} * 3.664 * 0.001 **Where:** **CO_2** = CO_2 emissions from fuel combustion, metric tons per year **Heat** = heat Input as calculated below (MMBtu per year) **CC_{EF}** = default carbon content emission factor provided in Chapter 12 of the GRP, kg carbon per MMBtu [2] **3.664** = CO_2 to carbon molar ratio **0.001** = conversion factor to convert kilograms to metric tons

Calculate heat content using the following equation:

Equation 12h
Heat = Steam * B **Where:** **Heat** = heat, MMBtu per year **Steam** = actual steam generated, pounds per year **B** = boiler design heat input/boiler design steam output, MMBtu per pound steam

24 *The applicable emission factors for MSW and Biomass Derived Fuel (BDF) are found in the GRP and regularly updated by The Registry.*

— EPS ST-06: Methods for Partitioning of Anthropogenic/Biogenic CO_2 Emissions

If your fuels or fuel mixtures are at least five percent biomass by weight and not pure biomass,[25] determine the biomass-derived portion of CO_2 emissions using ASTM D6866. You should conduct ASTM D6866 analysis at least every three months, and you should collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours. Then divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed. If there is a common fuel source to multiple combustion devices at the facility, you may elect to conduct ASTM D6866 testing for just one of the devices.

This method is consistent with that included in the GRP. Alternatively, for MSW and WDF, you may obtain information on the biomass portion of the fuel from a local waste characterization study, and partition the fossil/biogenic emissions accordingly. Studies conducted within the previous five years are acceptable, and must be for the specific source material and the applicable region, state or province.

— EPS ST-07: Methods for Calculating Biogenic CO_2 Emissions from Biogas Combustion

Biogas (Landfill Gas (LFG) or Digester Gas (DG)) usually includes a mixture of CO_2 and CH_4 in approximately equal proportions.[26] The Registry considers releases of the CO_2 in the raw gas to be a process emission, and when this gas is released to atmosphere it must be categorized separately from the combustion CO_2 that results when the CH_4 is used as a fuel (or flared). However, both sources of CO_2 are considered to be biogenic. Use methods EPS ST-02, EPS ST-03 or EPS ST-04 to calculate the biogenic CO_2 emissions. If natural gas (NG) is also used as a fuel to supplement power generation with LFG or DG, then the process and combustion CO_2 from that fuel should be categorized as anthropogenic.

12.4 Calculating Methane and Nitrous Oxide Emissions

Emissions of CH_4 and N_2O from stationary combustion may be estimated using default emission factors, source test data and/or CEMS using Fourier Transform Infrared spectroscopy, if available. Use EPS ST-08 below to calculate these emissions.

25 *Except for waste-derived fuels that are less than 30 percent by weight of total fuels combusted.*

26 *GRP Chapter 12*

— EPS ST-08: Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors or Source Test Data

You should use the methods in this section to calculate CH_4 and N_2O emissions from fuel combustion. The methods presented below are for fuel-based calculations using fuel-specific emission factors.

You may elect to calculate CH_4 and N_2O emissions using source-specific emission factors derived from source tests. Source test data must be less than three years old and must be specific to the site, fuel and engine type for which emissions are being calculated. If a source test result is below the non-detect limit, an emission factor of one-half the non-detect limit may be used. Source test data up to five years old may be used if the last two consecutive source tests (conducted at least one year apart) were below the non-detect limit.

In the absence of source-specific emission factors, you may use the default emission factors provided in Chapter 12 of the GRP for each type of fuel.

If the heat content of the fuel is measured, calculate each fuel's CH_4 and N_2O emissions and report them in metric tons using the following equation:

Equation 12i

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CH_4 or N_2O = combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year

n = period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = high heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = default CH_4 or N_2O emission factor provided in Chapter 12 of the GRP, kg CH_4 or N_2O per MMBtu

0.001 = factor to convert kg to metric tons

If the heat content of the fuel is not measured or if it is calculated, calculate each fuel's CH_4 and N_2O emissions and report them in metric tons using the following equation:

Equation 12j

CH_4 or N_2O= Fuel * HHV_D * EF* 0.001

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year

Fuel = mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = default high heat value specified by fuel type provided in Chapter 12 of the GRP or calculated heat value from EPS Method ST-05, MMBtu per unit of mass or volume

EF = default emission factor provided in Chapter 12 of the GRP, kg CH_4 or N_2O per MMBtu

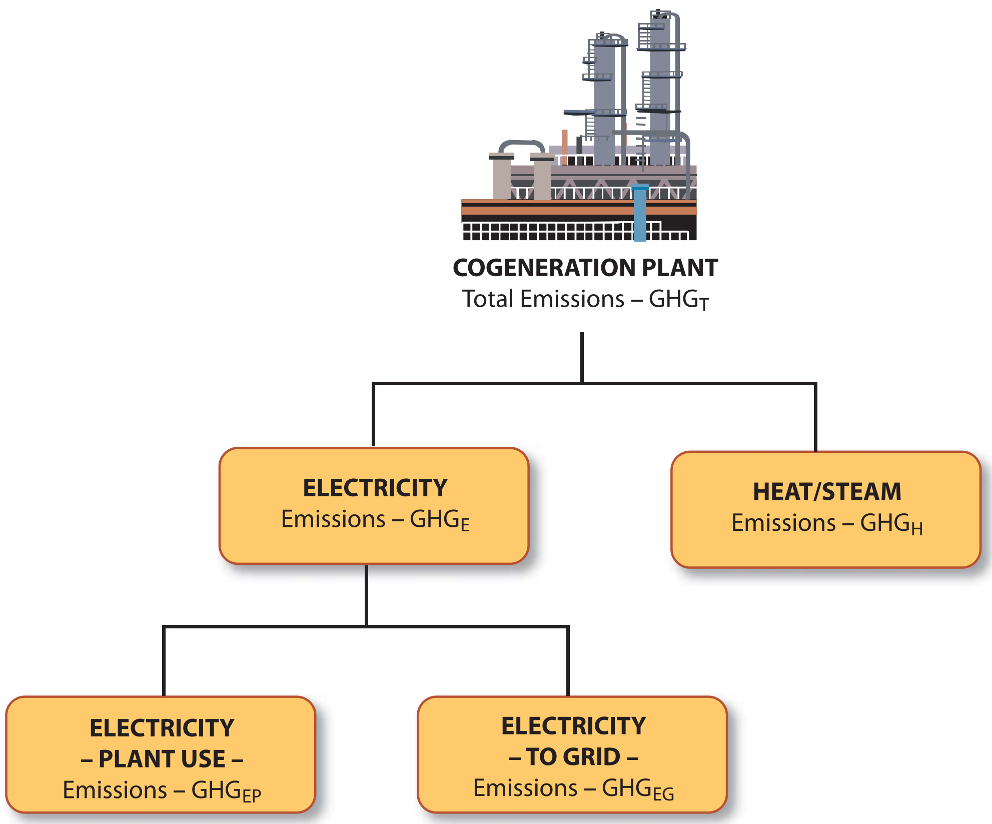
0.001 = factor to convert kg to metric tons

12.5 Allocating Emissions from Combined Heat and Power

If your facility operates a cogeneration unit or group of units and at least a portion of the electricity is exported to the grid, then you must calculate and report distributed emissions for each of your cogeneration systems. The method to achieve this is included in Chapter 12 of the GRP. The requirement to allocate emissions based on the heat and power outputs is used to generate the appropriate power generation metrics for this power. This is illustrated in Figure 12.1 below.

Note that all emissions from your cogeneration facility will be included in your Scope 1 emissions, regardless of the dispensation of heat or power.

Figure 12.1 Allocation of Emissions from a Cogeneration Plant



$GHG_T = GHG_E + GHG_H$ (Allocation Method from GRP, Chapter 12)

$MWh_T = MWh_P + MWh_G$

$GHG_{EP} = GHG_E * MWh_P / (MWh_T)$

$GHG_{EG} = GHG_E * MWh_G / (MWh_T)$

where:

GHG_T – greenhouse gas emissions – total stationary combustion
GHG_E – greenhouse gas emissions – electricity
GHG_H – greenhouse gas emissions – heat/steam
GHG_{EP} – greenhouse gas emissions – electricity to plant
GHG_{EG} – greenhouse gas emissions – electricity to grid

MWh_T – electricity net generation - total
MWh_P – electricity net generation - plant
MWh_G – electricity net generation - grid

12.6 Examples: Calculating Direct Emissions from Stationary Combustion

12.1

EXAMPLE 12.1
Coal-fired Power Plant Reporting With CEMS Data

Opal Power owns and operates Unit #2 of a coal-fired power plant. A CEMS unit is operated for Unit #2 in accordance with 40 CFR Part 75 (U.S. EPA). Opal Power has decided to report CO_2 emissions to The Registry using CEMS data, and is additionally providing fuel use data for purposes of calculating CH_4 and N_2O emissions using default emissions factors from the GRP.

Opal Power collects the following data to report emissions and electricity generation from this unit:

Annual Emissions of CO_2	= 2,952,000 tons (CEMS data reported to EPA)
Annual fuel usage	= 28,770,000 MMBtu (calculated from coal usage, GRP defaults)
Annual net generation	= 3,104,300 MWh
Fuel Type:	= sub bituminous coal
Boiler technology:	= dry bottom, wall-fired

Organizational Consolidation

Opal Power has a 100 percent equity share in Unit #2, and also has operational control. Therefore, the reported emissions will be the same for the operational boundaries and equity share consolidation methods.

CO_2 Emissions Reported Using CEMS: Direct Monitoring

2,952,000 tons CO_2 x (2000 lb/ton) ÷ (2204.62 lb/metric ton) = 2,678,013 metric tons CO_2.

CO_2 Emissions Calculated using Measured Heat Content and Default Carbon Content

Carbon Content for Sub bituminous Coal:	= 26.48 kg C/MMBtu (default, GRP Chapter 12)
Molecular Weight Ratio of CO_2/Carbon	= 44/12

(28,770,000 MMBtu) x (26.48 kg C/MMBtu) x (44 kg CO2/12 kg C) ÷ (1000 kg/metric ton) = 2,793,375 metric tons CO_2

CH_4 and N_2O Emissions Calculated Using Default Emission Factors by Sector and Technology Type

Emission Factors for Dry Bottom, Wall-Fired Boilers (Default, GRP Chapter 12):

0.7 g CH_4/MMBtu
0.5 g N_2O/MMBtu

(28,770,000 MMBtu) x (0.7 g CH_4/MMBtu) ÷ (1,000,000 g/metric ton) = 20.14 metric tons CH_4

(28,770,000 MMBtu) x (0.5 g N_2O/MMBtu) ÷ (1,000,000 g/metric ton) = 14.39 metric tons N_2O

12.2 EXAMPLE 12.2
Co-firing Of Natural Gas and Digester Gas - Direct Monitoring (CEMS)

Opal Power owns and operates a power generation facility that co-fires natural gas with digester gas from a wastewater treatment plant. Opal operates a CEMS unit in accordance with 40 CFR Part 75 which measures O_2 concentrations. CO_2 emissions are calculated from the O_2 CEMS, and annual source testing demonstrates that the calculated CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

Opal has decided to report CO_2 emissions to The Registry using the CEMS data, and to apportion the anthropogenic and biogenic CO_2 emissions using 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." Fuel use data (for natural gas and digester gas) are metered and used for calculating CH_4 and N_2O emissions using default emissions factors from the GRP.

Opal Power collects the following data to report total emissions from this facility:

Annual CO_2 Emissions	= 1,050,000 tons (calculated from CEMS)
Annual natural gas usage	= 14,825,000 kscf (metered)
Natural gas HHV	= 1,034 Btu/scf (measured and averaged using monthly data)
Annual digester gas usage	= 2,650,000 kscf (metered)
Digester gas HHV	= 629 Btu/scf (measured)
Biogenic Carbon/Total Carbon	= 17% (ASTM D6866-06a)

Total CO_2 Emissions
1,050,000 tons CO_2 x (2000 lb/ton) ÷ (2204.62 lb/metric ton) = 952,545 metric tons CO_2

Biogenic CO_2 Emissions
952,545 metric tons total CO_2 x 17% biogenic content = 161,933 metric tons

Anthropogenic CO_2 Emissions
952,545 metric tons total CO_2 - 161,933 metric tons biogenic CO_2 = 790,612 metric tons

Note: per GRP guidance (GRP Chapter 12), digester gas is considered to be 50 percent CH_4 and 50 percent CO_2 by volume. Site specific gas composition analysis data may be used for more accurate percentages. The CH_4 component is combusted to form CO_2 combustion emissions, while the CO_2 component passes through the generation facility and is considered CO_2 pass-through (process) emissions. Both components are included in the CEMS biogenic CO_2 emissions total.

12.3 EXAMPLE 12.3
Co-firing Of Natural Gas and Digester Gas - Heat Input Method

For the same facility as described in Example 12.2, this example shows how to calculate CO_2 emissions using measured heat input and default carbon content for natural gas and digester gas fuels.

Natural Gas
Carbon content for natural gas (with HHV of 1,034 Btu/scf): 14.47 kg C/MMBtu (default, GRP Chapter 12)
Molecular Weight Ratio of CO_2/Carbon = 44/12
(14,825,000 kcf) x (1,000 cf/kcf) x (1,034 Btu/cf) x (MMBtu/1,000,000 Btu) x (14.47 kg C/MMBtu) x (44 kg CO_2/12 kg C) ÷ (1000 kg/metric ton) = 813,308 metric tons CO_2 (anthropogenic)

Digester Gas
Carbon content for digester gas (CH_4 component only): 14.20 kg C/MMBtu
Molecular Weight Ratio of CO_2/Carbon = 44/12
(2,650,000 kscf) x (1,000 cf/kscf) x (629 Btu/scf) x (MMBtu/1,000,000 Btu) x (14.20 kg C/MMBtu) x (44 kg CO_2/12 kg C) ÷ (1000 kg/metric ton) = 86,787 metric tons combustion CO_2 (biogenic)

Volume of biogenic "pass-through" CO_2 = (2,650,000 kscf ÷ 2) = 1,325,000 kscf CO_2
(1,325,000 kscf) x 0.056 MT/kscf = 74,289 metric tons of biogenic pass-through CO_2

With this method, the total anthropogenic emissions are 813,308 metric tons, and the biogenic emissions are 161,076 metric tons.

Note: because Opal Power has selected to report CO_2 emissions using direct monitoring (CEMS), the CO_2 emissions calculated using EPS-ST-03 do not appear in the public report, but they are included in the private detailed inventory report.

12.4 EXAMPLE 12.4
Co-firing Of Natural Gas And Digester Gas - Ch_4 And N_2o Emissions

For the same facility as described in Examples 12.2 and 12.3, this example shows how to calculate CH_4 and N_2O emissions using measured heat input and default emission factors.

Emission factors for natural gas boilers: 0.9 g CH_4/MMBtu (default, GRP Chapter 12)
0.9 g N_2O/MMBtu (default, GRP Chapter 12)

Note. These emission factors are used for natural gas and digester gas as follows:

Natural Gas
(14,825,000 kcf natural gas) x (1,000 cf/kcf) x (1,034 Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g CH_4/MMBtu) ÷ (1,000,000 g/metric ton) = 13.80 metric tons CH_4
(14,825,000 kcf natural gas) x (1,000 cf/kcf) x (1,034 Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g N_2O/MMBtu) ÷ (1,000,000 g/metric ton) = = 13.80 metric tons N_2O

Digester Gas
(2,650,000 kcf digester gas) x (1,000 cf/kcf) x (629 Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g CH_4/MMBtu) ÷ (1,000,000 g/metric ton) = 1.5 metric tons CH_4
(2,650,000 kcf digester gas) x (1,000 cf/kcf) x (629Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g N_2O/MMBtu) ÷ (1,000,000 g/metric ton) = 1.5 metric tons N_2O

Chapter 13: Direct Emissions from Mobile Combustion

13.1 Calculating Carbon Dioxide Emissions from Mobile Combustion

REFER TO GRP.

13.2 Calculating Methane and Nitrous Oxide Emissions from Mobile Combustion

REFER TO GRP.

13.3 Example: Calculating Direct Emissions from Mobile Combustion

REFER TO GRP.

Chapter 14: Indirect Emissions from Electricity Use

Chapter 14 addresses the reporting of indirect emissions associated with the consumption of purchased or acquired electricity. The sections that follow provide a general description of indirect electricity emissions applicable to the EPS (Section 14.1), and methods for calculating emissions associated with transmission and distribution (T&D) losses (Section 14.2), emissions associated with bulk transmission system losses (Section 14.3), and emissions associated with electricity use in buildings and facilities (Section 14.4). The chapter ends with a brief discussion of other types of indirect emissions common to the EPS that may be optionally reported (Section 14.5).

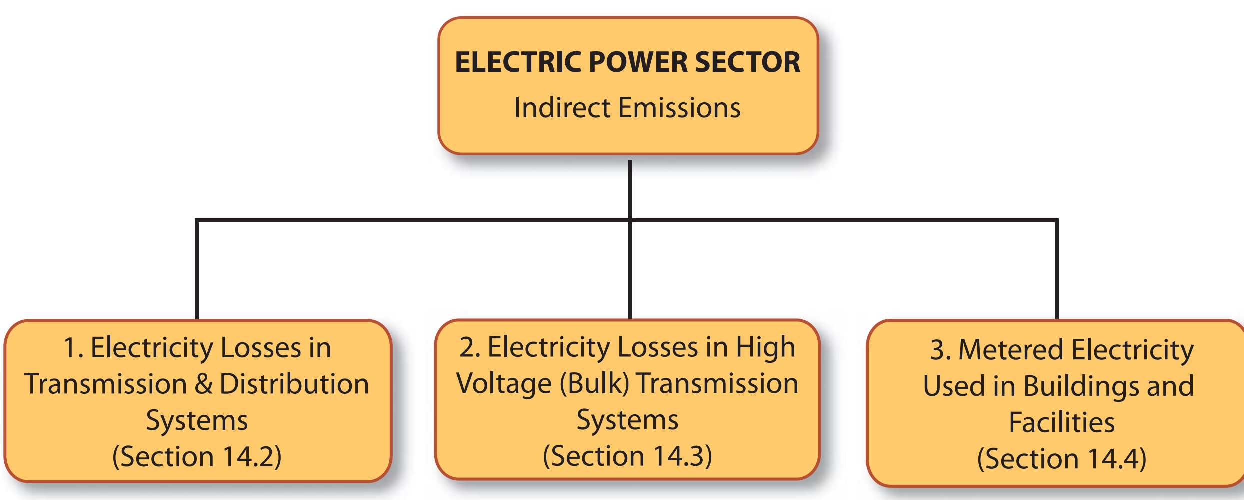
14.1 Quantifying Indirect Emissions from Electricity Use

In general, electricity is consumed in the EPS in three distinct categories as follows:

1. T&D systems used to deliver electricity to retail and wholesale customers.
2. High-voltage bulk power transmission systems.
3. Facilities and buildings.

These three categories of emissions are represented in Figure 14.1.

Figure 14.1 Categories of Indirect Emissions Applicable to the Electric Power Sector



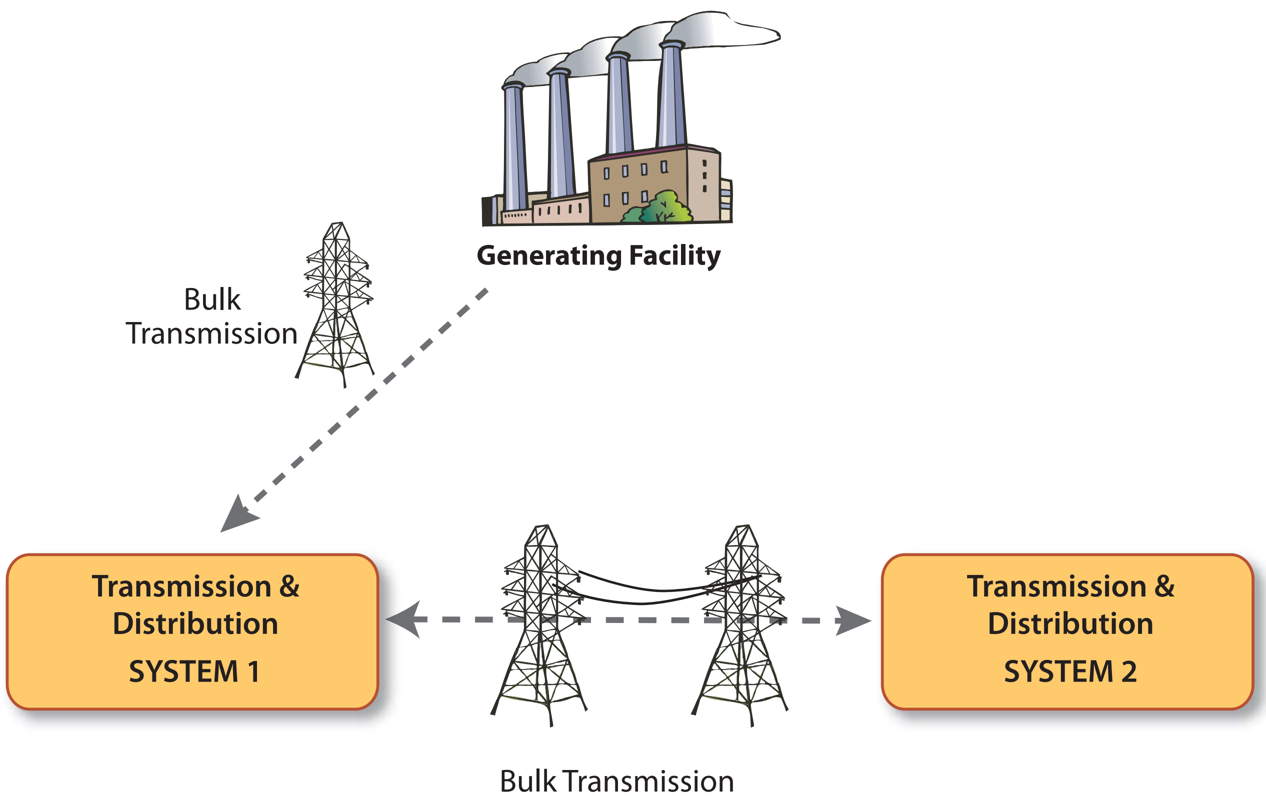
Members reporting indirect emissions from T&D systems at the local level may include utilities and other Local Distribution Companies (LDCs) and Cooperatives. Members that report emissions from high-voltage bulk transmission systems may include transmission companies, Balancing Authorities, Independent System Operators (ISOs), Wholesale Cooperatives and integrated utilities that also engage in local distribution. Members may also have some indirect emissions from the use of electricity in facilities and buildings.

If you control a local T&D system (e.g. serving a discrete service territory) you may aggregate the transmission and distribution components of the system together into a single "facility". If you own or control T&D systems that are essentially separate from each other and operated as separate systems (these systems may be geographically separate, have different supply resources, and/or have different customer bases), you must report data separately for each distinct system to ensure that losses and emissions are accurately determined for each system.

If you own or control a local T&D system and also own or control bulk power transmission lines that interconnect your T&D system with remote generation and/or other T&D systems (Figure 14.2), then you may choose to include the bulk power system with the T&D system it serves as a single "facility." If you aggregate emissions from these systems together, you should use the guidance in Section 14.2 to calculate emissions associated with losses for your combined system. You may alternately choose to report the bulk transmission line(s) as a separate facility. In this case, you should use the guidance provided in Section 14.3. In many instances bulk power transmission systems are controlled by entities that are not involved in power distribution and do not own or control local T&D systems. In these cases, the bulk transmission system must be reported as a distinct "facility." Additional guidance on how to report bulk transmission systems can be found in Section 14.3.

Your chosen organizational boundary approach and the nature of your control will determine whether or not you have the responsibility to report emissions from these bulk transmission systems (Section 4.6).

Figure 14.2 T&D Systems With Transmission Interconnections



If you operate a T&D system or bulk transmission system and you also generate power, you will need to report indirect emissions associated with the losses that occur on T&D and bulk transmission systems for all power that flows on the systems that are not self generated. You should not report the indirect emissions associated with the self-generated power flowing through your lines as this would result in the double counting of emissions.[27] However, you do need to understand how much self-generated power is flowing through your T&D system in order to calculate a system "loss factor" (as described in the next section).

14.2 Indirect Emissions from Electricity Use: Transmission and Distribution Losses

T&D system losses are a result of electricity consumption as it moves from one point to another in the T&D system. These losses occur in wires, transformers and other electricity system components due to resistance, unmetered paths to ground, and related electrical inefficiencies. The losses that occur on these power delivery systems are dependent on the

27 *World Resource Institute/World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition).*

physical characteristics of the lines, and the power that flows through them. In order to calculate the indirect emissions associated with these losses, Members with power delivery systems need to know how much power is conveyed through the lines, what the "loss factor" is for the system as a whole, and the emission factor (or carbon intensity) of the power, which in turn depends on the generation characteristics of the power.

This section includes methods for compiling the information needed to calculate the indirect emissions associated with T&D losses. Two alternatives are offered as follows:

> **EPS IE-01: Energy Balance Method:** This method is a detailed approach based on an energy balance analysis to determine a system-specific loss factor, and a detailed review of purchases to determine a more accurate estimate of the total emissions flowing through the system and, therefore, the Scope 2 emissions associated with the T&D losses. You must use this option if you intend to report the optional power deliveries metrics (Chapter 19).
>
> **EPS IE-02: Aggregated Power Flow Method:** The aggregated power flow method is a simplified approach based on default loss factors and default emission factors. Note, however, that you cannot use this option if you plan to report optional power deliveries metrics (Chapter 19).

Table 14.1 provides a summary of the differences between methods EPS IE-01 and EPS IE-02.

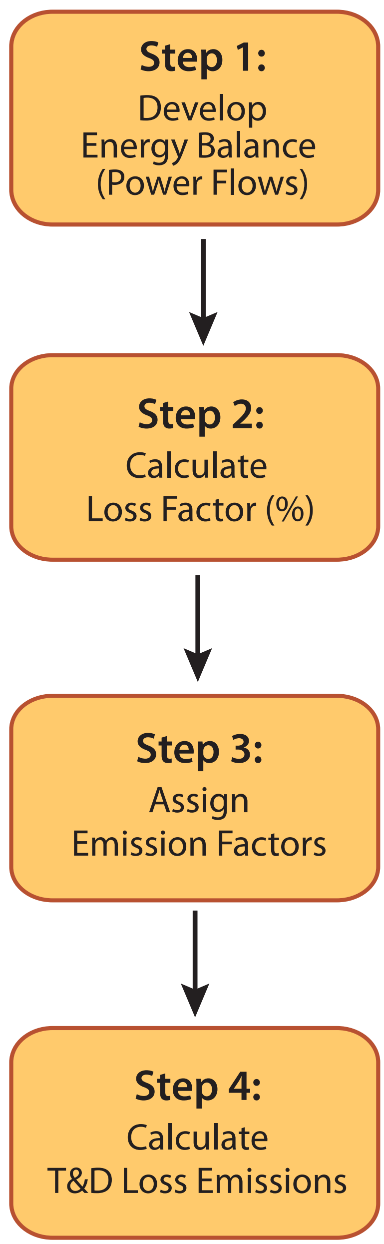
14.1 **TABLE 14.1**
Overview of Methods for Reporting T&D System Emissions

	Table 14.1 Indirect Emissions From Electricity Use			
	Method	**Power Flows**	**T&D Loss Factor**	**Emission Factors**
Emissions from T&D Systems	EPS IE-01	Energy Balance Method	Engineering Estimate, Modeled Loss Rate or Energy Balance Approach	Emission factors assigned to each purchase by counterparty or by fuel type
	EPS IE-02	Aggregated Power Flow Method	Default Factor	Average emission rates for eGRID sub-region, state, province or territory

Note:
Members are encouraged to use as much site-specific information as they have available. If you have sources for some but not all of the information required for EPS IE-01 you are encouraged to use a hybrid of methods EPS IE-01 and EPS IE-02.

Figure 14.3 summarizes the four steps you will need to follow to calculate the emissions associated with your T&D losses. These four steps are applied differently depending on the method you use to calculate your indirect emissions. These steps and their application for EPS IE-01 and EPS IE-02 are discussed in Sections 14.2.1 through 14.2.4.

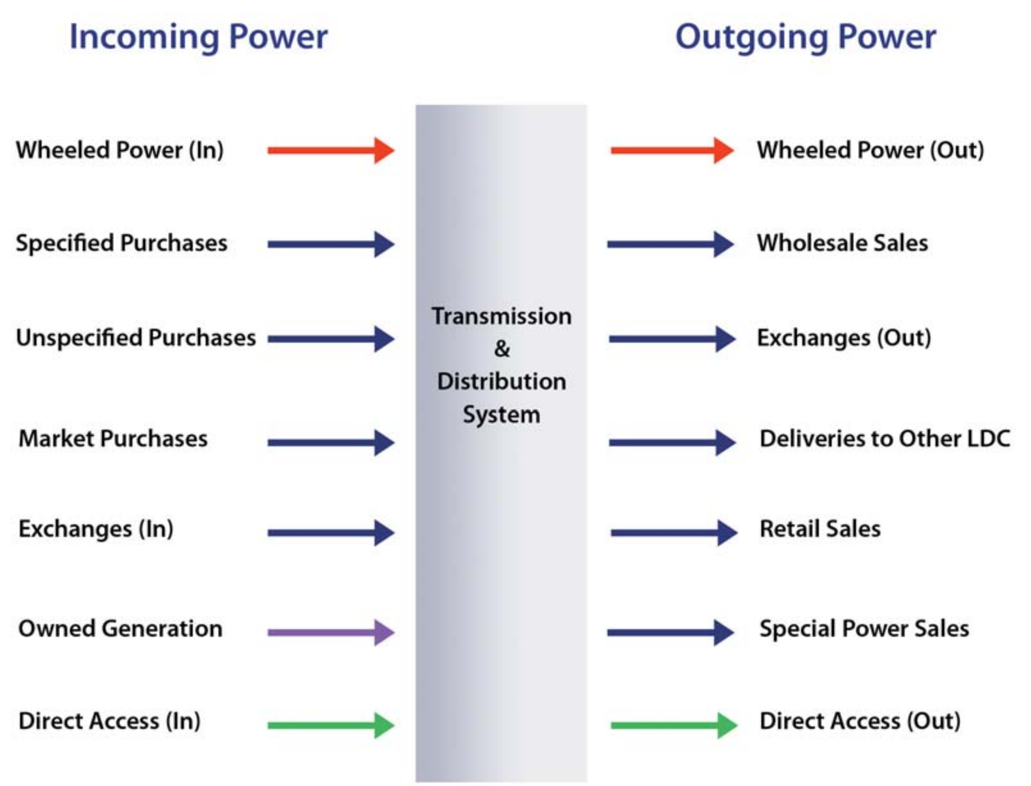
Figure 14.3 Four-Step Process for Calculating Emissions from T&D Losses and Associated Emissions



14.2.1 Step 1: Identify Power Flows Conveyed on the T&D System

Figure 14.4 provides a generalized illustration of how power flows onto a typical T&D system and where it goes when it leaves the system.

Figure 14.4 Energy Balance of a Typical T&D System Showing Power Flows



The two options to account for the power flows are described below.

— EPS IE-01: Accounting for Power Flows on a T&D System Using the Energy Balance Method

With the energy balance method, you will need to develop a detailed account of the energy that flows onto and out of your system. You must account for power flows onto your system as follows:

- Net generation delivered from each generating facility you own or operate
- Power received from each Specified Purchase
- Total power received from Spot Market Purchases
- Power purchased and received from all Other Sources ("Other Purchases")

- Power received from power exchanges
- Power received from transactions of power with a Balancing Authority (e.g., power exchanges made to relieve transmission congestion)
- Power conveyed through the system for others, including but not limited to power received from power generators, retail providers, and power marketers. This category includes Direct Access power and any other power wheeled across the system for others.

You must also account for power that flows out of the system as follows:

- Power delivered for retail sales
- Power delivered for wholesale sales
- Power exchanges (delivered)
- Power conveyed through the system for others (as discussed above)
- Power consumed in buildings and facilities you own and/or operate

If your T&D system is in the U.S. and you are required to submit a FERC Form 1, these power flows are available from the various sheets that make up the Form 1.[28] If you do not compile a FERC Form 1, you should refer to that form, and use it as a guide for gathering the data you need for your own system.

To properly account for power flows, you will need to define your system's boundaries including the Point of Receipt (POR) where each purchase of electricity is received by the system, and the Point of Delivery (POD) where electricity is delivered wholesale from the system. The POR is the first point of interconnection to your system where a purchase is received, and the POD is the interconnection where electricity is sold wholesale to another party. The PORs and PODs are usually well-defined substations. The PORs and PODs are likely to be at or near the boundary of the LDC service area for purchases made outside the service area, and at a local substation for power generated or purchased from facilities within the service area. Retail sales to customers usually occur within the system boundaries, and wholesale sales usually occur at a well-defined substation at the perimeter of the service area.

Each main category of power needed for the energy balance is discussed briefly below.

Owned/Controlled Power Generation – The requirements for reporting power flows from owned/controlled generation are discussed in Chapter 12 of the EPS Protocol. It should be noted that because both owned/controlled and purchased generation flow onto the T&D system, inclusion of both are important factors for determining the T&D losses (expressed in MWh) and the line loss factor.

Specified Purchase – This is a purchase from a particular generating unit or facility for which electricity generation can be confidently tracked due to its identification in a power contract or invoice. This category also includes contracts which tie the energy to specific resources and/or to specific group of facilities. It is important to differentiate these purchases, because they can be assigned facility or unit-specific emission factors.

28 *Available at: http://www.ferc.gov/docs-filing/eforms/form-1/viewer-instruct.asp*

Spot Market and Other Purchases – For spot market or other purchases, you must identify a region of origin for each purchase. The regions to be used are the eGRID sub-regions for the U.S. (GRP, Figure 14.2),[29] the Canadian Provinces/Territories (GRP, Table 14.2), and the Mexican States (GRP, Table 14.3). When the region of origin is uncertain, you will need to make a determination of the most likely place of origin. You may aggregate the power purchased by counterparty (supplying the power) if the purchases are known to originate in the same region.

Direct Access Deliveries – You should identify all power deliveries to end-use customers for other retail providers in a separate category.

Power Exchanges – These represent real energy flows out of and onto the T&D system, so they are included in the required energy balance of power flows. When reporting power transactions associated with exchange agreements, you should report electricity received as a power purchase together with the region of origin. This approach reflects the intent to track actual power flows (and emissions) wherever possible rather than the financial transaction.

"Off System Purchases" – Some purchases and sales made by a Load Serving Entity are specified for "off system" locations. You should remove all of these transactions from the T&D System Energy Balance because they have no influence on your T&D system losses.[30]

Power Deliveries – You must report all sales of power from the system (including retail and wholesale), power exchanges (delivered), and all power delivered through the system for others who request use of the transmission system (as discussed above). All wholesale sales and all other power conveyances are measured at the POD.

Self-Consumed Power – You should include all self-consumed power in the energy balance, including both self-generated and purchased power. This is the total amount of metered electricity taken from the grid and consumed in your facilities and buildings, whether billed or not.

"Book-outs" – Purchased power data records often include "virtual energy" reflective of hedge or speculative trades of energy that were not delivered to the system. Similarly, scheduled power records may include transactions that were initially scheduled, but subsequently canceled. These "book-outs" should not be included in the energy balance.

29 *Emissions & Generation Resource Integrated Database, U.S. EPA.*

30 *Note that these "off system" transactions are included in the U.S. FERC Form 1 report, so they need to be removed from the system energy balance required in the EPS Protocol.*

— EPS IE-02: Accounting for Power Flows on a T&D System Using the Aggregated Flow Method

With the aggregated flow method, you will need to obtain an aggregate of your power flows from a form such as the FERC Form 1 page 401 “Energy Account” and the EIA 861 Page 2 “Energy Balance Account.” These forms do not provide the degree of detail that the energy balance method does, but they are an acceptable alternative for those Members that do not plan to report power deliveries metrics.

14.2.2 Step 2: Develop T&D System Loss Factor

After identifying and reporting all power flows over the system, a loss factor needs to be calculated (EPS IE-01) or selected (EPS IE-02). The two options are discussed below.

— EPS IE-01: Calculating a Loss Factor Using the Energy Balance Method

You can calculate the T&D losses (MWh) by subtracting the total power you deliver and consume from the total power received into your system. The system average loss factor is the ratio of these losses to the total power received over an annual reporting period (expressed as a percentage). This energy balance approach needs to account for all energy flows into and out of the system as described in the previous section. To calculate a system loss factor using this approach, use Equation 14a, as follows:

Equation 14a
T&D System Loss Factor [%] = (Total Power Flows onto System [MWh] - Total Power Flows out of System [MWh]) / Total Power Flows onto System [MWh]

Another approach, consistent with the energy balance method, is to use an estimate of the losses derived from measured flow data through the system or modeling calculations available from a Balancing Authority. These estimates are based on current loading, ambient conditions, and measured losses on representative samples of T&D segments and components in the T&D system. The loss factor is the ratio of the modeled losses to the total energy flow into the system. If a modeled system loss factor is used, then you must have documentation from the entity that provides the calculated number or reference to a source where the loss factor is publicly available.

— EPS IE-02: Selecting a Default Loss Factor

You may use a default T&D loss factor based on the best avaliable eGRID data.[31] Table 14.2 shows the loss factors from the eGRID database for five grid regions in the United States. For Canada and Mexico, you may use the average loss factor for the entire United States (also included in Table 14.2) as a default.

14.2 TABLE 14.2
eGRID Average Loss Factors

Grid Region	2004	2005
East	6.54 %	6.41 %
West	2.48 %	5.33 %
Texas	7.69 %	6.18 %
Hawaii	-0.13 %	3.69 %
Alaska	3.69 %	2.79 %
United States		**5.60 %**

Source – eGRID 2007 (includes data for both years as shown above)

14.2.3 Step 3: Assign Emission Factors and Determine Scope 3 Emissions

The third step is to assign GHG emission factors (for CO_2, CH_4, N_2O) to the power that flows through the T&D system and calculate the Scope 3 emissions. Note that this step does not apply to power that you generate and report as Scope 1 emissions. These emissions are already reported according to the requirements in Chapter 12. The two options for selecting and assigning emission factors are presented below.

31 http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2007V1_1_year0504_STIE_USGC.xls.

— EPS IE-01: Assigning Specific Emission Factors to Power Flows

This section provides guidance for assigning emission factors for four general power purchase categories as follows:

Specified Purchases. Where unit, facility, or utility-specific purchases can be identified through contract and/or financial accounting records (such as invoices and payments), you can assign an emission factor applicable for that source. These emission factors may be obtained from one of the following sources: (a) metrics reported in The Registry's database; (b) facility-specific emission factors from eGRID or reports to EIA-906/920 (United States); (c) U.S. EPA Part 75 Electronic Database Reports (EDR); or (d) another equivalent third-party verified or governmental source (See text box pn page 67 for further discussion: Emissions Factors for Power Purchases). Applicable emission factors may be available from other state/provincial reporting programs, other public third-party verified registries, and/or proprietary databases.

If there is no unit or facility-specific emission factor available, you may use a fuel specific emission factor (Table 14.3). Table 14.3 includes CO_2 emission factors from the combustion of biogenic fuels, but other renewable energy sources with zero emissions are not included (i.e., wind, solar wave energy). At this time, hydro power purchases (large and small should be considered non-emitting). For specified purchases from known geothermal power production facilities that are known to use binary technology, the emission factors are zero. Emissions may be attributed to known non-binary geothermal purchases using the net power generation together with a default emission factor. Default emission factors for this method are 90.7 kg/ MWh (200 lb/MWh) for CO_2 and 0.75 kg/MWh (1.66 lb/MWh) for CH_4.[32]

32 These emission factors are based on the weighted average of data obtained from a range of geothermal energy production technologies. See Bloomfield, K. (INEEL), Joseph N. Moore (EGI), and Robert M. Neilson, Jr. (INEEL). 2003. "Geothermal Energy reduces Greenhouse Gases. CO_2 Emissions from Geothermal Energy Facilities are Insignificant Compared to Power Plants Burning Fossil Fuels." Geothermal Resources Council Bulletin, March/April 2003.

14.3 TABLE 14.3
Default CO_2 Emission Factors For Purchases From Specific Resources

Resource Type	CO_2 lbs/MWh	Resource Type		CO_2 lbs/MWh
Coal		**Natural Gas**		
Lignite Coal	2,402	CA (combined cycle two turbines)		909
Petroleum Coke	2,390	CS (combined cycle - single shaft)		860
Sub-Bituminous Coal	2,212	GT (combustion [gas] turbine)		1,329
Bituminous Coal	2,047	ST (steam turbine)		1,532
		IC (internal combustion)		1,226
Liquid/Gas Fossil Fuels				
Kerosene	2,130	**Biogenic Fuels**		
Waste Oil	1,306		**Anthropogenic**	**Biogenic**
Distillate Fuel Oil	1,604	Wood-Derived Solids	44	2,492
Residual Fuel Oil	1,499	Black Liquor	136	1,670
Jet Fuel	1,410	Landfill Gas	38	2,677
Other Fossil Gas	1,755	Municipal Solid Waste	1,353	2,513
Blast Furnace Gas	1,019			

Notes:

The data presented in this table were derived from the US EPA's eGRID-2007 based on data for 2005. The emission factors were derived by totaling the emissions and net power generation for each of the generating resource categories, and using these totals to derive an average of emissions per MWh.

For the eGRID facilities that use biogenic fuels (biomass, wood waste, biogas and MSW), there are some facilities that co-fire fossil fuels along with the biogenic fuel. For resource-specific emission factors, the anthropogenic emissions at these facilities have been averaged to give an overall average for the entire subset of each resource type. Thus, for resource-specific purchases, there will be a small amount of anthropogenic emissions for each of the biogenic fuels.

The eGRID database includes anthropogenic CO_2 emissions, but not biogenic CO_2. Biogenic emission factors for wood-derived solids and black liquor were derived using the heat input and net generation data from eGRID-2007 together with the default emission factors from the GRP. For landfill gas, the emissions were calculated using an emission factor from the California Air Resources Board's "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions". This was done to include the process emissions (from "pass-through" CO_2) as well as the combustion emissions.

MSW emission factors were derived using the eGRID-2007 data, and the biogenic/anthropogenic emissions were partitioned using a 65/35 percent split based on data reported by Covanta Energy.[33]

33 *"Updated Analysis of Greenhouse Gas Emissions and Mitigation from Municipal Solid Waste Management Options Using A Carbon Balance," Brian Bahor, Keith Weitz and Andrew Szurgot. Global Waste Management Symposium, June 30, 2008.*

Spot Market Purchases. For these purchases, you should use the annual average output emission rate for the applicable sub-region (or province/territory) where the power is obtained. These can be obtained from Chapter 14 of the GRP. [34]

Other Purchases (including Power Exchanges, Received). In some cases there may be sufficient data available and sufficient confidence in the source of the power to assign a facility or utility specific emission factor to the purchase. However, you should keep in mind that the power may not be delivered from a particular facility under certain circumstances even when the facility location is referred to in a power contract. For example, with firm power contracts, power may be received from one facility for most of the year, but alternative power must be provided when the facility is not available. For such cases, this protocol gives discretion to the Member, subject to Verification Body approval, to determine the most accurate emission factors to assign. However, if there is no reasonable justification for assigning a specific emission factor, then average output emission rates should be used, consistent with the treatment of Spot Market Purchases.

Direct Access Deliveries and Wheeled Power. If you do not have data on the source of power delivered for others – as with Direct Access – then these power deliveries should be treated the same as Spot Market or Other Purchases. Use measured and reported MWh data together with the eGRID or provincial annual average output rate emission factors (provided in GRP Tables 14.1, 14.2 and 14.3) for the sub-region or province of origin. If the Member does not know the sub-region or province of origin, then the local sub-region or province should be used. This also applies to wheeled power.

When emission factors have been assigned for each source, the emissions associated with each purchase can be estimated using Equation 14b, as follows:

Equation 14b

Emissions from Purchased Power[MT GHG] = Power Delivered onto System [MWh] x Emission Factor [MT GHG/MWh]

This calculation is repeated for each GHG (CO_2, CH_4, N_2O) using the appropriate emission factors identified above.

The text box that follows provides a discussion of specific sources of emissions factors for power purchases that Members may use for calculating T&D losses and emissions consistent with the provisions discussed above.

34 For the United States, the eGRID subregion annual output emissions rates are the system wide emissions divided by the system wide generation within each eGRID subregion. The Registry will regularly update the eGRID sub-region emission factors in the GRP as eGRID updates are issued by the U.S. EPA.

EMISSION FACTORS FOR POWER PURCHASES

The emission factor and the best data source to use for power purchases will depend on the type of power purchase.

Registry (Online) Databases
When the facility (or generating unit) is known, it may be possible to use a facility-specific or unit-specific emission factor. If the facility has reported data to The Registry or to other registries where data is publicly reported and third-party verified, it may be possible to obtain a facility specific CO_2 emission factor directly from The Registry's database or other databases.

U.S. EPA's eGRID Database
The eGRID database includes output emission rates (lb/MWh) for power generating facilities – for CO_2, CH_4 and N_2O emissions. In this case, it is possible to obtain facility emission factors for past years, though current-year or immediate past-year data are not likely to be available. The database includes average output emissions rates for sub-regions of the U.S that provide default emission factors on a regional basis. The database can also be used to derive utility or generator-specific average emission rates. You can use the utility or generator-specific average, if known, fuel-specific emission factors if the generation source is known (Table 14.3), or the regional average emission rate if there is no specific facility or utility/generator to which the purchase can be assigned.

U.S. DOE's EIA Power Generator Databases (EIA-906-920)
Each year, power generators in the U.S. report power generation data to the EIA. The reported data are available online, and provide another opportunity to develop facility emission factors. These data are not available at the combustion or stack level, and they do not include GHG emissions data. However, the emissions can be calculated using a default emission factor for the fuel type, using the heat input that is also reported in these datasets.

U.S. EPA's Electronic Data Reports for Power Generating Facilities
This data source is U.S. EPA's Electronic Data Reporting (EDR) system used for Acid Rain compliance reporting by large power generation facilities. The data elements reported include CO_2 emissions (short tons) and Gross Generation (MWh), and they are included at the stack level which is often consistent with the generating unit. This dataset may not be the best for unit-specific emission factors because the output gives Gross Generation (MWh) rather than Net Generation, and the power generation from non-emitting units (such as combined-cycle steam generators) is not included with the combustion unit-specific data.

Biogenic CO_2 Emission Factors
When selecting emission factors from agency databases for purchased electricity generated using fuels that have biogenic emissions (including Landfill Gas, Digester Gas, Biomass, Municipal Solid Waste, etc.), it is important to consider what assumptions are made by the agency in compiling the emissions dataset regarding biogenic CO_2 emissions. In some cases, if the power is generated with a combination of fossil and biomass fuels, the reported CO_2 emissions may be a combination of fossil and biogenic emissions, or they may just be fossil CO_2 emissions. You should refer to the Users' Guide of the database before selecting the emission factors for these types of purchases.

The Registry requires that biogenic CO_2 emissions be reported separately from anthropogenic emissions. This extends also to purchases. If biogenic CO_2 emissions cannot be separately determined, then Members should use regional average output emissions factors, as with Spot Market and Other Power purchases.

— EPS IE-02: Assigning Default Emission Factors to Aggregate Power Flows

If you are using the aggregate flow method, you may assign regional average output emissions factors to your aggregate purchases. Power purchases should be disaggregated to the extent possible by region of origin. Regional average output emissions factors may then be applied using equation 14b.

14.2.4 Step 4: Quantify Emissions from T&D Losses for Purchased Power

— EPS IE-01 and EPS IE-02: Quantifying Emissions for T&D Losses

To calculate your Scope 2 emissions from T&D losses associated with purchased power, use Equation 14c as follows:

Equation 14c
Emissions from T&D Losses [MT GHG] = Purchased Power Emissions [MT GHG] x T&D System Loss Factor [%]

This calculation is repeated for each GHG (CO_2, CH_4, N_2O) using the emissions totals derived in the previous section.

14.2.5 Example: Estimating Purchased Power Emissions

Example 14.1 shows how EPS IE-01 is applied in practice (for CO_2 emissions only) for an entity that purchases power from a range of sources and delivers that power through a T&D system.

14.1 EXAMPLE 14.1 Estimating Purchased Power Emissions

A vertically integrated utility located in Idaho generates power with one natural gas turbine generator (100 percent ownership) and purchases electricity from specified facilities, utilities and the spot market. The utility also has one exchange in place with another utility in the northwest to receive hydro power in the spring, and to deliver natural gas power in the summer. Over the course of the year, the power received onto their system was as followes:

Category/Facility	Comment	Power Received (MWh)
A. Owned Generation	Natural gas turbine generator	400,000
B. Specified Purchase	Known facility – coal power plant	1,000,000
C. Specified Purchase	Known facility – natural gas power plant	140,000
D. Specified Purchase	Known facility – hydro power plant	200,000
E. Resource-Specific Purchase	From utility that generates hydro power only	100,000
F. Resource-Specific Purchase	From utility that generates hydro power only	100,000
G. Spot Market Purchases	Purchased in Idaho (WECC Northwest)	40,000
H. Exchange Power (In)	Received from NW utility	20,000
	Total	**2,000,000**

Most of the power received into the system is sold to retail customers (1,800,000 MWh), with a small quantity of excess power resold wholesale (40,000 MWh). For the exchange, 20,000 MWh of power is delivered back to the NW utility.

For this example, the loss factor is determined by subtracting total power sold/delivered (1,860,000 MWh) from the total power received (2,000,000 MWh). The difference (140,000 MWh) is divided by the total power received to calculate the loss factor (seven percent).

Emission factors are assigned to each category of purchased power and the purchased power emissions are calculated as follows:

Category/Facility	Emission Factor (lb/ MWh)	Power Received (MWh)	Purchased Power CO_2 Emissions (Scope3) (MT)
A. Natural gas turbine generator	N/A	N/A	N/A
B. Known facility – coal power plant	2,150	1,000,000	975,225
C. Known facility – natural gas power plant	1,050	140,000	66,678
D. Known facility – hydro power plant	0	200,000	0
E. From utility that generates hydro power only	0	100,000	0
F. From utility that generates hydro power only	0	100,000	0
G. Purchased in Idaho (WECC Northwest)	921	40,000	16,712
H. Received from NW utility	0	20,000	0
Total		**2,000,000**	**1,058,615**

Note that losses and emissions are not counted for owned generation, so there is no emission factor and no purchased power emissions (i.e. Scope 3) shown for Facility A.

The T&D losses are calculated by multiplying the Scope 3 emissions by the loss factor as follows:

T&D Losses (Scope 2 emissions) = 1,058,615 MT x 7% = 74,103 MT

14.3 Bulk Power Transmission Systems

This section provides a method for quantifying losses on high voltage bulk transmission systems operated principally for the conveyance of wholesale power or wheeled power. This method is applicable to entities that own or control bulk transmission systems for regional wholesale conveyance (e.g. Balancing Authorities, ISOs, etc.).

The method presented below is similar to that provided in Section 14.2 for local T&D systems, but recognizes that these transactions are conducted almost entirely at transmission level voltages with lower losses, and are separate from an LDC system (See Figure 14.2). Similar to the calculation for T&D losses, the calculation of emissions associated with bulk transmission system losses requires data for the total power conveyed on the line or the system (MWh), the average loss factor (percent), and the emission factor for the electricity delivered to the system.

For every bulk transmission system, all transmission lines, substations and other associated equipment may be grouped for convenience into one system "facility." You should at a minimum report your bulk transmissions system at the appropriate level reflecting the geographical expanse (state, national or North American) of its lines. You may however choose to break down your system into more discrete state or national segments or segments that are consistent with subsidiaries that you may be required to report distinctly. However, in deciding the appropriate level for reporting, it is also important to be sure that loss factors can be determined for each segment that is reported separately.

Transmission system operators usually have information about the amount of power that flows through the system, and losses are usually assigned to each transaction based on theoretical or modeled loss factors. However, these same operators may not know the specific origin of the power or its generation type, especially with open access systems.

— EPS IE-03: Quantifying Losses on High Voltage Bulk Transmissions Systems

This method estimates the losses and emissions associated with power flows on bulk power transmission systems. The five steps in this methodology are:

(1) Decide how you will report bulk power transmission losses;
(2) Determine power flows on the transmission system;
(3) Determine a loss factor for each power flow;
(4) Assign emission factors (CO_2, CH_4 and N_2O) for each type of power delivered to the system; and
(5) Calculate and aggregate the emissions.

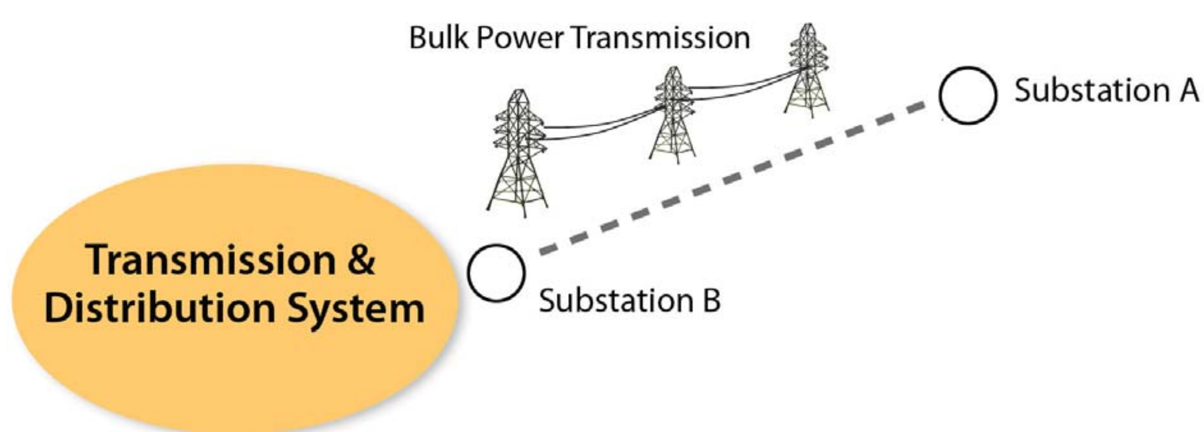
14.3.1 Step 1: Define how Bulk Transmission Losses will be Reported

If you do not own or control a bulk transmission system that is distinct from any local T&D system you reported according to the requirements in Section 14.2, you do not need to report under this section. Similarly, if you own or control both a T&D system and a bulk transmission system that delivers power you're your T&D system, you may choose to treat the two as a single "facility." In this case you should use Section 14.2 to determine emissions associated with losses (see Table 14 below, which provides additional guidance on integrating or separating bulk transmission with or from T&D systems).

However, if your transmission system(s) are considered to be a separate, stand-alone system(s), then the bulk power transmission losses should be evaluated separately from the rest of T&D system, and you should use the methodology presented here. The bulk power transmission losses may be reported as one "facility" for your entire bulk power transmission system, or as separate "facilities" for discrete bulk power transmission pathways within the system.

Figure 14.5 shows a simplified T&D system with a connected transmission system that may or may not be controlled by the same entity. Options for defining the reporting boundaries in this case are presented below for a range of control scenarios.

Figure 14.5 – Illustration of a T&D System Connected to a Bulk Power Transmission System



14.4 TABLE 14.4
Options For Reporting Bulk Transmission Losses

Options	How to Report Bulk Transmission Losses
Option 1 – Entity controls local T&D System, but no bulk power transmission outside the T&D service area. (Use EPS IE-01 or EPS IE-02 and report per 14.2)	No bulk transmission system. Include all power generated within the local T&D service area if it is received into the T&D system (whether owned or purchased). Report net generation at the generating facility step-up substation. Include wholesale purchases and power from remote generation at the place where it is received into the local T&D system (e.g., Substation B).
Option 2 – Entity controls bulk power transmission system, but no local T&D. (Continue using EPS IE-03)	Bulk transmission system considered distinct from any T&D systems it feeds. Report incoming power flows (e.g. at substation A) and outgoing power flows (e.g. at Substation B). These will include wholesale purchases, wheeled power and any direct access power delivered for others.
Option 3 – Same entity controls local T&D System and bulk power transmission outside the T&D service area. Entity elects to combine bulk power transmission with local T&D system for reporting power flows, losses and indirect GHG emissions. (Use EPS IE-01 or EPS IE-02 per section 14.2)	Report transmission power flows at the location where the power comes onto the combined system (e.g., at Substation A). Include wholesale purchases/ exchanges, wheeled power and direct access power. For all power generated within the local T&D service area and delivered to the T&D system (whether owned or purchased) report Net Generation at the generating facility step-up substation. Report bulk power flows leaving the system at the substation where power leaves the combined system.
Option 4 – Same entity controls local T&D System and bulk power transmission outside the T&D service area. Entity elects to create separate reporting "facilities" for the bulk power transmission system and the local T&D system. (Continue to use EPS IE-03 for the bulk transmission system but use EPS IE-01 or EPS IE-02 for the T&D system)	For the local T&D system, include all power generated within the local T&D service area if it is received into the T&D system (whether owned or purchased). Report Net Generation at the generating facility step-up substation. Include wholesale purchases and power from remote generation at the place where it is received into the local T&D system (e.g., Substation B). For the bulk power transmission system, report incoming power flows (e.g. at substation A) and outgoing power flows (e.g. at Substation B). These will include wholesale purchases, wheeled power and any direct access power delivered for others.

It should be noted that if you decide to report discrete bulk power transmission pathways as separate facilities, you will need to have power flow data specific to each of those pathways.

Methodologically, the following steps of EPS IE-03 parallel the steps of EPS IE-01 and EPS IE-02, but focus primarily on the treatment of bulk transmission systems. You may choose to consult EP IE-01 or EPS IE-02 for additional methodological detail.

14.3.2 Step 2: Determine Power Flows through the Bulk Transmission System

Once the bulk power transmission system has been defined, you must obtain information about its power flows. You must account for all power coming in (generated power, wholesale power purchases, exchanges (in) and wheeled power), and all power delivered out of the system (wholesale power sales, wheeled power deliveries). These power flows should be aggregated over your one-year reporting period (calendar year).

You may report the incoming power flows as a system total, or by place of origin, or by contract counterparty, or by generation resource (fuel type), if known. Having a greater level of detail about the incoming power flows provides the opportunity to select and assign more accurate emission rates to the power flows (Step 4, below), but this is not necessary to determine the energy balance and the bulk power transmission system loss factor (Step 3). Incoming wheeled power should be measured at the first point of receipt into the system, and aggregated for the year by supplier or by region of origin.

You may already track bulk power transmission system power flows for regulatory purposes,[35] and if so, these data may be used to develop the power flow energy balance you must report to The Registry. If these datasets are not readily available, you may be able to gather the data from the logs of real-time bulk power transactions compiled by operations.

14.3.3 Step 3: Select or Derive a Bulk Power Transmission Loss Factor

You may select or derive a bulk power transmission loss factor using one of the following options:

- **Engineering Estimate** – Use engineering estimates based on measured losses of known power and ambient conditions on each transmission segment, projected for the entire system for appropriately weighted average demand and ambient conditions over a reporting year. Alternatively you may use a modeled or calculated loss factor provided by the Balancing Authority or ISO. For Open Access systems, system average loss factors may be available from regulatory bodies such as FERC (e.g. Tariff Loss Factors).

[35] Two examples of regulatory reports that have this information (for reporters in the United States) are the FERC Form 1 and the EIA Form 861. For EPS Members that do not compile these reports, these reports do nevertheless provide an additional view of the power flow accounting principles being applied.

- **Default Loss Factor** – Use a default transmission loss factor of 2.0 percent.[36] It must be noted that if relying on the default factor, it must be applied to aggregate power flows into your transmission system, not power flows out of the system (14.3.2).

14.3.4 Step 4: Assign Emission Factor(s)

You may select or derive an emission factor using one of the following options:

- **Engineering Estimate** – If you have specific information about the source of the power (wholesale or wheeled), you may use an emission factor applicable to those sources. Refer to Section 14.2.3 for acceptable options.

- **Default Loss Factor** – If you know the eGRID subregion where the power originates (United States), you may use the eGRID regional average emission rate applicable to that region (Table 14.2). If you know the province where the power originates (Canada), you may use the average emission rate for that province (GRP Table 14.3). For Mexico, use the eGRID average for the United States as a default. If you do not know the source of the power, you may use the eGRID or Provincial average emission rate applicable to the location at which the power first enters your transmission system.

14.3.5 Step 5: Quantify Emissions Associated with Bulk Power Transmission Losses

Quantify the GHG emissions from bulk transmission losses using Equation 14d:

Equation 14d
Bulk transmission System Line Loss emissions [MT GHG] = Power transmitted onto the system [MWh] x emission factor [MT GHG/MWh] x Loss Factor [%]

Or more specifically:

Bulk transmission System Line Loss emissions [MT GHG] = SUM[(MWh_1 x kg/MWh_1)+ (MWh_2 x kg/MWh_2) + … (MWh_n x kg/MWh_n)] x MT/1000 kg x Loss Factor [%]

36 *A transmission loss factor of 2.0 percent is considered to be a representative average of the transmission tariff loss factors reported to FERC for open access transmission. Loss factors range from about 0.5 percent to 3.5 percent. A system specific average should be used when available through FERC or other recognized regulating agency, subject to a Verification Body's approval.*

You should repeat this calculation for all three GHGs (CO_2, CH_4, N_2O). This method will quantify the total emissions resulting from bulk power transmission system losses (or for each transmission pathway).

14.3.6 Example: Estimating Transmission & Distribution Losses for Bulk Power Transmission

14.2

EXAMPLE 14.1
Estimating T&D Losses for Bulk Power Transmission

A Transco (i.e. transmission company) generates 200,000 MWh and purchases 100,000 MWh to provide power for its utility customers. It also wheels 100,000 MWh of power across the system during the course of the year. It is assumed that all power is generated with natural gas as the primary fuel and the emission factor is assumed to be 0.5 MT/MWh. The following table shows how bulk power transmission losses are calculated for this example.

	MWh	MT CO_2
A. Own Generation	200,000	100,000
B. Power Received – Wholesale	100,000	50,000
C. Power Received – Wheeled	100,000	50,000
D. Power Received – Total (A + B + C)	400,000	
E. Power Delivered – Retail	46,000	
F. Power Delivered – Wholesale	248,000	
G. Power Delivered – Wheeled	98,000	
H. Power Delivered – Total (E + F + H)	392,000	
I. Emissions from non-generated received power (Scope 3) (B + C)		100,000
J. System Average Loss Factor (D-H)/D	2.0%	
K. Emissions from T&D Losses (Scope 2)		
L. Losses – Wholesale Purchases (B x J)	2,000	1,000
M. Losses – Wheeled Power (C x J)	2,000	1,000
N. Emissions from T&D Losses – Total (L + M)	4,000	2,000

14.4 Estimating Indirect Emissions from Power which is Purchased/Acquired and Consumed

This section provides a methodology for reporting indirect Scope 2 emissions from electricity purchased and consumed in buildings and facilities. In order to quantify these emissions, you will need to determine the amount of electricity consumed, estimate the fraction of consumed electricity that was purchased (not self-generated), and assign appropriate emission factors to these purchases. Most of the data required for this process have been collected or calculated to meet other reporting requirements in the EPS Protocol.

14.4.1 EPS IE-04

The power you may take from the grid and consume is typically comprised of a mix of owned generation and purchased electricity sources. Emissions from the portion of the consumed electricity that is from purchased or acquired sources must be reported as Scope 2 emissions. Emissions from consumed electricity that you generate are already reported as Scope 1 emissions, so they are not again reported in Scope 2.

To partition total consumption into these two categories, the following ratio is used:

Equation 14e
Power Purchased, as a fraction of Total Power Flows on System = (Power received from Specified Purchases, Spot Market Purchases, and Power Exchanges [MWh]) / (Total power flows onto the T&D system from Generation, Purchases and Power Exchanges [MWh])

This ratio should be applied to the metered power consumed at each facility where electricity is consumed.[37] Doing so will yield the portion of power consumed at each facility that, on average comes from purchases power rather than self generated power. Once your purchased power consumption has been calculated for each facility, you must multiply it by an appropriate emissions factor, as indicated in Equation 14f. This will give you the Scope 2 CO_2 emissions associated with the power you consumed in your buildings and facilities.

37 Note that, if the electricity consumed in buildings and facilities is not metered, then the consumption may be estimated based on the area and utility average electricity consumption rate for all metered facilities.

Equation 14f
CO_2 emissions = MWh Purchased and Consumed x Emission Factor The applicable emissions factors for CO_2 emissions are, in order of required use, as available: • EPS Metric D-3 (System-wide Electric Deliveries Metric—optionally calculated in Chapter 19), • EPS Metric D-1 (Electricity Deliveries Metric for Wholesale Power Sales—optionally calculated in Chapter 19), or • eGRID or provincial average factors for the applicable region if you do not elect to report either of the aforementioned optional metrics.

This calculation will also need to be repeated for CH_4 and N_2O emissions. Use the appropriate average emission factors from GRP Tables 14.1, 14.2 and 14.3.

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

In the GRP, Chapter 15 refers to indirect emissions from imported steam, district heating, cooling and electricity from a Combined Heat and Power (CHP) Plant. Members are required to report emissions from these sources according to the methodologies in the GRP.

Typically, Members in the EPS will not have indirect emissions from imported steam, district heating or cooling in the majority of their facilities. However, Members may have indirect emissions from heating and cooling in spaces they lease. Calculation methodologies for indirect emissions from heating and cooling leased spaces are included in chapters 15.2 and 15.3 of the GRP.

Chapter 16 Direct Fugitive Emissions

This chapter outlines methodologies for calculating a broad range of direct fugitive emissions from common EPS sources including emissions of SF_6 from circuit breakers and other equipment, HFCs from generating unit intake air cooling units, and CH_4 from coal storage. Members must apply the methodologies included below in EPS FG-01 through EPS FG-05 when quantifying emissions from the following sources:

- SF_6 Emissions
- HFC Emissions
- Coal Pile CH_4 Emissions
- CH_4 Emissions from Natural Gas Pipelines
- Fugitive Emissions from Hydro-Power Reservoirs (Optional)

Fugitive emissions are typically quantified using a mass-balance method that takes into account the quantity of gas used to “top up” a unit when there have been small fugitive leaks over a period of time. If there is an interval of several years between top-up events, the emissions should only be reported in the year when the gas is topped up. You must not report fugitive emissions that are averaged across the number of years between top up events when several years have passed between top up events.

16.1 **TABLE 16.1**
Overview of Methodologies for Reporting Fugitive Emissions in the EPS

Method	Emissions Source	Basis
EPS FG-01	SF_6 emissions from T&D and/or bulk transmission systems	U.S. EPA methodology
EPS FG-02	SF_6 emissions from T&D and/or bulk transmission systems	Environment Canada/ Canadian Electric Associations methodology
EPS FG-03 (simplified methodology)	SF_6 emissions from T&D and/or bulk transmission systems	Energy Information Administration methodology
EPS FG-04	HFCs from cooling units that support power generation	Mass balance
EPS FG-05	CH_4 from coal storage	Default emissions factors
EPS FG-06	CH_4 from natural gas pipelines	Default emissions factors
EPS FG-07 (optional)	CH_4 and CO_2 from reservoirs	IPCC methodology

16.1 Calculating Fugitive Sulfur Hexafluoride Emissions

SF_6 is used for electrical insulation and can escape into the atmosphere during normal operations of electrical transmission and distribution systems or when added to or extracted from breaker equipment. If you control power generating facilities you must report fugitive SF_6 emitted from equipment at your facilities. If you control transmissions and distribution systems you must report fugitive SF_6 emissions from all aspects of your transmission and distribution systems, including substations and circuit breakers.

Often SF_6 emissions from transmission and distribution sources consist of a larger number of small facilities that are dispersed across a region. The Registry explicitly allows for the aggregation of these facilities at the state level in order to streamline emission reporting.

Two mass-balance methods are presented in the EPS Protocol to estimate fugitive SF_6 emissions. The first is provided by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems (EPS FG-01), and the second is provided by Environment Canada and the Canadian Electricity Association (EPS FG-02).

If sufficient data are not available to quantify SF_6 emissions from your transmission and distribution systems using a mass-balance method, you should use the simplified EIA calculation method based on the miles of transmission lines you control (EPS FG-03).

— EPS FG-01:EPA SF_6 Fugitive Emissions Quantification Method

This quantification method is the U.S. EPA mass-balance methodology for estimating SF_6 emissions from electricity delivery systems. When using this quantification method, you must annually report your SF_6 emissions from each delivery system (i.e. facility) reported in The Registry's reporting software. This reporting is required to follow the structure you used to set up the facilities for your T&D system(s) and/or bulk transmission system(s) in Chapter 14.

The mass-balance method works by tracking and systematically accounting for uses of SF_6 for each electricity delivery system during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. Table 16.1 is a worksheet based on the mass-balance method. You should use the mass balance worksheet for each system that you report separately (see 14.1 for discussion of requirements related to reporting systems in aggregate or separately). The method has four sub calculations (A-D), a final total (E), and an optional emission rate calculation (F) as follows:

A. **Change in Inventory.** This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. The change in inventory will be negative if the quantity of SF_6 in storage increases over the course of the year.

B. **Purchases/Acquisitions of SF_6.** This is the sum of all the SF_6 acquired during the year either in storage containers or in equipment.

C. **Sales/Disbursements of SF_6**. This is the sum of all the SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment.

D. **Change in Total Nameplate Capacity of Equipment.** This is the net increase in the total volume of SF_6 using equipment in a facility during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 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 SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. This quantity will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. **Total Annual Emissions**. This is the total amount of SF_6 emitted over the course of the year from a facility, based on the information provided above.

F. **Emission Rate (optional).** By providing the total nameplate capacity of all the electrical equipment in the facility at the end of the year, you can obtain an estimate of the emission rate of the facility's equipment (in percent per year). The emission rate is equal to the total annual emissions at the facility divided by the total equipment nameplate capacity.

16.2

TABLE 16.2
U.S. EPA Methodology for Estimating SF_6 Emissions Worksheet
(To be applied to each Electric Power Delivery System)

SF_6 Emissions Reduction Partnership for Electric Power Systems

Annual Reporting Form

Name:		Company Name:	
Title:		Report Year:	
Phone:		Date Completed:	

Decrease in Inventory (SF_6 contained in cylinders, not electrical equipment)

Inventory (in cylinders, **not** equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Decrease in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Increase in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of new equipment		
11. Total nameplate capacity (proper full charge) of retired or sold equipment		
D. Increase in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF_6	kgs. SF6	Tonnes CO_2 equiv.
E. Total Emissions (A+B-C-D) (lbs.)	-	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	

16.1 EXAMPLE 16.1.1
Calculating Sulfur Hexafluoride Emissions

A retail provider, reporting using operational controls a portion of a transmission and distribution system located inside their geographical boundary. The retail provider has reported its portion of the transmission and distribution system as a single facility. In order to report the fugitive SF_6 emissions from this facility the retail provider makes the following calculations based on maintenance logs.

5,000 pounds = SF_6 inventory in cylinders at beginning of report year
9,000 pounds = SF_6 inventory in cylinders at the end of the year
-4,000 pounds = Decrease in inventory (5,000 – 9,000)

3,000 pounds = Purchases of SF_6 in cylinders
7,000 pounds = Provided by manufacturers inside new equipment purchased
5,000 pounds = Recovered from retired equipment
15,000 pounds = Total purchases (3,000 + 7,000 + 5,000)

0 = Sales/disbursements of SF_6

7,000 pounds = Capacity of new equipment (full charge)
6,000 pounds = Capacity of retired equipment (full charge)
1,000 pounds = Increase in capacity (7,000 – 6,000)

10,000 pounds = SF_6 emissions for the report year (-4,000 + 15,000 – 0 – 1,000)

Conversion: 10,000 pounds * 0.45359 kg/pound = 4,536 kg SF_6

— EPS FG-02: Environment Canada/Canadian Electric Association SF_6 Fugitive Emission Calculation Method

The Registry also allows its Members to quantify and report SF_6 emissions associated with electric power delivery systems using the Environment Canada/Canadian Electric Association SF_6 Fugitive Emission Calculation Method.

Please see the Registry's Electric Power Sector webpage for a full reproduction this methodology: http://www.theclimateregistry.org/resources/protocols/electric-power-sector-protocol/

— EPS FG-03: EIA SF_6 Fugitive Emissions Calculation Method (Simplified Methodology)

This section describes the EIA methodology for estimating SF_6 emissions from electric transmission and distribution equipment based on miles of transmission lines.[38] The applicable portion of Section 4.2.4 of this document is reproduced below. This methodology should be applied separately to each delivery system the Member is reporting.

38 *Documentation for Emissions of Greenhouse Gases in the United States 2006, October 2008.*

Emissions from Electric Power Systems from 1999 to present

Emissions from electric power systems from 1999 onward were estimated based on (1) reporting from utilities participating in U.S. EPA's SF_6 Emissions Reduction Partnership for Electric Power Systems, which began in 1999, and (2) utilities' transmission miles as reported in the 2001 and 2004 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors. (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV). Between 1999 and 2003, participating utilities represented between 31 percent and 35 percent of total U.S. transmission miles. The emissions reported by participating utilities each year were added to the emissions estimated for non-reporting utilities in that year. Emissions from non-reporting utilities were estimated using the results of a regression analysis that showed that the emissions of reporting utilities were most strongly correlated with their transmission miles. As described further below, the transmission miles of the various types of non-reporting utilities were multiplied by the appropriate regression coefficients, yielding an estimate of emissions. Transmission miles are clearly physically related to emissions, since in the United States, SF_6 is contained primarily in transmission equipment rated at or above 34.5 kV.

The regression equations reflect two distinctions among non-reporting utilities: (1) between small and large utilities (i.e., with less or more than 10,000 transmission miles, respectively), and (2) between utilities that do not participate in the SF_6 Emission Reduction Partnership (non-partners) and those that participate but that have not reported in a given year (non-reporting partners). (Historically, these non-reporting partners have accounted for 5 percent or less of total estimated partner emissions.) The distinction between small and large utilities was made because the regression analysis showed that the relationship between emissions and transmission miles differed for small and large facilities. The distinction between non-partners and non-reporting partners was made because the emission trends of these two groups were believed to be different. Reporting partners have reduced their emission rates significantly since 1999. The emission trend of non-reporting partners was believed to be similar to that of the reporting partners, because all partners commit to reducing SF_6 emissions through technically and economically feasible means. However, non-partners were assumed not to have implemented any changes that would have reduced emissions over time.

To estimate emissions from non-partners in every year since 1999, the following regression equations were used. These equations were developed based on the 1999 SF_6 emissions reported by 49 partner utilities (representing approximately 31 percent of U.S. transmission miles), and 2000 transmission mileage data obtained from the 2001 UDI Directory of Electric Power Producers and Distributors:

Non-partner small utilities (less than 10,000 transmission miles, in kilograms):
Emissions = 0.874 × Transmission Miles

Non-partner large utilities (more than 10,000 transmission miles, in kilograms):
Emissions = 0.558 × Transmission Miles

To estimate emissions from non-reporting partners in each year, the regression equations based on the emissions reported by partners in that year were used. To estimate non-reporting partner emissions, the regression equations are based on the SF_6 emissions reported by 51 partner utilities, and updated transmission mileage data obtained from the latest UDI Directory of Electric Power Producers and

Distributors. The resulting equations:

Non-reporting partner small utilities (less than 10,000 transmission miles, in kilograms):
Emissions = 0.398 × Transmission Miles

Non-reporting partner large utilities (more than 10,000 transmission miles, in kilograms):
Emissions = 0.387 × Transmission Miles

UDI Directories of Electric Power Producers and Distributors are used to obtain U.S. transmission system growth.

For each year, total emissions were then determined by summing the partner-reported emissions, the non-reporting partner emissions (determined with that year's regression equation for the partners), and the non-partner emissions (determined using the 1999 regression equation).

16.2 Fugitive HFC Emissions

If you have generating facilities that have cooling units directly related to power production, you must report fugitive HFC emissions at the facility level by compound. The reportable emissions will be for the same HFCs as indicated in the GRP. You may use the same type of mass balance methodology used to quantify SF_6 emissions or select the single unit methodology discussed in EPS Method FG-04.

— EPS FG-04: HFC Compounds Fugitive Emissions Quantification Methodology

Members with electric generating facilities are required to quantify fugitive HFC emissions separately for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases. You must use the same mass balance methodology provided in Chapter 16 of the GRP for reporting HFC emissions unless reporting for an individual cooling unit. You are required to report fugitive emissions for each HFC compound separately, as applicable, and to convert pounds of HFCs into kilograms, if necessary. This requirement does not apply to air or water cooling systems or condensers that do not contain HFCs.

If you are reporting for an individual cooling unit, you may calculate fugitive HFC emissions using service logs to document HFC usage and emissions. HFC emissions must be reported separately for each HFC compound as applicable. The service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year.

Alternatively, the following material balance equations are provided to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. Total fugitive HFC emissions are the sum of HFC emissions from each of the three applicable equations.

Equation 16a

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

$$HFC_{Service} = R_{recharge} - R_{recover}$$

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

Where:

$\mathbf{HFC_{Install}}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$\mathbf{HFC_{Service}}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

$\mathbf{HFC_{Retire}}$ = HFC emitted during the removal from service/retirement of the unit, kilograms;

$\mathbf{R_{new}}$ = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$\mathbf{C_{new}}$ = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$\mathbf{R_{recharge}}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$\mathbf{R_{recover}}$ = HFC recovered from the unit during maintenance and service, kilograms;

$\mathbf{C_{retire}}$ = Nameplate capacity of the retired unit, kilograms;

$\mathbf{R_{retire}}$ = HFC recovered from the retired unit, kilograms.

16.2 EXAMPLE 16.2.1
Calculating Hydrofluorocarbon Emissions from A Cooling Unit

An electric generating facility uses a chiller to cool input air for one of the electric generating turbines. The chiller uses HFC-134a refrigerant and was installed five years ago. The Member that controls the electric generating facility must determine its fugitive HFC-134a emissions. The information below was compiled from service logs:

$HFC_{Install}$ = 0 kg (the chiller was not installed during the report year)
HFC_{Retire} = 0 kg (the chiller was not retired during the report year)
$HFC_{Service} = R_{recharge} - R_{recover}$ = 23 kg – 0 kg = 23 kg

Where:

$R_{recharge}$ = (50 pounds HFC-134a) x (0.45359 kg/pound) = 23 kg (the amount of HFC-134a added to the chiller)

$R_{recover}$ = (0 pounds HFC-134a) x (0.45359 kg/pound) = 0 kg (the amount of HFC-134a recovered from the chiller)

Total fugitive HFC-134a = $HFC_{Install} + HFC_{Service} + HFC_{Retire}$
= 0 kg + 23 kg + 0 kg = 23 kg

16.3 Quantifying Fugitive Methane Emissions from Coal Storage

If you store coal at power plants or control coal mines, you must report fugitive CH_4 emitted from coal storage, as addressed in EPS FG-05.

— EPS FG-05: Method for Calculating Fugitive CH_4 Emissions from Coal Storage

Quantify fugitive CH_4 emissions from coal storage using the following equation:

Equation 16b
$CH_4 = PC * EF * CF_1 / CF_2$ **Where:** **CH_4** = CH_4 emissions in the report year, metric tons per year; **PC** = Purchased coal in the report year, tons per year; **EF** = Default emission factor for CH_4 based on coal origin and mine type provided in Table 15.2 below, scf CH_4/shortton; **CF_1** = Conversion factor equals 0.04228, lbs CH_4/scf; **CF_2** = Conversion factor equals 2,204.6, lbs/metric ton.

16.3

TABLE 16.3
Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)

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

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005 April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

16.4 Quantifying Fugitive CH_4 Emissions from Natural Gas Pipelines

Guidance is provided below for a simplified methodology for quantifying fugitive emissions associated with natural gas pipelines (onsite) that deliver fuel from the utility tie-in to the power generating unit. This methodology may be used consistent with the GRP's provisions on applications of simplified methodologies (Chapter 11).

If your pipeline and processing equipment are extensive, fugitive CH_4 emissions should be calculated using the methods included in documents that describe industry-standard methodologies such as the API's Compendium of GHG Emission Factors, the Intrastate Natural Gas Association GHG Guidance, or the American Gas Association GHG Guidance.

— EPS FG-06: Methods for Quantifying Fugitive Emissions from Natural Gas Pipelines

Fugitive emissions of CH_4 can occur in the pipelines and fuel processing equipment used to deliver gaseous fuel to power generating facilities and equipment. In most cases, the length of pipeline from the fuel provider to the point of combustion is very short and there is a limited degree of fuel conditioning needed. These factors typically result in small amounts of fugitive emissions from natural gas pipelines at electric generating facilities. Where these factors exist, fugitive CH_4 emissions can be quantified using the following estimation method:

Equation 16c

$$CH_4 = L * EF / 1000$$

Where:

CH_4 = Methane emissions from the natural gas pipeline, metric tons;
L = Length of pipe in miles;
EF = Default emission factor (1611 kg/mile-year);
1000 = Conversion factor from kg to metric tons.

16.5 Fugitive Emissions from Hydro-Power Reservoirs (Optional)

Prior to the 1990s, there was little or no data available on CO_2 and CH_4 emissions from reservoirs used to store water for power generation. There is now a growing body of literature on this subject, some of which suggests that the organic carbon stored in plants and soils in flooded areas decomposes to CO_2 and CH_4, and these gases are subsequently released to the atmosphere.

However, different regions and soils contain different amounts of stored organic carbon. Furthermore, the rate of decomposition of this carbon depends on local climatic conditions, reservoir area, and potentially a whole host of other site specific parameters. Consequently, the potential for GHG production is thought to vary tremendously from one reservoir site to another.

While the body of literature is growing and the scientific community is gaining a better understanding of the complex issues associated with these reservoir emissions, there is still no consensus on how to quantify these emissions in a standardized way that accommodates the broad range of variables involved. Direct measurement methodologies are still in their infancy and not widely available. For this reason, The Registry is not requiring Members to quantify emissions from reservoirs within their organizational boundaries at this time. However, if you determine that EPS FG-07 is adequate for your reservoir(s), then you may use that method to optionally report those emissions.

The Registry intends to adopt a requirement to report any GHGs emitted from reservoirs once a feasible and defensible methodology becomes available, consistent with its requirement for complete reporting.

— EPS FG-07 (OPTIONAL): Methods for Quantifying Fugitive Emissions from Hydro-Power Reservoirs

Duchemin, E.J. T. Huttunen, A. Tremblay, R. Delmas and C.F. Silveira Menezes, 2006a (Lead authors). "*Appendix 2 – Possible approach for estimating CO_2 emissions from lands converted to permanently flooded lands*". Basis for future methodological development. In Eggletion, H.S., L. Buendia, K. Iwa, T. Ngara and K. Tanabe (eds.), 2006. Intergovernmental Panel on Climate Change (IPCC), National Greenhouse Gas Inventories Guidelines, Vol. 4 – Agriculture, Forestry and Other Land Use, IGES, Kanagawa, Japan, pp. AP2.1-AP2.9

Duchemin, E.J. T. Huttunen, A. Tremblay, R. Delmas and C.F. Silveira Menezes, 2006a (Lead authors). "*Appendix 3 – CH_4 Emissions from Flooded lands: Basis for future methodological development*". In Eggletion, H.S., L. Buendia, K. Iwa, T. Ngara and K. Tanabe (eds.), 2006. Intergovernmental Panel on Climate Change (IPCC), National Greenhouse Gas Inventories Guidelines, Vol. 4 – Agriculture, Forestry and Other Land Use, IGES, Kanagawa, Japan, pp. AP3.1-AP3.8

Chapter 17 Direct Process Emissions

This chapter includes methodologies to quantify emissions for typical sources of process emissions in the Electric Power Sector, including acid gas scrubbers (Section 15.2.1), geothermal power generation (Section 15.2.2), and other common sources (Section 15.2.3).

The need for reporting of process emissions from other small sources is addressed in EPS PR-05.

17.1 TABLE 17.1
Overview of Methodologies for Reporting Process Emissions in the EPS

Method	Emissions Source	Basis
EPS PR-01	Acid gas scrubbers	Mass balance
EPS PR-02	Geothermal emissions	Default emissions factor
EPS PR-03	Geothermal emissions	Site specific emissions factor

17.1 Quantifying Process Emissions from Acid Gas Scrubbers

— EPS PR-01: CO_2 Process Emissions Calculation Methodology for Acid Gas Scrubbers

If you use acid gas scrubbers or add an acid gas reagent to a combustion source, there may be CO_2 emissions that occur during the SO_2 scrubbing process, depending on the type of reagent used. The CO_2 emissions from acid gas scrubbers are categorized as process emissions.

If you calculate CO_2 emissions from stationary combustion using a CEMS method, the process emissions from acid gas scrubbers are most likely included in the CO_2 concentrations used in the CEMS methodology. In this case, you are not required to report process emissions separately from total CO_2 emissions for the facility, and you will simply indicate in The Registry's reporting software that these emissions are accounted for in the total CO_2 emissions reported from fuel combustion.

If you calculate CO_2 emissions using a fuel-based method, then a separate calculation is needed to calculate and report CO_2 emissions from acid gas scrubbers, as discussed below. The following equation[39] must be used to quantify CO_2 emissions from the acid gas process:

Equation 17a

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{MW})$$

Where:

CO_2 = CO_2 emitted from sorbent for the report year, metric tons;
S = Limestone or other sorbent used in the report year, metric tons;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$ = molecular weight of carbon dioxide (44);
$Sorbent_{MW}$ = molecular weight of sorbent (if calcium carbonate, 100).

In order to quantify emissions from the acid gas process you must first determine the amount of limestone ($CaCO_3$) or sorbent used during the reporting year. This can be done by identifying total sorbent inventory at the beginning of the year, adding the total sorbent purchases during the year, and then subtracting the total sorbent inventory at year end. You will need to make the necessary conversions in order to express total sorbent used as metric tons for the year.

The variable "R" in the above equation is the ratio of the number of moles of CO_2 released upon capture of one of mole of SO_2. Variable "R" is dependent on the type of sorbent used in the scrubbing process. If limestone is the sorbent, R is equal to 1.0.

Note that there are no CO_2 process emissions from the scrubber if calcium oxide (Quick Lime) is used as the sorbent.

You may use alternative methodologies to quantify the CO_2 emissions from the acid gas process provided they are explicitly accepted or approved by a federal, state or provincial agency. If using an alternative quantification methodology you must indicate the methodology and the agency that accepts it in The Registry's reporting software.

39 *California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, California Code of Regulations, Title 17, Subchapter 10.*

17.1

EXAMPLE 17.1.1
Calculating Carbon Dioxide Emissions from Acid Gas Scrubber

A coal-fired generating facility uses limestone as the sorbent for its SO_2 scrubber. CO_2 emissions from coal combustion are calculated using the fuel-based methodology in EPS ST-04. Since this methodology does not account for the CO_2 emitted from the SO_2 scrubber, the CO_2 emissions from the acid gas scrubber must be calculated in addition to the CO_2 emissions reported from fuel combustion. To do so, the following information is gathered:

2,000 tons = Inventory of limestone at beginning of report year

11,000 tons = Limestone purchased during the report year

3,000 tons = Inventory of limestone at the end of the report year

1 = R for limestone

44 = molecular weight of CO_2

100 = molecular weight of limestone ($CaCO_3$)

Thus, the amount of limestone used in the scrubber during the year was 10,000 tons (2,000 + 11,000 – 3,000). The 10,000 short tons of limestone is converted to 9,072 metric tons (10,000 * 0.9072). Values are then substituted into the formula in Equation 17a to determine CO_2 emissions as follows:

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{MW})$$

$$CO_2 = 9{,}072 * 1 * (44/100) = 3{,}992 \text{ metric tons}$$

17.2 Quantifying Process Emissions from Geothermal Power Generation

If you operate a geothermal electricity generating facility, you are required to calculate and report process emissions if the technology releases geothermal steam to atmosphere as part of the power generation process. In this case, there will be emissions of CO_2 and CH_4 from the geothermal steam vented to atmosphere.

There are three main technologies used to convert hydrothermal fluids to electric power. The conversion technologies are dry steam, flash, and binary cycle. The type of conversion used depends on the state of the fluid (whether steam or water) and its temperature. Dry steam power plant systems were the first type of geothermal power generation plants built. They use the steam from the geothermal reservoir as it comes from wells, and route it directly through turbine/generator units to produce electricity. Flash steam plants are the most common type of geothermal power generation plants in operation today. They use water at temperatures greater than 360°F (182°C) that is pumped under high pressure to the generation equipment

at the surface. Binary cycle geothermal power generation plants differ from dry steam and flash steam systems in that the water or steam from the geothermal reservoir never comes in contact with the turbine/generator units.

Process emissions from the geothermal process are dependent on the concentration of CO_2 and CH_4 in the geothermal steam, and the amount of steam vented to atmosphere. For binary plants, there are typically no emissions to atmosphere.

Two possible methods for estimating CO_2 and CH_4 emissions from geothermal processes are included below. The first method provides a basis for calculating direct emissions using the geothermal heat input and the second method uses the measured concentration and flow of CO_2/CH_4 in the vented steam.

— EPS PR-02

Using the first method you may quantify CO_2 emissions using the following equation:

Equation 17b
$CO_2 = EF * Heat * (0.001)$
Where
CO_2 = CO_2 emissions, metric tons per year;
EF = Default process CO_2 emission factor for geothermal facilities (7.53 kg/MMBtu)[40]; and
Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year.

You can use CO_2 emissions to estimate the CH_4 emissions if the relative concentration of CH_4 to CO_2 in the process steam is known.

— EPS PR-03

In the second method for quantifying CO_2 and/or CH_4 emissions, you are given the option to develop your own site-specific emission factors derived from site-specific source test data or gas sample analyses. The degree of certainty in the results will depend on the frequency of sampling. It is preferable with this method to derive source test data at least annually, and from the complete set of wells providing steam to the power generation unit.

[40] *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, Appendix C. American Petroleum Institute (API), February 2004.*

17.2 EXAMPLE 17.2.1
Calculating Carbon Dioxide Emissions from Geothermal Facility

Calculate the process CO_2 emissions associated with a geothermal facility where the heat taken from steam was 1,300,000 MMBtu.

Use EPS PR-02 and Equation 17(c) as follows:

Process CO_2 emissions = EF * Heat * (0.001)

Process CO_2 emissions = 7.53 kg CO_2/MMBtu * 1,300,000 MMBtu * (0.001)

= 9,789 metric tons CO_2

17.3 Calculating Process Emissions from Other Common Sources within the EPS

There are several small sources of process emissions that are associated with power generation as listed below. No specific methods are provided for estimating these emissions as they are very dependent on the technologies used, facility-specific operational and maintenance procedures, etc. Members should report emissions from these sources consistent with the GRP's provisions on the application of simplified estimation methodologies (Chapter 11). These sources may include:

1. Emissions of nitrous oxide from Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems used for post-combustion control of oxides of nitrogen (NO_x). Based on data provided in the American Petroleum Institute "Compendium of GHG Emissions Methodologies for the Oil and Gas Industry", the addition of NO_x controls increase N_2O emissions by an order of magnitude for Selective Catalytic Reduction systems on gas turbines and increases N_2O emissions by a factor of 3.5 for natural gas-fired heaters/boilers.[41] (However, in general, concentrations of N_2O in the combustion exhaust gases are typically three to four orders of magnitude less than CO_2.)
2. Venting of natural gas (CH_4) during the start-up and/or shut-down for some gas-fired turbines used as compressors or prime movers in power generation.
3. Venting of CO_2 which is used to purge hydrogen from electricity generators. This procedure may be used prior to generator maintenance, and is likely to be a very low frequency event with very low emissions.
4. Venting of CO_2, HFCs and/or PFCs during the testing of fire suppression systems that use these gases as a fire suppressant on power generating units.

41 *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, Appendix C. American Petroleum Institute (API), February 2004.*

PART IV: REPORTING YOUR EMISSIONS

Chapter 18: Additional Reporting Requirements

This chapter defines the indicator data that Members using the EPS Protocol must report and the calculation methodologies for power generation metrics, which are required to be reported to The Registry.

Emissions calculations from previous chapters are used in combination with the indicator data described here to develop sector-specific power generation metrics.

The EPS Protocol provides guidance for reporting two different classes of emissions metrics, power generation metrics and power deliveries metrics. Reporting the latter is optional and described in Chapter 19. Both express emissions per unit of power, either from the Member's owned or controlled generation sources or associated with the power that they deliver, which may be a combination of owned generation and purchased power.

Some of the benefits of developing and reporting standardized metrics for the electric power sector are as follows:

1. To provide a basis for consistent comparison between industry members, regardless of entity size.
2. To track an entity's carbon intensity performance over time as a complement to absolute emissions reporting.
3. To provide meaningful carbon intensity information to customers who purchase electricity wholesale from a power generator. Power generation metrics will be useful to utilities and intermediaries that purchase their power.

All of the emissions data needed to calculate the required power generation metrics are entered into The Registry's reporting software as part of your inventory. Therefore, most of the metrics will be calculated automatically in The Registry's reporting software, down to the facility level. As such, there should be little or no additional burden associated with the development of these metrics.

All metrics discussed below are based on CO_2 emissions per unit of output, rather than CO_2e. For power generation involving the combustion of fossil fuels, CO_2 accounts for the majority of emissions from the EPS, and it provides a consistent and reliable basis for tracking emissions over time, and for comparing the emissions from different facilities and entities. Additionally, CO_2e metrics would be less useful to customers who have to report CO_2, CH_4, and N_2O separately rather than one CO_2e value.

The metrics rely on only those CO_2 emissions which are directly related to power generation (with anthropogenic and biogenic emissions treated separately). Thus, the only sources of emissions to be included are direct stationary combustion and process geothermal and acid gas scrubber emissions, or in the case of biogenic metrics, biogenic process emissions. Specifically not included are the CO_2 emissions from sources such as coal piles, fugitive leaks from pipelines, venting of fuel gas from turbines at start-up and shut-down, from fire suppression for power generation, and from CO_2 used to purge hydrogen from generators. Emissions of gases other than CO_2 are not used in the metric calculations.

18.1 Compiling Data for Power Generation Metrics

For each generating facility in which you have an ownership interest, you must report the indicator data listed below: [42]

- Facility name
- Total facility net generation (MWhr)
- Your equity share in the facility (percent)
- Net generation - equity share (MWhr)
- Power exported to own T&D system (MWhr)
- Power exported to grid (MWhr)

If you only have an ownership interest in one or more specific units at a generating facility (rather than the entire facility), you must provide the data listed above at the unit level.

You must report power generation metrics for all generating facilities you own and for all shared units, including those with no emissions.The Registry's reporting software will then compile an entity average generation metric that includes all generation facilities and units.

18.2 Power Generation Metrics

For power generators and any entity that delivers power to the grid on a net annual basis, power generation metrics must be reported under this EPS Protocol. Members that own or control non-combustion generation facilities must also report these metrics, even for power generation with low or no GHG emissions.

All power generation metrics are based on the emissions directly related to the power generation and proportional to the power output. The emissions do not include any upstream emissions or any emissions from ancillary equipment and operations at the power generating facility.

One source of process emissions that is related to power generation directly is the CO_2 from acid gas scrubbers. If a CEMS unit is used, the CO_2 emissions will be automatically included as part of the stationary combustion emissions total. For consistency, if fuel based calculations are used, the scrubber emissions will need to be added to the CO_2 emissions in the metric calculation. Process emissions of CO_2 from geothermal power generation should also be included in the anthropogenic emissions metric calculations.

With the biogenic emissions metrics, the process emissions of biogenic CO_2 must be included as well as the combustion CO_2. This is an important consideration when biogas is used as a fuel (Section 12.3). In this case, the process emissions are considered to be directly related to power generation.

42 *All power generation metrics are based on the equity share of emissions and corresponding power generation (MWh). The power generation metrics do not use the emissions associated with the control consolidation methodology.*

In terms of organizational boundaries, the generation metrics are based on the equity share of power generated (net generation) and the equivalent emissions associated with that share of the generation. If you have a large equity share in a facility (e.g. 80 percent) and you take a small portion of the power to serve end use customers (e.g. 20 percent), the generation metric should be based on 80 percent of the emissions and 80 percent of the power output.[43]

Table 18.1 presents a summary of the generation metrics that must be reported by all power generators. However, only those metrics applicable to the Member's scope of operations need to be calculated. For example, a Member that operates three natural gas power plants will report EPS Metric G-1 for each facility and G-4 for all facilities combined. EPS Metrics G-2 and EPS Metric G-3 would not apply.

18.1 TABLE 18.1
Summary of Required Power Generation Metrics

Ref	Metric	Comment	Units
EPS Metric G-1	Fossil Generation	Anthropogenic CO_2 (MT) / Net Generation (MWh)	CO_2 / MWh (Net)
EPS Metric G-2	Biofuels Generation	Biogenic CO_2 (MT) / Net Biogenic Power Generation (MWh)	MT Biogenic CO_2 / Biogenic MWh
EPS Metric G-3	Geothermal Generation	Geothermal Process CO_2 / Geothermal MWh	MT Process CO_2 / Geothermal MWh
EPS Metric G-4	Company Average	MT CO_2 / MWh (All Generation)	MT CO_2 / MWh (All Generation)

EPS Metric G-1. Metric for Fossil Generated Electricity: Metric tons of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt-hour of fossil-generated electricity. This metric is calculated for each entity-owned or controlled fossil fuel fired electric generating facility and for all owned or controlled fossil facilities combined. This metric does not include any biogenic CO_2 emissions from biogenic sources.[44]

EPS Metric G-2. Metric Electricity Generated from Combustion of Biofuels: Metric tons of direct biogenic CO_2 emissions per net megawatt-hour of electricity generated.[45] The metric must include biogenic process emissions (i.e. biogenic CO_2 that is mixed with CH_4 in LFG and DG) as well as combustion emissions. Only the generation that is directly attributable to the biofuel combustion is included in this metric. The metric is calculated for each entity-owned or controlled generating unit that uses biofuels. Biofuel here includes biogas (LFG and DG), biomass, Waste Derived Fuels (WDFs), and the biogenic component of MSW.

43 Note that this differs from the approach used for the electricity deliveries metric. (See Section 17.2).

44 This metric includes MWh from generated and purchased biomass sources, but not the biogenic CO_2 emissions.

45 Direct biogenic emissions may come from stationary combustion, process emissions (like CO_2 "pass-through" for Landfill Gas) or from fugitive emissions directly related to the power generation.

EPS Metric G-3. Metric for Geothermal Electricity Generation: Metric tons of direct CO_2 emissions from process/fugitive emissions per net megawatt-hour of electricity generated for each entity-owned or controlled electric generating facility.

EPS Metric G-4. Metric for System-wide Electricity Generation: Metric tons of direct anthropogenic CO_2 emissions for electricity generation per net megawatt-hour of electricity generated for all owned or controlled facilities combined. The numerator for this metric includes the equity share of anthropogenic CO_2 emissions from fossil fuel combustion, process emissions from SO_2 scrubbers, geothermal fugitive emissions, and all other CO_2 emissions directly related to the power generation, but no biogenic CO_2 emissions from the combustion of biofuels nor emissions from other activities onsite that are not directly related to power generation. The denominator includes the equity portion of all power generated by the EPS Member from all sources including coal, natural gas, distillate fuel, hydro, nuclear, renewables, etc. (Note that there is no equivalent system-wide metric for biogenic emissions.)

For all these metrics, the emissions are taken directly from the direct emissions calculations in Chapters 12 and 16.

The following details are addressed in the accounting methodology used for compiling these metrics:

- For a cogeneration facility, the generation metrics include only the CO_2 emissions allocated to electricity rather than the total CO_2 emissions.
- For geothermal facilities, the process emissions of CO_2 are considered to be anthropogenic.
- For any generation source which has biogenic and anthropogenic emissions, (e.g., a wood plant with fuel oil as a starting fuel), a separate metric will be developed for each fuel type. For the anthropogenic emissions, the Net Generation (MWh) from power produced using biogenic sources is included, but the biogenic emissions are not. The biogenic CO_2 emissions are accounted for separately in the inventory and in the biogenic emission metric (EPS Metric G-2).
- The system-wide average generation metric includes the MWh from biofuel power generation, but not the biogenic emissions.

Fossil fuels used at startup do not need to be included in EPS Metric G-2 or EPS Metric G-4.

Chapter 19: Optional Reporting

The EPS Protocol provides the option for reporting efficiency metrics related to wholesale and retail power deliveries, if applicable.

Reporting efficiency metrics (or carbon intensities) allows Members to monitor trends in the carbon intensity of the electricity it acquires and sells to its customers. Over time, an LSE may increase its total GHG emissions to meet growing demand, but if it becomes more efficient, the metrics (representing emissions per unit of output) would provide an important measure to reflect these system improvements regardless of whether the emissions increased or decreased. Therefore, efficiency metrics can provide a valuable source of information to determine the LSE's full impact on GHG emissions over time. Industry observers may also be interested in comparing the environmental performance of power producers of different sizes, which is not easy to evaluate on the basis of absolute emissions. Standardized metrics provide the means to do this on a consistent basis.

The Registry anticipates that the power deliveries metrics reported by Members under the EPS Protocol will become a valuable source of emission factors for other Registry Members to use when calculating their own indirect emissions. Members that choose to report power deliveries metrics will provide a valuable service to their wholesale and/or retail customers.

The following sections discuss the reporting methods that must be followed when a Member chooses to report power deliveries metrics.

19.1 Compiling Power Deliveries Data

Customers that purchase electric power are becoming increasingly interested in the carbon intensity of the power they purchase. Reporting these power deliveries metrics is a way to provide information to your customers and have credible data that adheres to The Registry's well-defined standards and third-party verification requirements. Metrics are calculated in units of CO_2 in order to allow each Member to compile their GHG emissions by gas.[46]

For Members that deliver power to wholesale or retail customers, the reporting of power deliveries metrics is optional under the EPS Protocol. However, if you choose to report these metrics, you must follow the methodologies outlined in this section, and the reported power deliveries metrics must be third-party verified.

If you choose to calculate one or more power deliveries metrics you need to establish the customer categories you will have for your power deliveries, and then assign the power generation and power purchases to specific customer categories. For a Load Serving Entity (LSE), the simplest form of the power deliveries metric will be to have all sources of power (generated and purchased or exchanged) flowing into

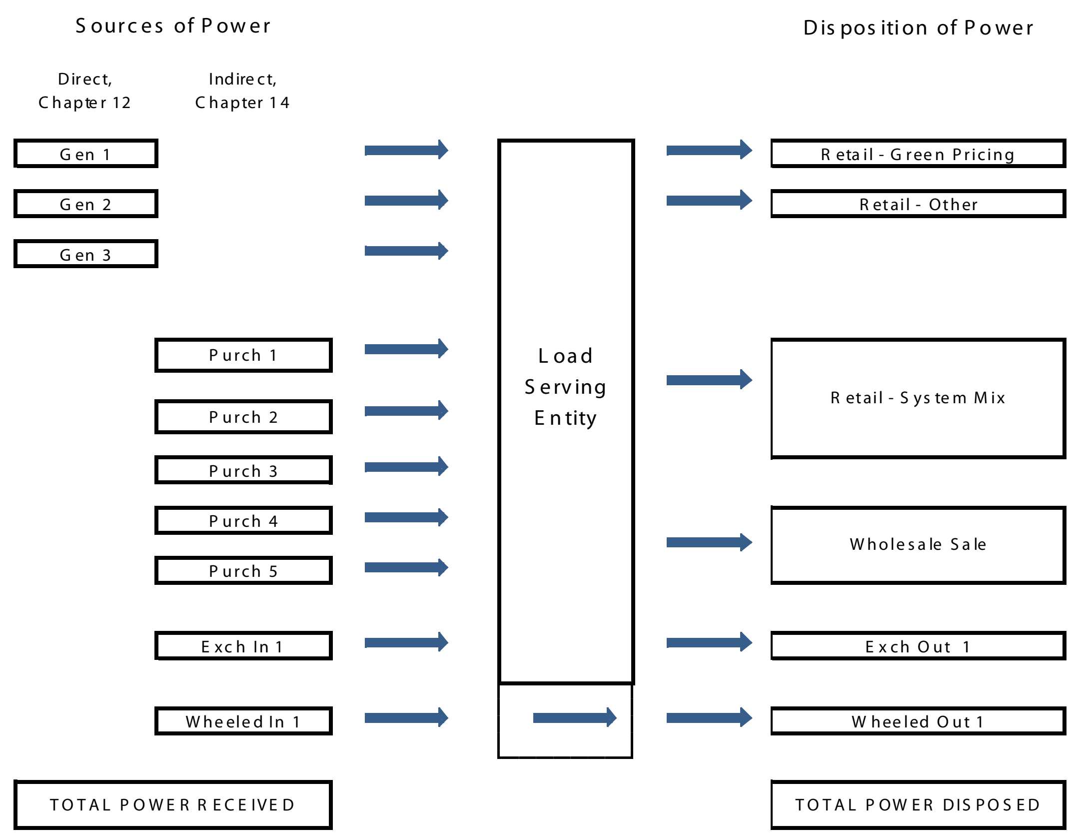
46 It should be noted that, even though the metrics include CO_2 emissions only, the end-users of electricity will still have to quantify their Scope 2 emissions associated with electricity use for CH_4 and N_2O, and this would be done using the default factors for these gases provided in the GRP.

one system mix, where the metric for the system mix would be the metric used for power delivered to all customer categories.

Another option would be to assign one group of purchased (or generated) power directly to a specific customer category. For example, you may assign specified power purchased from a wind farm to your green pricing program, and then have all other purchases flow to the mix. In some cases, there may be a need to have multiple categories of delivered power to meet the needs of multiple customers, and this may include wholesale sales as well as a range of retail products.

Once these categories are defined, you will need to compile a table showing the power delivered to the system from each source or each group of sources. You may group the sources of purchased power by supplier or counterparty, or by fuel type, especially for purchases. Exchanges (received) must also be included in this table. Refer to Figure 19.1 for an example of this table.

Figure 19.1 Schematic Showing Power Flow Accounting for a Load Serving Entity



For all power received into the system, aggregate each power resource separately – fossil, biogenic, geothermal, other zero emissions generation (nuclear and hydro). An example of this data compilation process was included in Chapter 14 (Example 14.1).

19.2 Developing Power Deliveries Metrics

If you elect to report power delivery metrics you can choose to report a single system-average metric applicable to all customers (Option A), or to report separate metrics for your wholesale sales, retail sales, and/or special power products (Option B). You might choose to develop multiple metrics for the electricity delivered to distinct customer groups if you are extensively involved in wholesale power transactions or providing a special power product like a "Green Pricing Program." If you have a distinctly separate generation type in one portion of your service area (such as fuel-oil generation in a rural area not connected to the grid) it may also be beneficial to develop multiple power deliveries metrics.

When calculating power deliveries metrics, you should aggregate the power and associated emissions for the power that flows to the customer group you have defined.

A special case to consider is when you have a large equity share in a facility (e.g. 80 percent) and you take a small portion of the power to serve end use customers (e.g., 20 percent). In this example, the electric deliveries metric (for which this power is assigned) should be based on 20 percent of the emissions and 20 percent of the power output. (Note that this differs from the approach used for the required generation metrics.)

In the EPS Protocol, there are no separate power deliveries metrics related to biogenic emissions. The power from these sources (MWh) is included in the deliveries metrics, with zero anthropogenic emissions.

Table 19.1 provides a summary of the electric deliveries metrics that you may choose to report.

19.1 **TABLE 19.1**
Summary of Power Deliveries Metrics

Ref	Metric	Units
EPS Metric D-1	Wholesale Electric Deliveries	MT CO_2 / MWh
EPS Metric D-2	Special Power Electric Deliveries	MT CO_2 / MWh
EPS Metric D-3	Retail Electric Deliveries	MT CO_2 / MWh

The metrics calculations are summarized below, and Figure 19.2 presents a flow chart showing how Members may define and report multiple electric deliveries metrics for wholesale power, special power products (such as a green pricing program), and for retail power. As the methods are applied, it is important to account for all the power and emissions flowing into the system – through owned generation and purchased power – to ensure that no carbon is "lost" in this accounting process.

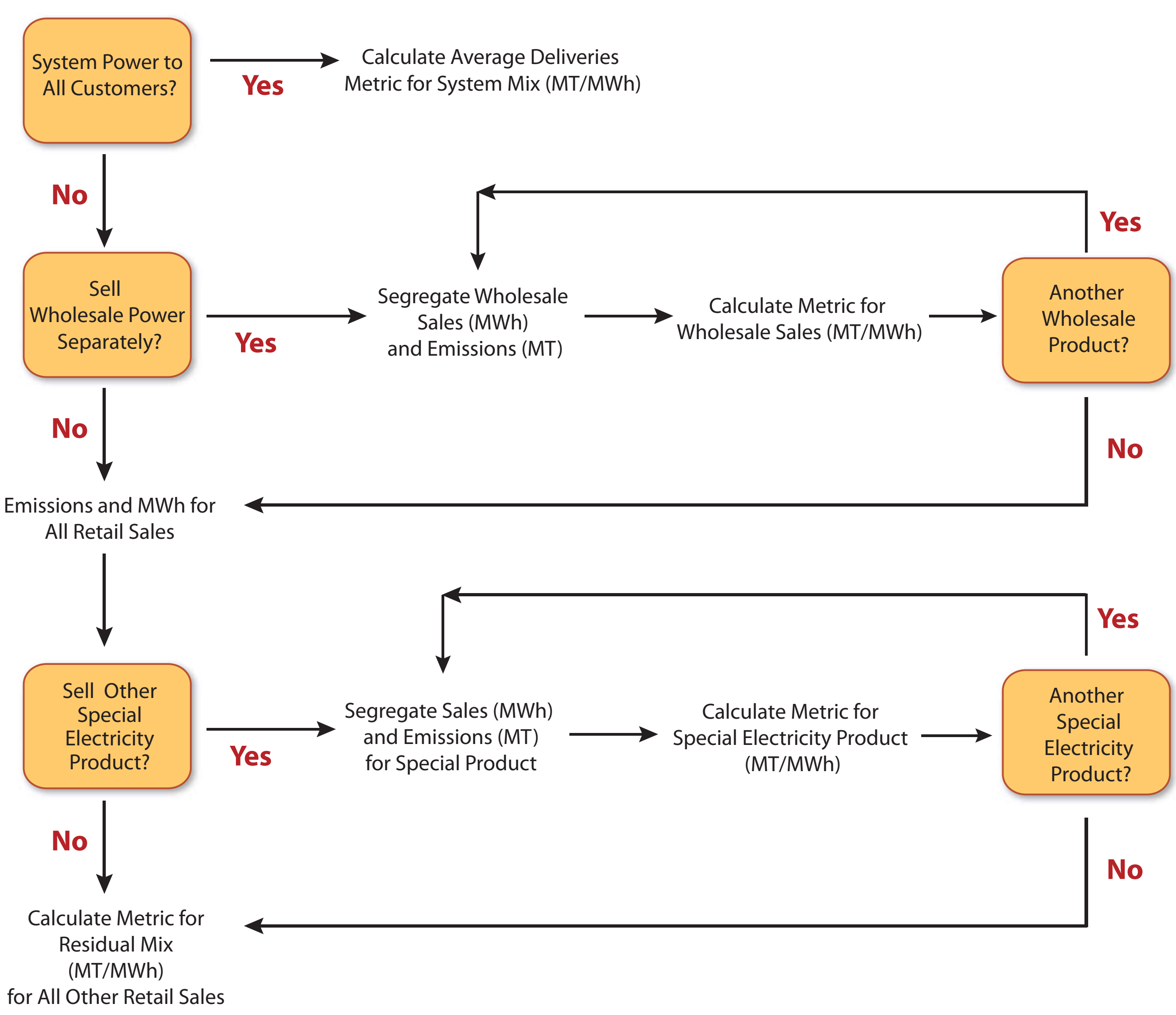
EPS Metric D-1. Electric Deliveries Metric for Retail Sales: Metric tons of anthropogenic CO_2 emissions from electricity generation and purchases per net megawatt-hour of electricity delivered to retail customers. The numerator for this metric includes the portion of CO_2 from all anthropogenic CO_2 emissions sources directly related to the owned power generation delivered to the system, plus the CO_2 emissions associated with all purchased power.[47] The denominator includes the equity portion of all power delivered by the Member from all sources. If you choose to report any of the other deliveries metrics (below), then must remove the emissions and power associated with those other products before calculating the retail deliveries metric. With Option A, this metric becomes the system-average metric used to designate the carbon intensity applicable to all sales.

EPS Metric D-2. Electric Deliveries Metric for Wholesale Power Sales: Metric tons of anthropogenic CO_2 emissions from electricity generation and purchases for the portion of electricity resold at the wholesale level. There is no requirement to derive a separate metric for wholesale power sales, but if used, the power and emissions assigned to this category are set aside and deducted from the remaining power mix delivered to retail customers. The power assigned to wholesale sales has to be clearly tied to specific sources of generation and/or specific power purchases. When this metric is used, the retail sales metric (EPS Metric D-1) must be adjusted, such that the generation and emissions assigned to wholesale sales are deducted from the remaining power mix delivered to retail customers.

EPS Metric D-3. Electric Deliveries Metrics for Special Power Product: Metric tons of anthropogenic CO_2 emissions from electricity generation and purchases for the portion of electricity sold as a special power product. There is no requirement to derive separate metrics for special power products, but if used, the power and emissions assigned to this special product are set aside and deducted from the remaining power mix delivered to retail customers. The power assigned to each special product has to be clearly tied to specific sources of generation and/or specific power purchases. When this metric is used, the retail sales metric (EPS Metric D-1) needs to be adjusted, such that the generation and emissions assigned to special power sales are deducted from the remaining power mix delivered to retail customers.

47 *If wholesale power is resold and accounted for separately under the wholesale metric below, then the emissions and power associated with wholesale sales can be subtracted from the numerator and denominator, respectively*

Figure 19.2 Flow Chart of Options for Reporting Electric Deliveries Metrics



19.1

EXAMPLE 19.2.1
Developing Power Deliveries Metrics

Company X has an equity share in two power plants (one fired with coal and one with natural gas), and purchases power from a wind farm. It delivers power to retail customers, offers a green power "special power" product, and sells a portion of its power wholesale. Relevant data for this scenario are presented in the following tables:

Source	Power Generated/ Purchased	CO_2 Emissions
Coal Plant	1,000,000 MWh	1,000,000 MT
Natural Gas Plant	1,000,000 MWh	500,000 MT
Wind Farm	500,000 MWh	0 MT
Total	2,500,000 MWh	1,500,000 MT

Customer	Power Delivered
Retail End-Users	2,000,000 MWh
Green Power	100,000 MWh
Wholesale	400,000 MWh
Total	2,500,000 MWh

There are several options for reporting metrics for this example:

1. With Option A, Company X chooses to report one system-average power deliveries metric (EPS Metric D-1), which would be 0.6 MT/MWh (1,500,000 MT / 2,500,000 MWh).

2. With Option B, Company X might report two metrics – one for its green power product and one for all remaining power sales. It designates a portion of the wind power to fulfill the green power obligation (100,000 MWh), and the rest of the wind power goes into the system mix. In this case the Special Power Deliveries Metric (EPS Metric D-2) for its green power product would be 0.0 MT/MWh, and the remaining metric (EPS Metric D-1) would be 0.625 MT/MWh (1,500,000 MT / 2,400,000 MWh).

3. Alternatively with Option B, Company X could report separate metrics for all three categories, developed as follows. First it would assign power and emissions to wholesale sales (e.g., designate excess coal generation for wholesale sales (400,000 MWh with 400,000 MT of emissions giving a metric of 1.0 MT/MWh). Next it could assign the wind power to the green pricing product (100,000 MWh with no emissions for a special power product metric of 0 MT/MWh). Finally, it would apply all remaining power and emissions to retail sales (2,000,000 MWh and 1,100,000 MT giving a retail deliveries metric of 0.55 MT/MWh).

19.3 Adjusting Power Deliveries Metrics to Account for the Purchase of Certificates

The purchase and sale of Renewable Energy Certificates (RECs), Tradable Renewables Credits (TRCs), Tradable Renewable Energy Certificates (TRECs), "Green Tags", and other special electricity certificates are common practice in the EPS. These certificates are used by market participants in order to meet certain mandatory or voluntary commitments regarding the power mix delivered to its customers. For example, RECs may be purchased to comply with a state or provincial Renewable Portfolio Standard, or to support the claims made regarding a Green Pricing Program or Product offered to retail or wholesale customer.

This section of the EPS Protocol discusses how such certificates may be used by Members to adjust power deliveries metrics and to report these adjusted metrics publicly. The section includes:

- A brief overview of special power certificates and the practice of trading these certificates (Section 19.3.1)
- An accounting methodology that allows Members to adjust their deliveries metrics to account for certificate purchases; (Section 19.3.2)
- A discussion of how these transactions might affect The Registry's overall framework of reporting based on the eGRID regional average emission factors; (Section 19.3.4)
- A brief discussion of other special power programs and their relationship to The Registry's entity-level inventory reporting system. (Section 19.4)

19.3.1 Overview of Special Power Programs and Power Certificates

Many Members in the EPS purchase or sell "green power" certificates such as Renewable Energy Certificates (RECs), Tradable Renewable Credits (TRCs), Tradable Renewable Energy Certificates (TRECs), and other certificates linked to special types of power generation (collectively referred to in this protocol as power certificates).[48] Power certificates provide proof that a given unit of electricity has been generated from a qualified resource connected to the grid (e.g. in the case of RECs a qualified renewable resource).[49] These certificates are often "unbundled" and sold separately from the underlying physical electricity associated with the generation source, and in this way they provide a mechanism for certificate buyers to incentivize the generation of specific types of power.

48 These certificates are sometimes also referred to as green tags, green energy certificates, or tradable renewable certificates.

49 As originally proposed by the following: Jansen Jaap, "A Green Jewel Box?", Environmental Finance, March 2003 pp 27. and Natsource. Williamson, Matthew, "Estimating Benefits from Renewable Energy", CEC Technical Meeting, July 17, 2003 and Environmental Resources Trust. Renewable Energy Certificates and Air Emission Benefits: Developing an Appropriate Definition for RECs. April 2004.

Specifically this chapter focuses on how Members can account for purchases and sales of these special power certificates in their emissions metrics. It does not address methods for end users of electricity to account for direct purchases of power certificates, as those methods are addressed in the GRP. The methods in this chapter discuss how you adjust your own power delivery metrics if you buy or sell a special power certificate, and how this affects the regional average metrics.

The Registry recognizes that the bulk of the current transactions in special power certificates in North America involve RECs or other “green power” products that are associated with zero or low emitting sources. Because of the size of the market for RECs and the value The Registry sees in promoting low emitting sources of power, this protocol provides a method for appropriately recognizing purchases of RECs and special power certificates by Members in their power deliveries metrics. The approach taken in this section applies equally to all power certificates that can be verifiably linked to a specific source of generation and meet certain basic requirements.

The adjustment methodology in this section should not be used when the certificates are bundled with the renewable power or low emissions generation. In this case, the power flows into the LSE’s system (whether generated or purchased), and the benefits of the low emissions power (generated or purchased) are inherently reflected in the inventory.

All specified purchases of power must include certificates with the electricity, whether or not the purchase is intended to apply toward the LSE’s RPS target or toward a special power product. This is required in order to prevent reporters from counting both the specified power emissions in their power purchases and separately via a certificate linked to that power in their adjusted metrics.

19.3.2 Accounting for Unbundled RECs and Special Certificates

When an LSE purchases an unbundled special power certificate, the EPS Protocol allows it to account for the effect the transactions have on the GHG intensity of the electricity mix that the LSE delivers to its customers. This is done by calculating an adjusted emission metric for the power product to which the certificates are being applied. Making this adjustment to the metric is optional. If you intend to calculate an adjusted metric, you will need to report information about all eligible RECs or special power certificates purchased or retired for the emissions year.

Also, power generators that create and sell special power certificates (linked to any portion of their generation) are required to provide a full accounting of those certificate sales. The requirements for disclosing certificate purchases and sales are presented in a four-step process outlined below.

Step 1: Eligibility of Green and Special Power Certificates

You must report any purchase of a REC or special power certificate in CRIS if you wish to calculate an adjusted emissions metric. The eligibility requirements are as follows:

- Certificates must be purchased from an entity that is different and distinct from your own organization (i.e., not included within your organizational boundaries).
- Certificates must be third-party certified or registered in a publicly accessible registry or tracking system.
- Certificates must be unambiguously tied to a specific power generation facility or unit with a known emissions rate.
- Certificates must be of the same vintage as the emissions reporting year against which they are to be applied or retired no more than six months prior to the start of the year or three months after the end of the year.
- Certificates must be retired prior to the date on which you wish to apply them, and this must be reported to The Registry.
- Facilities from which certificates are derived must be located in North America (Canada, United States, or Mexico).

There are no limits on the number of certificates that may be used in this capacity. Certificates used to meet your Renewable Portfolio Standard (if applicable) must be applied to the retail power metric (or system-average), and may not be applied to a separate power product (e.g., green pricing program).

Step 2: GHG Emissions from Green or Special Power Technologies

The Registry expects that most certificates reported by Members will be associated with low or zero emission power sources. However, to adjust your emissions metric, you must determine the CO_2 emissions (anthropogenic only) attributable to the underlying power source, if any. Though the CO_2 emissions from renewable energy power generation are usually small, it is important to account for the emissions that do occur. This reporting should include all direct emissions operationally related to the generation of the underlying electricity. An example would be the process CO_2 emissions from some forms of geothermal energy production.

You will need to attribute these CO_2 emissions to the RECs or special power certificates that you intend to apply to your reporting year inventory in the same way as you would if the renewable energy were bundled power (generated or purchased). Chapter 14 of the GRP and Table 14.1 in this EPS Protocol provide default emission factors that can be used to calculate emissions for the RECs or other certificates when the generation does have associated CO_2 emissions.

Step 3: Reporting Green and Special Power Certificates

When reporting green power certificates purchased in The Registry's reporting software, you will need to input the following information:

- Number of certificates and MWh represented
- Relevant serial numbers or identification numbers associated with certificates
- Renewable energy facility or facilities that created the certificate
- Type of technology used to create the certificate
- Name of the eGRID region, Canadian province/territory or Mexican state served by the renewable energy facility
- Anthropogenic GHG emissions associated with the underlying power
- "Vintage" or dates for certificate power generation
- Registry or tracking system used for certificate registration and date of retirement
- Intended use of certificate – for green power product or for system average adjustment/RPS requirement

If you sell any unbundled certificates, you must report the following information about the certificates that are sold:

- Number of certificates created and sold (MWh) during emissions year
- Name of registry or tracking system used for certificate registration
- Relevant serial numbers or identification numbers associated with certificates

Step 4: Adjusting Emissions Metrics to Account for Certificate Purchases

Accounting for the purchase of RECs and other certificates from zero or low emissions generation provides a way to lower the carbon intensity of one or more electricity products delivered to your customers. This section outlines the method used within The Registry's reporting software to make the adjustment to the efficiency metrics.

In this approach, certificates are treated as if they represent the underlying power generation to which they were associated. They are used to displace an equivalent amount of power from your actual power mix with the emissions profile associated with the certificate. The Registry's reporting software will first calculate the emissions metric without the application of certificates, and then calculate a "Certificate-Adjusted" metric that incorporates the low emissions generation.

First, you will need to select which power product the certificate(s) will be applied to and make that selection in The Registry's reporting software. (Note that the same certificates cannot be applied to more than one power product.) The Registry's reporting software will sum the power and all the emissions associated with this power product, subtract a portion of that power and emissions equivalent to the amount of power represented by the certificate(s), and then add back the same amount of power with the emissions (if any) associated with the certificate(s). How this calculation works in practice is illustrated in the example given below.

19.3.3 Example: Adjusting the Deliveries Metrics to Account for Special Power Certificate Purchases

19.2

EXAMPLE 19.2
Adjusting the Deliveries Metrics to Account For Special Power Certificate Purchases

A Member chose to report its power deliveries metrics to The Registry and has used the method in Chapter 19 of the EPS Protocol to develop three metrics. The metric calculations are summarized below:

Electricity Product	MWh	Scope 1 + Scope 3 CO_2 Emissions (MT)	Efficiency Metric (kg/ MWh)
Green Pricing Program	1,500,000	150,000	100
Retail Sales		24,000,000	300
Wholesale Electricity	1,200,000	600,000	400

This same Member purchased 1,000,000 MWh of unbundled Renewable Energy Credits from a wind power generator during the reporting year, and applied those credits to the Green Pricing Program to develop an adjusted metric for this product. This adjustment for the Green Pricing Program is shown below:

Electricity Product	MWh	Scope 1 + Scope 3 CO_2 Emissions (MT)	Efficiency Metric (kg/MWh)
Renewable Energy Certificates	1,000,000	0	0
Power from Member's own power mix	500,000	50,000	100
Green Pricing Program - Adjusted	1,500,000	50,000	33

The resulting adjusted metric (33 kg/MWh) is made available as an alternate power deliveries metric for the Green Pricing Program electricity, and this is included in The Registry's reporting software public report. (The shaded cells in this table show the calculations that are made in The Registry's reporting software, but these will not be included in the public report.)

19.3.4 Implications for the Regional Average Emission Factors

Allowing Members to adjust their efficiency metrics to account for certificate purchases may cause a need to rebalance the regional average emission factor as purchased RECs are accounted for. If the number of certificates reported by Registry Members and the claimed power transfers created by the certificate accounting approach described above become substantial, it could render regional default factors inaccurate and lead to a type of double counting. The Registry will monitor and undertake these adjustments in a phased approach.

During the first year of EPS reporting, no adjustments will be made for certificate transactions because the number certificates reported is likely to represent a very small percentage in emissions terms of the regional average power mixes. In subsequent years of EPS reporting, the eGRID or provincial emission factors for each region will be adjusted if the claimed certificates would result in a change of more than five percent to any regional emission factor. This approach should provide reasonable protection against the double counting of emission reductions in any material way, and is considered to be an adequate response for a voluntary reporting program in which not all GHG emitters are expected to participate.

19.4 Other Special Power Programs

It is important to emphasize that The Registry provides an entity-wide inventory emissions reporting framework, and it is not a project accounting system. As such, the reporting of offset projects and sequestration projects are not currently supported by this program. The Registry recognizes that some utilities support Special Power Products through the purchase of GHG offsets. These programs differ from products based on the delivery of low carbon emissions power or the use of certificates linked to such power. Members that offer these types of offset based programs are encouraged to report on them in the supplementary portion of their emissions inventory report in The Registry's reporting software.

19.5 Other Optional Emissions

As noted in Section 5.5, emissions associated with the upstream extraction and production of fuels consumed in the generation of electricity may be reported as optional data. Examples include emissions from mining of coal, nuclear fuels, refining of gasoline, extraction of natural gas, and production of hydrogen (if used as a fuel), transport of natural gas, upstream emissions from the manufacture of power generating equipment, and the lifecycle emissions from biofuels, etc.

Chapter 20: Reporting Your Data Using The Registry's Reporting Software

REFER TO GRP.

20.1 The Registry's Reporting Software Overview

REFER TO GRP.

20.2 Help with The Registry's Reporting Software

REFER TO GRP.

Chapter 21: Third-Party Verification

An overview of verification is provided in the GRP. Members should also consult the GVP and its EPS addendum in order to learn about specific requirements for verification bodies conducting verification activities in the EPS. Of particular import are application of materiality to metrics and to required subsidiary reporting (Chapter 4)

21.1 Background: The Purpose of The Registry's Verification Process

REFER TO GRP.

21.2 Activities To Be Completed by the Member in Preparation for Verification

REFER TO GRP.

21.3 Batch Verification Option

REFER TO GRP.

21.4 Verification Concepts

REFER TO GRP.

21.5 Verification Cycle

REFER TO GRP.

21.6 Conducting Verification Activities

REFER TO GRP.

21.7 Activities To Be Completed After the Verification Body Reports Its Findings

REFER TO GRP.

21.8 Unverified Emission Reports

REFER TO GRP.

Chapter 22: Public Emission Reports

22.1 Required Public Disclosure

REFER TO GRP.

In addition to the public reporting requirements laid out in the GRP, EPS emission reports will also include the required Scope 3 emissions and required & optional metrics described in earlier chapters of this protocol.

22.2 Confidential Business Information

REFER TO GRP.

GLOSSARY OF TERMS

The terms included in this glossary are sector-specific terms used in the EPS Protocol. Other terms more generally applicable to GHG reporting are included in the GRP.

Term	Definition
Ancillary Services	Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services may include: load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.
Balancing Authority	A Balancing Authority is the entity responsible for operating a control area. It matches generation with loads and maintains frequency within limits.
Boiler	A device for generating steam for power, processing, or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained in the boiler. The heat added to this fluid in the boiler is delivered to an end use.
Bottom Cycle Plant	Electricity Generator using heat from combustion that has already been useful in another process or thermal cycle.
Bulk Power System/ Bulk Transmission System	A term commonly applied to the portion of an electric utility system that encompasses the high voltage power resources used for bulk power transmission.
Bulk Power Transmission	A functional or voltage classification relating to the high voltage, high power carrying portion of the transmission system. (Also refer toTransmission)
Busbar	The power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.
Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.
Capacity Factor	The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percentage.
Co-firing	Combustion of more than one fuel in a single generating unit. The co-firing may occur when fuels are used in combination or on their own at different times during the reporting period. Co-firing may involve the fossil fuels and/or biomass fuels.
Cogeneration Facility	An industrial structure, installation, plant, building, or self-generation facility, which may include one or more cogeneration systems.

Term	Definition
Combined Cycle	Any electric generating technology in which electricity is produced from two or more different thermal cycles using shared heat from a common combustion process. Commonly, a gas turbine electricity generator in which exhaust gas heat is used to produce steam in a boiler which in turn drives a steam turbine electricity generator. The steam produced in this example might also be used for additional purposes, thus becoming a cogenerator.
Continuous Emission Monitoring System (CEMS)	CEMS is the continuous direct measurement of pollutants or other exhaust gas constituents caused to be emitted into the atmosphere due to combustion or industrial processes. Depending on fossil fuel type and operating permit requirements, CEMS systems may include monitors for exhaust gas concentration, volumetric exhaust gas flow rate, and other constituents of interest. For liquid and gaseous fuels of known, consistent carbon content, CEMS may measure mass flow of fuel in lieu of CO_2 measurement in the exhaust gas stack. The term “CEMS” may include those systems where there is fuel flow measurement but no other relevant stack measurements (e.g., with natural gas power generation). A computer-based data acquisition and handling system (DAHS) is usually considered a part of the CEMS. The DAHS records raw emissions data, performs calculations with the data, and often combines the data with other plant process information.
Control Area	Electric power system in which operators match loads to resources within the system, maintain scheduled interchange between control areas, maintain frequency within reasonable limits, and provide sufficient generation capacity to maintain operating reserves. (Also refer to Balancing Authority.)
Cooperatively Owned Utility	A cooperatively owned utility (or “electric cooperative”) is a utility that is owned by its members who are often rural farmers and/or communities. Cooperatives may be Generation and Transmission Cooperatives or Distribution Cooperatives, and they provide electric service to their members.
Demand	The rate at which electric energy (power) is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.
Demand-Side Management	The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Term	Definition
Direct Access	The ability of a retail customer to purchase electricity directly from an Electric Service Provider other than their incumbent Local Distribution Company.
Direct Monitoring	Direct monitoring of exhaust stream contents in the form of continuous emissions monitoring (CEM) or periodic exhaust gas (grab) sampling.
Distributed Emissions	CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and potentially other product outputs.
Distribution System	The lower voltage system of power lines, poles, substations and transformers, directly connected to homes and businesses.
Duct Burner (Duct Firing)	A combustion heat source used to supplement heat exiting an upstream process and prior to being used in another process. (Also refer to Heat Recovery Steam Generator and Supplemental Firing).
Electric Plant (Physical)	A facility for generating electricity by converting a primary source of energy into electrical energy.
Electric System Losses	The loss of electric energy between the point of generation and its point of intended use. Electric energy is lost primarily due to resistance heating of transmission and distribution system wires and transformers.
Electric Utility	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public, and is defined as a utility under the statutes and rules by which it is regulated. Electric utilities include privately owned companies (investor-owned utilities and cooperative utilities), and publicly owned agencies (including federal utilities, crown corporations, state and provincials authorities, municipals, public power districts and irrigation districts).
Electrical Energy	The generation or use of electric power by a device over a period of time, typically expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).
Electricity Generating Facility	See Generating Facility
Electricity Power Generator	See Independent Power Producer.
Electricity Transaction	The purchase, sale, import, export or exchange of electric power.
End User	A firm or individual that purchases products for its own consumption and not for resale (i.e., an ultimate consumer).

Term	Definition
Exchange Agreement	See Power Exchange Agreement.
Exempt Wholesale Generator	A corporate entity that owns an “eligible generating facility” under the Act. This category of power producer was created by the Energy Policy Act of 1992 (EPACT). EWGs are wholesale producers that do not sell electricity in the retail market and do not own transmission facilities. EWGs are not regulated and utilities are not required to buy their power.
Firm Power	Power for which the purchaser asks the seller to provide assurance that the purchased capacity will be available at a specified time. Firm power can be tied to a specified facility, but the seller typically can provide other power when the specified facility generation is not available.
Fuel Totalizer	A meter that sums the volume or mass of fuel used (rather than the flow rate of fuel).
Generating Facility	A facility that generates electricity and includes one or more generating units at the same location.
Generating Unit	A combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.
Generation (Electricity)	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).
Generator	See Independent Power Generator
Geothermal Plant	A plant with turbines powered by heat extracted from the earth using steam, hot water, or compatible working fluid recirculated through hot subterranean rock.
Gross Generation	The electrical output at the terminals (busbar) of the generator, typically expressed in Power (MW), or Energy (MWh).
Heat Rate	A measurement used in the energy industry to calculate how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy. Heat rates are typically expressed as net heat rates.

Term	Definition
Heat Recovery Steam Generator	A boiler using heat all or mostly from a combustion source that has already been useful in another thermal process. (Also refer to Cogeneration, Combined Cycle, Bottoming Cycle, and Duct Burner).
Heating Value	The amount of energy released when a fuel is burned completely. Care must be taken not to confuse higher heating value (HHV) and lower heating value (LHV) of a fuel. This is particularly true for computing fuel use or CO_2 production using heat rates or efficiencies of conversion.
Holding Company	An investor-owned utility which is a parent company established to own one or more operating electric utility companies that are integrated with one another.
Independent Power Producers	As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term may include, but is not limited to, cogenerators and small power producers and other non-utility electricity producers, such as exempt wholesale generators who sell electricity. In the protocol, the term Electric Power Generator is used interchangeably with Independent Power Producer.
Independent System Operator (ISO)	An impartial third-party that maintains secure and economic operation of an open access transmission system on a regional basis. An ISO provides availability and transmission pricing services to all users on the transmission grid.
kilowatt	A unit of electrical power that is 1000 watts. A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower.
kilowatt-hour (kWh)	The electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour.
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.
Load	An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. (Also refer to Demand).
Local Distribution Company	A Local Distribution Company Provider is an electric utility that physically delivers electricity to retail electricity consumers over its own wires.

Term	Definition
Load Serving Entity	A Load Serving Entities (LSE) is an entity that provides electric service to end-use retail consumers and to wholesale customers.
Marketer	See Power Marketer.
Megawatt	A unit of power equal to one million watts, or 1000 kilowatts
Megawatt-Hour	A unit of energy equal to one thousand kilowatt-hours or 1 million watt-hours. i.e., the energy equivalent to 1 MW of power lasting 1 hour.
MMBtu	A unit of energy; Million Btus (Btu x10^6); 1 MMBtu = 1 DecaTherm = 10 Therms = 1055 Mega Joules (MJ)
Municipal Utility	A municipal utility is a non-profit utility that is owned and operated by the community it serves; it is a civil government entity.
Nameplate Generating Capacity	The rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).
Net Capacity	The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.
Net Energy for Load	The electrical energy requirements of an electric system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy placed in storage at energy storage facilities.
Net Generation	Gross generation minus station service or unit service power requirements, usually expressed in megawatt-hours (MWh).
Net Power Generated	The gross generation minus station service or unit service power requirements, expressed in Megawatts (MW) or megawatt-hours (MWh) over a specified time period. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.
NERC E-Tag	North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across control areas (Balancing Authorities).
North American Electric Reliability Council (NERC)	North American Electric Reliability Corporation. NERC is an international, independent, self-regulatory, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America. The NERC Regions are listed at: http://www.nerc.com/page.php?cid=1|9|119
Non-Utility Generator (NUG)	A privately owned company that generates power for its own use or for sale to the utilities and others. An electricity generator may or may not be interconnected to the electric grid.

Term	Definition
Point of Delivery	A location on an electric system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or the busbar of a generator.
Point of Receipt	A location on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.
Power	Power as used without elaboration in this protocol commonly means electricity, except where context or modifier makes clear that another meaning is intended (e.g. horsepower or n^{th} Power). Power has the specific technical definition of the rate at which energy is transferred or energy flux.
Power Contract	An arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.
Power Generator	See Independent Power Producer.
Power Exchange Agreement	A commitment between electricity suppliers to swap energy for energy (i.e. later repayment-in-kind for an initial power delivery).
Power Marketer	A purchasing/selling entity that buys and sells electricity wholesale, and does not sell power to retail electricity consumers. Power marketers do not own or operate power generation, transmission or distribution facilities.
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.
Prime Mover	The type of equipment such as an engine or water wheel that converts prime energy (e.g., fossil fuel, solar, hydro, wind, biomass) into kinetic energy that drives a rotating electric generator. For purposes of this protocol "Prime Movers" include direct and solid state electrical generation devices such as fuel cells and Photovoltaics.
Qualifying Facility (QF)	A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by FERC (Federal Energy Regulatory Commission) pursuant to PURPA (Public Utility Regulatory Policy Act). Refer to CFR, Title 18, Part 292.
Renewable Energy	Energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, biomass, MSW, tidal power, sea currents, and ocean thermal gradients.
Retail Consumer	A consumer of energy and an end-use customer. Includes residential, commercial and industrial customers, regardless of size.

Term	Definition
Retail Electricity Provider	An entity that provides electricity to be delivered at retail rates to end users. A Retail Electricity Provider is a Load Serving Entity that may or may not be the Local Distribution Company.
Retail Service Provider	See Retail Electricity Provider.
Self-Generation Facility	A facility dedicated to serving a particular end user, usually located on the user's premises. The facility may either be owned directly by the end user or owned by an entity with a contractual arrangement to provide electricity to meet some or all of the user's load.
Source	Source means direct greenhouse gas emission source.
Specified Source of Power	Specified source of power or specified source means a particular generating unit or facility for which electrical generation and imputed GHG emissions can be confidently tracked due to full or partial ownership or due to its identification in a power contract.
Stocks	A supply of fuel accumulated for future use. This includes, but is not limited to, coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.
Storage	Energy transferred from one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more usable to the original supplying entity.
Substation	A facility for switching electrical elements, transforming voltage, regulating power, or metering.
Supplemental Firing	A combustion energy input to a cogeneration or Combined Cycle facility used to increase quantity and/or quality of heat in an exhaust stream for use in a downstream process (Also refer to Duct Burner).
System	See Transmission and Distribution System.
Thermal Host (Heat Host)	The user of the steam or heat output of a cogeneration facility.
Tolling Agreement	This is an agreement whereby one entity (e.g., utility) provides fuel to another entity (e.g. a generator) to combust and generate electricity using the fuel. The generator receives compensation from the fuel provider in return for the electricity generated.
Topping Cycle Plant	An electrical generation plant using combustion heat in the first or highest temperature portion of a cogeneration facility and/or Combined Cycle Generation Plant.
Transformer	An electrical device for changing the voltage of alternating current.

Term	Definition
Transmission (Electric)	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission and Distribution System	Transmission and Distribution equipment that is owned or operated by a single entity and operated as a balance of supply and demand.
Unit	See Generating Unit.
Underground Gas Storage	The use of sub-surface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, natural geological reservoirs (depleted oil or gas fields) or water-bearing sands topped by an impermeable cap rock (aquifer).
Unspecified Source (of Power)	Unspecified source of power or unspecified source means electricity generation that cannot be matched to a particular generating facility.
Useful Power Output	The electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.
Useful Thermal Output	Useful thermal output means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users (i.e. total thermal energy made available and consumed in processes and applications other than electrical generation).
Utility	See Electric Utility.
Waste-Derived Fuel	A fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics or solvents, biomass such as dried sewage or impregnated saw dust, or fractions of both fossil fuels and biomass such as municipal solid waste or tires.
Wheeled Power	Electricity that passes from one system to another over transmission facilities of an intervening system without being purchased or sold (i.e. owned) by the transmission entity.
Wholesale Sales	Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

1 This source is not unique to EPS, but the methodology for estimating emissions is unique for many Members where the electricity consumed includes self-generated power (Chapter 14).

2 The Registry updates the emission factors in Chapter 12 of the GRP on a regular basis, including those for Canada and Mexico.

3 The applicable emission factors for MSW and Biomass Derived Fuel (BDF) are found in the GRP and regularly updated by The Registry.

4 Source: U.S. Energy Information Administration, Electric Power Annual with data for 2005, carbon dioxide uncontrolled emission factors website see http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (Accessed 10/9/07).

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Attachment Item 14B

GREENHOUSE GAS PROTOCOL

Global Protocol for Community-Scale Greenhouse Gas Emission Inventories

An Accounting and Reporting Standard for Cities

WORLD RESOURCES INSTITUTE

C40 CITIES CLIMATE LEADERSHIP GROUP

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Detailed Table of Contents

The term “city” is used throughout this document to refer to geographically discernable subnational entities, such as communities, townships, cities, and neighborhoods. In this document, “city” is also used to indicate all levels of subnational jurisdiction as well as local government as legal entities of public administration.

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Foreword

Cities are integral to tackling the global challenge of climate change, as both a major source of greenhouse gas emissions, and a major source of innovative climate solutions. An estimated 70 percent of the world's energy-related greenhouse gas emissions come from cities, a number that is likely to continue to increase as two-thirds of all people are expected to live in urban areas by mid-century. At the same time, cities are designing and implementing groundbreaking solutions to mitigate climate change — promoting sustainable development and increasing climate resilience while reducing emissions. In order to have maximum global impact, however, city leaders need a standard by which to measure their emissions and identify the most effective ways to mitigate them.

The *Global Protocol for Community-Scale Greenhouse Gas Emission Inventories* (GPC) offers cities and local governments a robust, transparent and globally-accepted framework to consistently identify, calculate and report on city greenhouse gases. This includes emissions released within city boundaries as well as those occurring outside them as a result of activities taking place within the city.

The GPC establishes credible emissions accounting and reporting practices that help cities develop an emissions baseline, set mitigation goals, create more targeted climate action plans and track progress over time, as well as strengthen opportunities for cities to partner with other levels of government and increase access to local and international climate financing.

The GPC has already been adopted as a central component of the Compact of Mayors, the world's largest cooperative effort among mayors and city officials to reduce greenhouse gas emissions, track progress and prepare for the impacts of climate change. Launched in September 2014, the Compact aims to undertake a transparent and supportive approach to reduce greenhouse gas emissions and address climate risk, in a manner consistent with – and complementary to – the international climate negotiation process under the United Nations Framework Convention on Climate Change.

Urban areas are a logical setting for implementing and measuring climate action. Local governments can be more nimble where regional or national governments are more restricted by bureaucracy. Mayors, local councils and community leaders understand local needs and constraints, which often results in bolder, more effective action being taken. They can track the performance of city services, guide change in the community and set regulations that govern land use, building efficiency, and local transportation.

Thousands of cities are already taking action to reduce emissions and improve climate resilience. With the GPC, these cities and their advocates have a global standard to track greenhouse gas performance and lead the way to a more sustainable future.

Andrew Steer
President and CEO, WRI

Eduardo Paes
C40 Chair and Mayor of Rio de Janeiro

David Cadman
President, ICLEI

Executive Summary

Cities are the global centers of communication, commerce and culture. They are also a significant, and growing, source of energy consumption and greenhouse gas (GHG) emissions. A city's ability to take effective action on mitigating climate change, and monitor progress, depends on having access to good quality data on GHG emissions. Planning for climate action begins with developing a GHG inventory. An inventory enables cities to understand the emissions contribution of different activities in the community.

Introduction

Inventory methods that cities have used to date vary significantly. This inconsistency makes comparisons between cities difficult, raises questions around data quality, and limits the ability to aggregate local, subnational, and national government GHG emissions data. To allow for more credible and meaningful reporting, greater consistency in GHG accounting is required. The Global Protocol for Community-Scale Greenhouse Gas Emission Inventories (GPC) responds to this challenge and offers a robust and clear framework that builds on existing methodologies for calculating and reporting city-wide GHG emissions.

The GPC requires cities to measure and disclose a comprehensive inventory of GHG emissions and to total these emissions using two distinct but complementary approaches. One captures emissions from both production and consumption activities taking place within the city boundary, including some emissions released outside the city boundary. The other categorizes all emissions into "scopes," depending on where they physically occur. Separate accounting of emissions physically released within the city boundary should be used for aggregation of multiple city inventories in order to avoid double counting.

The GPC is divided into three main parts:

- **Part I** introduces the GPC reporting and accounting principles, sets out how to define the inventory boundary, specifies reporting requirements and offers a sample reporting template

- **Part II** provides overarching and sector-specific accounting and reporting guidance for sourcing data and calculating emissions, including calculation methods and equations
- **Part III** shows how inventories can be used to set mitigation goals and track performance over time, and shows how cities can manage inventory quality

Note, the term "city" is used throughout this document to refer to any geographically discernable subnational entity, such as a community, town, city, or province, and covers all levels of subnational jurisdiction as well as local government as legal entities of public administration.

Defining an inventory boundary and emission sources

To use the GPC, cities must first define an inventory boundary. This identifies the geographic area, time span, gases, and emission sources, covered by a GHG inventory. Any geographic boundary may be used for the GHG inventory. Depending on the purpose of the inventory, the boundary can align with the administrative boundary of a local government, a ward or borough within a city, a combination of administrative divisions, a metropolitan area, or another geographically identifiable entity. The GPC is designed to account for GHG emissions in a single reporting year and covers the seven gases covered by the Kyoto Protocol (Section 3.3 in the report).

GHG emissions from city activities shall be classified into six main sectors:

- Stationary energy
- Transportation
- Waste
- Industrial processes and product use (IPPU)
- Agriculture, forestry, and other land use (AFOLU)
- Any other emissions occurring outside the geographic boundary as a result of city activities. These emissions are not covered in this version of the GPC but may be reported separately

Table 1 breaks these six sectors down by sub-sector.

Table 1 Sectors and sub-sectors of city GHG emissions

Sectors and sub-sectors
STATIONARY ENERGY
Residential buildings
Commercial and institutional buildings and facilities
Manufacturing industries and construction
Energy industries
Agriculture, forestry, and fishing activities
Non-specified sources
Fugitive emissions from mining, processing, storage, and transportation of coal
Fugitive emissions from oil and natural gas systems
TRANSPORTATION
On-road
Railways
Waterborne navigation
Aviation
Off-road
WASTE
Solid waste disposal
Biological treatment of waste
Incineration and open burning
Wastewater treatment and discharge
INDUSTRIAL PROCESSES AND PRODUCT USE (IPPU)
Industrial processes
Product use
AGRICULTURE, FORESTRY AND OTHER LAND USE (AFOLU)
Livestock
Land
Aggregate sources and non-CO_2 emission sources on land
OTHER SCOPE 3

Categorizing emissions

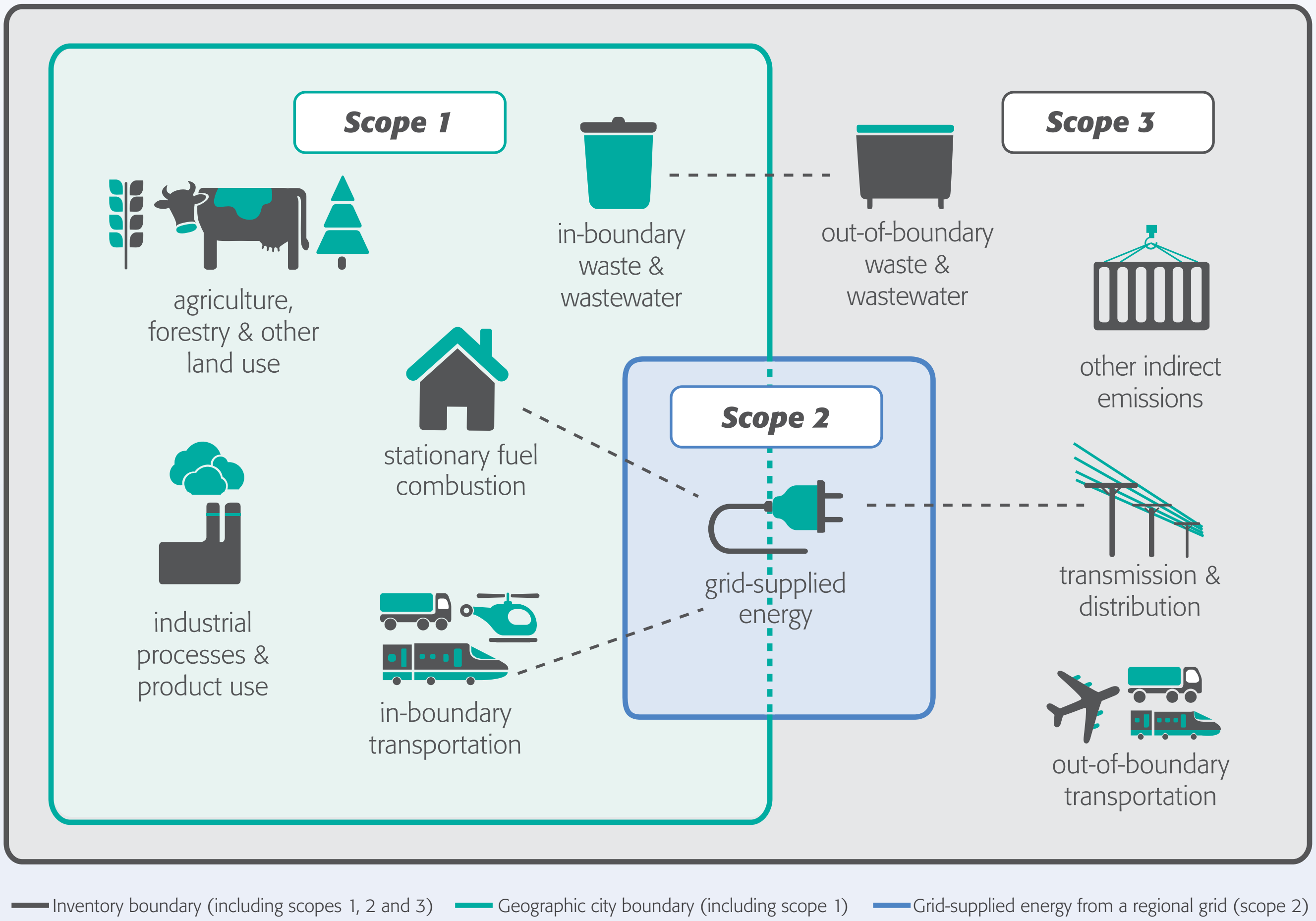
Activities taking place within a city can generate GHG emissions that occur inside the city boundary as well as outside the city boundary. To distinguish among them, the GPC groups emissions into three categories based on where they occur: scope 1, scope 2 or scope 3 emissions. Definitions are provided in Table 2, based on an adapted application of the scopes framework used in the *GHG Protocol Corporate Standard*.

The scopes framework helps to differentiate emissions occurring physically within the city (scope 1), from those occurring outside the city (scope 3) and from the use of electricity, steam, and/or heating/cooling supplied by grids which may or may not cross city boundaries (scope 2). Scope 1 emissions may also be termed "territorial" emissions because they occur discretely within the territory defined by the geographic boundary. Figure 1 illustrates which emission sources occur solely within the geographic boundary established for the inventory, which occur outside the geographic boundary, and which may occur across the geographic boundary.

Table 2 Scopes definitions for city inventories

Scope	Definition
Scope 1	GHG emissions from sources located within the city boundary
Scope 2	GHG emissions occurring as a consequence of the use of grid-supplied electricity, heat, steam and/or cooling within the city boundary
Scope 3	All other GHG emissions that occur outside the city boundary as a result of activities taking place within the city boundary

Figure 1 Sources and boundaries of city GHG emissions



Aggregating city inventories

The GPC has been designed to allow city inventories to be aggregated at subnational and national levels in order to:

- Improve the data quality of a national inventory, particularly where major cities' inventories are reported;
- Measure the contribution of city mitigation actions to regional or national GHG emission reduction targets;
- And identify innovative transboundary and cross-sectorial strategies for GHG mitigation.

Aggregation of multiple city inventories can be accomplished by combining the scope 1 (territorial) emissions of cities whose inventory boundaries do not overlap geographically.

Reporting requirements

The GPC requires cities to report their emissions by gas, scope, sector and subsector, and to add up emissions using two distinct but complementary approaches:

- **Scopes framework:** This totals all emissions by scope 1, 2 and 3. Scope 1 (or territorial emissions) allows for the separate accounting of all GHG emissions produced within the geographic boundary of the city, consistent with national-level GHG reporting.
- **City-induced framework:** This totals GHG emissions attributable to activities taking place within the geographic boundary of the city. It covers selected scope 1, 2 and 3 emission sources representing the key emitting sources occurring in almost all cities, and for which standardized methods are generally available.

Chapter 4 of the GPC sets out reporting requirements and explains how to add up emission totals. Cities may also report emissions based on relevant local or program-specific requirements in addition to the requirements of the GPC. GHG inventories should be updated on a regular basis using the most recent data available. The GPC recommends that cities update their inventory on an annual basis, as it provides frequent and timely progress on overall GHG emissions.

Table 3 summarizes the emissions sources and scopes covered by the GPC for both city-level and territorial reporting. Cities should aim to cover all emissions for which reliable data are available. To accommodate limitations in data availability and differences in emission sources between cities, the GPC requires the use of notation keys, as recommended in IPCC Guidelines, and an accompanying explanation to justify exclusion or partial accounting of GHG emission source categories.

The city-induced framework gives cities the option of selecting between two reporting levels: BASIC or BASIC+. The BASIC level covers scope 1 and scope 2 emissions from stationary energy and transportation, as well as scope 1 and scope 3 emissions from waste. BASIC+ involves more challenging data collection and calculation processes, and additionally includes emissions from IPPU and AFOLU and transboundary transportation. Therefore, where these sources are significant and relevant for a city, the city should aim to report according to BASIC+. The sources covered in BASIC+ also align with sources required for national reporting in IPCC guidelines.

Tick marks in Table 3 indicate which emissions sources are covered by the GPC, and cells are colored to indicate their inclusion in city-level BASIC or BASIC+ totals and the territorial total. Rows written in italics represent sub-sector emissions required for territorial emission totals but not BASIC/BASIC+. Gray cells in the scope 2 column indicate emission sources that do not have applicable GHG emissions in that scope category. Emission sources corresponding to the blank boxes in the scope 3 column are not required for reporting, but may be identified and disclosed separately under Other Scope 3.

The GPC provides a sample reporting template that covers all reporting requirements. Cities may report GHG emissions in a variety of additional formats depending on purpose and audience, and may also disaggregate emissions by fuel type, municipal operations within each sector or sub-sector, etc.

Figure 2 Sources and scopes covered by the GPC

Sectors and sub-sectors	Scope 1	Scope 2	Scope 3
STATIONARY ENERGY			
Residential buildings	✓	✓	✓
Commercial and institutional buildings and facilities	✓	✓	✓
Manufacturing industries and construction	✓	✓	✓
Energy industries	✓	✓	✓
Energy generation supplied to the grid	✓		
Agriculture, forestry, and fishing activities	✓	✓	✓
Non-specified sources	✓	✓	✓
Fugitive emissions from mining, processing, storage, and transportation of coal	✓		
Fugitive emissions from oil and natural gas systems	✓		
TRANSPORTATION			
On-road	✓	✓	✓
Railways	✓	✓	✓
Waterborne navigation	✓	✓	✓
Aviation	✓	✓	✓
Off-road	✓	✓	
WASTE			
Disposal of solid waste generated in the city	✓		✓
Disposal of solid waste generated outside the city	✓		
Biological treatment of waste generated in the city	✓		✓
Biological treatment of waste generated outside the city	✓		
Incineration and open burning of waste generated in the city	✓		✓
Incineration and open burning of waste generated outside the city	✓		
Wastewater generated in the city	✓		✓
Wastewater generated outside the city	✓		
INDUSTRIAL PROCESSES AND PRODUCT USE (IPPU)			
Industrial processes	✓		
Product use	✓		
AGRICULTURE, FORESTRY AND OTHER LAND USE (AFOLU)			
Livestock	✓		
Land	✓		
Aggregate sources and non-CO_2 emission sources on land	✓		
OTHER SCOPE 3			
Other Scope 3			

✓ Sources covered by the GPC

Sources required for BASIC reporting

+ Sources required for BASIC+ reporting

Sources required for territorial total but not for BASIC/BASIC+ reporting (*italics*)

Sources included in Other Scope 3

Non-applicable emissions

Calculating GHG emissions

Part II of the GPC provides overarching and sector-specific reporting guidance for sourcing data and calculating emissions. Cities should select the most appropriate methodologies based on the purpose of their inventory, availability of data, and consistency with their country's national inventory and/or other measurement and reporting programs in which they participate. The GPC does not require specific methodologies to be used to produce emissions data; rather it specifies the principles and rules for compiling a city-wide GHG emissions inventory. Where relevant, the GPC recommends using methodologies aligned with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*.

For most emission sources, cities will need to estimate GHG emissions by multiplying activity data by an emission factor associated with the activity being measured. Activity data is a quantitative measure of a level of activity that results in GHG emissions taking place during a given period of time (e.g., volume of gas used, kilometers driven, tonnes of waste sent to landfill, etc.). An emission factor is a measure of the mass of GHG emissions relative to a unit of activity. For example, estimating CO_2 emissions from the use of electricity involves multiplying data on kilowatt-hours (kWh) of electricity used by the emission factor ($kgCO_2$/kWh) for electricity, which will depend on the technology and type of fuel used to generate the electricity. GHG emissions data shall be reported as metric tonnes of each GHG as well as CO_2 equivalents (CO_2e).

Data can be gathered from a variety of sources, including government departments and statistics agencies, a country's national GHG inventory report, universities and research institutes, scientific and technical articles in environmental books, journals and reports, and sector experts/stakeholder organizations. In general, it is preferable to use local and national data over international data, and data from publicly-available, peer-reviewed and reputable sources, often available through government publications. Where the best available activity data do not align with the geographical boundary of the city or the time period of the assessment, the data can be adapted to meet the inventory boundary by adjusting for changes in activity using a scaling factor. Emission factors should be relevant to the inventory boundary and specific to the activity being measured.

Tracking progress and setting goals

Inventories can be used as the basis for setting mitigation goals and tracking performance over time. For many cities with existing climate action plans and targets, the mitigation goal boundary used will be different to the inventory boundary outlined above or will apply to a subset of the GHGs, scopes, or emission sources set out in the GPC. Cities are encouraged to align their mitigation goal boundary to the GPC inventory boundary, but where the mitigation goal boundary remains different from the GPC inventory boundary, cities should explain the differences, and reason for the differences, to avoid any confusion.

Managing inventory quality and verification

The GPC does not require that cities verify their inventory results, but recommends that cities choose the level and type of verification that meets their needs and capacity. To manage inventory quality over time, cities should establish a management plan for the inventory process. The design of an inventory management plan should provide for the selection, application, and updating of inventory methodologies as new data and research become available.

Verification involves an assessment of the completeness and accuracy of reported data. Cities may choose to verify their data to demonstrate that their calculations are in accordance with the requirements of the GPC and provide confidence to users that the reported GHG emissions are a fair reflection of a city's activities. This can be used to increase credibility of publicly reported emissions information with external audiences and increase confidence in the data used to develop climate action plans, set GHG targets and track progress. Verification can be performed by the same organization that conducted the GPC assessment (self-verification), or by an independent organization (third-party verification).

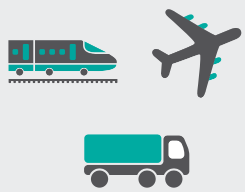
Figure 3 Emission source sectors

Sectors in the GPC

STATIONARY ENERGY

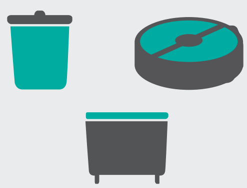
Stationary energy sources are one of the largest contributors to a city's GHG emissions. These emissions come from the combustion of fuel in residential, commercial and institutional buildings and facilities and manufacturing industries and construction, as well as power plants to generate grid-supplied energy. This sector also includes fugitive emissions, which typically occur during extraction, transformation, and transportation of primary fossil fuels.

TRANSPORTATION



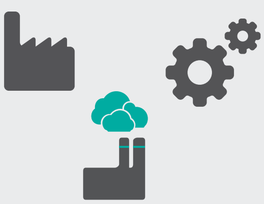
Transportation covers all journeys by road, rail, water and air, including inter-city and international travel. GHG emissions are produced directly by the combustion of fuel or indirectly by the use of grid-supplied electricity. Collecting accurate data for transportation activities, calculating emissions and allocating these emissions to cities can be a particularly challenging process. To accommodate variations in data availability, existing transportation models, and inventory purposes, the GPC offers additional flexibility in calculating emissions from transportation.

WASTE



Waste disposal and treatment produces GHG emissions through aerobic or anaerobic decomposition, or incineration. GHG emissions from solid waste shall be calculated by disposal route, namely landfill, biological treatment and incineration and open burning. If methane is recovered from solid waste or wastewater treatment facilities as an energy source, it shall be reported under Stationary Energy. Similarly, emissions from incineration with energy recovery are reported under Stationary Energy.

INDUSTRIAL PROCESSES AND PRODUCT USE (IPPU)



GHG emissions are produced from a wide variety of non-energy related industrial activities. The main emission sources are releases from industrial processes that chemically or physically transform materials (e.g., the blast furnace in the iron and steel industry, and ammonia and other chemical products manufactured from fossil fuels and used as chemical feedstock). During these processes many different GHGs can be produced. In addition, certain products used by industry and end-consumers, such as refrigerants, foams or aerosol cans, also contain GHGs which can be released during use and disposal.

AGRICULTURE, FORESTRY AND OTHER LAND USE (AFOLU)

Emissions from the Agriculture, Forestry and Other Land Use (AFOLU) sector are produced through a variety of pathways, including livestock (enteric fermentation and manure management), land use and land use change (e.g., forested land being cleared for cropland or settlements), and aggregate sources and non-CO_2 emission sources on land (e.g., fertilizer application and rice cultivation). Given the highly variable nature of land-use and agricultural activity across geographies, GHG emissions from AFOLU are amongst the most complex categories for GHG accounting.

"If we want to turn the tide against climate change, cities will need to lead the way. Compact and efficient cities can dramatically reduce emissions and will drive innovation and sustained economic growth. Until recently there has been no consistent way to measure city-level emissions. Now, that has changed. We now have a common international standard to inform strategies to cut emissions and create better, more livable cities.

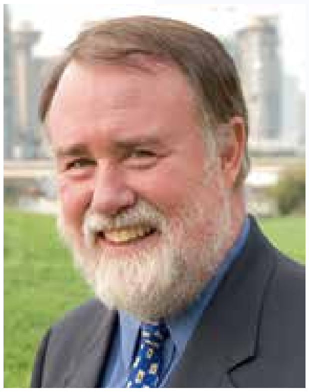
—Andrew Steer, President and CEO, WRI

"As C40 Chair and Mayor of Rio de Janeiro, I know that building a greenhouse gas emissions inventory enables city leaders to manage their emissions reduction efforts, allocate resources and develop comprehensive climate action plans. With the launch of the GPC, cities now have a consistent, transparent and internationally recognized approach to measuring and reporting citywide emissions, allowing for credible comparison and aggregation across timescales and geographies. On behalf of C40, I would like to thank WRI and ICLEI for their partnership in building this powerful standard that will benefit cities across the globe. I strongly encourage other cities around the world to take up this new standard as a key step in the global fight against climate change.

—Eduardo Paes, C40 Chair and Mayor of Rio de Janeiro

"With the launch of the GPC, we now have the most comprehensive greenhouse gas accounting and reporting framework for cities worldwide. Drafting and piloting since 2012, the GPC marks a historic international consensus on GHG accounting and reporting emissions, allowing local governments to measure and track their performances in a consistent standard, guided by international best practices. This published version would not have been possible without the excellent cooperation between WRI, C40 and ICLEI, as well as the practical insight and valuable feedback provided by the 35 pilot cities that tested earlier versions in their cities. ICLEI wants to thank these partners and cities for their indispensable contribution to this game-changing Protocol.

—David Cadman, President, ICLEI



PART I
Introduction and Reporting Requirements

1 Introduction

Cities are the global centers of communication, commerce and culture. They are also a significant, and growing, source of energy consumption and account for a large percentage of global greenhouse gas (GHG) emissions. With a majority of the world's urban areas situated on coastlines, cities are also particularly vulnerable to global environmental change, such as rising sea levels and coastal storms. Therefore, cities play a key role in tackling climate change and responding to climate impacts.

1.1 Cities and climate change

A city's ability to take effective action on mitigating climate change, and monitor progress, depends on having access to good quality data on GHG emissions. Planning for climate action begins with developing a GHG inventory. An inventory enables cities to understand the emissions contribution of different activities in the community. It allows cities to determine where to best direct mitigation efforts, create a strategy to reduce GHG emissions, and track their progress. Many cities have already developed GHG inventories, and use them to set emission reduction targets, inform their climate action plans, and track their performance.

In addition, a city-wide GHG inventory can help cities meet legal and voluntary requirements to measure and report GHG emissions data. A growing number of cities are choosing to disclose GHG emissions data through voluntary reporting platforms, such as the carbon*n* Climate Registry and CDP to enhance transparency and give stakeholders easier access to their results. Furthermore, it is often a requirement or prerequisite from city project funders and donors that cities measure their GHG emissions using best practice standards.

However, the inventory methods that cities have used to date vary in terms of what emission sources and GHGs are included in the inventory; how emissions sources are defined and categorized; and how transboundary emissions are treated. This inconsistency makes comparisons between cities difficult, raises questions around data quality, and limits the ability to aggregate local, subnational, and national government GHG emissions data.

To allow for more credible reporting, meaningful benchmarking and aggregation of climate data, greater consistency in GHG accounting is required. This *Global Protocol for Community-Scale Greenhouse Gas Emission Inventories* (GPC) responds to this challenge, offering a robust and clear framework that builds on existing methodologies for calculating and reporting city-wide GHG emissions.

1.2 Purpose of the GPC

The GPC sets out requirements and provides guidance for calculating and reporting city-wide GHG emissions, consistent with the *2006 IPCC (Intergovernmental Panel on Climate Change) Guidelines for National Greenhouse Gas Inventories* (also referred to as just *IPCC Guidelines* throughout this report). The GPC seeks to:

- Help cities develop a comprehensive and robust GHG inventory in order to support climate action planning.
- Help cities establish a base year emissions inventory, set reduction targets, and track their performance.
- Ensure consistent and transparent measurement and reporting of GHG emissions between cities, following internationally recognized GHG accounting and reporting principles.
- Enable city inventories to be aggregated at subnational and national levels.[1]
- Demonstrate the important role that cities play in tackling climate change, and facilitate insight through benchmarking—and aggregation—of comparable data.

1.3 Who should use the GPC

The GPC can be used by anyone assessing the GHG emissions of a geographically defined, subnational area. Although the GPC is primarily designed for cities, the accounting framework can also be used for boroughs or wards within a city, towns, districts, counties, prefectures, provinces, and states. In this document, the term "city" is used to refer to all of these jurisdictions, unless otherwise specified. However, the GPC does not define what geographic boundary constitutes a "city". Similarly, the terms "community-scale" is used to refer to inventories encompassing any of these geographic designations, and is used interchangeably with "city-scale" or "city-wide" inventories.

Policy makers at the regional or national level can also use this standard to understand how to aggregate multiple cities' emissions together to improve national inventory data, to inform mitigation goals or policies, or to track city emission trends.[2]

1.4 Using the GPC

The GPC provides a robust framework for accounting and reporting city-wide GHG emissions. It requires cities to measure and disclose a comprehensive inventory of GHG emissions and to aggregate these using two distinct but complementary frameworks: one focusing on geographically defined emissions, the other on city-induced emissions. The former allows for the aggregation of multiple city inventories while avoiding double counting. The GPC includes guidance on compiling city-wide GHG inventories and also offers a sample reporting template (see Table 4.3).

Specific methodology guidance for each sector is provided in PART II (Chapters 6–10). These chapters identify calculation methods and data options, and provide calculation equations or procedures where relevant. The GPC also references *IPCC Guidelines* and other resources to assist cities in completing these calculations and sourcing relevant data. Cities can implement the requirements of the GPC using a variety of local, national or default data depending on what is available. See Table 1.1 to identify key chapter themes and questions.

1. Aggregation of multiple city inventories can be used to: improve the data quality of a national inventory, particularly where major cities' inventories are reported; measure the contribution of city-wide mitigation actions. to regional or national GHG emission reduction targets; and identify innovative transboundary and cross-sectorial strategies for GHG mitigation.

2. Individual businesses, residents or institutions in a city can use this standard to understand the overall performance of the city, but should not calculate their individual footprint by taking GPC reported emissions divided by the population of the city. Instead, individuals or organizations should use corporate or institution-based methods for their own inventories.

1.4.1 Shall, Should and May Terminology

The GPC uses precise language to indicate which provisions of the standard are requirements, which are recommendations, and which are permissible or allowable options that cities may choose to follow.

- The term **"shall"** is used throughout this standard to indicate what is required in order for a GHG inventory to be in compliance with the GPC.
- The term **"should"** is used to indicate a recommendation, but not a requirement.
- The term **"may"** is used to indicate an option that is permissible or allowable.

1.5 Relationship to other city protocols and standards

The GPC builds upon the knowledge, experiences, and practices of existing standards used by cities to measure city-wide GHG emissions. An overview of these and how their requirements and boundaries relate to the GPC is provided in Appendix A. Upon publication, the GPC will supersede

Table 1.1 What parts of the GPC should I read?

Type of accounting	Purpose
How does the GPC compare to other inventory methods used by cities?	Ch. 1 and Appendix A
What are the key principles to follow in creating a GHG inventory?	Ch. 2
What are notation keys, and how should they be used?	Ch. 2 and Ch. 4
What activities should I include in my GHG inventory? What gases? What time frame?	Ch. 3
How do I distinguish emissions occurring within the geographic boundary of the inventory, vs. those outside of the boundary?	Ch. 3
What are the reporting requirements for a city-wide GHG inventory?	Ch. 4
How do I collect data for the inventory?	Ch. 5
How do I calculate emissions from stationary energy production and use?	Ch. 6
How do I calculate emissions from transportation?	Ch. 7
How do I calculate emissions from waste treatment?	Ch. 8
How do I calculate emissions from industrial processes and product use?	Ch. 9
How do I calculate emissions from agriculture, forestry and other land use?	Ch. 10
How do I set a base year, set GHG emission reduction targets, and track emissions over time?	Ch. 11
How do I ensure inventory quality over time, and prepare for verification?	Ch. 12
How should I report emissions from local government operations?	Appendix B
Where do I find a quick overview of methodologies in the GPC?	Appendix C

the provisions related to community GHG emissions of the International Local Government Greenhouse Gas Emissions Analysis Protocol (developed by ICLEI), and the International Standard for Determining Greenhouse Gas Emissions for Cities (developed by The World Bank, United Nations Environment Programme (UNEP), and UN-HABITAT).

1.6 How this standard was developed

The GPC is the result of a collaborative effort between the GHG Protocol at World Resources Institute (WRI), C40 Cities Climate Leadership Group (C40), and ICLEI—Local Governments for Sustainability (ICLEI). See Table 1.2 for a short description of each organization.

Development of the GPC began in São Paulo in June 2011 as a result of a Memorandum of Understanding between C40 and ICLEI. In 2012, the partnership expanded to include WRI and the Joint Work Programme of the Cities Alliance between the World Bank, UNEP, and UN-HABITAT.

An early draft (Version 0.9) was released in March 2012 for public comment. The GPC was then updated (Pilot Version 1.0) and tested with 35 cities worldwide. Based on the pilot testing feedback, the GPC was revised and issued for a second public comment (Version 2.0) in July-August 2014.

Table 1.3 GPC development process

Date		Milestone
2011	June	Memorandum of Understanding between C40 and ICLEI
2012	March	GPC Draft Pilot (Version 0.9) released for public comment
	May	GPC Draft Pilot (Version 1.0) released
2013		Pilot testing with 35 cities worldwide
2014	July	GPC Draft (Version 2.0) released for public comment
	December	Final GPC published

In 2015 the GPC authors will begin developing an expanded version, which will provide additional guidance on identifying and quantifying GHG emissions occurring outside the city boundary associated with cities' activities (scope 3 emissions). This will allow cities to take a broader and more

Table 1.2 GPC authors

Organization	Description
WRI and the GHG Protocol	• WRI is a global research organization that works closely with leaders to turn big ideas into action to sustain a healthy environment—the foundation of economic opportunity and human well-being. The GHG Protocol is a partnership of businesses, non-governmental organizations, governments, and others convened by WRI and the World Business Council for Sustainable Development to develop internationally-accepted GHG accounting and reporting standards and tools.
C40	• C40 is a network of the world's megacities committed to addressing climate change both locally and globally. Established in 2005, C40 is comprised of 70 cities from around the world and offers an effective forum where cities can collaborate, share knowledge and drive meaningful, measurable and sustainable action on climate change.
ICLEI	• ICLEI is a leading association of cities and local governments dedicated to sustainable development. ICLEI represents a movement of over 1,000 cities and towns in 88 countries. ICLEI promotes local action for global sustainability and supports cities to become sustainable, resilient, resource-efficient, biodiverse, and low-carbon.

Attachment Item 14B

holistic approach to measuring their GHG impact, as well as identify opportunities for realizing more efficient urban supply chains.

1.7 Local government operations

In addition to compiling a city-wide GHG inventory, local governments may also want to measure GHG emissions from their own municipal operations via a local government operations (LGO) inventory. An LGO inventory allows local governments to identify GHG reduction opportunities across their jurisdiction and demonstrate leadership in taking action. While this is not a requirement of the GPC, LGO data may also be useful in compiling information for a city-wide inventory. For example, activity data from city-owned or operated buildings, facilities, landfills or land can be more precise than estimating activity data from those sectors based on scaled regional or national data. Appendix B provides further information on developing an LGO inventory.

2 Accounting and Reporting Principles

This chapter outlines the accounting and reporting principles for city-wide GHG emissions inventories. It also introduces notation keys, a disclosure practice which can help cities fulfill these principles.

Requirements in this chapter

A city GHG inventory shall follow the principles of relevance, completeness, consistency, transparency and accuracy.

2.1 Accounting and reporting principles

Accounting and reporting for city-wide GHG emissions is based on the following principles adapted from the *GHG Protocol Corporate Standard*[3] in order to represent a fair and true account of emissions:

Relevance: The reported GHG emissions shall appropriately reflect emissions occurring as a result of activities and consumption patterns of the city. The inventory will also serve the decision-making needs of the city, taking into consideration relevant local, subnational, and national regulations. The principle of relevance applies when selecting data sources, and determining and prioritizing data collection improvements.

Completeness: Cities shall account for all required emissions sources within the inventory boundary. Any exclusion of emission sources shall be justified and clearly explained. Notation keys shall be used when an emission source is excluded, and/or not occurring (see Section 2.2).

Consistency: Emissions calculations shall be consistent in approach, boundary, and methodology. Using consistent methodologies for calculating GHG emissions enables meaningful documentation of emission changes over time, trend analysis, and comparisons between cities. Calculating emissions should follow the methodological approaches provided by the GPC. Any deviation from the preferred methodologies shall be disclosed and justified.

Transparency: Activity data, emission sources, emission factors, and accounting methodologies require adequate

3. See *GHG Protocol Corporate Standard*, 2004.

documentation and disclosure to enable verification. The information should be sufficient to allow individuals outside of the inventory process to use the same source data and derive the same results. All exclusions shall be clearly identified, disclosed and justified.

Accuracy: The calculation of GHG emissions shall not systematically overstate or understate actual GHG emissions. Accuracy should be sufficient enough to give decision makers and the public reasonable assurance of the integrity of the reported information. Uncertainties in the quantification process shall be reduced to the extent that it is possible and practical.

Guidance on using principles: Within the requirements of this standard, a city will need to make important decisions in terms of setting the inventory boundary, choosing calculation methods, deciding whether to include additional scope 3 sources, etc. Tradeoffs between the five principles above may be required based on the objectives or needs of the city. For example, achieving a complete inventory may at times require using less accurate data (see Box 2.1). Over time, as both the accuracy and completeness of GHG data increase, the need for tradeoffs between these accounting principles will likely diminish.

Box 2.1 Kampala data challenges

Data limitations created a challenge for the city of Kampala, Uganda when it undertook its first GHG inventory in 2013.[4] Data from different years and sources were scaled or combined in order to complete the inventory. For instance, 2004 data from the Uganda Bureau of Statistics were scaled using a 2009 demographic and health survey from the same bureau. Commercial activities were estimated based on highly disaggregated data from a 2005 business register, while residential data were based on a household survey from the inventory year. In this instance Kampala decided to trade data accuracy for a broader data set to meet their objective of completing a city-wide inventory covering all relevant sectors.

4. Makerere University. Greenhouse Gas Emissions Inventory for Kampala City and Metropolitan Region, 2013. http://mirror.unhabitat.org/downloads/docs/12220_1_595178.pdf

2.2 Notation keys

Data collection is an integral part of developing and updating a GHG inventory. Data will likely come from a variety of sources and will vary in quality, format, and completeness. In many cases, it will need to be adapted for the purposes of the inventory. The GPC recognizes these challenges and sets out data collection principles and approaches in Chapter 5, and overall inventory quality methods in Chapter 12. It also provides guidance on gathering existing data, generating new data, and adapting data for inventory use.

To accommodate limitations in data availability and differences in emission sources between cities, the GPC requires the use of notation keys, as recommended in *IPCC Guidelines*. Where notation keys are used, cities shall provide an accompanying explanation to justify exclusions or partial accounting of GHG emission source categories.

Table 2.1 Use of notation keys[5]

Notation key	Definition	Explanation
IE	Included Elsewhere	GHG emissions for this activity are estimated and presented in another category of the inventory. That category shall be noted in the explanation.
NE	Not Estimated	Emissions occur but have not been estimated or reported; justification for exclusion shall be noted in the explanation.
NO	Not Occurring	An activity or process does not occur or exist within the city.
C	Confidential	GHG emissions which could lead to the disclosure of confidential information and can therefore not be reported.

When collecting emissions data, the first step is identifying whether or not an activity occurs in a city. If it does not, the notation key "NO" is used for the relevant GHG emission source category. For example, a landlocked city with no transport by water would use the notation key "NO" to indicate that GHG emissions from water transport do not occur. If the activity *does* occur in the city—and data are available—then the emissions should be reported. However, if the data are also included in another emissions source category or cannot be disaggregated, the notation key "IE" shall be used with appropriate explanation in order to avoid double counting, and the category in which they are included should be identified. For example, emissions from waste incineration would use "IE" if these emissions were also reported under generation of energy for use in buildings. If the data are available but cannot be reported for reasons of data confidentiality and cannot be included in another emissions source category, the notation key "C" would be used. For instance, certain military operations or industrial facilities may not permit public data disclosure where this impacts security. Finally, if the data are not available and, therefore, the emissions are not estimated, the notation key "NE" would be used. The latter should be avoided by exploring multiple methodologies and data sources to estimate emissions. See Box 2.2 for an example of notation key usage in an inventory.

5. *2006 IPCC Guidelines* also includes the notation key "NA—Not Applicable" for activities that occur but do not result in specific GHG emissions. For the purposes of the GPC, the notation key "NA" does not apply because the use of notation keys in the GPC is focused on GHG emission source categories, rather than specific gases, and does not require the same level of disaggregation as national inventories.

Box 2.2 Use of notation keys—Johannesburg

Johannesburg, South Africa, completed its first GHG inventory in 2014, and used notation keys to explain where emissions data are missing for the sources listed in the GPC accounting and reporting framework. Owing to a lack of good quality data, the city was unable to estimate emissions from two sectors—Industrial Processes and Product Use (*IPPU*) and Agriculture, Forestry and Other Land Use (*AFOLU*). The notation key NE was used to indicate this. Furthermore, being a landlocked city with no major river or other waterway, there are no emissions from water-borne navigation and thus the notation key NO was used. Finally, grid-supplied energy data were available but only disaggregated by residential and non-residential buildings. Emissions from the use of grid-supplied energy in manufacturing industry and construction were therefore included in the total use of grid-supplied energy in commercial and institutional buildings and facilities. The city used notation key IE to indicate this and explain why no emissions were reported for grid-supplied energy use in manufacturing industry and construction.

3 Setting the Inventory Boundary

An inventory boundary identifies the gases, emission sources, geographic area, and time span covered by a GHG inventory. The inventory boundary is designed to provide a city with a comprehensive understanding of where emissions are coming from as well as an indication of where it can take action or influence change.

Requirements in this chapter

The assessment boundary shall include all seven Kyoto Protocol GHGs occurring within the geographic boundary of the city, as well as specified emissions occurring out-of-boundary as a result of city activities. The inventory shall cover a continuous 12-month period.

3.1 Geographic boundary

Cities shall establish a geographic boundary that identifies the spatial dimension or physical perimeter of the inventory's boundary. Any geographic boundary may be used for the GHG inventory, and cities shall maintain the same boundary for consistent inventory comparison over time (see Chapter 11 for information about recalculating base years to reflect structural changes). Depending on the purpose of the inventory, the boundary can align with the administrative boundary of a local government, a ward or borough within a city, a combination of administrative divisions, a metropolitan area, or another geographically identifiable entity. The boundary should be chosen independently of the location of any buildings or facilities under municipal—or other government—control, such as power generation facilities or landfill sites outside of the city's geographic boundary.

3.2 Time period

The GPC is designed to account for city GHG emissions within a single reporting year. The inventory shall cover a continuous period of 12 months, ideally aligning to

either a calendar year or a financial year, consistent with the time periods most commonly used by the city.

Calculation methodologies in the GPC generally quantify emissions released during the reporting year. In certain cases—in the *Waste* sector, for instance—the available or nationally-consistent methodologies may also estimate the future emissions that result from activities conducted within the reporting year (see waste emissions accounting in Chapter 8).

3.3 Greenhouse gases

Cities shall account for emissions of the seven gases currently required for most national GHG inventory reporting under the Kyoto Protocol: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).[6]

3.4 GHG emission sources

GHG emissions from city activities shall be classified into six main sectors, including:

- Stationary energy
- Transportation
- Waste
- Industrial processes and product use (*IPPU*)
- Agriculture, forestry, and other land use (*AFOLU*)
- Any other emissions occurring outside the geographic boundary as a result of city activities (collectively referred to as *Other Scope 3*). These emissions are not covered in this version of the GPC: see Section 3.6.

Emissions from these sectors shall be sub-divided into sub-sectors and may be further sub-divided into sub-categories. These designations include[7]:

- **Sectors**, for GPC purposes, define the topmost categorization of city-wide GHG sources, distinct from one another, that together make up the city's GHG emission sources activities.
- **Sub-sectors** are divisions that make up a sector (e.g., waste treatment methods, or transport modes such as aviation or on-road).
- **Sub-categories** are used to denote an additional level of categorization, such as vehicle types within the sub-sector of each transport mode, or building types within the stationary energy sector. Sub-categories provide opportunities to use disaggregated data, improve inventory detail, and help identify mitigation actions and policies.

Table 3.1 lists the six sectors and sub-sectors.

6. NF_3 is the seventh GHG to be added to the international accounting and reporting rules under the UNFCCC/Kyoto Protocol. NF_3 was added to the second compliance period of the Kyoto Protocol, beginning in 2012 and ending in either 2017 or 2020.

7. *2006 IPCC Guidelines* include similar sector breakdowns, described in Volume 1, Chapter 8, Section 8.2.4, Sectors and Categories. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol1

Table 3.1 Sectors and sub-sectors of city GHG emissions

Sectors and sub-sectors
STATIONARY ENERGY
Residential buildings
Commercial and institutional buildings and facilities
Manufacturing industries and construction
Energy industries
Agriculture, forestry, and fishing activities
Non-specified sources
Fugitive emissions from mining, processing, storage, and transportation of coal
Fugitive emissions from oil and natural gas systems
TRANSPORTATION
On-road
Railways
Waterborne navigation
Aviation
Off-road
WASTE
Solid waste disposal
Biological treatment of waste
Incineration and open burning
Wastewater treatment and discharge
INDUSTRIAL PROCESSES AND PRODUCT USE (IPPU)
Industrial processes
Product use
AGRICULTURE, FORESTRY AND OTHER LAND USE (AFOLU)
Livestock
Land
Aggregate sources and non-CO_2 emission sources on land
OTHER SCOPE 3

3.5 Categorizing emissions by scope

Activities taking place within a city can generate GHG emissions that occur inside the city boundary as well as outside the city boundary. To distinguish between these, the GPC groups emissions into three categories based on where they occur: scope 1, scope 2 or scope 3 emissions. Definitions are provided in Table 3.2, based on an adapted application of the scopes framework used in the *GHG Protocol Corporate Standard.*[8]

The GPC distinguishes between emissions that physically occur within the city (scope 1), from those that occur outside the city but are driven by activities taking place within the city's boundaries (scope 3), from those that occur from the use of electricity, steam, and/or heating/cooling supplied by grids which may or may not cross city boundaries (scope 2)., Scope 1 emissions may also be termed "territorial" emissions, because they are produced solely within the territory defined by the geographic boundary.

Figure 3.1 illustrates which emission sources occur solely within the geographic boundary established for the inventory, which occur outside the geographic boundary, and which may occur across the geographic boundary.

Table 3.2 Scopes definitions for city inventories

Scope	Definition
Scope 1	GHG emissions from sources located within the city boundary.
Scope 2	GHG emissions occurring as a consequence of the use of grid-supplied electricity, heat, steam and/or cooling within the city boundary.
Scope 3	All other GHG emissions that occur outside the city boundary as a result of activities taking place within the city boundary.

8. The scopes framework is derived from the *GHG Protocol Corporate Standard,* where the scopes are considered to be operational boundaries based on an inventory boundary established by the company's chosen consolidation approach. In the GPC, the geographic boundary serves as the boundary. See Appendix A for a comparison of how the scopes framework is applied in corporate GHG inventories compared to city GHG inventories.

Chapters 6 to 10 provide additional guidance on how to categorize emissions into scopes and sub-sectors and sub-categories.

3.5.1 Aggregating city inventories

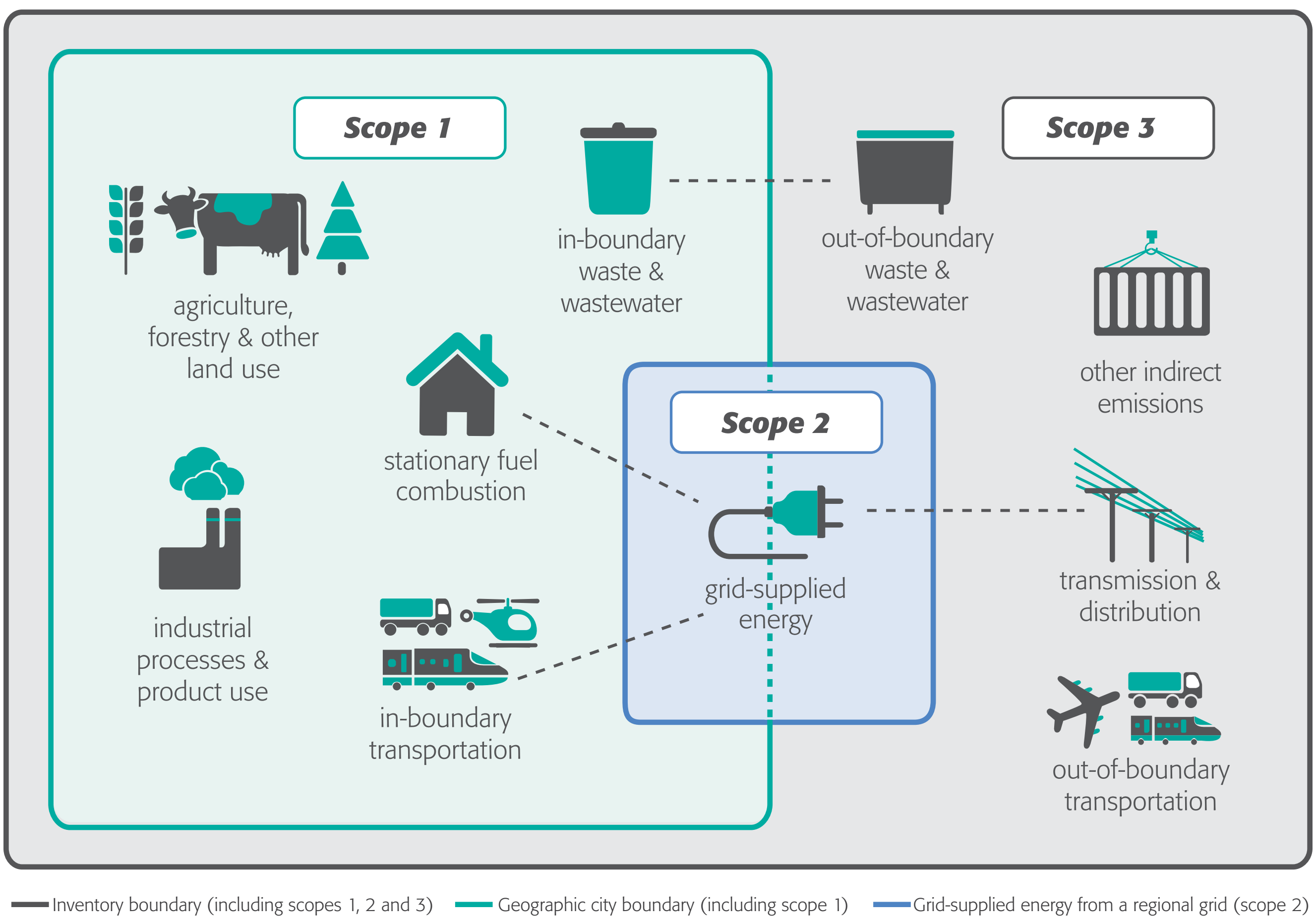
In addition, the GPC has been designed to allow city inventories to be aggregated at subnational and national levels in order to:

- Improve the data quality of a national inventory, particularly where major cities' inventories are reported;
- Measure the contribution of city mitigation actions to regional or national GHG emission reduction targets; and
- Identify innovative transboundary and cross-sectorial strategies for GHG mitigation.

For policy makers or other national authorities, multiple city inventory aggregation is accomplished by combining only the scope 1 emissions reported by cities. This is also termed "territorial" accounting. Aggregating only scope 1 emissions from cities without overlapping geographic boundaries ensures that the aggregated results will not double count any emission sources, since emissions can only be physically generated in one location.[9]

9. For the transportation sector in particular, policy makers should seek to collect emissions data from cities based on comparable methods. For instance, the fuel sales method relies on discrete points of fuel sales located within city geographic boundaries and can more easily be aggregated together without double counting.

Figure 3.1 Sources and boundaries of city GHG emissions



3.6 Other scope 3 emissions

Cities, by virtue of their size and connectivity, inevitably give rise to GHG emissions beyond their boundaries. Measuring these emissions allows cities to take a more holistic approach to tackling climate change by assessing the GHG impact of their supply chains, and identifying areas of shared responsibility for upstream and downstream GHG emissions.

The GPC includes scope 3 accounting for a limited number of emission sources, including transmission and distribution losses associated with grid-supplied energy, and waste disposal and treatment outside the city boundary and transboundary transportation.

Cities may optionally report *Other Scope 3* sources associated with activity in a city—such as GHG emissions embodied in fuels, water, food and construction materials. To support cities in measuring these and other scope 3 emissions in a robust and consistent manner, the GPC authors anticipate providing additional guidance on estimating emissions from key goods and services produced outside the city boundary.

Consumption-based accounting is an alternative to the sector-based approach to measuring city emissions adopted by the GPC. This focuses on the consumption of *all* goods and services by *residents* of a city, and GHG emissions are reported by consumption category rather than the emission source categories set out in the GPC. The consumption-based approach allocates GHG emissions to the final consumers of goods and services, rather than to the original producers of those GHG emissions. As such GHG emissions from visitor activities and the production of goods and services within the city boundary that are exported for consumption outside the city boundary are excluded. Consumption-based inventories typically use an input-output model, which links household consumption patterns and trade flows to energy use and GHG emissions, and their categories cut across those set out in the GPC. This approach is complementary to the GPC and provides a different insight into a city's GHG emissions profile (see Box 3.1). Please see Appendix A for references to existing methodologies used by cities.

3.7 Boundaries for mitigation goals

For many cities with existing climate action plans and targets, the mitigation goal boundary used can be different to the inventory boundary outlined above. However, cities are encouraged to align their mitigation goal boundary with the GPC inventory boundary. Mitigation goals can apply to a city's overall emissions or to a subset of the GHGs, scopes, or emission sources set out in the GPC.

Where the mitigation goal boundary differs from the GPC inventory boundary, cities should explain the differences, and reason for the differences, to avoid any confusion. See Chapter 4 for how cities can report offsetting measures, and Chapter 11 for how to set reduction targets.

Box 3.1 Scope 3 sources—King County

King County in the U.S. state of Washington carried out a study published in 2012[10] using 2008 data to estimate the emissions associated with all goods and services consumed by the region's two million residents, regardless of where the emissions were produced. This kind of "consumption-based" GHG inventory provides an additional view of a community's contribution to climate change. The consumption-based inventory used economic data on purchasing behaviors and "input-output" analysis to estimate the emissions released to produce, transport, sell, use and dispose of all the materials, goods, and services consumed by the region. Total emissions were estimated at 55 million $MTCO_2e$, over a quarter of which were released outside the United States. Overall, emissions associated with local consumption by residents, governments and businesses, including from the production of goods, food and services from outside the County, were more than twice as high as emissions that occurred inside the County's borders. King County's "geographic-plus" based inventory separately estimated regional emissions at 23 million $MTCO_2e$ using a methodology similar to the GPC. The difference in emissions reflects the different sources covered by the two methodologies. Note, some sources are included in both inventories and therefore the results should not be added together.

10. *Source:* King County and SEI (2012) Greenhouse Gas Emissions in King County: An updated Geographic-plus inventory, a Consumption-based Inventory, and an Ongoing Tracking Framework. http://your.kingcounty.gov/dnrp/library/dnrp-directors-office/climate/2008-emissions-inventory/ghg-inventory-summary.pdf

4 Reporting Requirements

The GPC provides a robust and transparent accounting and reporting system for city-wide GHG emissions.

The GPC requires cities to report their emissions using two distinct but complementary approaches:

- The **scopes framework** allows cities to comprehensively report all GHG emissions attributable to activities taking place within the geographic boundary of the city by categorizing the emission sources into in-boundary sources (scope 1, or "territorial"), grid-supplied energy sources (scope 2), and out-of-boundary sources (scope 3). Scope 1 allows for a territorial approach to aggregating multiple cities' inventories, consistent with national-level GHG reporting.
- The **city-induced framework** measures GHG emissions attributable to activities taking place within the geographic boundary of the city. This covers selected scope 1, 2 and 3 emission sources. It provides two reporting levels demonstrating different levels of completeness. The **BASIC** level covers emission sources that occur in almost all cities (*Stationary Energy*, in-boundary transportation, and in-boundary generated waste) and the calculation methodologies and data are more readily available. The **BASIC+** level has a more comprehensive coverage of emissions sources (BASIC sources plus *IPPU*, *AFOLU*, transboundary transportation, and energy transmission and distribution losses) and reflects more challenging data collection and calculation procedures.

This chapter sets out reporting requirements and explains how to aggregate emission totals for both frameworks. Cities may also report emissions based on relevant local or program-specific requirements in addition to the requirements of the GPC.

GHG inventories should be updated on a regular basis using the most recent data available. The GPC recommends cities update their inventory on an annual basis, as it provides frequent and timely progress on overall GHG emissions reduction efforts.

4.1 The scopes and city-induced frameworks

Figure 4.1 provides an overview of the above-mentioned scopes and BASIC/BASIC+ frameworks as well as breakdowns by sector and sub-sector. Cities should aim to cover all emissions for which reliable data are available. Notation keys shall be used to indicate any data gaps.

The GPC requires reporting for one of two reporting levels: BASIC and BASIC+. BASIC covers scope 1 and scope 2 emissions from *Stationary Energy* and *Transportation*, as well as in-boundary generated waste. BASIC+ reflects more challenging data collection and calculation processes, and additionally includes emissions from *IPPU, AFOLU,* transboundary transportation, and energy transmission and distribution losses. Where these sources are significant and relevant for a city, the city should aim to report according to BASIC+. The sources covered in BASIC+ also align with sources required for national reporting in *IPCC Guidelines*. Cities shall indicate the reporting level chosen for their inventory. A city choosing BASIC+ shall have no emissions from BASIC sources that are "Not Estimated."

Cities reporting additional scope 3 sources beyond the requirements of BASIC+ should classify these as *Other Scope 3* and document the methods they have used to estimate these emissions. These shall be reported separately from the BASIC/BASIC+ totals.

Note, for the BASIC and BASIC+ reporting levels, emissions from grid-supplied energy are calculated at the point of energy consumption and emissions from waste at the point of waste generation. For territorial (scope 1) accounting, emissions from grid-supplied energy are calculated at the point of energy generation and emissions from waste at the point of waste disposed. Box 4.1 below articulates the emission sources and scopes included in each reporting level.

Tick marks in Figure 4.1 indicate which emission sources are covered by the GPC, and cells are colored to indicate their inclusion in the BASIC or BASIC+ totals and the territorial (scope 1) total. Rows written in italics represent sub-sector emissions required for territorial emission totals but not BASIC/BASIC+. Gray cells in the scope 2 and scope 3 columns indicate emission sources that do not have applicable GHG emissions in that scope category. Emission sources corresponding to the orange boxes in the scope 3 column are not required for reporting, but may be identified and disclosed separately under *Other Scope 3*. In the case of *Waste*, *IPPU* or *AFOLU*, facilities in these sectors will likely use grid-supplied energy, but these emissions are reported

Box 4.1 Emission sources and scopes in BASIC and BASIC+

Emission sources and scopes included in **BASIC** totals:

- All scope 1 emissions from *Stationary Energy* sources (excluding energy production supplied to the grid, which shall be reported in the scope 1 total)
- All scope 1 emissions from *Transportation* sources
- All scope 1 emissions from *Waste* sources (excluding emissions from imported waste, which shall be reported in the scope 1 total)
- All scope 2 emissions from *Stationary Energy* sources and transportation
- Scope 3 emissions from treatment of exported waste

BASIC+ totals include all BASIC sources, plus:

- All scope 1 emissions from *IPPU*
- All scope 1 emissions from *AFOLU*
- Scope 3 emissions from *Stationary Energy* sources (only transmission and distribution losses), and from *Transportation*

Figure 4.1 Sources and scopes covered by the GPC

Sectors and sub-sectors	Scope 1	Scope 2	Scope 3
STATIONARY ENERGY			
Residential buildings	✓	✓	✓
Commercial and institutional buildings and facilities	✓	✓	✓
Manufacturing industries and construction	✓	✓	✓
Energy industries	✓	✓	✓
Energy generation supplied to the grid	✓		
Agriculture, forestry, and fishing activities	✓	✓	✓
Non-specified sources	✓	✓	✓
Fugitive emissions from mining, processing, storage, and transportation of coal	✓		
Fugitive emissions from oil and natural gas systems	✓		
TRANSPORTATION			
On-road	✓	✓	✓
Railways	✓	✓	✓
Waterborne navigation	✓	✓	✓
Aviation	✓	✓	✓
Off-road	✓	✓	
WASTE			
Disposal of solid waste generated in the city	✓		✓
Disposal of solid waste generated outside the city	✓		
Biological treatment of waste generated in the city	✓		✓
Biological treatment of waste generated outside the city	✓		
Incineration and open burning of waste generated in the city	✓		✓
Incineration and open burning of waste generated outside the city	✓		
Wastewater generated in the city	✓		✓
Wastewater generated outside the city	✓		
INDUSTRIAL PROCESSES AND PRODUCT USE (IPPU)			
Industrial processes	✓		
Product use	✓		
AGRICULTURE, FORESTRY AND OTHER LAND USE (AFOLU)			
Livestock	✓		
Land	✓		
Aggregate sources and non-CO_2 emission sources on land	✓		
OTHER SCOPE 3			
Other Scope 3			

✓ Sources covered by the GPC

Sources required for BASIC reporting

\+ Sources required for BASIC+ reporting

Sources required for territorial total but not for BASIC/BASIC+ reporting (*italics*)

Sources included in Other Scope 3

Non-applicable emissions

by commercial and institutional buildings and facilities sub-sector under *Stationary Energy.*

Chapters 6 to 10 provide additional guidance on how to categorize emissions from these sectors and sub-sectors into scopes.

4.2 Reporting requirements

City GHG inventories shall report the following information:

4.2.1 Description of the inventory boundary

- A description of the geographic boundary. Cities should include a map of the geographic boundary that includes a depiction of the region, and rationale used for selecting the geographic boundary.
- An outline of the activities included in the inventory, and if other scope 3 are included, a list specifying which types of activities are covered.
- Any specific exclusion of required sources, facilities, and/or operations. These shall be identified using notation keys (see Section 2.2), along with a clear justification for their exclusion.
- The continuous 12-month reporting period covered.
- The reporting level chosen (BASIC or BASIC+).
- An overview of the reporting city, including total geographic land area, resident population, and GDP. Cities should also include other information, such as an indication of the number of commuters in the city who are not residents, the composition of the economy, climate, and land use activities (accompanied by a land use map). This background can help cities report relevant ratio indicators about performance, such as emissions per geographic area, person, GDP, etc.

4.2.2 Information on emissions

Table 4.3 provides a sample reporting structure that covers all of these reporting requirements outlined above. Cities may report GHG emissions in a variety of additional formats depending on purpose and audience, and may also disaggregate emissions by fuel type, municipal operations within each sector or sub-sector, etc. However, they shall comply with the following requirements:

- **Emissions by sector:** GHG emissions shall be reported for each sector and sub-sector. Emissions sequestered by CO_2 capture and storage systems shall be excluded from emission totals for applicable sectors. However, cities may report these separately.
- **Emissions by scope**: GHG emissions shall be reported by scope 1, scope 2, and scope 3 separately. These scope totals shall be independent of any GHG trades such as sales, purchases, transfers, or banking of allowances.
- **Emissions by gas:** GHG emissions shall be reported in metric tonnes and expressed by gas (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and NF_3) and by CO_2 equivalent (CO_2e). CO_2 equivalent can be determined by multiplying each gas by its respective global warming potential (GWP), as described in Chapter 5.
- **Emissions by total**: GHG emissions shall be aggregated according to the scopes framework and the city-induced framework (BASIC+ or BASIC, based on the reporting level chosen).
- **Emissions from biogenic origin:** CO_2 emissions from combustion of materials of biogenic origin (e.g., biomass, biofuel, etc.) shall be reported separately from the scopes and other gases. For reference, this should be under column CO_2(b) in the reporting framework (Table 4.3), but not counted in emissions totals. See Box 4.2 for more on biogenic reporting.

Box 4.2 Reporting biogenic CO_2 emissions

Biogenic emissions are those that result from the combustion of biomass materials that naturally sequester CO_2, including materials used to make biofuels (e.g. crops, vegetable oils, or animal fats). For the purposes of national-level GHG inventories, land-use activities are recorded as both sinks and sources of CO_2 emissions. Reporting emissions from combusting these biogenic fuels would result in double counting on a national level. The GPC also records land-use changes, and combusted biofuels may be linked to land-use changes in its own inventory, or other cities' inventories.

4.2.3 Information on methodologies and data quality

- For methodologies used to calculate or measure emissions, cities shall provide a reference or link to any calculation tools used. For each emission source sector, cities shall provide a description of the types and sources of data, including activity data, emission factors, and global warming potential (GWP) values used to calculate emissions.
- Cities shall provide an assessment of data quality for activity data and emission factors used in quantification, following a High-Medium-Low rating (see Section 5.6). For reference, these are noted in Table 4.3 as Activity Data (AD) and Emission Factor (EF), respectively, under the data quality columns.

4.2.4 Information on emission changes

- If a city has set a mitigation goal, it shall identify the year chosen as the base year and report base year emissions.
- If the city is using an inventory to track progress toward a mitigation goal, the city shall identify a significance threshold that triggers base year emissions recalculation (such as acquisition of existing neighboring communities, changes in reporting boundaries or calculation methodologies, etc.). See Chapter 11 for choosing a base year and recalculation procedures. Cities should explain measures taken to ensure consistency when there is a change in methodologies (e.g., change in data collection method or calculation method).

4.3 Reporting recommendations

Where relevant, cities should also provide in the inventory:

- **Scope 2 emissions based on a market-based method calculation** (Table 4.4(a)). This reflects any electricity products or programs that city consumers participate in, generally provided by the electricity supplier serving the city. See Chapter 6 for a description on how to report this.
- **Offset credit transactions** (Table 4.4(b)). If offset credits are generated in the geographic boundary and sold, these should be documented separately from emissions reporting. In addition, any offsets purchased from outside the geographic boundary should be separately reported and not "netted" or deducted from the reported inventory results.
- **Renewable energy generation (in MWh or KWh) produced within the geographic boundary, or reflecting an investment by the city** (Table 4.4(c)). This information can help a city identify renewable production that otherwise only indirectly impacts scope 2 emissions (through a lower grid average emission factor) and that would not be visible in scope 1 emissions for energy generation (due to its zero emissions profile).

4.4 GPC reporting framework

The following tables highlight key reporting requirements and recommendations of the GPC and together represent the larger reporting framework. With the help of notation keys, a city shall report all of the required information in Table 4.1, Table 4.2, and Table 4.3. Alternative reporting formats may be used depending on inventory purpose. A city may also report data required in Tables 4.4, where such information is relevant and available.

Table 4.1 Inventory city information

Inventory boundary	City Information
Name of city	
Country	
Inventory year	
Geographic boundary	
Land area (km^2)	
Resident population	
GDP (US$)	
Composition of economy	
Climate	
Other information	

Table 4.2 **GHG Emissions Summary**

Sector		Total by scope (tCO_2e)				Total by city-induced reporting level (tCO_2e)	
		Scope 1 (Territorial)	**Scope 2**	**Scope 3 included in BASIC/ BASIC+**	**Other Scope 3**	**BASIC**	**BASIC+**
Stationary Energy	Energy use (all I emissions except I.4.4)						
	Energy generation supplied to the grid (I.4.4)						
Transportation (all II emissions)							
Waste	Generated in the city (all III.X.1 and III.X.2).						
	Generated outside city (all III.X.3)						
IPPU (all IV emissions)							
AFOLU (all V emissions)							
Total		(All territorial emissions)				(All BASIC emissions)	(All BASIC & BASIC+ emissions)

Sources required for BASIC reporting

\+ Sources required for BASIC+ reporting

Sources included in Other Scope 3

Sources required for territorial total but not for BASIC/BASIC+ reporting (*italics*)

Non-applicable emissions

Table 4.2 summarizes the emission required for scopes totals and for the city-induced framework's BASIC/BASIC+ reporting levels. It references the line numbers and coloring from the detailed Table 4.3. *Note:* Aggregation of multiple city inventories is accomplished by combining the scope 1 (territorial) emissions of cities whose inventory boundaries do not overlap geographically.

Table 4.3 GHG Emissions Report

Attachment Item 14B

GPC ref No.	Scope	GHG Emissions Source (By Sector and Sub-sector)	Notation keys
I		**STATIONARY ENERGY**	
I.1		Residential buildings	
I.1.1	1	Emissions from fuel combustion within the city boundary	
I.1.2	2	Emissions from grid-supplied energy consumed within the city boundary	
I.1.3	3	Emissions from transmission and distribution losses from grid-supplied energy consumption	
I.2		Commercial and institutional buildings and facilities	
I.2.1	1	Emissions from fuel combustion within the city boundary	
I.2.2	2	Emissions from grid-supplied energy consumed within the city boundary	
I.2.3	3	Emissions from transmission and distribution losses from grid-supplied energy consumption	
I.3		Manufacturing industries and construction	
I.3.1	1	Emissions from fuel combustion within the city boundary	
I.3.2	2	Emissions from grid-supplied energy consumed within the city boundary	
I.3.3	3	Emissions from transmission and distribution losses from grid-supplied energy consumption	
I.4		Energy industries	
I.4.1	1	Emissions from energy used in power plant auxiliary operations within the city boundary	
I.4.2	2	Emissions from grid-supplied energy consumed in power plant auxiliary operations within the city boundary	
I.4.3	3	Emissions from transmission and distribution losses from grid-supplied energy consumption in power plant auxiliary operations	
I.4.4	1	*Emissions from energy generation supplied to the grid*	
I.5		Agriculture, forestry and fishing activities	
I.5.1	1	Emissions from fuel combustion within the city boundary	
I.5.2	2	Emissions from grid-supplied energy consumed within the city boundary	
I.5.3	3	Emissions from transmission and distribution losses from grid-supplied energy consumption	
I.6		Non-specified sources	
I.6.1	1	Emissions from fuel combustion within the city boundary	
I.6.2	2	Emissions from grid-supplied energy consumed within the city boundary	
I.6.3	3	Emissions from transmission and distribution losses from grid-supplied energy consumption	
I.7		Fugitive emissions from mining, processing, storage, and transportation of coal	
I.7.1	1	Emissions from fugitive emissions within the city boundary	
I.8		Fugitive emissions from oil and natural gas systems	
I.8.1	1	Emissions from fugitive emissions within the city boundary	
II		**TRANSPORTATION**	
II.1		On-road transportation	
II.1.1	1	Emissions from fuel combustion on-road transportation occurring within the city boundary	
II.1.2	2	Emissions from grid-supplied energy consumed within the city boundary for on-road transportation	
II.1.3	3	Emissions from portion of transboundary journeys occurring outside the city boundary, and transmission and distribution losses from grid-supplied energy consumption	
II.2		Railways	
II.2.1	1	Emissions from fuel combustion for railway transportation occurring within the city boundary	
II.2.2	2	Emissions from grid-supplied energy consumed within the city boundary for railways	
II.2.3	3	Emissions from portion of transboundary journeys occurring outside the city boundary, and transmission and distribution losses from grid-supplied energy consumption	
II.3		Waterborne navigation	
II.3.1	1	Emissions from fuel combustion for waterborne navigation occurring within the city boundary	
II.3.2	2	Emissions from grid-supplied energy consumed within the city boundary for waterborne navigation	
II.3.3	3	Emissions from portion of transboundary journeys occurring outside the city boundary, and transmission and distribution losses from grid-supplied energy consumption	
II.4		Aviation	
II.4.1	1	Emissions from fuel combustion for aviation occurring within the city boundary	
II.4.2	2	Emissions from grid-supplied energy consumed within the city boundary for aviation	
II.4.3	3	Emissions from portion of transboundary journeys occurring outside the city boundary, and transmission and distribution losses from grid-supplied energy consumption	
II.5		Off-road transportation	
II.5.1	1	Emissions from fuel combustion for off-road transportation occurring within the city boundary	
II.5.2	2	Emissions from grid-supplied energy consumed within the city boundary for off-road transportation	
III		**WASTE**	
III.1		Solid waste disposal	
III.1.1	1	Emissions from solid waste generated within the city boundary and disposed in landfills or open dumps within the city boundary	
III.1.2	3	Emissions from solid waste generated within the city boundary but disposed in landfills or open dumps outside the city boundary	
III.1.3	1	*Emissions from waste generated outside the city boundary and disposed in landfills or open dumps within the city boundary*	
III.2		Biological treatment of waste	
III.2.1	1	Emissions from solid waste generated within the city boundary that is treated biologically within the city boundary	
III.2.2	3	Emissions from solid waste generated within the city boundary but treated biologically outside of the city boundary	
III.2.3	1	*Emissions from waste generated outside the city boundary but treated biologically within the city boundary*	
III.3		Incineration and open burning	
III.3.1	1	Emissions from solid waste generated and treated within the city boundary	
III.3.2	3	Emissions from solid waste generated within the city boundary but treated outside of the city boundary	
III.3.3	1	*Emissions from waste generated outside the city boundary but treated within the city boundary*	
III.4		Wastewater treatment and discharge	
III.4.1	1	Emissions from wastewater generated and treated within the city boundary	
III.4.2	3	Emissions from wastewater generated within the city boundary but treated outside of the city boundary	
III.4.3	1	*Emissions from wastewater generated outside the city boundary but treated within the city boundary*	
IV		**INDUSTRIAL PROCESSES and PRODUCT USES (IPPU)**	
IV.1	1	Emissions from industrial processes occurring within the city boundary	
IV.2	1	Emissions from product use occurring within the city boundary	
V		**AGRICULTURE, FORESTRY and OTHER LAND USE (AFOLU)**	
V.1	1	Emissions from livestock within the city boundary	
V.2	1	Emissions from land within the city boundary	
V.3	1	Emissions from aggregate sources and non-CO_2 emission sources on land within the city boundary	
VI		**OTHER SCOPE 3**	
VI.1	3	Other Scope 3	

Gases (in tonnes)									Data Quality		Explanatory comments (i.e. description of methods or notation keys used)
CO_2	CH_4	N_2O	HFC	PFC	SF_6	NF_3	Total CO_2e	$CO_2(b)$	AD	EF	

Sources required for BASIC reporting

+ Sources required for BASIC+ reporting

Sources included in Other Scope 3

Sources required for territorial total but not for BASIC/BASIC+ reporting (*italics*)

Non-applicable emissions

Optional information items

Table 4.4(a) Scope 2 emissions based on market-based method

Contractual instrument or program type	Quantity of energy (kWh, MWh, BTU, etc.)	Emission factor conveyed by the instrument	Total GHG emissions (tCO_2e)
TOTAL market-based scope 2 emissions (in tCO_2e)			

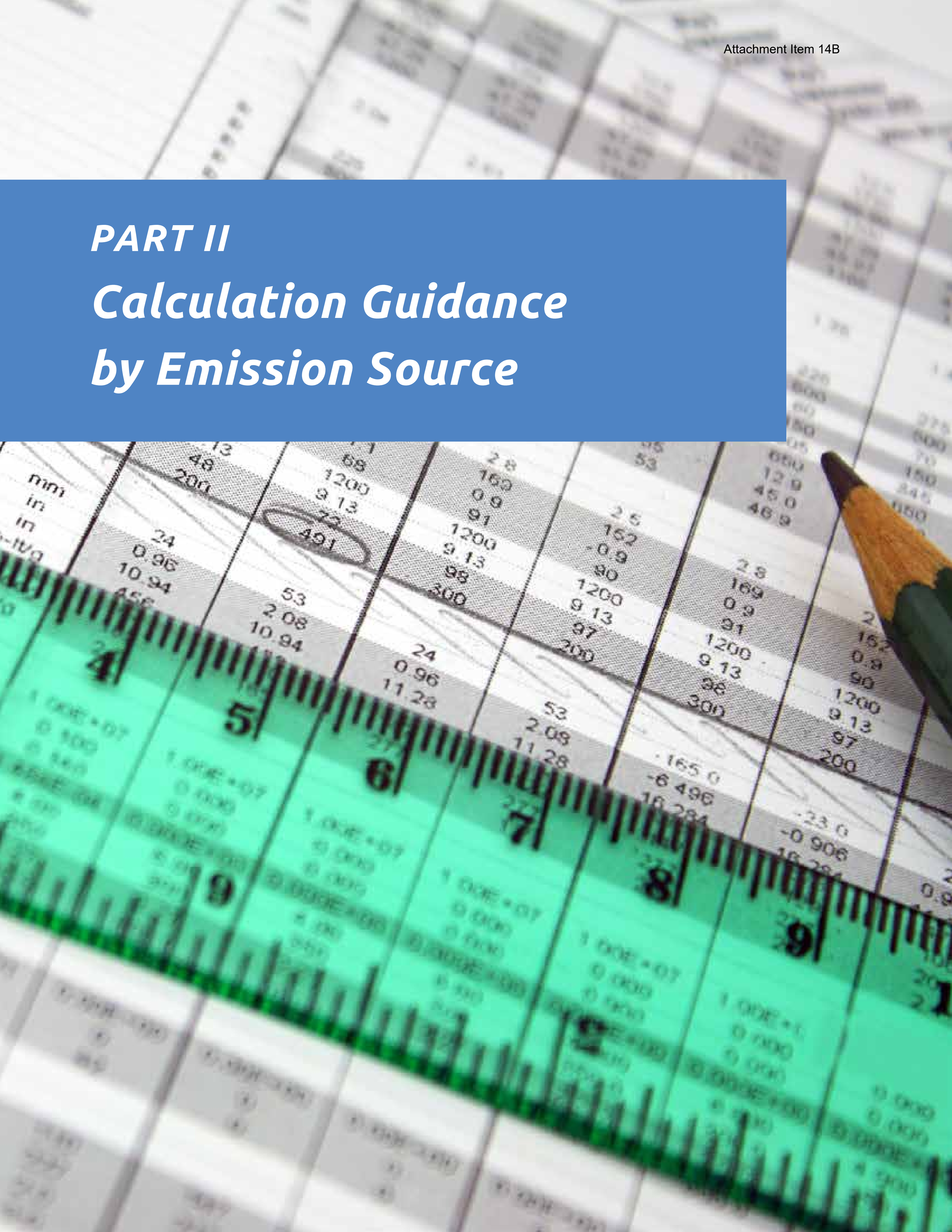
Table 4.4(b) Offset credit transactions

Offset credits generated within the geographic boundary and sold	Total GHG emissions (tCO_2e)

Offset credits purchased from outside the geographic boundary (e.g., to meet a city reduction goal)	Total GHG emissions (tCO_2e)

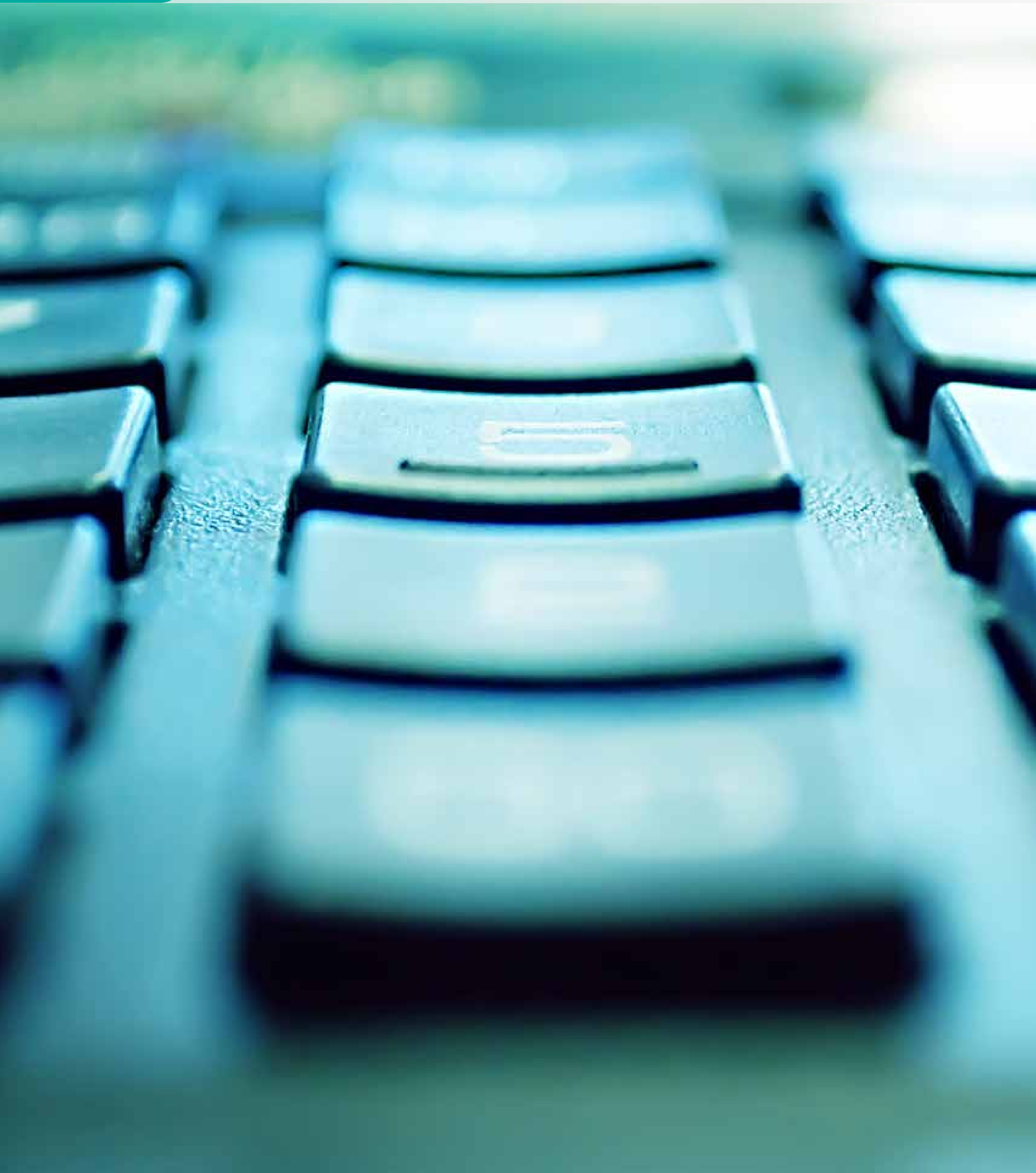
Table 4.4(c) Renewable energy production or investments

Technology type	Total annual production of grid-delivered energy	Located in geographic boundary?	If outside boundary, percentage of ownership by city?



PART II
Calculation Guidance by Emission Source

5 Overview of Calculating GHG Emissions



The GPC specifies the principles and rules for compiling a city-wide GHG emissions inventory; it does not require specific methodologies to be used to produce emissions data. This chapter provides overarching guidance for sourcing activity data and calculating emission factors. It also sets out guidance for calculating GHG emissions consistent with the requirements set out in Chapters 6 to 10.

5.1 Calculation methodology

Emission calculation methodologies define the calculation formulas and necessary activity data and emission factors to determine total emissions from specified activities. Cities should select the most appropriate methodologies based on the purpose of their inventory, availability of data, and consistency with their country's national inventory and/or other measurement and reporting programs in which they participate. An overview of methodologies outlined in the GPC is provided in Appendix C.

5.1.1 *IPCC Guidelines* and methodology tiers

Unless stated otherwise, calculation methodologies referenced in the GPC are consistent with the *IPCC Guidelines*. Where different methodologies are used, cities should ensure they meet the requirements of the GPC and document the methodologies they have used in their inventory report.

In *IPCC Guidelines*, three hierarchical tiers are used to categorize the methodological complexity of emissions factors and activity data. Tier 1 uses default data and simple equations, while Tiers 2 and 3 are each more demanding in terms of complexity and data requirements. Tier 2 methodologies typically use country-specific emission factors. These tiers, if properly implemented, successively reduce uncertainty and increase accuracy. The GPC does not use tiers to define methodologies but makes references to them when referring to *IPCC Guidelines*.

5.1.2 Calculation overview

For some activities, cities will be able to use direct measurements of GHG emissions (e.g., through use of continuous emissions monitoring systems at power stations). However, for most emission sources, cities will need to estimate GHG emissions by multiplying activity data by an emission factor associated with the activity being measured (see Equation 5.1).

Equation 5.1 Emission factor approach for calculating GHG emissions

$$\text{GHG emissions} = \text{Activity data} \times \text{Emission factor}$$

Activity data is a quantitative measure of a level of activity that results in GHG emissions taking place during a given period of time (e.g., volume of gas used, kilometers driven, tonnes of solid waste sent to landfill, etc.). An emission factor is a measure of the mass of GHG emissions relative to a unit of activity. For example, estimating CO_2 emissions from the use of electricity involves multiplying data on kilowatt-hours (kWh) of electricity used by the emission factor ($kgCO_2$/kWh) for electricity, which will depend on the technology and type of fuel used to generate the electricity.

Table 5.1 Data collection principles[11]

Data collection principles
Establish collection processes that lead to continuous improvement of the data sets used in the inventory (resource prioritization, planning, implementation, documentation, etc.)
Prioritize improvements on the collection of data needed to improve estimates of key categories which are the largest, have the greatest potential to change, or have the greatest uncertainty
Review data collection activities and methodological needs on a regular basis to guide progressive, and efficient, inventory improvement
Work with data suppliers to support consistent and continuing information flows

5.2 Activity data

Data collection is an integral part of developing and updating a GHG inventory. This includes gathering existing data, generating new data, and adapting data for inventory use. Table 5.1 sets out the methodological principles of data collection that underpin good practice.

5.3 Sourcing activity data

It is good practice to start data collection activities with an initial screening of available data sources. This will be an iterative process to improve the quality of data used and should be driven by two primary considerations:

- Data should be from reliable and robust sources
- Data should be time- and geographically-specific to the inventory boundary, and technology-specific to the activity being measured

Data can be gathered from a variety of sources, including government departments and statistics agencies, a country's national GHG inventory report, universities and research institutes, scientific and technical articles in environmental books, journals and reports, and sector experts/stakeholder organizations. In general, it is preferable to use local and national data over international data, and data from publicly-available, peer-reviewed and reputable sources, often available through government publications.

The following information should be requested and recorded when sourcing data:

- Definition and description of the data set: time series, sector breakdown, units, assumptions, uncertainties and known gaps
- Frequency and timescales for data collection and publication
- Contact name and organization(s)

It may be necessary to generate new data if the required activity data does not exist or cannot be estimated from existing sources. This could involve physical measurement[12], sampling activities, or surveys. Surveys may be the best option for most emission sources, given the tailored data needs of city-wide GHG inventories,

11. Adapted from *2006 IPCC Guidelines*, Chapter 2.

12. For example, direct measurement of point source GHG emissions from an industrial or waste treatment facility.

although they can be relatively expensive and time-consuming without proper guidance.[13]

5.3.1 Adapting data for inventory use (scaling data)

Where the best available activity data do not align with the geographical boundary of the city or the time period of the assessment, the data can be adapted to meet the inventory boundary by adjusting for changes in activity using a scaling factor. The scaling factor represents the ratio between the available data and the required inventory data, and should reflect a high degree of correlation to variations in the data. Scaled data can be useful and relevant where data for the inventory year, or city-specific data, are unavailable or incomplete.[14, 15]

Cities should use calendar year data whenever available in conformance with national inventory practices. However, if calendar year data are unavailable, then other types of annual year data (e.g., non-calendar fiscal year data, April—March) may be used, provided the collection periods are well-documented and used consistently over time to avoid bias in the trend. These do not need to be adjusted.

The general formula for scaling data is found in Equation 5.2.

References are made throughout Chapters 6–10 on how to scale data from a national or regional level to the city for different emission sectors. Recommended scaling factors are also provided, including how to account for energy use changes based on weather.[16] If a city chooses a different scaling factor than the one recommended, the relationship between the alternate scaling factor and activity data for the emissions source should be documented in the

Equation 5.2 Scaling methodology

$$\textbf{Inventory data} = \frac{\text{Factor}_{\text{Inventory data}}}{\text{Factor}_{\text{Available data}}} \times \text{Available data}$$

Available data	Activity (or emissions) data available which needs to be scaled to align with the inventory boundary
Inventory data	Activity (or emissions) data total for the city
$\text{Factor}_{\text{Inventory}}$	Scaling factor data point for the inventory
$\text{Factor}_{\text{Available data}}$	Scaling factor data point for the original data

Population is one of the most common factors used to scale data because, in the absence of major technological and behavioral changes, the number of people is a key driver of GHG emissions, particularly in the residential sector. For example, the following equation may be used for adjusting household waste data if data for the inventory year are not available:

$$\textbf{City household waste data 2014} = \frac{\text{City Population}_{2014}}{\text{City Population}_{2013}} \times \text{City household waste data 2013}$$

Other scaling factors, such as GDP or industry yield or turnover, may be more suitable to scale data for economic activities.

13. Volume 1, Chapter 2: *Approaches to Data Collection, Annex 2A.2* of the *2006 IPCC Guidelines* provides more general guidance on performing surveys. Specific guidance on conducting surveys in developing countries can be found in *United Nations, Household Sample Surveys in Developing and Transition Countries* (New York, 2005). Available at: unstats.un.org/unsd/HHsurveys/part1_new.htm

14. For example: gaps in periodic data; recent data are not yet available; only regional or national data are available; data do not align with the geographical boundary of the city; or data are only available for part of the city or part of the year.

15. The scaling factor methodology is also applicable to data collected using surveys of a representative sample-set, and can be used to scale-up real data to represent activity of the entire city.

16. For example, where energy use from a previous year is to be adjusted, variations in weather will also need to be considered. This is due to the high correlation between temperature and energy use to heat or cool buildings. The adjustment is made using a regression analysis of energy use from a previous year against a combination of heating degree-days (HDD) or cooling degree-days (CDD), as appropriate. The inventory-year CDD and HDD are then used to estimate weather-adjusted inventory-year energy use data. This should only be carried out where energy use data can clearly be allocated to heating or cooling. Where this allocation is not clear, no weather correction should be made.

inventory report. In all cases the original data, scaling factor data points, and data sources should be documented.

5.4 Emission factors

Emission factors convert activity data into a mass of GHG emissions; tonnes of CO_2 released per kilometer travelled, for example, or the ratio of CH_4 emissions produced to amount of waste landfilled. Emission factors should be relevant to the inventory boundary, specific to the activity being measured, and sourced from credible government, industry, or academic sources.

If no local, regional, or country-specific sources are available, cities should use IPCC default factors or data from the Emission Factor Database (EFDB)[17], or other standard values from international bodies that reflect national circumstances.[18]

17. The EFDB is a continuously revised web-based information exchange forum for EFs and other parameters relevant for the estimation of emissions or removals of GHGs at national level. The database can be queried over the internet at www.ipcc-nggip.iges.or.jp/EFDB/main.php.

18. Volume 1, Chapter 2: "Approaches to Data Collection", Section 2.2.4, Table 2.2 of the *2006 IPCC Guidelines* provides a comprehensive guide to identifying potential sources of emission factors.

5.5 Conversion of data to standard units and CO_2 equivalent

The International System of Units (SI units) should be used for measurement and reporting of activity data, and all GHG emissions data shall be reported as metric tonnes of each GHG as indicated in Table 4.3, as well as CO_2 equivalents (CO_2e). Where only the latter is available, this shall be clearly identified and justified in order to be in conformance with the GPC. The same applies where emission factors or emissions data are unavailable for specific gases. CO_2e is a universal unit of measurement that accounts for the global warming potential (GWP) when measuring and comparing GHG emissions from different gases. Individual GHGs should be converted into CO_2e by multiplying by the 100-year GWP coefficients in the latest version of the *IPCC Guidelines* or the version used by the country's national inventory body (see Table 5.2). Where this is not possible (e.g., when the best available emission factors are expressed only in CO_2e and not listed separately by gas), an accompanying explanation should be provided.

Any changes in GWP values used should be reflected in the city's historical emissions profile (see Section 11.3).

Table 5.2 GWP of major GHG gases

Name	Formula	GWP values in IPCC Second Assessment Report[19] (CO_2e)	GWP values in IPCC Third Assessment Report[20] (CO_2e)	GWP values in IPCC Fourth Assessment Report[21] (CO_2e)	GWP values in IPCC Fifth Assessment Report[22] (CO_2e)
Carbon dioxide	CO_2	1	1	1	1
Methane	CH_4	21	23	25	28
Nitrous oxide	N_2O	310	296	298	265
Sulfur hexafluoride	SF_6	23,900	22,200	22,800	23,500
Carbon tetrafluoride	CF_4	6,500	5,700	7,390	6,630
Hexafluoroethane	C_2F_6	9,200	11,900	12,200	11,100
HFC-23	CHF_3	11,700	12,000	14,800	12,400
HFC-32	CH_2F_2	650	550	675	677
HFC-41	CH_3F	150	97	92	116
HFC-125	C_2HF_5	2,800	3,400	3,500	3,170
HFC-134	$C_2H_2F_4$	1,000	1,100	1,100	1,120
HFC-134a	CH_2FCF_3	1,300	1,300	14,300	1,300
HFC-143	$C_2H_3F_3$	300	330	353	328
HFC-143a	$C_2H_3F_3$	3,800	4,300	4,470	4,800
HFC-152a	$C_2H_4F_2$	140	120	124	138
HFC-227ea	C_3HF_7	2,900	3,500	3,220	3,350
HFC-236fa	$C_3H_2F_6$	6,300	9,400	9,810	8,060
HFC-245ca	$C_3H_3F_5$	560	950	1,030	716
Nitrogen trifluoride	NF_3	-	-	17,200	16,100

19. IPCC. 1995, IPCC Second Assessment Report: Climate Change 1995
20. IPCC. 2001, IPCC Third Assessment Report: Climate Change 2001
21. IPCC. 2007, IPCC Fourth Assessment Report: Climate Change 2007
22. IPCC. 2013, IPCC Fifth Assessment Report: Climate Change 2013

5.6 Managing data quality and uncertainty

All data sources used and assumptions made when estimating GHG emissions, whether through scaling, extrapolation, or models, will need to be referenced to ensure full transparency. The IPCC uses "tiers" to rank methodology, and increasing accuracy in methodology often requires more detailed or higher quality data. In the GPC, where relevant, references are provided within each emission source category chapter (Chapters 6–10) to the corresponding IPCC methodology tiers and methods.

In addition to identifying the method used to calculate emissions, cities shall also evaluate the quality of both the activity data and the emission factors used. Each of these shall be assessed as high, medium or low, based on the degree to which data reflect the geographical location of the activity, the time or age of the activity and any technologies used, the assessment boundary and emission source, and whether data have been obtained from reliable and verifiable sources. See Table 5.3 for an overview of these overall quality indicators.

Table 5.3 Data quality assessment

Data quality	Activity data	Emission factor
High (H)	Detailed activity data	Specific emission factors
Medium (M)	Modeled activity data using robust assumptions	More general emission factors
Low (L)	Highly-modeled or uncertain activity data	Default emission factors

5.7 Verification

Verification involves an assessment of the completeness and accuracy of reported data. Cities may choose to verify their data to demonstrate that their calculations are in accordance with the requirements of the GPC and provide confidence to users that the reported GHG emissions are a fair reflection of a city's activities. Verification can be performed by the same organization that conducted the GPC assessment (self-verification), or by an independent organization (third-party verification). Guidance on verification is provided in Chapter 12.

6 Stationary Energy

Stationary energy sources are one of the largest contributors to a city's GHG emissions. These emissions come from fuel combustion, as well as fugitive emissions released in the process of generating, delivering, and consuming useful forms of energy (such as electricity or heat).

Requirements in this chapter

For BASIC:

Cities shall report all GHG emissions from **Stationary Energy** ***sources and fugitive emissions in scope 1, and those from use of grid-supplied electricity, steam, heating, and cooling in scope 2.***

For BASIC+:

Cities shall report all BASIC sources and scope 3 GHG emissions associated with transmission and distribution (T&D) losses from grid-supplied electricity, steam, heating, and cooling.

Emissions from energy generation supplied to the grid shall be reported as part of total scope 1 emissions, but not included in BASIC/BASIC+ totals.

Attachment Item 14B

6.1 Categorizing stationary energy sector emissions by scope

Scope 1: Emissions from fuel combustion and fugitive emissions in the city

Scope 1 includes emissions from the combustion of fuels[23] in buildings, industries, and from the conversion of primary energy sources in refineries and power plants located within the city boundary. Fossil resource exploration and refinement, including any offshore exploration that occurs within the city boundary, is also included in scope 1.

The inventory boundary of certain cities may contain non-urban areas that include agricultural, forestry, and fishing activities. Emissions from stationary fuel combustion from these activities, such as portable generators, shall be reported as scope 1 emissions.

Scope 2: Emissions from the consumption of grid-supplied electricity, steam, heating and cooling in the city

Electricity consumption is typically the largest source of scope 2 emissions. It occurs when buildings and facilities in the city consume electricity from local, regional or national electric grids. Grid-distributed steam, heat and cooling rely on smaller-scale distribution infrastructure, but may still cross city boundaries.

For scope 2 reporting, cities shall report emissions from *all* grid-supplied energy consumption within the boundary, regardless of where the energy is produced. Cities that set GHG targets related to energy consumption "net" of energy produced within the city should report these emissions separately as an information item.

Scope 3: Distribution losses from grid-supplied electricity, steam, heating and cooling in the city

Scope 3 emissions include transmission and distribution losses from the use of grid-supplied electricity, steam, heating and cooling in a city. Other upstream emissions from electricity supply may be reported in *Other Scope 3*.

There may also be out-of-boundary energy use associated with activities occurring in the city (e.g., electricity used by a neighboring city to treat wastewater produced by the reporting city), but these are not required for reporting under BASIC or BASIC+, but may be reported in *Other Scope 3.*

These emission sources and their scope categorization are summarized in Table 6.1.

6.2 Defining energy source sub-sectors

The *Stationary Energy* sector can be divided into nine sub-sectors. Seven of these nine produce emissions from both energy production and consumption, while the remaining two relate to fugitive emissions from fuel-related activities. Table 6.2 below provides detailed descriptions of *Stationary Energy* source sub-sectors. Cities may adopt additional city- or country-specific categories where data allows, but should clearly describe the differences and assumptions in inventories. Cities may further subdivide these sub-sectors into sub-categories that are more useful for mitigation action planning.

23. Non-energy uses of fossil fuel are reported under the *IPPU* sector. To differentiate energy and non-energy use of fossil fuel, please see Chapter 9.

Table 6.1 Stationary Energy Overview

GHG Emission Source	Scope 1	Scope 2	Scope 3
STATIONARY ENERGY	Emissions from fuel combustion and fugitive emissions within the city boundary	Emissions from consumption of grid-supplied energy consumed within the city boundary	Transmission and distribution losses from the use of grid-supplied energy
Residential buildings	I.1.1	I.1.2	I.1.3
Commercial and institutional buildings and facilities	I.2.1	I.2.2	I.2.3
Manufacturing industries and construction	I.3.1	I.3.2	I.3.3
Energy industries	I.4.1	I.4.2	I.4.3
Energy generation supplied to the grid	I.4.4		
Agriculture, forestry and fishing activities	I.5.1	I.5.2	I.5.3
Non-specified sources	I.6.1	I.6.2	I.6.3
Fugitive emissions from mining, processing, storage and transportation of coal	I.7.1		
Fugitive emissions from oil and natural gas systems	I.8.1		

Sources required for BASIC reporting

\+ Sources required for BASIC+ reporting

Sources included in Other Scope 3

Sources required for territorial total but not for BASIC/BASIC+ reporting (*italics*)

Non-applicable emissions

6.3 Calculating stationary fuel combustion emissions

Emissions from *Stationary Energy* sources are calculated by multiplying fuel consumption (activity data) by the corresponding emission factors for each fuel, by gas. For activity data, cities should aim to obtain:

- **Real consumption data for each fuel type, disaggregated by sub-sector.** This information is typically monitored at the point of fuel use or fuel sale, and should ideally be obtained from utility or fuel providers. Depending on the type of fuel dispensary, fuel sales may be for *Stationary Energy* sources *or* for mobile *Transportation* sources. Cities should ensure sales information is disaggregated between these two sectors.
- **A representative sample set of real consumption data from surveys.** While surveying for fuel consumption for each sub-sector, determine the built space (i.e., square meters of office space and other building characteristics) of the surveyed buildings for scaling factor.
- **Modeled energy consumption data.** Determine energy intensity, by building and/or facility type, expressed as energy used per square meter (e.g., GJ/m^2/year) or per unit of output.
- **Incomplete or aggregate real consumption data:**
  - Where fuel consumption data by sub-sector are unavailable, but data are available for total emissions from stationary sources within the city, apportion by total built space for each sub-sector or building type.
  - Where data are only available for a few of the total number of fuel suppliers, determine the population (or other indicators such as industrial output, floor space, etc.) served by real data to scale-up the partial data for total city-wide energy consumption.

- Where data are only available for one building type, determine a stationary combustion energy intensity figure by using built space of that building type, and use as a scaling factor with built space for the other building types.
- **Regional or national fuel consumption data scaled down using population or other indicators.**

The rest of Section 6.3 applies this emissions calculation method to each energy sub-sector, identifying further sub-categories and clarifying where emissions from multi-functional buildings or related sectoral operations should be reported.

Table 6.2 Definitions of stationary energy source sub-sectors

Sub-sectors	Definition
Emissions from stationary energy production and use	Emissions from the intentional oxidation of materials within a stationary apparatus that is designed to raise heat and provide it either as heat or as mechanical work to a process, or for use away from the apparatus
I.1 Residential buildings	All emissions from energy use in households
I.2 Commercial buildings and facilities	All emissions from energy use in commercial buildings and facilities
I.2 Institutional buildings and facilities	All emissions from energy use in public buildings such as schools, hospitals, government offices, highway street lighting, and other public facilities
I.3 Manufacturing industries and construction	All emissions from energy use in industrial facilities and construction activities, except those included in energy industries sub-sector. This also includes combustion for the generation of electricity and heat for own use in these industries.
I.4 Energy industries	All emissions from energy production and energy use in energy industries
1.4.4 Energy generation supplied to the grid	All emissions from the generation of energy for grid-distributed electricity, steam, heat and cooling
I.5 Agriculture, forestry, and fishing activities	All emissions from energy use in agriculture, forestry, and fishing activities
I.6 Non-specified sources	All remaining emissions from facilities producing or consuming energy not specified elsewhere
Fugitive emissions from fuel	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of fuel to the point of final use *Note:* Some product uses may also give rise to emissions termed as "fugitive," such as the release of refrigerants and fire suppressants. These shall be reported in IPPU.
I.7 Mining, processing, storage, and transportation of coal	Includes all intentional and unintentional emissions from the extraction, processing, storage and transport of fuel in the city
I.8 Oil and natural gas systems	Fugitive emissions from all oil and natural gas activities occurring in the city. The primary sources of these emissions may include fugitive equipment leaks, evaporation losses, venting, flaring and accidental releases

6.3.1 Residential, commercial, and institutional buildings and facilities

Commercial and institutional buildings and facilities (e.g. public or government-owned facilities) provide public services for community needs, including safety, security, communications, recreation, sport, education, health, public administration, religious, cultural and social.[24] This includes commercial buildings and establishments, such as retail outlets, shopping complexes, office buildings; institutional buildings, such as schools, hospitals, police stations, government offices; and facilities, such as street lighting on highways, secondary roads and pedestrian areas, parking, mass transit, docks, navigation aids, fire and police protection, water supply, waste collection and treatment (including drainage), and public recreation areas.

While the GPC recommends that cities report building emissions in relevant sub-sectors, cities may further subdivide these into more detailed sub-categories. For example, residential buildings can be divided into high-rise buildings and landed buildings; commercial buildings may be divided into different sizes and/or types of activities such as retail, office, etc.; and institutional buildings may be divided into different uses, including schools, hospitals, and government offices. Cities may also further divide the emissions into different energy usages such as cooking, heating, and hot water in residential buildings. Detailed, disaggregated data helps cities identify emissions hotspots more precisely and design more specific mitigation actions.

Emissions from energy used in informal settlements or social housing shall be reported in the residential sub-sector, even if the settlements' local government pays for that energy use.

Multi-function uses for buildings and facilities

A city may identify multiple functional uses for buildings, which complicates sub-sector classification. In these cases, cities can either subdivide mixed use buildings based on square meters of a building (and "subdivide" the activity data and resulting emissions), categorize buildings according to their designated usages, or categorize the entire building under one of the sub-categories and provide justification. Possible scenarios include:

- **Mixed use buildings**
  Some buildings may include residential units, ground floor commercial space, and offices. In the absence of floor-by-floor information and activity data, a GHG inventory team may conduct a specific survey to identify such information. In some countries, energy tariffs and billing are different for residential and commercial purposes, so the energy use activity data may be more easily identified.
- **Office buildings in industrial establishments**
  Cities may have one or more office buildings attached to an industrial complex. When industry is the main activity at the site and the property is designated for industrial use, the attached office building should be categorized as part of the industrial complex and emissions reported under the *manufacturing industries and construction* sub-sector or *energy industries* sub-sector, as appropriate. Where countries or regions have specific regulations defining these office buildings as commercial buildings, cities should apply the *relevance* principle outlined in Section 2.1 and allocate emissions to the locally appropriate sub-sector.
- **Workers' quarters in industrial establishments**
  In instances where there are permanent workers quarters within the compounds of an industrial site, cities should categorize emissions from buildings based on their designated usages. Whenever possible, cities should report the GHG emissions from these workers quarters in the *residential buildings* sub-sector when their main purpose is to provide residence. Cities should conduct a survey to identify these workers quarters and count their associated GHG emissions in the *residential buildings* sub-sector. In the absence of such data, cities may report these emissions as part of the emissions from the industrial site.

  In the case of temporary workers quarters, such as those at construction sites, if cities find it difficult to obtain specific energy consumption information, cities may continue to report them with the associated industrial or construction activities.

24. The Council for Scientific and Industrial Research. "Guidelines for Human Settlement Planning and Design." 2000: Chapter 5.5. Online at www.csir.co.za/Built_environment/RedBook.

The GPC does not provide specific definitions for *permanent* and *temporary* workers quarters. Cities should adopt the definitions used in their local regulations. In the absence of local definitions, workers quarters for construction activities should be considered as *temporary,* considering that the nature of construction activity itself is temporary. If workers quarters in an industrial site are built and demolished within a period shorter than a GHG inventory cycle, it should be considered *temporary* (see Table 6.3 for suggested definitions).

- **Residential units in agricultural farms**
  When the jurisdictions of cities cover rural areas, there may be individual residential units in agricultural farms. GHG emissions from household activities such as heating and cooking in these individual units should be included in *residential buildings*. However, emissions from activities related to agricultural activities, such as portable generators for lighting of livestock farms and water pumps in aquaculture farms, should be categorized as *agriculture, forestry, and fishing activities*. If only total consumption for the farm area is available, cities can subdivide this based on average household energy use or average farm equipment usage.

6.3.2 Manufacturing industries and construction

This sub-sector includes energy use in manufacturing industries and construction activities. Fuel combustion occurs in stationary equipment, including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc. Where data are available, GHG emissions from relevant sub-categories should be reported using the 13 sub-categories identified in the *IPCC Guidelines* under the *manufacturing industries and construction* sub-sectors (see Table 6.4).

Cities should apply these sub-categories to ensure consistency with national GHG inventories, as appropriate.

Industrial facilities may incur emissions that are included in other sectors of the GPC. Cities should distinguish between the following when classifying emissions:

- **Relationship between manufacture of transport equipment and Transportation sector**
  Cities should not double count emissions from transport equipment manufacturing and the *Transportation* sector (Chapter 7). Transport equipment manufacturing refers to GHG emissions from the manufacture of motor vehicles, ships, boats, railway and tramway locomotives, and aircraft and spacecraft, while the *Transportation* sector refers to the GHG emissions from the use of these vehicles.

- **Relationship between on-road and off-road transportation**
  GHG emissions from all on-road transportation activities by industries that occur outside the industrial site—e.g., delivery of raw materials, products, and services and employee travels—shall be reported under the *Transportation* sector (Chapter 7).

  Off-road transportation activities should be categorized according to the area where they occur. For instance, GHG emissions of off-road transportation activities (vehicle and mobile machinery) occurring within industrial premises should be reported under either the *manufacturing industries and construction* sub-sector, or *energy industries* sub-sector. Table 6.5 provides an overview of reporting guidance for off-road transportation related to the *manufacturing industries and construction* sub-sector, *energy industries* sub-

Table 6.3 Definitions of temporary and permanent workers quarters

Type of premises	Temporary	Permanent
Industries	Quarters built and demolished within a period shorter than 12 months (an inventory cycle)	Quarters that exist for more than 12 months
Construction	All workers quarters for construction activities should be considered temporary	Not applicable unless otherwise specified in local regulations

Table 6.4 Detailed sub-categories of manufacturing industries and construction sub-sector, from the International Standard Industrial Classification (ISIC)[25]

Sub-categories[26]	ISIC Classification	Description
Iron and steel	ISIC Group 271 and Class 2731	Manufacture of primary iron and steel products, including the operation of blast furnaces, steel converters, rolling and finishing mills, and casting
Non-ferrous metals	ISIC Group 272 and Class 2732	Production, smelting, and refinement of precious metals and other non-ferrous metals from ore or scrap
Chemicals	ISIC Division 24	The manufacture of basic chemicals, fertilizer and nitrogen compounds, plastics, synthetic rubber, agro-chemical products, paints and coatings, pharmaceuticals, cleaning agents, synthetic fibers, and other chemical products
Pulp, paper and print	ISIC Divisions 21 and 22	Pulp, paper, paperboard, paper products; publishing and reproduction of recorded media
Food processing, beverages, and tobacco	ISIC Divisions 15 and 16	Production, processing, and preservation of food and food products, beverages, and tobacco products
Non-metallic minerals	ISIC Division 26	Manufacture and production of glass and glass products, ceramics, cements, plasters, and stone
Transport equipment	ISIC Divisions 34 and 35	Motor vehicles, trailers, accessories and components, sea vessels, railway vehicles, aircraft and spacecraft, and cycles
Machinery	ISIC Divisions 28, 29, 30, 31, 32	Fabricated metal products, machinery and equipment, electrical machinery and apparatuses, communications equipment, and associated goods
Mining (excluding fuels) and quarrying	ISIC Divisions 13 and 14	Mining of iron, non-ferrous ores, salt, and other minerals; quarrying of stone, sand, and clay
Wood and wood products	ISIC Division 20	Sawmilling and planning of wood; the production of wood products and cork, straw, and other wood-based materials
Construction	ISIC Division 45	Site preparation, construction installation, building completion, and construction equipment
Textile and leather	ISIC Division 17, 18, 19	Spinning, weaving, dyeing, of textiles and manufacture of apparel, tanning and manufacture of leather and footwear
Non-specific industries	Activities not included above	Any manufacturing industry/construction not included above, including water collection, treatment, supply; wastewater treatment and disposal; and waste collection, treatment, and disposal

sector, *agriculture, forestry, and fishing activities* sub-sector, *non-specified* sub-sector, and *off-road transportation* sub-sector (under *Transportation* sector).

25. Further descriptions of each subcategory can be found in the *International Standard Industrial Classification (ISIC) of All Economic Activities*, Revision 3.

26. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*

Table 6.5 Overview of reporting guidance for off-road transportation activities

Type of off-road activities	Reporting guidance
Off-road vehicle and mobile machinery within industrial premises and construction sites	Report as a Stationary Energy source under manufacturing industries and construction sub-sector or energy industries sub-sector as appropriate
Off-road vehicle and mobile machinery within agriculture farms, forests, and aquaculture farms	Report as a Stationary Energy source under agriculture, forestry, and fishing activities sub-sector
Off-road vehicle and mobile machinery within the transportation facility premises such as airports, harbors, bus terminals, and train stations	Report as a Transportation source under off-road transportation sub-sector
Off-road vehicle and mobile machinery within military premises	Report as a Stationary Energy source under unidentified activities sub-sector

- **Relationship between water supply system, solid waste, and wastewater treatment and disposal facilities**
  Most cities operate solid waste and wastewater treatment and disposal facilities. These facilities produce methane (CH_4) from decay of solid wastes and anaerobic degradation of wastewater, which shall be reported under *Waste* sector. Wastewater collection, treatment, and supply systems consume energy to power water pumps, boilers, mechanical separation equipment at material recovery facilities, water treatment facilities, and other equipment. GHG emissions from energy use for these operations should be reported under *institutional* (public facility) or *industrial* (private industrial facility) sub-sectors. If the energy use is from on-site fuel combustion, these emissions are reported as scope 1. Electricity use in these facilities is reported as scope 2 emissions.

  This also applies to direct fuel combustion for operating off-road vehicles, machinery, and buildings within the waste facility (which should be reported as scope 1 emissions). Typical off-road machinery includes compactors and bulldozers, which spread and compact solid waste on the working surface of landfills. However, off-road vehicles and machinery do not include on-road transportation of wastes, which shall be reported under *Transportation* sector (Chapter 7).

6.3.3 Energy industries

Energy industries include three basic types of activities[27]:

- Primary fuel production (e.g., coal mining, and oil and gas extraction)
- Fuel processing and conversion (e.g., crude oil to petroleum products in refineries, coal to coke and coke oven gas in coke ovens)
- Energy production supplied to a grid (e.g., electricity generation and district heating) or used on-site for auxiliary energy use

Where applicable and possible, cities should follow *IPCC Guidelines* and disaggregate accounting and reporting of *energy industries* sub-sector into different sub-categories as detailed in Table 6.6.

Emissions from the following energy generation types may be classified and reported as follows:

- **Cogeneration and tri-generation**
  Cogeneration, or combined heat and power (CHP), is the use of power plant or heat engine systems to simultaneously generate electricity and useful heat. Tri-generation, or combined cooling, heat and power (CCHP), refers to the simultaneous generation of electricity, heat, and cooling. GHG emissions from these facilities should be calculated based on the quantity of fuel combusted. Emissions from this combustion shall

27. 2006 IPCC Guidelines for National Greenhouse Gas Inventories

Table 6.6 Detailed sub-categories of energy industries sub-sector[28]

Sub-categories	Descriptions	Detailed breakdown
Energy, including electricity, steam, heat/ cooling	Emissions from main activity producers of electricity generation, combined heat and power generation, and heat plants. Main activity producers (often termed public utilities) are defined as those whose primary activity is to supply energy to the public, but the organization may be under public or private ownership. Emissions from on-site use of fuel should be included. However, emissions from auto-producers (which generate electricity/heat wholly or partly for their own use, as an activity that supports their primary activity) should be assigned to the sector where they were generated (such as industrial, or institutional). Auto-producers may be under public or private ownership.	**Energy generation sold and distributed** comprises emissions from all fuel use for electricity generation from main activity producers (reported under I.4.4) except those from combined heat and power plants (see CHP below). This includes emissions from the incineration of waste or waste byproducts for the purpose of generating electricity. This subcategory is required for scope 1 (territorial) reporting, but not BASIC/BASIC+. **Auxiliary energy use** on the site of energy production facilities (e.g., a small administrative office adjacent to a power plant). Energy produced at power plants is used "on-site" for auxiliary operations before being sold and distributed to a grid (reported under I.4.1). It is therefore not grid-distributed energy consumption. Auxiliary energy use and sold/distributed energy should together add up to total emissions from fuel combusted for energy generation. **Combined heat and power generation (CHP)** Emissions from production of both heat and electrical power from main activity producers for sale to the public, at a single CHP facility. **Heat plants** Production of heat for city-wide district heating or industrial usage. Distributed by pipe network.
Petroleum refining	All combustion activities supporting the refining of petroleum products including on-site combustion for the generation of electricity and heat for own use.	N/A
Manufacture of solid fuels and other energy industries	This includes combustion emissions from fuel use during the manufacture of secondary and tertiary products from solid fuels including production of charcoal. Emissions from own on-site fuel use should be included. Also includes combustion for the generation of electricity and heat for own use in these industries.	**Manufacture of solid fuels** Emissions arising from fuel combustion for the production of coke, brown coal briquettes and patent fuel. **Other energy industries** Combustion emissions arising from the energy-producing industries own (on-site) energy use not mentioned above or for which separate data are not available. This includes emissions from on-site energy use for the production of charcoal, bagasse, saw dust, cotton stalks and carbonizing of biofuels as well as fuel used for coal mining, oil and gas extraction and the processing and upgrading of natural gas. This category also includes emissions from pre-combustion processing for CO_2 capture and storage.

28.2006 IPCC Guidelines for National Greenhouse Gas Inventories be reported in scope 1 for grid-supplied energy production (1.4.4), and for added transparency, cities can identify the portion of those scope 1 emissions attributable to heat/steam vs. electricity production.[29] This allocation can be performed using the percentage of each energy output (% of total MMBUT or GJ from electricity and from heat).

- **Waste-to-energy and bioenergy**
  Where waste is used to generate energy, emissions are counted as *Stationary Energy* sources. This includes energy recovered from landfill gas or waste combustion. When a power plant is generating electricity from biomass fuels, the resulting CH_4 and N_2O emissions shall be reported under scope 1 in *energy industries* sub-sector while biogenic CO_2 shall be reported separately from the scopes (CO_2 emissions are effectively "reported" in *AFOLU*, as the biofuel usage is linked to corresponding land use change or carbon stock change). If waste decomposition or treatment is not used for energy generation, emissions are reported in scope 1 in the *Waste* sector (see Chapter 8).

  Table 6.7 provides an overview of principles to help avoid double counting between *Waste*, *Stationary Energy*, and *AFOLU* sectors.

29. Different methods may be used to perform this allocation, see *GHG Protocol* methodology www.ghgprotocol.org/files/ghgp/tools/CHP_guidance_v1.0.pdf

6.3.4 Agriculture, forestry, and fishing activities

This sub-sector covers GHG emissions from direct fuel combustion in agricultural activities, including plant and animal cultivation, afforestation and reforestation activities, and fishery activities (e.g., fishing and aquaculture). These emissions are typically from the operation of farm vehicles and machinery, generators to power lights, pumps, heaters, coolers, and others. In order to avoid double counting with other sectors and sub-sectors, Table 6.8 provides reporting guidance for typical emissions sources in agriculture, forestry, and fishing activities.

Table 6.7 An overview of reporting categorization for waste-to-energy and bioenergy emissions

Activity	Purpose	CO_2	CH_4 and N_2O
Landfill gas combustion	As part of waste disposal process	Report biogenic CO_2 emissions under Waste sector (separately from any fossil CO_2 emissions)	Report emissions under Waste sector
	Energy generation	Report biogenic CO_2 under Stationary Energy sector (separately from any fossil CO_2 emissions)	Report emissions under Stationary Energy sector
Waste incineration	Waste disposal (no energy recovery)	Report CO_2 emissions under Waste sector (with biogenic CO_2 reported separately from any fossil CO_2 emissions)	Report emissions as Waste sector
	Energy generation	Report CO_2 emissions under Stationary Energy sector (with biogenic CO_2 reported separately from any fossil CO_2 emissions)	Report emissions under Stationary Energy sector
Biomass incineration	Waste disposal	Report biogenic CO_2 emissions under Waste sector (separately from any fossil CO_2 emissions)	Report emissions under Waste sector
	Energy generation	Report biogenic CO_2 emissions under Stationary Energy sector (separately from any fossil CO_2 emissions)	Report emissions under Stationary Energy sector

Table 6.8 Reporting guidance for energy sources in agriculture, forestry, and fishing activities

Sources of emission	Reporting guidance
Off-road vehicles and machinery (stationary and mobile) used for agriculture, forestry, and fishing activities	Report as a Stationary Energy source under agriculture, forestry, and fishing activities sub-sector
On-road transportation to and from the locations of agriculture, forestry, and fishing activities	Report under Transportation sector
Burning of agricultural residues	Report under AFOLU sector
Enteric fermentation and manure management	Report under AFOLU sector

6.3.5 Non-specified sources

This subcategory includes all remaining emissions from *Stationary Energy* sources that are not specified elsewhere, including emissions from direct fuel combustion for stationary units in military establishments.

6.4 Calculating fugitive emissions from fuels

A small portion of emissions from the energy sector frequently arises as fugitive emissions, which typically occur during extraction, transformation, and transportation of primary fossil fuels. Where applicable, cities should account for fugitive emissions from the following sub-sectors: 1) *mining, processing, storage, and transportation of coal*; and 2) *oil and natural gas systems*. When calculating fugitive emissions, cities should take into account any fugitive emission removals or sequestration that may be required by law.

6.4.1 Mining, processing, storage, and transportation of coal

The geological processes of coal formation produce CH_4 and CO_4, collectively known as seam gas. It is trapped in the coal seam until the coal is exposed and broken during mining or post-mining operations, which can include handling, processing, and transportation of coal, low temperature oxidation of coal, and uncontrolled combustion of coal. At these points, the emitted gases are termed fugitive emissions. When accounting for and reporting fugitive emissions from coal mines, cities should categorize the emissions as mining and post-mining (handling) for both underground mines and surface mines.

- **Methane recovery and utilization**
  Fugitive methane emissions may be recovered for direct utilization as a natural gas resource or by flaring to produce CO_2 that has a lower global warming potential.
  - When recovered methane is utilized as an energy source, the associated emissions should be accounted for under *Stationary Energy.*
  - When recovered methane is fed into a gas distribution system and used as a natural gas, the associated fugitive emissions should be reported under *oil and natural gas systems* sub-sector.
  - When it is flared, the associated emissions should be reported under *mining, processing, storage, and transportation of coal* sub-sector.

- **Time period of inventory**
  All fugitive emissions should be accounted for based on the emissions and recovery operations that occur during the assessment period of the inventory, regardless of when the coal seam is mined through.

Cities can determine coal production at surface and underground mines within the city boundary by inquiring with mining companies, mine owners, or coal mining regulators. Cities should separate data by average overburden depth for surface mines and average mining depth for underground mines, and then apply emission

factors per unit of production for mining and post-mining fugitive emissions.[30]

6.4.2 Oil and natural gas systems

Fugitive emissions from oil and natural gas systems include GHG emissions from all operations to produce, collect, process or refine, and deliver natural gas and petroleum products to market. Specific sources include, but are not limited to, equipment leaks, evaporation and flashing losses, venting, flaring, incineration, and accidental releases. Cities should also include emissions from all offshore operations that fall within the inventory boundary.

The following emissions are *not* included in this category:

- Fugitive emissions from carbon capture and storage projects
- Fugitive emissions that occur at industrial facilities other than oil and gas facilities, or those associated with the end use of oil and gas products at anything other than oil and gas facilities, which are reported under *IPPU* sector
- Fugitive emissions from waste disposal activities that occur outside of the oil and gas industry, which are reported under *Waste sector.*

30. IPCC default values can be found in the *2006 IPCC Guidelines*, Volume 2, Chapter 4, Fugitive Emissions. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol2

6.5 Calculating emissions from grid-supplied energy consumption

Scope 2 represents all grid-supplied electricity, steam, heating and cooling consumed within the city boundary. Electricity is the most common form of grid-supplied energy, used in almost all homes, offices, other buildings, and outdoor lighting. Grid-supplied energy in the form of direct steam (heating) and/or chilled water (cooling) is typically provided by district energy systems, which may cover a smaller geographic area than electricity grids, which are typically regional. In all cases, using grid-supplied energy entails emissions produced at generation facilities *off-site* from the consumption facilities. Depending on the city and the structure of the grid, these energy generators can be located outside the geographic boundary at various locations tied to or exporting to the regional grid, or from generators located *within* the city boundary.

6.5.1 Location-based and market-based calculation methods

With regional grid networks, energy consumers can assess emissions from their consumption based on two methods: a location-based method or a market-based method. Both methods serve to allocate emissions from the point of generation to their final point of use. A location-based method is based on average energy generation emission factors for defined locations, including local, sub-national or national boundaries. It yields a grid average emission factor representing the energy produced in a region, and allocates that to energy consumers in that region.

Cities shall use the location-based method for scope 2 calculations in the GPC, and may separately document emissions from the market-based method (see Box 6.1). The supplemental market-based figure can help cities understand the choices of individual consumers, businesses and institutions, growing the market demand for low-carbon energy.

6.5.2 Relationship between energy generation (scope 1) and energy consumption (scope 2)

Cities may have energy generation facilities located inside the geographic boundary for the inventory, but in most instances a city cannot prove that its energy consumption is supplied by the resources located within the boundary. While it is generally the case that a city's aggregate energy demand will be met with a set of relatively local generation resources, cities cannot assume that their aggregate electricity consumption from regional electricity grids is met in full or in part by energy produced within the city boundary. This is not possible to guarantee due to fluctuating regional demand at any given moment, grid constraints, exports and other contractual arrangements.[31]

Therefore, cities shall report scope 2 emissions from *all* grid-supplied energy consumed in the city. Cities may also separately report this total energy consumption in MWh/kWh/BTU, etc. for added transparency.

Box 6.1 The market-based method for scope 2 accounting

As described in the GHG Protocol *Scope 2 Guidance*, the market-based method for scope 2 based on allocating emissions from energy generators to consumers based on "contractual instruments" such as utility-specific emission factors, energy attribute certificates, or other contracts. In many countries, energy suppliers or utilities can provide consumers with emissions factors for either their standard portfolio or for any low-carbon or renewable energy consumer labels, tariffs, or other programs. The method reflects contractual relationships between energy suppliers and customers, so a city-wide market-based scope 2 total would reflect emissions from only those resources that individual consumers have matched with contractual instruments.

If these instruments follow the GHG Protocol *Scope 2 Guidance* requirements on Quality Criteria, market-based scope 2 accounting can provide an indication of the emissions from energy choices that businesses, institutions, or residential consumers have made, and provide an incentive for the market to create more low-carbon energy.

BASIC/BASIC+ reporting avoids double counting by excluding scope 1 emissions from energy generation supplied to the grid. Cities shall report scope 1 and scope 2 separately and not sum them together (see Section 3.5).

6.5.3 Calculating grid-supplied electricity emissions

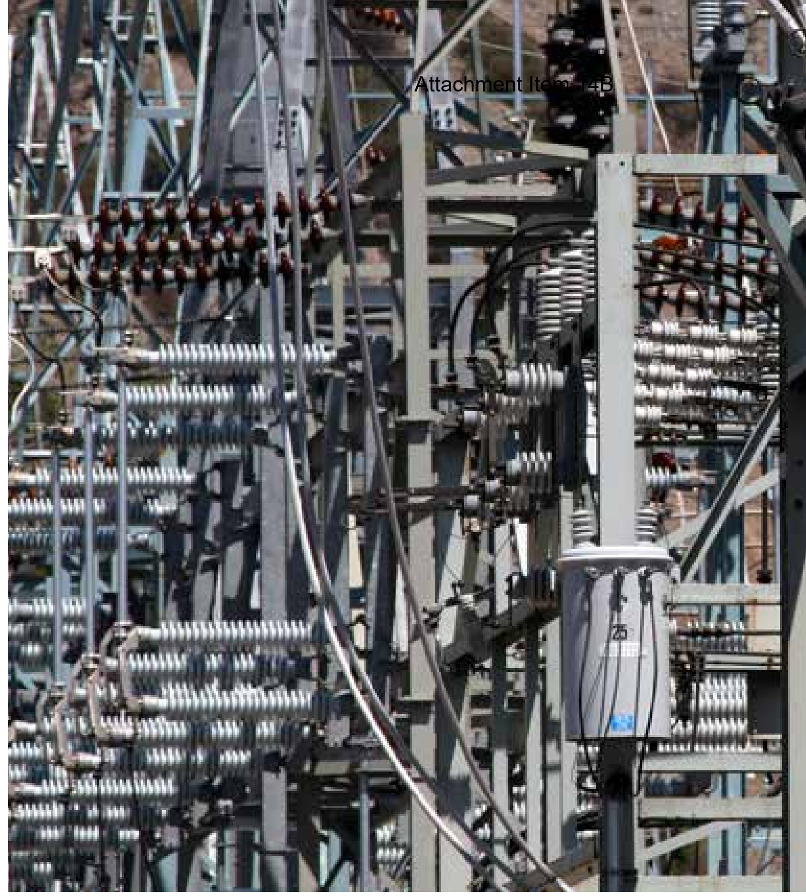
Electricity is the most common form of grid-supplied energy, used in almost all homes, offices, other buildings, and outdoor lighting. This section provides guidance on calculating scope 2 emissions from each sector and sub-sector, which are mainly based on bottom-up methods using activity data of each source. To calculate scope 2 emissions, cities should obtain activity data following the list of preferred data here:

31. See NERC website, "Understanding the Grid": http://www.nerc.com/page.php?cid=1|15

- **Real consumption data from utility providers, disaggregated by building type or non-building facility for Stationary Energy:**
    - Where consumption data by building type is unavailable, but total community energy consumption data for buildings are available by energy type, apportion by total built space for each building type.
    - Where data are only available for a few of the total number of energy utilities, determine the population served by real data to scale-up for total city-wide energy consumption. Alternately use built space as the scaling factor.
    - Where data are only available for one building type, determine an energy end-use intensity figure by using built space of that building type, and use as a scaling factor with total built space for the other building types. However, it should be noted that different building uses have very different energy intensity values, particularly when comparing commercial and institutional buildings with residential uses.
- **Representative sample sets of real consumption data from surveys** scaled up for total city-wide fuel consumption and based on the total built space for each building type.
- **Modeled energy consumption data** by building and/or facility type, adjusted for inventory-year consumption data by weather.
- **Regional or national consumption data** scaled down using population, adjusted for inventory-year consumption data by weather.

For an example of identifying electricity consumption data from tariff codes, see Box 6.2.

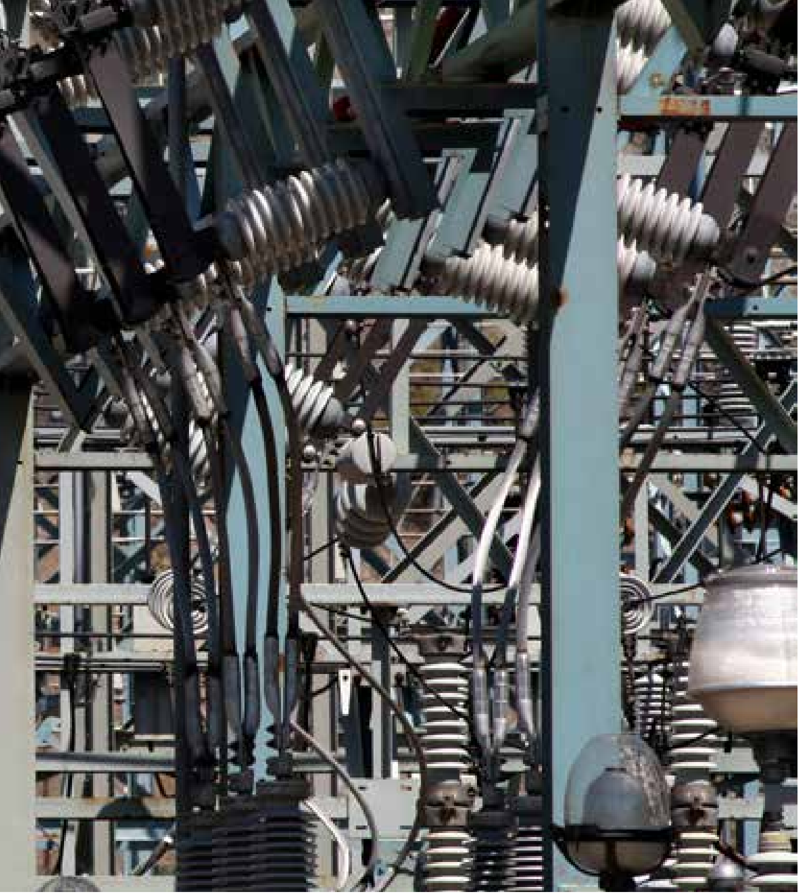
Cities should use regional or sub-national grid average emissions factors. If these are not available, national electricity production emission factors may be used.



Box 6.2 Identifying electricity consumption data—Ekurhuleni Metropolitan Municipality

Ekurhuleni Metropolitan Municipality in South Africa used tariff codes associated with end users to disaggregate 2011 electricity use by sector.[32] Electricity in Ekurhuleni is delivered by Eskom, a public utility and electricity producer, and then redistributed by the municipality to the relevant end users. Some of the tariff descriptions enabled Ekurhuleni to categorize electricity consumption into residential, commercial, or industrial sub-sectors. However, some of the tariff descriptions did not provide adequate information for categorization. To allocate emissions to some of the end users lacking tariff code data, Ekurhuleni classified high voltage, large energy consumers as industrial users, and classified low-voltage, small energy consumers as residential.

32. ICLEI—Africa. "Local Renewables: South-south cooperation between cities in India, Indonesia and South Africa," 2013. Online at: http://carbonn.org/uploads/tx_carbonndata/LocalRenewables_EMM_Energy%20Urban%20Profile_Final%20Draft_5April2013_stdPDF_09.pdf



Box 6.3 Local electricity grid emission factors–Waterloo Region

The Waterloo Region of Canada used provincial emission factors for Ontario to determine emissions from electricity consumption in the community.[34] Canada's national electricity consumption emission factor in 2010 was 0.21 kg CO_2e/kWh, but provincial data are available. Therefore, Waterloo Region used the most recent provincial emission factors provided by Environment Canada's Annual National Inventory Report. The emission factor for electricity consumed in the province of Ontario was estimated to be 0.15 kg CO_2e/kWh. The provincial level emission factor is a more accurate reflection of the energy mix supplying Waterloo Region.

See Box 6.3 for an example of the application of sub-national location-based emission factors.

6.5.4 Calculating grid-supplied steam, heating and cooling emissions

Many cities consume energy through district steam, heating and/or cooling systems. GHG emissions from the steam/heat/cooling consumed in city shall be counted as scope 2 emissions, categorized by the sub-sector consuming the energy (see Section 6.3.3). The emission factors should reflect the average emissions rate for the energy generation facilities supplying the district steam, heating and/or cooling systems, which should be available through the local energy utility or district grid operator.[33]

6.6 Calculating transmission and distribution loss emissions

During the transmission and distribution of electricity, steam, heating and cooling on a grid, some of the energy produced at the power station is lost during delivery to end consumers. Emissions associated with these transmission and distribution losses are reported in scope 3 as part of out-of-boundary emissions associated with city activities. Calculating these emissions requires a grid loss factor,[35] which is usually provided by local utility or government publications. Multiplying total consumption for each grid-supplied energy type (activity data for scope 2) by their corresponding loss factor yields the activity data for transmission and distribution (T&D) losses. This figure is then multiplied by the grid average emissions factors.

33. See footnote 26.

34. The Climate Collaborative. "Discussion Paper: Community GHG Inventory and Forecast for Waterloo Region," May 2012. Online at: http://www.regionofwaterloo.ca/en/aboutTheEnvironment/resources/CommunityGHGInventoryForecastforWaterlooRegion_DiscussionPaper_May2012.pdf

35. Transmission and distribution losses vary by location, see The World Bank's World Development Indicators (WDI) for an indication of national transmission and distribution losses as a percent of output, see: http://data.worldbank.org/indicator/EG.ELC.LOSS.ZS

7 *Transportation*

City transportation systems are designed to move people and goods within and beyond city borders. Transport vehicles and mobile equipment or machinery produce GHG emissions directly by combusting fuel or indirectly by consuming grid-delivered electricity.

Requirements in this chapter:

For BASIC:

Cities shall report all GHG emissions from combustion of fuels in transportation occurring within the city boundary in scope 1, and GHG emissions from grid-supplied electricity used for transportation within the city boundary for transportation in scope 2.

For BASIC+:

Cities shall report all BASIC sources and scope 3 GHG emissions associated with transboundary transportation.

7.1 Categorizing transportation emissions by scope

City transit via road, rail, water or air can either be wholly contained within the city boundary (e.g., a city-only bus route) or, more often, will cross city boundaries into neighboring communities. There are typically four types of transboundary trips:

1. Trips that originate in the city and terminate outside the city
2. Trips that originate outside the city and terminate in the city
3. Regional transit (typically buses and trains) with an intermediate stop (or multiple stops) within the city
4. Trips that pass through the city, with both origin and destination outside the city

Unlike stationary emission sectors, transit by definition is mobile and can pose challenges in both accurately calculating emissions and allocating them to the cities linked to the transit activity. But a transportation sector GHG inventory can be a vital metric that shows the impact of transportation policies and mitigation projects over time. While cities have varying levels of control or influence over regional transportation policies and infrastructure decisions that affect the transit routes of their city, a transportation inventory should inform and support actions that can influence emission reductions.

Depending on the available data and objectives of the inventory, different methods can be used to quantify and allocate transportation emissions. The methods most commonly used for transportation modeling and planning vary in terms of their "system boundaries," or how the resulting data can be attributable to a city's geographic boundary and thus the GPC scopes framework. The GPC does not require a specific calculation method for each transport mode, and therefore the emissions reported in each scope will likely vary by method. As with other GPC emissions sectors, reporting transport emissions in either scope 1 or 3 should only reflect emissions from combustion-only emissions. The upstream emissions from fuels used (including exploration of mineral oil, refinery processes, etc.) may be reported in *Other Scope 3*.

Transportation emissions accounting should reflect the following scopes:

Scope 1: Emissions from transportation occurring in the city
Scope 1 includes all GHG emissions from the transport of people and freight occurring within the city boundary.

Scope 2: Emissions from grid-supplied electricity used in the city for transportation
Scope 2 includes all GHG emissions from the generation of grid-supplied electricity used for electric-powered vehicles. The amount of electricity used should be assessed at the point of consumption within the city boundary.

Scope 3: Emissions from the portion of transboundary journeys occurring outside the city, and transmission and distribution losses from grid-supplied energy from electric vehicle use
This includes the out-of-city portion of all transboundary GHG emissions from trips that either originate or terminate within the city boundaries. This may include the out-of-city portion of on-road transit that burns fuel, or any out-of-city stops for an electric railway.

The transportation emissions from large regional transit hubs (e.g., airports or seaports) serving the city, but outside of the geographic boundary, should be counted in scope 3. These emissions are driven by activities within the city and should be included to provide a more holistic view of the city's transportation sector. Emissions from energy use at buildings or facilities related to transportation, such as docks, mass transit stations, airports and marine ports, should be reported in *Stationary Energy* sector.

These emission sources and their scope categorization are summarized in Table 7.1.

7.2 Defining transport modes

The GPC categorizes emission sources in the transportation sector by transit mode, including:

- **On-road transportation,** including electric and fuel-powered cars, taxis, buses, etc.
- **Railway,** including trams, urban railway subway systems, regional (inter-city) commuter rail transport, national rail system, and international rail systems, etc.
- **Water-borne transportation,** including sightseeing ferries, domestic inter-city vehicles, or international water–borne vehicles.
- **Aviation,** including helicopters, domestic inter-city flights, and international flights, etc.
- **Off-road transportation,** including airport ground support equipment, agricultural tractors, chain saws, forklifts, snowmobiles, etc.

Cities should identify the applicable sub-categories within each transit mode, and report emissions for these sub-categories as well as sub-sectors if data is available.

Table 7.1 Transportation Overview

GHG Emission Source	Scope 1	Scope 2	Scope 3
TRANSPORTATION	Emissions from fuel combustion for transportation occurring in the city	Emissions from consumption of grid-supplied energy for in-boundary transportation	Emissions from portion of transboundary journeys occurring outside the city, and transmission and distribution losses from grid-supplied energy
On-road transportation	II.1.1	II.1.2	II.1.3
Railways	II.2.1	II.2.2	II.2.3
Water transport	II.3.1	II.3.2	II.3.3
Aviation	II.4.1	II.4.2	II.4.3
Off-road transportation	II.5.1	II.5.2	

Sources required for BASIC reporting

\+ Sources required for BASIC+ reporting

Sources included in Other Scope 3

7.3 Calculating on-road transportation emissions

On-road vehicles are designed for transporting people, property or material on common or public roads, thoroughfares, or highways. This category includes vehicles such as buses, cars, trucks, motorcycles, on-road waste collection and transportation vehicles (e.g. compactor trucks), etc. Most vehicles burn liquid or gaseous fuel in internal combustion engines. The combustion of these fuels produces CO_2, CH_4, and N_2O, often referred to collectively as tailpipe emissions. Increasingly, electric or hybrid vehicles can also be charged at stations within or outside the city. The methodology chosen for calculating on-road transportation emissions from fuel combustion will impact how scope 1 and scope 3 emissions are allocated for transboundary journeys. Scope 2 emissions should be calculated based on consumption at charging stations in the city boundary, regardless of the trip destination. Charging stations might be at homes or workplaces that are already included in the *Stationary Energy* sector. Cities should ensure that energy used for electric vehicle charging is separate from, and not double counted with, energy used in these other *Stationary Energy* sub-sectors.

7.3.1 Transportation methodology options

The GPC does not prescribe a specific method for calculating on-road emissions due to variations in data availability, existing transportation models, and inventory purposes. However, cities should calculate and report emissions based on one of four common methods[36] identified in Figure 7.3 and described in Table 7.2, and shall clearly document the methods used in the inventory reports. The GPC recommends cities use the *induced activity* approach, as it provides results more suited to local policy making.

The methodologies for estimating transport emissions can be broadly categorized as top-down and bottom-up approaches.

- **Top-down** approaches start with fuel consumption as a proxy for travel behavior. Here, emissions are the result of total fuel sold multiplied by a GHG emission factor for each fuel.
- **Bottom-up** approaches begin with detailed activity data. Bottom-up approaches generally rely on an ASIF framework for determining total emissions (see Figure 7.1).

36. GIZ. *Balancing Transport Greenhouse Gas Emissions in Cities—A Review of Practices in Germany.* 2012.

The ASIF framework relates travel activity, the mode share, energy intensity of each mode, fuel, and vehicle type, and carbon content of each fuel to total emissions. The amount of **Activity (A)** is often measured as VKT (vehicle kilometers traveled), which reflects the number and length of trips. **Mode share (S)** describes the portion of trips taken by different modes (e.g., walking, biking, public transport, private car) and vehicle types (e.g., motorcycle, car, bus, truck). Energy **Intensity (I)** by mode, often simplified as energy consumed per vehicle kilometer, is a function of vehicle types, characteristics (e.g., the occupancy or load factor, represented as passengers per km or tonnes cargo per km) and driving conditions (e.g., often shown in drive cycles, a series of data points showing the vehicle speed over time). Carbon content of the fuel, or **Fuel** factor **(F)**, is primarily based on the composition of the local fuel stock.[37, 38]

Most cities start with top-down approaches and progress towards more detailed bottom-up methodologies that enable more effective emissions mitigation assessments and transportation planning. A robust inventory can use data under each approach to validate results and improve reliability.

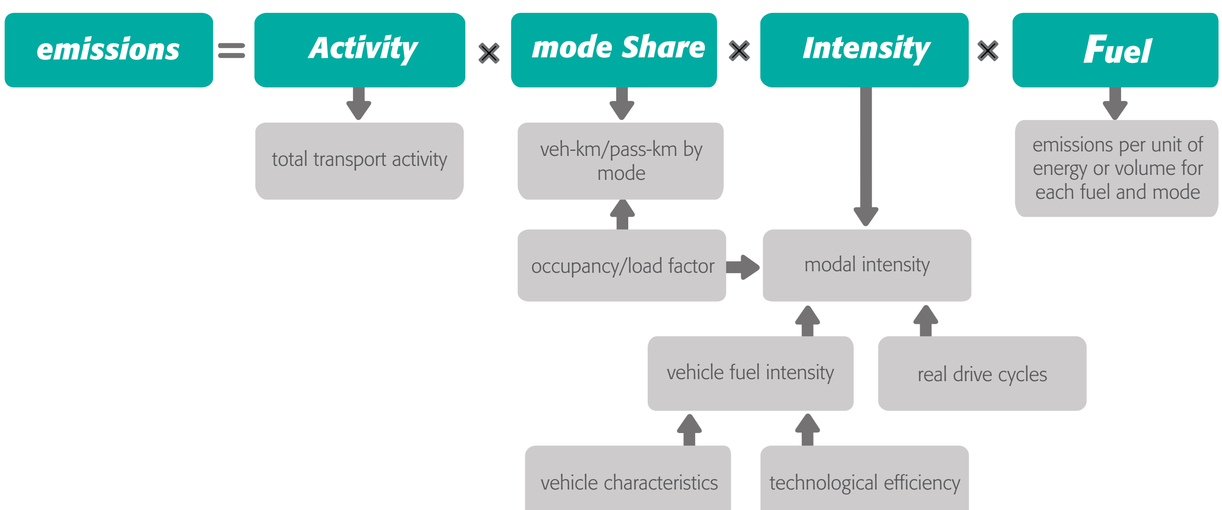
Figure 7.3 illustrates which type of transportation activity is reflected in each method. Table 7.3 further shows how to allocate these activity emissions in scopes 1, 2 and 3.

Fuel sales method

This method calculates on-road transportation emissions based on the total fuel sold within the city boundary. In theory, this approach treats sold fuel as a proxy for transportation activity. The activity data on the volume of fuel sold within the city boundary can be obtained from fuel dispensing facilities and/or distributors, or fuel sales tax receipts. If a strictly in-boundary fuel sales figure is unavailable, data may still be available at the regional scale (through distributors). This data should be scaled-down using vehicle ownership data or other appropriate scaling factors. Calculating fuel sales emissions requires multiplying activity data (quantity of fuel sold) by the GHG-content of the fuel by gas (CO_2, CH_4, N_2O).

To allocate total fuel sales by on-road vehicle sub-category, apportioning factors can be determined based on vehicle registration by vehicle class (starting with vehicle

Figure 7.1 ASIF framework[39]



37. Cooper, E., Jiang X., Fong W. K., Schmied M., and GIZ. *Scoping Study on Developing a Preferred Methodology and Tool to Estimate Citywide Transport Greenhouse Gas Emissions,* unpublished, 2013

38. Schipper, L., Fabian, H., & Leather, J. *Transport and Carbon Dioxide Emissions: Forecasts, Options Analysis, and Evaluation.* 2009.

39. Ibid

registrations within the city, then state or region, and finally national), survey or other methods.

All fuel sales from in-boundary fuel dispensaries should be accounted for in scope 1, even though fuel purchases may be for transboundary trips. Maintaining all fuel sales emissions in scope 1 also enables more effective multi-city aggregation. However, cities may conduct surveys or use other methods to allocate total fuel sales into scope 1 and scope 3 emissions.

Induced activity method

This method seeks to quantify transportation emissions *induced* by the city, including trips that begin, end, or are fully contained within the city (usually excluding pass-through trips). The method relies on models or surveys to assess the number and length of all on-road trips occurring—both transboundary and in-boundary only. This yields a vehicle kilometers traveled (VKT) figure for each identified vehicle class. It also requires information on vehicle fuel intensity (or efficiency) and fuel emission factors.

These models are more common in U.S. cities[40], and identify the *origin* and *destination* of each trip assessed. To reflect the responsibility shared by both cities inducing these trips, cities can use an *origin-destination* allocation in two ways:

1. **Reporting 50% of transboundary trips (and excluding pass-through trips).** Of that 50%, the portion that occurs within the city boundary is reported in scope 1, while the remaining percent that occurs outside the boundary is reported in scope 3. If 50% of the trip is entirely within the city boundary (e.g., a trip that just passes the city boundary), then the entire 50% should be in scope 1. One hundred percent of all in-boundary trips that begin and end in the same city are included, but pass-through trips are excluded from scope 1 even though they represent "in-boundary" traffic (since they are not "induced" by the city). One challenge of this approach is that due to differences in traffic models, there may be portions of a trip that occur in the city boundary but are not reflected in scope 1. As illustrated in Figure 7.2, "Section A" may include in-boundary emissions that are not tracked in scope 1. Cities can disclose these omissions if they are identified by the model. See Box 7.1 for one city's application of a travel demand model.
2. **Reporting departing on-road trips only.** For simplicity, cities may account for only departing on-road trips. Here, 100% of the trip is counted, with in-boundary section as scope 1 and out-of-boundary section as scope 3.

40. Ibid

Box 7.1 On-road calculation based on models—North Park

The community of North Park in San Diego, California, was chosen as the study area to test methodology for generating VMT (vehicle miles traveled) data from a regional travel demand model. The San Diego Association of Regional Governments (SANDAG) developed an approach for using traffic modeling software to generate VMT data disaggregated into trip types compatible with the origin-destination approach. Emissions from trips that start and end in the study area (internal-internal) are fully allocated to the city. Emissions from trips that have one trip-end within the study area (internal-external and external-internal) are allocated to the city at 50%. Pass-through trips (external-external) are excluded from the analysis.[41]

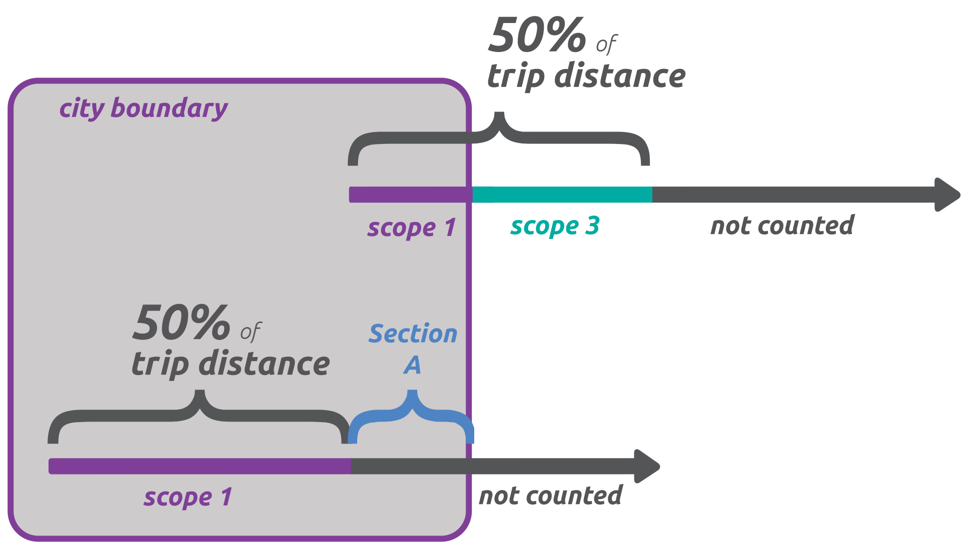
Geographic or territorial method

This method quantifies emissions from transportation activity occurring solely within city boundaries, regardless of the trip's origin or destination. Some European traffic demand models[42] quantify these emissions primarily for

41. For more information, see the technical white paper "Vehicle Mile Traveled Calculations Using SANDAG Regional Travel Demand Model" [pdf]: http://www.sandag.org/uploads/publicationid/publicationid_1795_16802.pdf

42. Ibid Schipper, L., Fabian, H., & Leather, J. *Transport and Carbon Dioxide Emissions: Forecasts, Options Analysis, and Evaluation*. 2009.

Figure 7.2 **Induced activity allocation**



local air pollution estimates or traffic pricing, but GHG emissions can be quantified based on the same ASIF model, limiting VKT to in-city travel.

This model aligns with scope 1 emissions, as all in-boundary transportation is included. Although no out-of-boundary trips are assessed or quantified, additional surveys could be combined in order to report scope 3 emissions as the portion of out-of-boundary transit.

Resident activity method

This method quantifies emissions from transportation activity undertaken by city residents only. It requires information on resident VKT, from vehicle registration records and surveys on resident travels. While these kinds of surveys may be more manageable and cost-effective than traffic models, their limitation to resident activity overlooks the impact of non-city resident traffic by commuters, tourists, logistics providers, and other travelers. Here, an inventory could apply the origin-destination allocation approach to allocate emissions from resident travel over scope 1 and 3.

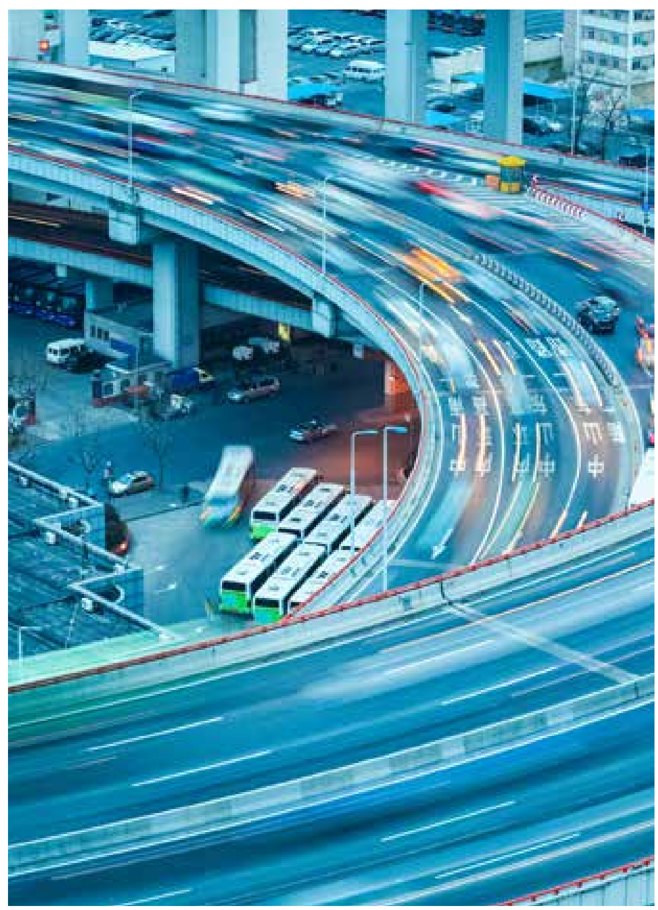
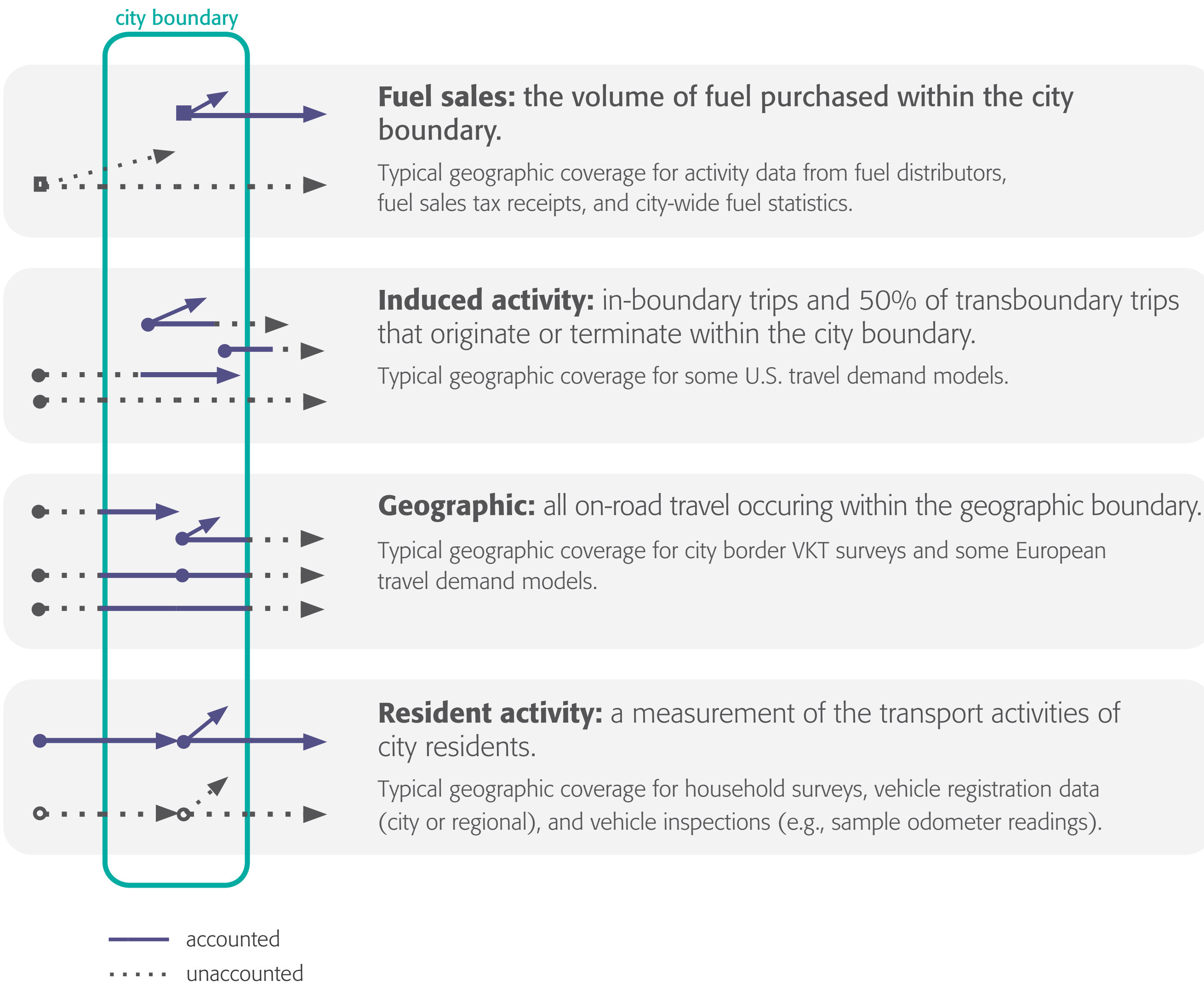


Figure 7.3 **Methodology system boundaries**



7.3.2 How to select on-road calculation methodologies

To determine which methodologies to use for on-road transportation, cities should first consult any transport models developed by city transportation planners. In the absence of a transportation model, cities can use the fuel sales method.

The scale of differences in emission results based on these methods may be significant. Cities should decide which methodology and boundaries to use based on the quality and availability of data, regional practices, and the objectives of the inventory. For instance, fuel sales can be more accurate to show overall reductions in fuel consumption, while models and surveys can give detailed information on how specific transportation sectors are evolving and help prioritize mitigation actions. See Table 7.3 for a comparison of these approaches. Cities should seek consistent methods over time or document when methods have changed (see base year recalculation in Chapter 11).

Table 7.2 Boundary types and scopes allocation

Method	Allocation principle	Scope 1	Scope 2	Scope 3
Fuel Sales Approach	Not applicable unless additional steps taken	All emission from fuel sold within boundary	Any electric charging station in the city boundary	Not applicable unless fuel sales allocated between scope 1 and 3 by specified method
City-induced Activity (e.g. US demand models)	Origin-Destination	In-boundary trips and in-boundary portion of 50% of transboundary trips (pass-through trips excluded)		Out-of-boundary portion of 50% of transboundary trip
		In-boundary trips and in-boundary portion of all departing transboundary trips (pass-through trips excluded)		Out-of-boundary portion of all departing transboundary trips
Geographic/ Territorial (e.g., European demand models)	Not applicable	All traffic occurring within city boundaries, regardless of origin or destination		Not applicable unless additional steps taken
Resident Activity	Options	Either resident activity is all scope 1, or use origin-destination		N/A or origin-destination used

Table 7.3 Comparing top-down and bottom-up methodologies for on-road transportation

Methodology	Advantages	Disadvantages
Fuel sales	• More consistent with national inventory practices • Well suited to aggregation with other city's transportation inventories if all fuel sold in boundary is classified as scope 1. • Less costly • Less time-consuming to conduct • Do not require high level of technical capacity	• Does not capture all on-road travel, as vehicles may be fueled at locations outside the city boundary but driven within the city • Does not disaggregate the reasons for travel emissions, e.g., origin, destination, vehicle efficiency changes, modal shift, etc. • Does not comprehensively demonstrate mitigation potential • Does not allow for allocating emissions by scope (unless additional steps are taken)
VKT and model-based (induced activity, territorial, resident activity)	• Can produce detailed and more actionable data for transportation planning • Integrates better with existing city transport models and planning processes	• More expensive, time consuming, and less comparable between cities due to variation in models used

7.3.3 Changing transportation methodologies over time

Over time, cities may be able to obtain more accurate or relevant data using new technologies, methods, or models. As new means for improving the accuracy of activity data and emission factors become available, cities may switch the methodology in the inventory and should clearly indicate the method used.

Changing methodologies can pose challenges for cities using base year inventory results to track progress toward implementing goals. Cities should follow base year recalculation procedures described in Chapter 11, disclosing the reason for recalculation. Alternatively, if recalculated base year emissions are not possible to develop due to limitations on historic data or limitations in modeling, cities may continue to report transportation emissions over time with methods used in the base year.

7.4 Calculating railway transportation emissions

Railways can be used to transport people and goods, and are powered by a locomotive, which typically uses energy through combustion of diesel fuels or electricity (known as electric traction). Rail transit can be further divided into four sub-categories, as shown with examples in Table 7.4. Each can be further classified as passenger or freight.

The allocation principle for railway broadly reflects an assessment of "induced activity," but reports all in-city railway travel as scope 1 while the out-of-boundary portion of transboundary railway journeys can be apportioned on the basis of city passengers or goods.

7.4.1 Calculating scope 1 emissions

Scope 1 emissions include emissions from direct combustion of fossil fuels incurred during the length of railway transit within the city boundary for railway lines that have stops in the city boundary. Based on available data and local circumstances, cities may either include or omit emissions from pass-through rail trips that do not stop in the city boundary. Whichever the case, cities shall transparently report the adopted approach for estimating railway emissions and indicate whether it covers pass-through rail transit.

Table 7.4 Railway types

Railway type	Examples
Urban train/subway systems	Tokyo transit system
Regional (inter-city) commuter rail transport	Tokyo subway/train systems that connect to the adjacent cities like Yokohama, Tsukuba, and Chiba
National rail	Japan national railway system operated by the Japanese Rail
International rail systems	Trans-Europe rail systems such as Eurostar

Rail fuel combustion is typically diesel, but may also use natural gas or coal, or include compressed natural gas (CNG) or biofuels.[43] Cities should obtain fuel consumption data from the railway operator(s) by fuel types and by application (e.g., transit system, freight, etc.) for the distance covered within the city boundary (scope 1) and the lines' extension outside the city (see scope 3).

Where detailed activity data are unavailable, cities can also:

- Use rail company queries or surveys
  - Survey rail companies for real fuel consumption and amount of goods or people moved (movement driver).
  - Calculate real fuel consumption per tonne of freight and/or per person (e.g., gallons of diesel per person).
- Scale up incomplete transportation activity data (e.g., tonnes freight and/or people movement). Total city activity may be determined through local, state, or national statistics or transportation agencies for the city.
- Scale down regional transit system fuel consumption based on:
  - Population served by the region's model and the population of the city, to derive an in-boundary number.
  - Share of transit revenue service miles served by the region (utilize data on scheduled stops and length of the railway) and the number of miles that are within the city's geopolitical boundary.
- Scale down national railway fuel consumption based on city population or other indicators.

43. Diesel locomotives also consume lubricant oils, emissions from which are included in *IPPU*.

7.4.2 Calculating scope 2 emissions

Grid-supplied electricity used to power rail-based transportation systems is accounted for at points of supply (where the electricity is being supplied to the railway system), regardless of trip origin or destination. Therefore, all electricity charged for railway vehicle travel within the city boundary shall be accounted for under scope 2 emissions. Cities can seek this data from the railway operator, utility provider, or scale down regional or national statistics.

7.4.3 Calculating scope 3 emissions

Transboundary railway emissions (from either direct fuel combustion or grid-supplied electricity charged outside the city) can be allocated based on type of railway service and geographic range. For instance:

- For urban transit systems, lines may extend outside city boundaries into suburbs within a metro area geographic range. Here, all out-of-boundary emissions could be recorded in scope 3.
- For inter-city, national or international railway travel, a city can allocate based on:
    - Resident travel, where the number of city residents disembarking at each out-of-boundary stop (relative to the total riders on the out-of-boundary stops) can be used to scale down total emissions from the out-of-boundary stops. Cities can determine this based on surveys.
    - Freight quantity (weight or volume), where the freight quantity coming from the city (relative to the total freight on the out-of-boundary stops) can be used to scale down total emissions from out-of-boundary stops.

7.5 Calculating waterborne navigation emissions

Water transportation includes ships, ferries, and other boats operating within the city boundary, as well as marine-vessels whose journeys originate or end at ports within the city's boundary but travel to destinations outside of the city. While water transportation can be a significant source of emissions globally, most emissions occur during oceanic journeys outside of the boundaries of a port city.

IPCC Guidelines allow for exclusion of international waterborne navigation and air travel, but these journeys and their associated emissions can be useful for a city to understand the full impact of the transit connecting through the city. The GPC requires water transportation wholly occurring within a city to be reported in scope 1 for BASIC, while emissions from all departing ships for inter-city/national/international trips shall be reported in scope 3 under BASIC+.

7.5.1 Calculating scope 1 emissions

Scope 1 includes emissions from direct combustion of fossil fuels for all trips that originate and terminate within the city boundary. This includes all riverine trips within the city boundary as well as marine ferries and boats that travel between seaports within the city boundary (including sightseeing ferries that depart from and return to the same seaport within the city boundary). To calculate scope 1 emissions, cities can:

- Obtain total real fuel sales estimates of fuel loaded onto marine vessels by inquiring with shipping companies, fuel suppliers (e.g., quantity of fuels delivered to port facilities), or individual port and marine authorities, separated by geographic scale of activity.
  - Where a representative sampling survey is used, identify the driver of activity at the sample site (e.g., tonnes of freight or number of people), and use driver information to scale-up the activity data to the city-scale.
  - Total city activity may be determined through local, state, or national statistics or transportation agencies for the city.
- Estimate distances traveled and resulting fuel usage.
  - Use ferry movement schedules to calculate distances traveled.
  - Utilize fuel economy figures for boats.
- Scale national level data down using appropriate scaling factors.
  - National marine navigation data may be found through national maritime (marine) administration agencies.

7.5.2 Calculating scope 2 emissions

Scope 2 includes emissions from any grid-supplied energy that marine-vessels purchase and consume, typically at docks, ports or harbors (this should be distinguished from electricity consumption at other stationary port structures, such as a marina). Cities should seek data from port operators on water vessel consumption.

7.5.3 Calculating scope 3 emissions

In this case, Scope 3 covers emissions from departing transboundary trips powered by direct fuel combustion, apportioned to cover those departing trips that are attributable to the city. Cities can estimate the proportion of passengers and cargo traveling from the city, using official records, manifests, or surveys to determine the apportionment. Emissions from transboundary trips can be calculated based on:

- VKT, or the distance travelled from the seaport within the city to the next destination
- Fuel combustion, quantifying the combustion of fuel loaded at the stations within the city boundary

Cities shall transparently document the methods used in the inventory reports.

7.6 Calculating aviation emissions

Civil aviation, or air travel, includes emissions from airborne trips occurring within the geographic boundary (e.g., helicopters operating within the city) and emissions from flights departing airports that serve the city. A significant amount of emissions associated with air travel occur outside the city boundary. Airports located within a city, or under local jurisdiction, typically service the greater region in which the city exists. These complexities make it challenging to properly account for and attribute aviation emissions. For simplicity, scope 3 includes all emissions from departing flights. Cities may report just the portion of scope 3 aviation emissions produced by travelers departing the city. This is in line with the origin and destination model described with the induced activity method in Section 7.3.1. Cities shall transparently document the methods used in the inventory reports.

Cities should also disaggregate data between domestic and international flights to improve integration with national GHG inventories.[44] Oftentimes, the separation of data between in-boundary (scope 1), domestic, and international aviation may be difficult to obtain. Classification of airports should indicate whether the airports service local, national, or international needs.

44. Fuel use data is disaggregated from national and international trips as a UNFCCC/IPCC reporting requirement. Under the *2006 IPCC Guidelines*, national governments are required to calculate domestic (trips occurring within the geopolitical boundary of the country) waterborne navigation and aviation trips, while international trips are designated as optional.

7.6.1 Calculating scope 1 emissions

Scope 1 includes emissions from the direct combustion of fuel for all aviation trips that depart and land within the city boundary (e.g., local helicopter, light aircraft, sightseeing and training flights). The methodology for quantifying aviation emissions is similar to the methodology provided for waterborne navigation in Section 7.5:

- Obtain activity data in the form of total real fuel sales estimates of fuel loaded onto aircraft by inquiring with airports, airlines, or port authorities.
  - Where real data for all airports are unavailable, utilize a survey of a sample of airports. Identify the driver of activity at the sample site (e.g., goods and freight or passenger movement), and use driver information to scale up the activity data to the city-scale.
  - Total city activity may be determined through local, state, or national statistics or transportation agencies for the city.
- Where in-city aviation data are unavailable:
  - Survey local helicopter companies and airlines for fuel use data.
  - Estimate other local aviation use through schedule information and fuel economy estimates.
- Alternatively, scale national level data down using population or GDP per capita.
  - National aviation data may be found through national aviation administration agencies (e.g. U.S. FAA).
- Apply emission factors, which can be disaggregated by fuel type and technology (typically provided by national environmental agencies or research institutions), or use default IPCC emission factors.[45]

7.6.2 Calculating scope 2 emissions

Scope 2 includes any grid-supplied energy consumed by aircraft charging at airports.[46] Any grid-supplied energy consumed at airport facilities should be included in *Stationary Energy* (institutional or commercial facilities).

45. IPCC default emission factors can be found in Volume 2 Energy; Chapter 3 Mobile Combustion; Section 3.6 Civil Aviation; CO_2 Table 3.6.4 and CH_4 and N2O Table 3.6.5. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol2

46. Grid-supplied fixed ground power provided by the airport.

7.6.3 Calculating scope 3 emissions

Scope 3 includes emissions from departing flights at airports that serve the city, whether the airport is located within the geographic boundary or outside of it. Cities should identify the types of fuels consumed in departing aviation trips, the quantity (volume or energy) of each type of fuel consumed by the aircraft associated with these flights, and whether the trips are domestic or international.

Quantification follows the same process described in 7.6.1. Additional resources for obtaining activity data include statistical offices or transportation agencies, airport records, air traffic control records or official records, or published air traffic schedules.

The city may report just the emissions from departing flights that are attributable to the city by estimating the proportion of passengers traveling from the city, using carrier flight data or surveys to determine the allocation. Cities shall transparently document the methods used in the inventory reports.

7.7 Calculating off-road transportation emissions

Off-road vehicles are those designed or adapted for travel on unpaved terrain. This category typically includes all-terrain vehicles, landscaping and construction equipment, tractors, bulldozers, amphibious vehicles, snowmobiles and other off-road recreational vehicles. For the purposes of the GPC, only activities in the city (scope 1 and scope 2) emissions are included.

Cities should only report under the *off-road transportation* sub-sector emissions from off-road transportation activities within transportation facility premises such as airports, harbors, bus terminals, and train stations. Other off-road transportation activities within industrial premises and construction sites, agriculture farms, forests, aquaculture farms, and military premises, are reported under *Stationary Energy* (see Table 6.5 Overview of reporting guidance for off-road transportation activities for guidance on classifying these emissions).

All GHG emissions from combustion of fuels in off-road vehicles within the city boundary shall be reported under scope 1. Emissions from generation of grid-supplied

Box 7.2 Reporting emissions from regional transport hubs—London[47]

London, United Kingdom, is a major international transport hub. It has two international airports located within the city boundary (London Heathrow and London City) and four international airports located outside the city boundary (London Gatwick, London Luton, London Stansted and London Southend).

To calculate GHG emissions from transboundary air travel, the distance travelled by departing aircraft from these airports is apportioned to London based on the percentage of air travel at each airport serving the city, i.e. those flights used by residents, workers and visitors. The latter is obtained from a survey conducted by the UK Civil Aviation Authority on the origin/destination patterns of terminating passengers at major UK airports. This survey suggests that airports further afield also serve London but to a very limited extent and are therefore not included in the calculations.

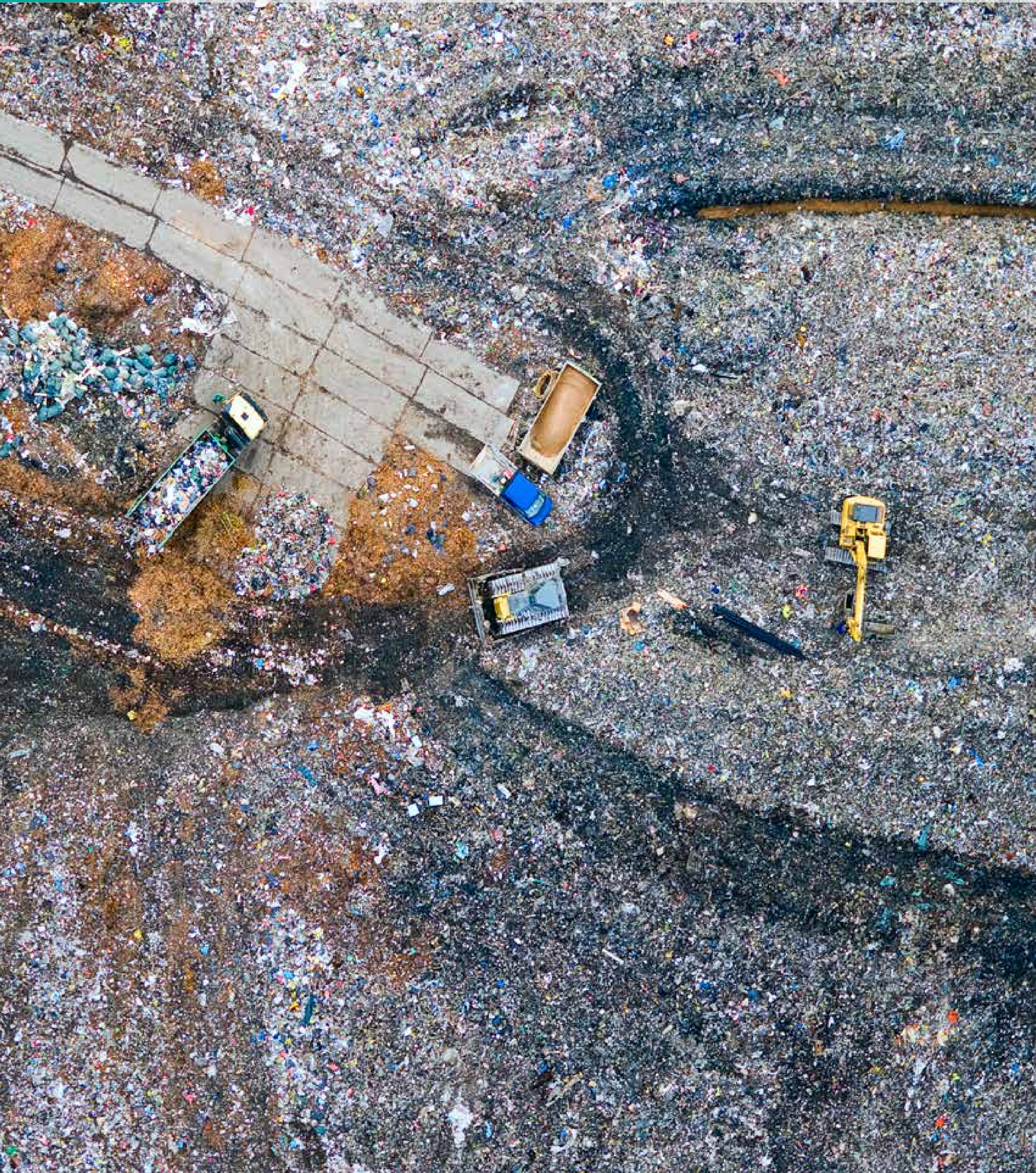
electricity used to power off-road vehicles shall be reported under scope 2 emissions.

Comprehensive top-down activity data on off-road vehicles are often unavailable, and alternative methods are typically necessary to estimate emissions within this category. Some options include:

- Conducting a survey:
  - Be sure to include households, construction, and relevant businesses to capture gardening, landscaping, construction, and recreational equipment.
  - Use population served by the survey to scale for the city, generally. More specifically, aggregate scale of sub-sectors for increased accuracy:
    - Construction permits served by the survey to scale for total permits issued for the city
    - Number of households (or population) served by the survey to scale for total city households (or population)
- Using national—or regional, where available—off-road modeling software:
  - Requires inputs on number of engines and technology types:
- Engine populations
    - Annual hours of use (can be estimated, based upon city characteristics)
    - Power rating (derived from off-road vehicle types)
  - U.S. EPA has a tool that can be used for this purpose, NONROAD 2005:
    - Available on the U.S. EPA website: www.epa.gov/otaq/nonrdmdl.htm
- Scale national off-road mobile fuel consumption down according to population share.

47. *Source:* BSI (2014) Application of PAS 2070—London, United Kingdom: An assessment of greenhouse gas emissions of a city. http://shop.bsigroup.com/upload/PAS2070_case_study_bookmarked.pdf

8 Waste



Cities produce solid waste and wastewater (together referred to collectively as "waste") that may be disposed of and/or treated at facilities inside the city boundary, or transported to other cities for treatment. Waste disposal and treatment produces GHG emissions through aerobic or anaerobic decomposition, or incineration.

Requirements in this chapter:

For BASIC:

Cities shall report all GHG emissions from disposal or treatment of waste generated within the city boundary, whether treated inside or outside the city boundary.

Emissions from waste imported from outside the city but treated inside the city shall be* excluded *from BASIC/BASIC+ totals. These emissions shall still be reported in total scope 1 emissions.

8.1 Categorizing waste and wastewater emissions

Solid waste and wastewater may be generated and treated within the same city boundary, or in different cities. For accounting purposes, the following rules apply:

Scope 1: Emissions from waste treated inside the city
This includes all GHG emissions from treatment and disposal of waste within the city boundary regardless whether the waste is generated within or outside the city boundary. Only GHG emissions from waste generated by the city shall be reported under BASIC/BASIC+. GHG emissions from imported waste shall be reported as scope 1, but not added to BASIC/BASIC+ totals.

Scope 2: Not applicable
All emissions from the use of grid-supplied electricity in waste treatment facilities within the city boundary shall be reported under scope 2 in *Stationary Energy, commercial* and *institutional buildings and facilities* (I.2.2).

Scope 3: Emissions from waste generated by the city but treated outside the city
This includes all GHG emissions from treatment of waste generated by the city but treated at a facility outside the city boundary.

Figure 8.1 illustrates boundary considerations for emission sources in the *Waste* sector. In this figure, the blue border represents the city's geographic boundary and:

- **A** illustrates waste generated outside of the city boundary and treated within the boundary
- **B** illustrates waste generated and treated within the city's boundary
- **C** illustrates waste generated inside the boundary and treated outside of the boundary

Based on the above, the reporting requirement for the *Waste* sector is as follows:

- Scope 1 emissions = emissions from **A+B** (all emissions generated within the city boundary)
- Scope 3 emissions = emissions from **C**
- Emissions reported for BASIC and BASIC+ = emissions from **B+C** (all emissions resulting from waste generated by the city)

Waste emission sources and their scope categorizations are summarized in Table 8.1.

Figure 8.1 Boundaries for imported and exported waste

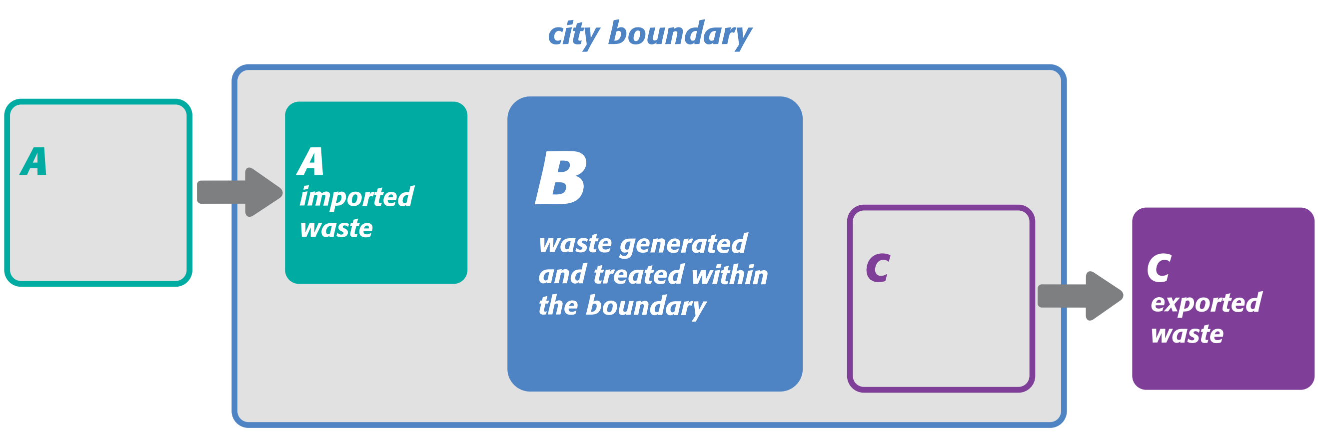


Table 8.1 Waste Overview

GHG Emission Source	Scope 1	Scope 2	Scope 3
WASTE	Emissions from in-boundary waste treatment		Emissions from waste generated in the city but treated out-of-boundary
Solid waste generated in the city disposed in landfills or open dumps	III.1.1		III.1.2
Solid waste generated outside the city disposed in landfills or open dumps	III.1.3		
Solid waste generated in the city that is treated biologically	III.2.1		III.2.2
Solid waste generated outside the city that is treated biologically	III.2.3		
Solid waste generated in the city incinerated or burned in the open	III.3.1		III.3.2
Solid waste generated outside the city incinerated or burned in the open	III.3.3		
Wastewater generated in the city	III.4.1		III.4.2
Wastewater generated outside the city	III.4.3		

Sources required for BASIC reporting

\+ Sources required for BASIC+ reporting

Sources required for territorial total but not for BASIC/BASIC+ reporting (*italics*)

Non-applicable emissions

8.2 Defining Solid Waste types and general calculation procedures

This chapter provides accounting guidance for city governments to estimate CO_2, CH_4, and N_2O from the following waste management activities:

1. Solid waste disposal in landfills[48] or dump sites, including disposal in an unmanaged site, disposal in a managed dump or disposal in a sanitary landfill
2. Biological treatment of solid waste
3. Incineration and open burning of waste
4. Wastewater treatment and discharge

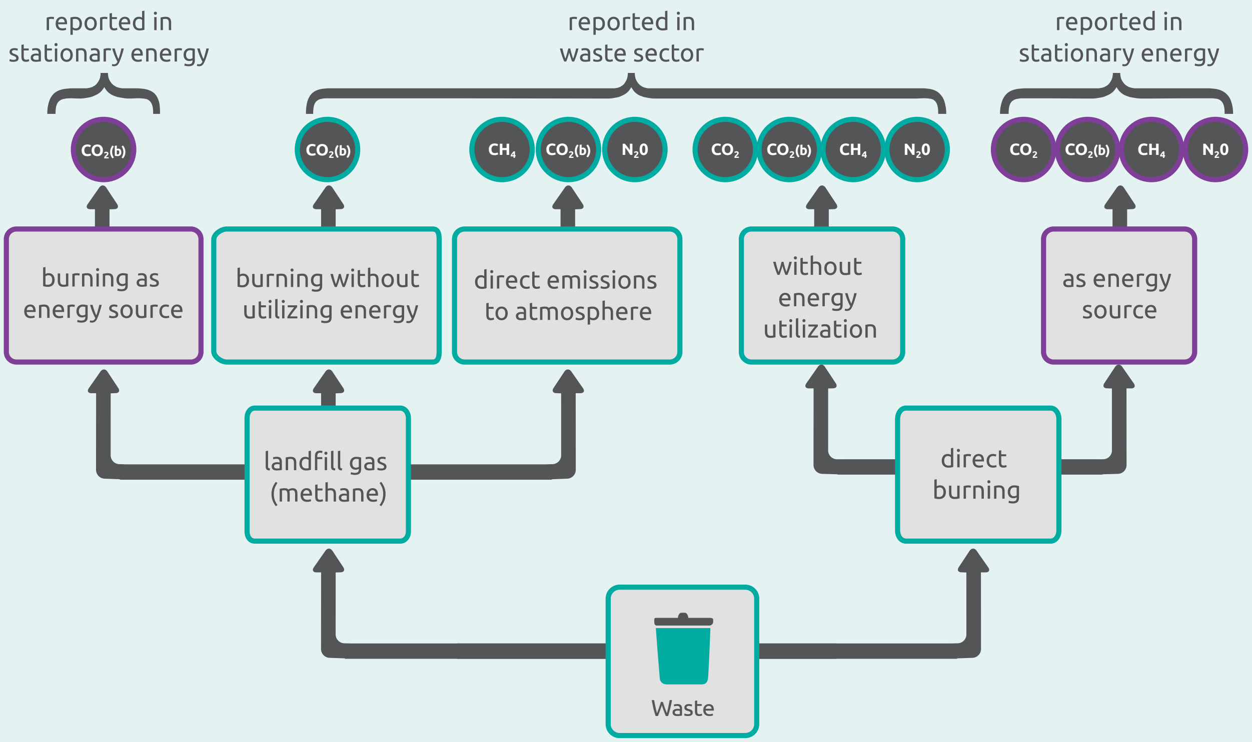
48. In many cities, a portion of solid waste generated is not formally treated by the city and ends up in open dumps or other unmanaged sites. The term "landfill" is used as shorthand for both managed and unmanaged solid waste disposal sites. Similarly, waste may be incinerated at formal incineration facilities as well as informal open burning sites. As described in Sections 8.3 to 8.5, cities should calculate emissions from managed disposal, treatment or incineration sites first, and separately document emissions from unmanaged disposal sites.

8.2.1 Defining solid waste types

Waste type categories and waste collection methods vary by country. Cities should identify city-specific waste composition and waste generation data where possible, to achieve more accurate calculation results. However, for cities without data on current or historic solid waste generation quantities and composition, or waste treatment methods, the GPC provides a set of default solid waste types and definitions (outlined below) consistent with *IPCC Guidelines*. Cities should also consult *IPCC Guidelines* for guidance on conducting waste composition analyses in addition to default values for specific countries/regions. This chapter focuses on GHG emissions from different types of solid waste generated from offices, households, shops, markets, restaurants, public institutions, industrial installations, water works and sewage facilities, construction and demolition sites and agricultural activities. These default types of solid waste include:

Box 8.1 Waste and stationary energy emissions

As described in Chapter 6, *Stationary Energy* (Table 6.7), if methane is recovered from solid waste or wastewater treatment facilities as energy sources, those GHG emissions shall be reported under *Stationary Energy*. Emissions from waste incineration without energy recovery are reported under the *Waste* sector, while emissions from incineration with energy recovery are reported in *Stationary Energy*, both with a distinction between fossil and biogenic carbon dioxide (CO_2(b)) emissions. See below for an illustrated explanation of these differences.



1. **Municipal solid waste (MSW)**
   MSW is generally defined as waste collected by municipalities or other local authorities. MSW typically includes: food waste, garden and park waste, paper and cardboard, wood, textiles, disposable diapers, rubber and leather, plastics, metal, glass, and other materials (e.g., ash, dirt, dust, soil, electronic waste).

2. **Sludge**
   In some cities, domestic wastewater sludge is reported as MSW, and industrial wastewater treatment sludge in industrial waste. Other cities may consider all sludge as industrial waste. Cities should indicate this classification when reporting sludge emissions.

3. **Industrial Waste**
   Industrial waste generation and composition vary depending on the type of industry and processes/technologies used and how the waste is classified by country. For example, construction and demolition waste can be included in industrial waste, MSW, or defined as a separate category. In many countries industrial waste is managed as a specific stream and the waste amounts are not covered by general waste statistics.

   In most developing countries industrial wastes are included in the municipal solid waste stream. Therefore, it is difficult to obtain data on industrial waste separately, and cities should carefully notate the category when reporting *Waste* sector emissions.

4. **Other waste**

   Clinical waste: These wastes cover a range of materials including plastic syringes, animal tissues, bandages and cloths. Some countries choose to include these items under MSW. Clinical waste is usually incinerated, but on occasion may be disposed of at solid waste disposal sites (SWDS). No regional or country-specific default data are given for clinical waste generation and management.

   Hazardous waste: Waste oil, waste solvents, ash, cinder, and other wastes with hazardous properties—such as flammability, explosiveness, causticity, and toxicity—are included in hazardous waste. Hazardous wastes are generally collected, treated and disposed of separately from non-hazardous MSW and industrial waste streams.

   In most countries, GHG emissions from clinical and hazardous wastes are less than those coming from other waste streams, so the GPC does not provide methodological guidance specifically for "Other Waste." When a city has specific needs, city government can apply the waste composition and waste treatment data to MSW methodology.

8.2.2 General emissions quantification steps

The quantification of GHG emissions from solid waste disposal and treatment is determined by two main factors: the mass of waste disposed and the amount of degradable organic carbon (DOC) within the waste, which determines the methane generation potential. In the case of incineration, the two main factors for quantifying emissions are the mass of waste disposed and the amount of fossil carbon it contains.

Detailed guidance for quantifying waste mass and degradable organic content includes the following steps:

- **Determine the quantity (mass) of waste generated by the city and how and where it is treated.** For all disposal and treatment types, cities should identify the quantity of waste generated in the analysis year. For solid waste disposed in landfills/open dumps, historic waste quantity data or estimates may also be needed depending on the calculation method chosen. In instances where multiple cities are contributing waste to the same disposal sites, each city will apportion those emissions based on the ratio of historical waste contributed to the landfill (See Box 8.2 for an example of emissions apportionment between cities).

  In the absence of local or country-specific data on waste generation and disposal, the *2006 IPCC Guidelines* provide national default values for waste generation rates based upon a tonnes/capita/year basis and default breakdowns of fraction of waste disposed in landfills (SWDS), incinerated, composted (biological treatment), and unspecified (landfill methodology applies here).[49]

- **Determine the emission factor.** Disposal and treatment of municipal, industrial and other solid waste produces significant amounts of methane (CH_4). CH_4 produced at solid waste disposal sites (SWDS) contributes approximately 3 to 4 percent to annual global anthropogenic GHG emissions.[50] In addition to CH_4, SWDS also produce biogenic carbon dioxide (CO_2(b)) and non-methane volatile organic compounds (NMVOCs) as well as smaller amounts of nitrous oxide (N_2O), nitrogen oxides (NO_x), and carbon monoxide (CO). This section focuses only on guidance for methane emissions calculation, but cities should consult IPCC or other local resources to calculate other GHGs like N_2O.

  For solid waste disposal, the emission factor is illustrated as methane generation potential (L_0), which is a function of degradable organic content (DOC). This factor is further explained in Section 8.2.3.

- **Multiply quantity of waste disposed by relevant emission factors to determine total emissions.** Distinct components of the waste stream (e.g., waste disposed in managed sites versus waste disposed in unmanaged dumps) should be paired with appropriate emission factors and associated emissions should be

49. *2006 IPCC Guidelines*, Volume 5: Waste, Chapter 2: Waste Generation, Composition, and Management, Annex2A.1. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol5

50. IPCC (2001). Summary for Policymakers and Technical Summary of *Climate Change 2001: Mitigation. Contribution of Working Group III to the Third Assessment Report of the Intergovernmental Panel on Climate Change,* Bert Metz *et al.* eds. Cambridge University Press, Cambridge, United Kingdom

Box 8.2 Reporting scope 1 emissions from the Waste sector—Lahti

In Lahti, Finland, municipally-owned Päijät-Häme Waste Disposal Ltd serves not only the city of Lahti, but 21 other municipalities and 200,000 residents around the Päijät-Häme region as well. All relevant GHG emissions from waste treatment facilities in Lahti, which manage both the waste generated by the city itself and by entities outside the city boundary, are around two times larger than the GHG emissions from Lahti residents only. Therefore, the GPC recommends that the city of Lahti report all emissions from the entire *Waste* sector under scope 1 with an accompanying explanation about the proportion of emissions from imported MSW.

calculated separately. The following sections provide more detailed information on how these steps should be conducted.

8.2.3 Determining solid waste composition and degradable organic content (DOC)

The preferred method to determine the composition of the solid waste stream is to undertake a solid waste composition study, using survey data and a systematic approach to analyze the waste stream and determine the waste source (paper, wood, textiles, garden waste, etc.). In addition, the analysis should indicate the fraction of DOC and fossilized carbon present in each matter type and the dry weight percentages of each matter type. In the absence of a comprehensive waste composition study, *IPCC Guidelines* provide sample regional and country-specific data to determine waste composition and carbon factors in the weight of wet waste.[51]

DOC represents a ratio or percentage that can be calculated from a weighted average of the carbon content of various components of the waste stream.

51. Default values are available in Volume 5: Waste, Chapter 2: Waste Generation, Composition, and Management (Table 2.3 and Table 2.4).

Equation 8.1 estimates DOC using default carbon content values.

Equation 8.1 Degradable organic carbon (DOC)[52]

$$\text{DOC} = (0.15 \times A) + (0.2 \times B) + (0.4 \times C) + (0.43 \times D) + (0.24 \times E) + (0.15 \times F)$$

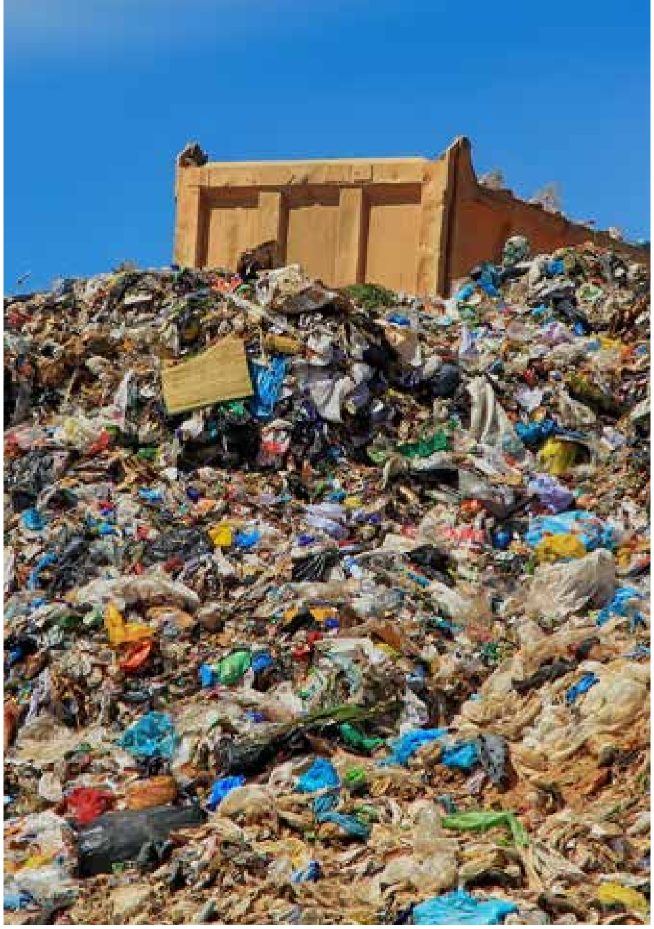
A	=	Fraction of solid waste that is food
B	=	Fraction of solid waste that is garden waste and other plant debris
C	=	Fraction of solid waste that is paper
D	=	Fraction of solid waste that is wood
E	=	Fraction of solid waste that is textiles
F	=	Fraction of solid waste that is industrial waste

8.3 Calculating emissions from solid waste disposal

Solid waste may be disposed of at managed sites (e.g., sanitary landfill and managed dumps), and at unmanaged disposal sites (e.g., open dumps, including above-ground piles, holes in the ground, and dumping into natural features, such as ravines). Cities should first calculate emissions from managed disposal sites, and separately calculate and document emissions from unmanaged disposal sites.

Activity data on quantities of waste generated and disposed at managed sites can be calculated based on records from waste collection services and weigh-ins at the landfill. Waste disposed at unmanaged sites (e.g., open dumps) can be estimated by subtracting the amount of waste disposed at managed sites from the total waste generated. Total waste generated can be calculated by

52. Equation adapted from *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000). Default carbon content values sourced from IPCC Waste Model spreadsheet, available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/5_Volume5/V5_2_Ch2_Waste_Data.pdf. For city specific waste generation and waste composition data user can also consult World Bank paper: *What a Waste: A Global Review of Solid Waste Management*



multiplying the per capita waste generation rate (tonnes/capita/yr) by the population (capita). Guidance on collecting this information is available in *IPCC Guidelines*.

Accounting methods

Methane emissions from landfills continue several decades (or sometimes even centuries) after waste disposal. Waste disposed in a given year thereby contributes to GHG emissions in that year and in subsequent years. Likewise, methane emissions released from a landfill in any given year include emissions from waste disposed that year, as well as from waste disposed in prior years.

Therefore, the GPC provides two commonly acceptable methods for estimating methane emissions from solid waste disposal: first order of decay and methane commitment.

- **First order of decay (FOD)** assigns landfill emissions based on emissions during that year. It counts GHGs actually emitted that year, regardless of when the waste was disposed. The FOD model assumes that the degradable organic component (DOC) in waste decays slowly over a few decades, during which CH_4 and CO_2 are released. If conditions are constant, the rate of CH_4 production depends solely on the amount of carbon remaining in the waste. As a result, CH_4 emissions are highest in the first few years after waste is initially deposited in a disposal site, then gradually decline as the degradable carbon in the waste is consumed by the bacteria responsible for the decay. The FOD method provides a more accurate estimate of annual emissions—and is recommended in *IPCC Guidelines*—but it requires historical waste disposal information that might not be readily available. Cities may estimate historic data by method provided in section 8.3.1.
- **Methane commitment (MC)** assigns landfill emissions based on waste disposed in a given year. It takes a lifecycle and mass-balance approach and calculates landfill emissions based on the amount of waste disposed in a given year, regardless of when the emissions actually occur (a portion of emissions are released every year after the waste is disposed). For most cities, the MC method will consistently overstate GHG emissions by assuming that all DOC disposed in a given year will decay and produce methane immediately.

Table 8.2 provides a simplified comparison between these two methods based on user considerations, including consistency with national inventories, data availability, etc.

8.3.1 First order of decay (FOD) model

Due to the complexity of this model, the GPC recommends that cities use the IPCC Waste Model[53] (2006), which provides two options for the estimation of emissions from solid waste that can be chosen depending on the available activity data. The first option is a multi-phase model based on waste composition data. The second option is single-phase model based on bulk waste (solid waste). Emissions from industrial waste and sludge are estimated in a similar way to bulk solid waste. When waste composition is relatively stable, both options give similar results. However, when rapid changes in waste composition occur, the different calculation options may yield different results.

Cities should seek to identify actual historical waste disposal information, but in its absence cities can estimate historic waste and related emissions based on total waste in place,

53. An Excel version of the IPCC Waste Model tool can be downloaded online at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/5_Volume5/IPCC_Waste_Model.xls

Table 8.2 Comparing Methane Commitment to First Order Decay method

User Consideration	Methane commitment (MC)	First Order of Decay (FOD)
Simplicity of implementation, data requirements	**Advantage:** Based on quantity of waste disposed during inventory year, requiring no knowledge of prior disposal.	**Disadvantage:** Based on quantity of waste disposed during inventory year as well as existing waste in landfill(s). Requires historic waste disposal information.
Consistency with annualized emissions inventories	**Disadvantage:** Does not represent GHG emissions during inventory year. Rolls together current and future emissions and treats them as equal. Inconsistent with other emissions in the inventory.	**Advantage:** Represents GHG emissions during the inventory year, consistent with other emissions in the inventory.
Decision-making for future waste management practices	**Disadvantage:** May lead to overestimation of emission reduction potential.	**Advantage:** Spreads benefits of avoided landfill disposal over upcoming years.
Credit for source reduction/recycling	**Advantage:** Accounts for emissions affected by source reduction, reuse, and recycling.	**Disadvantage:** For materials with significant landfill impacts, FOD not as immediately sensitive to source reduction, reuse, and recycling efforts.
Credit for engineering controls, heat/power generation	**Disadvantage:** Doesn't count current emissions from historic waste in landfills, thus downplaying opportunities to reduce those emissions via engineering controls.	**Advantage:** Suitable for approximating amount of landfill gas available for flaring, heat recovery, or power generation projects.
Credit for avoided landfill disposal	**Disadvantage:** Overstates short-term benefits of avoided landfill disposal.	**Advantage:** Spreads benefits of avoided landfill disposal over upcoming years, minimizing overestimation of emission reduction potential.
Accuracy	**Disadvantage:** Requires predicting future gas collection efficiency and modeling parameters over the life of future emissions.	**Advantage:** More accurate reflects total emissions occurring in the inventory year.

years of operation, and population data over time. The starting and ending years for the annual disposal inputs to the FOD model can be determined as long as any of the following additional data are available:

1. Site opening and closing year
2. Site opening year, total capacity (in m^3), and density conversion (Mg/m^3)
3. Current waste in place and site closure date or capacity (with conversion to Mg)

With this information, the IPCC Waste Model (2006) model outlined above can be used. The iterative process of FOD model is illustrated in Equation 8.2.

8.3.2 Methane commitment model

Downstream emissions associated with solid waste sent to landfill during the inventory year can be calculated using the following equation for each landfill:

Methane generation potential, L_0

Methane generation potential (L_0) is an emission factor that specifies the amount of CH_4 generated per tonne of solid waste. L_0 is based on the portion of degradable organic carbon (DOC) that is present in solid waste, which is in turn based on the composition of the waste stream. L_0 can also vary depending on the characteristics of the landfill. Unmanaged landfills produce less CH_4 from a

Equation 8.2 First order of decay (FOD) model estimate for solid waste sent to landfill

$$CH_4 \text{ emissions} = \{ \textstyle\sum_x [MSW_x \times L_0(x) \times ((1 - e^{-k}) \times e^{-k(t-x)})] - R(t)\} \times (1 - OX)$$

Description			Value
CH_4 emissions	=	Total CH_4 emissions in tonnes	Computed
x	=	Landfill opening year or earliest year of historical data available	User input
t	=	Inventory year	User input
MSW_x	=	Total municipal solid waste disposed at SWDS in year x in tonnes	User input
R	=	Methane collected and removed (ton) in inventory year	User input
L_0	=	Methane generation potential	Consult equation 8.4
k	=	Methane generation rate constant, which is related to the time taken for the DOC in waste to decay to half its initial mass (the "half-life")	User Input or consult default value in table 3.4 of 2006 IPCC guidelines, vol. 3: waste, chapter 3: solid waste disposal, p. 3.17
OX	=	Oxidation factor	0.1 for well-managed landfills; 0 for unmanaged landfills

Source: IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)

Equation 8.3 Methane commitment estimate for solid waste sent to landfill

$$CH_4 \text{ emissions} = MSW_x \times L_0 \times (1\text{-}f_{rec}) \times (1\text{-}OX)$$

Description			Value
CH_4 emissions	=	Total CH_4 emissions in metric tonnes	Computed
MSW_x	=	Mass of solid waste sent to landfill in inventory year, measured in metric tonnes	User input
L_0	=	Methane generation potential	Equation 8.4 Methane generation potential
f_{rec}	=	Fraction of methane recovered at the landfill (flared or energy recovery)	User input
OX	=	Oxidation factor	0.1 for well-managed landfills; 0 for unmanaged landfills

Source: Adapted from *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*

Equation 8.4 Methane generation potential, L_0

$$L_0 = MCF \times DOC \times DOC_F \times F \times 16/12$$

Description			Value
L_0	=	Methane generation potential	Computed
MCF	=	Methane correction factor based on type of landfill site for the year of deposition (managed, unmanaged, etc., fraction)	Managed = 1.0 Unmanaged (≥5 m deep) = 0.8 Unmanaged (<5 m deep) = 0.4 Uncategorized = 0.6
DOC	=	Degradable organic carbon in year of deposition, fraction (tonnes C/tonnes waste)	Equation 8.1
DOC_F	=	Fraction of DOC that is ultimately degraded (reflects the fact that some organic carbon does not degrade)	Assumed equal to 0.6
F	=	Fraction of methane in landfill gas	Default range 0.4-0.6 (usually taken to be 0.5)
16/12	=	Stoichiometric ratio between methane and carbon	

Source: IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)

given amount of waste than managed landfills because a larger fraction of waste decomposes aerobically in the top layers of a landfill. Wetter waste (including precipitation impacts) will correspond with a lower DOC. L_0 can be determined using the IPCC equation (see equation 8.4).

8.4 Calculating emissions from biological treatment of solid waste

The biological treatment of waste refers to composting and anaerobic digestion of organic waste, such as food waste, garden and park waste, sludge, and other organic waste sources. Biological treatment of solid waste reduces overall waste volume for final disposal (in landfill or incineration) and reduces the toxicity of the waste.

In cases where waste is biologically treated (e.g., composting), cities shall report the CH_4, N_2O and non-biogenic CO_2 emissions associated with the biological treatment of waste based upon the amount of city-generated waste treated in the analysis year. In cases where a city does not incinerate or biologically treat the waste, these emissions categories can be labeled as "Not Occurring."

Data on composting and anaerobic treatment should be collected separately, in order to use different sets of emission factors. Where there is gas recovery from anaerobic digestion, cities should subtract recovered gas amount from total estimated CH_4 to determine net CH_4 from anaerobic digestion.

8.5 Calculating emissions from waste incineration and open burning

Incineration is a controlled, industrial process, often with energy recovery where inputs and emissions can be measured and data is often available. By contrast, open burning is an uncontrolled, often illicit process with different emissions and can typically only be estimated based on collection rates. Users should calculate emissions from incineration and open burning separately, using different data. Cities shall report the CH_4, N_2O and non-biogenic CO_2 emissions associated with waste combustion based

Equation 8.5 Direct emissions from biologically treated solid waste

$$CH_4 \text{ Emissions} = (\textstyle\sum_i (m_i \times F\_CH4_i) \times 10^{-3} - R)$$

$$N_2O \text{ Emissions} = (\textstyle\sum_i (m_i \times EF\_N2O_i) \times 10^{-3})$$

Description			Value
CH_4 emissions	=	Total CH_4 emissions in tonnes	Computed
N_2O emissions	=	Total N_2O emissions in tonnes	Computed
m	=	Mass of organic waste treated by biological treatment type i, kg	User input
EF_ CH4	=	CH_4 emissions factor based upon treatment type, i	User input or default value from table 8.3 Biological treatment emission factor
EF_ N2O	=	N_2O emissions factor based upon treatment type, i	User input or default value User input or default value from table 8.3 Biological treatment emission factor
i	=	Treatment type: composting or anaerobic digestion	User input
R	=	Total tonnes of CH_4 recovered in the inventory year, if gas recovery system is in place	User input, measured at recovery point

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 4: Biological Treatment of Solid Waste

Table 8.3 Biological treatment emission factors

Treatment type	CH_4 Emissions Factors (g CH_4/ kg waste)		N_2O Emissions Factors (g N_2O /kg waste)	
	Dry waste	Wet waste	Dry waste	Wet waste
Composting	10	4	0.6	0.3
Anaerobic digestion at biogas facilities	2	1	N/A	N/A

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 4: Biological Treatment of Solid Waste

upon the amount of city-generated waste incinerated in the analysis year.

CO_2 emissions associated with incineration facilities can be estimated based on the mass of waste incinerated at the facility, the total carbon content in the waste, and the fraction of carbon in the solid waste of fossil origin.

Non-CO_2 emissions, such as CH_4 and N_2O, are more dependent on technology and conditions during the incineration process. For further information, cities should follow the quantification guidelines outlined in the *2006 IPCC Guidelines* (Volume 5, Chapter 5).

To calculate emissions from waste incineration, cities must identify:

- Quantity (mass) of total solid waste incinerated in the city, and the portion of waste generated by other communities and incinerated in the inventory analysis year (if calculating for in-boundary incineration facilities)
- Type of technology and conditions used in the incineration process
- "Energy transformation efficiency" (applies to incineration with energy recovery)

Equation 8.6 Non-biogenic CO_2 emissions from the incineration of waste

$$\mathbf{CO_2\ Emissions} =$$
$$m \times \sum_i (WF_i \times dm_i \times CF_i \times FCF_i \times OF_i) \times (44/12)$$

Description			Value
CO_2 emissions	=	Total CO_2 emissions from incineration of solid waste in tonnes	Computed
m	=	Mass of waste incinerated, in tonnes	User input
WF_i	=	Fraction of waste consisting of type i matter	User input[54]
dm_i	=	Dry matter content in the type i matter	User input (default values provided in Table 8.4 below)
CF_i	=	Fraction of carbon in the dry matter of type i matter	
FCF_i	=	Fraction of fossil carbon in the total carbon component of type i matter	
OF_i	=	Oxidation fraction or factor	
i	=	Matter type of the Solid Waste incinerated such as paper/cardboard, textile, food waste, etc.	

Note: $\sum_i WF_i = 1$

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories

54. Default data available in *2006 IPCC Guidelines*, Vol. 5, Ch. 2, Table 2.4

Table 8.4 **Default data for CO_2 emission factors for incineration and open burning**

Parameters	Management practice	MSW	Industrial Waste (%)	Clinical Waste (%)	Sewage Sludge (%)[Note 4]	Fossil liquid waste (%)[Note 5]
Dry matter content in % of wet weight		(see Note 1)	NA	NA	NA	NA
Total carbon content in % of dry weight		(see Note 1)	50	60	40 – 50	80
Fossil carbon fraction in % of total carbon content		(see Note 2)	90	40	0	100
Oxidation factor in % of carbon input	Incineration	100	100	100	100	100
	Open-burning (see Note 3)	58	NO	NO	NO	NO

Note 1: Use default data from Default data available in *2006 IPCC Guidelines*, Vol. 5, Ch. 2, Table 2.4 in Section 2.3 Waste composition and equation 5.8 (for dry matter), Equation 5.9 (for carbon content) and Equation 5.10 (for fossil carbon fraction) in *2006 IPCC Guidelines*, Vol. 5, Ch. 5
Note 2: Default data by industry type is given in *2006 IPCC Guidelines*, Vol. 5, Ch. 2 Table 2.5 in Section 2.3 Waste composition. For estimation of emissions, use equations mentioned in Note 1.
Note 3: When waste is open-burned, refuse weight is reduced by approximately 49 to 67 percent (US-EPA, 1997, p.79). A default value of 58 percent is suggested.
Note 4: See Section 2.3.2 Sludge in Chapter 2.
Note 5: Fossil liquid waste is here defined as industrial and municipal residues, based on mineral oil, natural gas or other fossil fuels. It includes waste formerly used as solvents and lubricants. It does not include wastewater, unless it is incinerated (e.g., because of a high solvent content) The total carbon content of fossil liquid waste is provided in percent of wet weight and not in percent of dry weight (GIO, 2005).
References: *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 5, chapter 5: Incineration and Open Burning of Waste

Equation 8.7 **CH_4 emissions from the incineration of waste**

$$CH_4\ \text{Emissions} = \sum(IW_i \times EF_i) \times 10^{-6}$$

Description			Value
CH_4 Emissions	=	CH_4 emissions in inventory year, tonnes	Computed
IW_i	=	Amount of solid waste of type i incinerated or open-burned, tonnes	User Input
EF_i	=	Aggregate CH_4 emission factor, g CH_4/ton of waste type i	User Input (default values provided in Table 8.5 below)
10^{-6}	=	Converting factor from gCH_4 to t CH_4	
i	=	Category or type of waste incinerated/open-burned, specified as follows: MSW municipal solid waste, ISW: industrial solid waste, HW: hazardous waste, CW: clinical waste, SS: sewage sludge, others (that must be specified)	User input

Table 8.5 CH_4 **emission factors for incineration of MSW**

Type of premises	Temporary	Permanent
Continuous incineration	stoker	0.2
	fluidised bed Note1	~0
Semi-continuous incineration	stoker	6
	fluidised bed	188
Batch type incineration	stoker	60
	fluidised bed	237

Note: In the study cited for this emission factor, the measured CH_4 concentration in the exhaust air was lower than the concentration in ambient air.
Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, chapter 5: Incineration and Open Burning of Waste

Equation 8.8 N_2O emissions from the incineration of waste

$$N_2O\ \text{Emissions} = \sum(IW_i \times EF_i) \times 10^{-6}$$

Description			Value
N_2O Emissions	=	N_2O emissions in inventory year, in tonnes	Computed
IW_i	=	Amount of solid waste of type i incinerated or open-burned, in tonnes	User Input
EF_i	=	Aggregate N_2O emission factor, g CH_4/ton of waste type i	User Input (default values provided in Table 8.6 below)
i	=	Category or type of waste incinerated/open-burned, specified as follows: MSW: municipal solid waste, ISW: industrial solid waste, HW: hazardous waste, CW: clinical waste, SS: sewage sludge, others (that must be specified)	User input

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, chapter 5: Incineration and Open Burning of Waste

Table 8.6 Default N_2O emission factors for different types of waste and management practices

Type of waste	Technology / Management practice	Emission factor (g N_2O / t waste)	weight basis
MSW	continuous and semi-continuous incinerators	50	wet weight
MSW	batch-type incinerators	60	wet weight
MSW	open burning	150	dry weight
Industrial waste	all types of incineration	100	wet weight
Sludge (except sewage sludge)	all types of incineration	450	wet weight
Sewage sludge	incineration	990	dry weight
		900	wet weight

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, chapter 5: Incineration and Open Burning of Waste

8.6 Calculating emissions from wastewater treatment

Municipal wastewater can be treated aerobically (in presence of oxygen) or anaerobically (in absence of oxygen). When wastewater is treated anaerobically, methane (CH_4) is produced. Both types of treatment also generate nitrous oxide (N_2O) through the nitrification and denitrification of sewage nitrogen. N_2O and CH_4 are potent GHGs that are accounted for during wastewater treatment, while CO_2 from wastewater treatment is considered to be of biogenic origin and reported outside the scopes.

There are a variety of ways wastewater is handled, collected, and treated. Distinctions between capacities and methods of wastewater handling vary greatly country-to-country and city-to-city. Depending on the wastewater source, it can generally be categorized as domestic wastewater or industrial wastewater, and cities must report emissions from both. Domestic wastewater is defined as wastewater from household water use, while industrial wastewater is from industrial practices only. Industrial wastewater may be treated on-site or released into domestic sewer systems. Any wastewater released into the domestic sewer system, those emissions should be included with the domestic wastewater emissions.

8.6.1 Calculating methane emissions from wastewater treatment and handling

In order to quantify the methane emissions from both industrial and domestic wastewater treatment, cities will need to know:

- The quantity of wastewater generated.
- How wastewater and sewage are treated (see Box 8.3 for information on wastewater discharge directly into open bodies of water).
- The wastewater's source and its organic content. This can be estimated based on population of the cities served and the city's composition in the case of domestic wastewater, or the city's industrial sector in the case of industrial waste water.
- Proportion of wastewater treated from other cities at facilities located within the city's boundaries (this can be estimated based upon other cities' population served).

Box 8.3 Estimating emissions from wastewater directly discharged into an open body of water

In many developing countries, wastewater is directly discharged into open lakes, rivers or oceans. Cities may assume negligible GHG emissions from this action due to the low concentration of organic content. However, if the wastewater is discharged into a stagnant open body of water, GHG emissions can be estimated using the specific COD/BOD value from the water body outlined in Equation 8.9.

The organic content of wastewater differs depending on whether the treatment is industrial or residential, as shown in Equation 8.9. The income group suggested in variable *i* influences the usage of treatment/pathway, and therefore influences the emission factor.

Equation 8.9 CH_4 generation from wastewater treatment

$$CH_4 \text{ emissions} = \sum_i [(TOW_i - S_i)\, EF_i - R_i] \times 10^{-3}$$

Description			Value
CH_4 emissions	=	Total CH_4 emissions in metric tonnes	Computed
TOW_i	=	Organic content in the wastewater **For domestic wastewater:** total organics in wastewater in inventory year, kg BOD/yr[Note 1] **For industrial wastewater:** total organically degradable material in wastewater from industry i in inventory year, kg COD/yr	Equation 8.10
EF_i	=	Emission factor kg CH_4 per kg BOD or kg CH_4 per kg COD[Note 2]	Equation 8.10
S_i	=	Organic component removed as sludge in inventory year, kg COD/yr or kg BOD/yr	User input
R_i	=	Amount of CH_4 recovered in inventory year, kg CH_4/yr	User input
i	=	Type of wastewater **For domestic wastewater:** income group for each wastewater treatment and handling system **For industrial wastewater:** total organically degradable material in wastewater from industry i in inventory year, kg COD/yr	Equation 8.10

Note 1: Biochemical Oxygen Demand (BOD): The BOD concentration indicates only the amount of carbon that is aerobically biodegradable. The standard measurement for BOD is a 5-day test, denoted as BOD_5. The term "BOD" in this chapter refers to BOD_5.

Note 2: Chemical Oxygen Demand (COD): COD measures the total material available for chemical oxidation (both biodegradable and non-biodegradable).

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, chapter 6: Wastewater Treatment and Discharge

Equation 8.10 Organic content and emission factors in domestic wastewater[55]

$$\mathbf{TOW_i} = P \times BOD \times I \times 365$$

$$\mathbf{EF_j} = B_o \times MCF_j \times U_i \times T_{i,j}$$

Description			Value
TOW_i	=	For domestic wastewater: total organics in wastewater in inventory year, kg BOD/yr	Computed
P		City's population in inventory year (person)	User input[56]
BOD	=	City-specific per capita BOD in inventory year, g/person/day	User input
I	=	Correction factor for additional industrial BOD discharged into sewers	In the absence of expert judgment, a city may apply default value 1.25 for collected wastewater, and 1.00 for uncollected.[57]
EF_i	=	Emission factor for each treatment and handling system	Computed
B_o	=	Maximum CH_4 producing capacity	User input or default value: • 0.6 kg CH_4/kg BOD • 0.25 kg CH_4/kg COD
MCF_j	=	Methane correction factor (fraction)	User input[58]
U_i	=	Fraction of population in income group i in inventory year	User input[59]
$T_{i,j}$	=	Degree of utilization (ratio) of treatment/discharge pathway or system, j, for each income group fraction i in inventory year	

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, chapter 6: Wastewater Treatment and Discharge

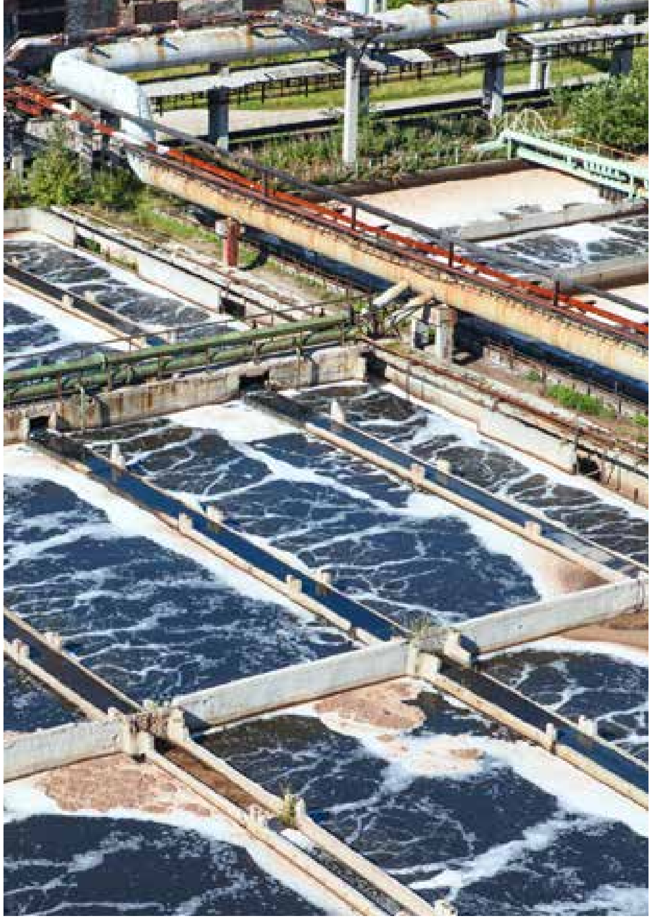
55. Due to the complexity, the GPC only provides guidance for assumption of TOW and EF for domestic wastewater treatment. For industrial wastewater treatment please consult section 6.2.3 of chapter 6, volume 5 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*.

56. If city-specific data are not available, city can consult national specific data or reference the default national value provided by *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (table 6.4 of Volume 5, Chapter 6: Wastewater Treatment and Discharge)

57. Based on expert judgment by the authors, it expresses the BOD from industries and establishments (e.g., restaurants, butchers or grocery stores) that is co-discharged with domestic wastewater. In some countries, information from industrial discharge permits may be available to improve *i*. Otherwise, expert judgment is recommended.

58. Or consult with default value provided by *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (table 6.3 (domestic) and table 6.8 (industrial) of Volume 5, Chapter 6: Wastewater Treatment and Discharge)

59. Or consult with default value provided by *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (table 6.5 of Volume 5, Chapter 6: Wastewater Treatment and Discharge)



8.6.2 Calculating nitrous oxide emissions from wastewater treatment and handling

Nitrous oxide (N_2O) emissions can occur as direct emissions from treatment plants or as indirect emissions from wastewater after disposal of effluent into waterways, lakes or seas. Direct emissions from nitrification and denitrification at wastewater treatment plants are considered as a minor source and not quantified here. Therefore, this section addresses indirect N_2O emissions from wastewater treatment effluent that is discharged into aquatic environments.

Equation 8.11 Indirect N_2O emissions from wastewater effluent

$$\textbf{N}_2\textbf{O emissions} = [(P \times Protein \times F_{NPR} \times F_{NON-CON} \times F_{IND-COM}) - N_{SLUDGE}] \times EF_{EFFLUENT} \times 44/28 \times 10^{-3}$$

Description			Value
N_2O emissions	=	Total N_2O emissions in tonnes	Computed
P	=	Total population served by the water treatment plant	User input
Protein	=	Annual per capita protein consumption, kg/person/yr	User input
$F_{NON-CON}$	=	Factor to adjust for non-consumed protein	1.1 for countries with no garbage disposals, 1.4 for countries with garbage disposals
F_{NPR}	=	Fraction of nitrogen in protein	0.16, kg N/kg protein
$F_{IND-COM}$	=	Factor for industrial and commercial co-discharged protein into the sewer system	1.25
N_{SLUDGE}	=	Nitrogen removed with sludge, kg N/yr	User input or default value: 0
$EF_{EFFLUENT}$	=	Emission factor for N_2O emissions from discharged to wastewater in kg N_2O-N per kg N_2O	0.005
44/ 28	=	The conversion of kg N_2O-N into kg N_2O	

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, chapter 6: Wastewater Treatment and Discharge

9 Industrial Processes and Product Use

GHG emissions can result from non-energy related industrial activities and product uses. All GHG emissions occurring from industrial processes, product use, and non-energy uses of fossil fuel, shall be assessed and reported under *IPPU*.

Requirements in this chapter

For BASIC+:

Cities shall report all GHG emissions from IPPU in scope 1.

9.1 Categorizing IPPU emissions by scope

Scope 1: Emissions from industrial processes and product uses occurring within the city

Scope 2: Not applicable
All emissions from the use of grid-supplied electricity in industrial or manufacturing facilities within the city boundary shall be reported under scope 2 in *Stationary Energy, manufacturing industry and construction* (I.3.2).

Scope 3: Other out-of-boundary emissions
Emissions from *IPPU* outside the city are not included in the inventory boundary but may be reported under *Other Scope 3* emissions as appropriate.

These emission sources and their scope categorization are summarized in Table 9.1.

9.2 Defining industrial processes and product uses

The industrial processes and product uses included in this category are summarized in Table 9.2.

9.2.1 Separating IPPU GHG emissions and energy-related GHG emissions

Allocation of emissions from the use of fossil fuel between the *Stationary Energy* and *IPPU* sectors can be complex.

Table 9.1 IPPU Overview

GHG Emission Source	Scope 1	Scope 2	Scope 3
INDUSTRIAL PROCESSES AND PRODUCT USE	Emissions from industrial processes and product use occurring within the city boundary		
Industrial processes	IV.1		
Product use	IV.2		

Sources required for BASIC+ reporting

Non-applicable emissions

Sources included in Other Scope 3

Table 9.2 Example industrial processes and product uses

GHG emission sources	Example industrial processes or product use
GHG emissions from industrial processes	• Production and use of mineral products (Section 9.3.1) • Production and use of chemicals (Section 9.3.2) • Production of metals (Section 9.3.3)
GHG emissions from product use	• Lubricants and paraffin waxes used in non-energy products (Section 9.4.1) • FC gases used in electronics production (Section 9.4.2) • Fluorinated gases used as substitutes for Ozone depleting substances (Section 9.4.3)

The GPC follows *IPCC Guidelines*,[60] which define "fuel combustion" in an industrial process context as: *"the intentional oxidation of material within an apparatus that is designed to provide heat or mechanical work to a process, or for use away from the apparatus."*

Therefore:

- If the fuels are combusted for energy use, the emission from fuel uses shall be counted under *Stationary Energy*.
- If the derived fuels are transferred for combustion in another source category, the emissions shall be reported under *Stationary Energy*.
- If combustion emissions from fuels are obtained directly or indirectly from the feedstock, those emissions shall be allocated to *IPPU*.

60. Box 1.1 from *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3 IPPU, Chapter 1 introduction.

- If heat is released from a chemical reaction, the emissions from that chemical reaction shall be reported as an industrial process in *IPPU*.

CO_2 capture and storage

In certain *IPPU* categories, particularly large point sources of emissions, there may be emissions capture for recovery and use, or destruction. Cities should identify detailed city-specific or plant-level data on capture and abatement activities, and any abatement totals should be deducted from the emission total for that sub-sector or process.

9.3 Calculation guidance for industrial processes

GHG emissions are produced from a wide variety of industrial activities. The main emission sources are releases from industrial processes that chemically or physically transform materials (e.g., the blast furnace in the iron and steel industry, and ammonia and other chemical products manufactured from fossil fuels used as chemical feedstock). During these processes, many different GHGs, including CO_2, CH_4, N_2O, HFCs and PFCs, can be produced. The following sections will illustrate a methodological guide for emissions from industrial processes by industrial type.

9.3.1 Mineral industry emissions

Three industrial processes are highlighted under the mineral industry: cement production, lime production, and glass production. For these processes, the release of CO_2 is the calcination of carbonate compounds, during which—through heating—a metallic oxide is formed. A typical calcination reaction for the mineral calcite (or calcium carbonate) is shown in Equation 9.1.

To calculate mineral industry emissions, cities will need to know:

- Major mineral production industries within the city boundary
- Annual mineral product output and raw material consumption in the industrial process
- Emission factor of raw material or product

Cities should use factory-specific production data and regionally-specific emission factors. If a city does not have access to factory-specific data, IPCC methodologies and data sources are listed in Table 9.3.

Simplified formulae for calculating emissions from these mineral industrial processes are illustrated in Equations 9.2–9.4.

Equation 9.1 Calcination example

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2$$

Table 9.3 Calculating mineral industry emissions

Emission sources	GHG emissions	Simplest approach for quantifying emissions[61]	Source of active data	Link to default emission factor calculation
Cement production	CO_2	Emission factor multiplied with weight (mass) of Clinker produced	• Contact the operators or owners of the industrial facilities at which the processes occur and obtain relevant activity data. • Contact national inventory compiler to ask for specific production data within the city boundary.	2.2.1.2 of Page 2.11 from Chapter 2 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Lime production		Emission factor multiplied with weight (mass) of each type of lime produced		Table 2.4 of Page 2.22 from Chapter 2 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Glass production		Emission factor multiplied with weight (mass) melted for each type of glass produced		Table 2.6 of Page 2.30 from Chapter 2 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*

61. The GPC utilizes the IPCC's more simplified Tier 1 method—which involves using default IPCC data—when accounting for emissions from the mineral industry, and other industries outlined in this chapter. If users have facility-specific production data and emission factors they should consult the tier 2 and tier 3 methods found in *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3.

Equation 9.2 Emissions from cement production

$$CO_2 \text{ emissions} = M_{cl} \times EF_{cl}$$

Description			Value
CO_2 emissions	=	CO_2 emissions in tonnes	Computed
M_{cl}	=	Weight (mass) of clinker produced in metric tonnes	User input
EF_{cl}	=	CO_2 per mass unit of clinker produced (e.g., CO_2/tonne clinker)	User input or default value

Equation 9.3 Emissions from lime production

$$CO_2 \text{ emissions} = \sum(EF_{lime,i} \times M_{lime,\,i})$$

Description			Value
CO_2 emissions	=	CO_2 emissions in tonnes	Computed
M_{lime}	=	Weight (mass) of lime produced of lime type i in metric tonnes	User input
EF_{lime}	=	CO_2 per mass unit of lime produced of lime type i (e.g. CO_2/tonne lime of type i)	User input or default value
i	=	Type of lime	

Equation 9.4 Emissions from glass production

$$CO_2 \text{ emissions} = M_g \times EF \times (1-CR)$$

Description			Value
CO_2 emissions	=	CO_2 emissions in tonnes	Computed
M_{cl}	=	Mass of melted glass of type i (e.g., float, container, fiber glass, etc.), tonnes	User input
EF_{cl}	=	Emission factor for manufacturing of glass of type i, tonnes CO_2/tonne glass melted	User input or default value
CR_i		Cullet ratio[62] for manufacturing of glass of type i	User input or default value

62. In practice, glass makers recycle a certain amount of scrap glass (cullet) when making new glass. Cullet ratio is the fraction of the furnace charge represented by cullet.

9.3.2 Chemical industry emissions

GHG emissions arise from the production of various inorganic and organic chemicals, including:

- Ammonia
- Nitric acid
- Adipic acid
- Caprolactam, glyoxal, and glyoxylic acid
- Carbide
- Titanium dioxide
- Soda ash

Emissions from the chemical industry depend on the technology used. Cities need to know:

- Major chemical production industry within the city boundaries
- Annual mineral product output and raw material consumption in the industrial process
- Technology used in the industrial process
- Emission factors of different product/raw material in different production technology

Cities should obtain industrial facility data and emission factors from:

- Continuous emissions monitoring (CEM), where emissions are directly measured at all times
- Periodic emissions monitoring undertaken over a period(s) that is reflective of the usual pattern of the plant's operation to derive an emission factor that is multiplied by output to derive emissions
- Irregular sampling to derive an emission factor that is multiplied by output to derive emissions

If a city does not have access to factory-specific data for the chemical industry, IPCC methods are outlined in Table 9.4.

9.3.3 Emissions from metal industry

GHG emissions can result from the production of iron steel and metallurgical coke, ferroalloy, aluminum, magnesium, lead and zinc.

Emissions from metal industry depend on the technology and raw material type used in production processes. In order to estimate metal industry emissions, cities need to know:

- Major metal production industry within the city boundaries
- Annual metal production output and different types of raw material consumption
- Technology used in the metal production process
- Emission factors of different product/raw material in different production technology

Cities should seek data and emission factors from:

- CEM where emissions are directly measured at all times
- Periodic emissions monitoring that is undertaken over a period(s) that is reflective of the usual pattern of the plant's operation to derive an emission factor that is multiplied by output to derive emissions
- Irregular sampling to derive an emission factor that is multiplied by output to derive emissions

If a city does not have access to factory-specific data for the metal industry, IPCC methods are outlined in Table 9.5.

Attachment Item 14B

Table 9.4 Calculating chemical industry emissions

Emission sources	GHG emissions	Simplest approach for quantifying emissions	Source of active data	Link to default emission factor calculation
Ammonia production	CO_2	Ammonia production multiplied by fuel emission factor	• Contact the operators or owners of the industrial facilities at which the processes occur and obtain relevant activity data • Contact national inventory compiler to ask for specific production data within the city boundary	Table 3.1 of Page 3.15 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Nitric acid production	N_2O	Nitric acid production multiplied by default emission factor		Table 3.3 of Page 3.23 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Adipic acid production	N_2O	Adipic acid production multiplied by default emission factor		Table 3.4 of Page 3.15 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Caprolactam production	N_2O	Caprolactam production multiplied by default emission factor		Table 3.5 of Page 3.36 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Carbride production	CO_2 and CH_4	Carbride production multiplied by default emission factor		Table 3.7 of Page 3.44 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Titanium dioxide production	CO_2	Titanium slag production multiplied by default emission factor		Table 3.9 of Page 3.49 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Soda ash production	CO_2	Soda ash production, or Trona used, multiplied by default emission factor		Table 3.1 of Page 3.15 from Chapter 3 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*

Table 9.5 Metal industry

Emission sources	GHG emissions	Simplest approach for quantifying emissions	Source of active data	Link to default emission factor calculation
Metallurgical coke production	CO_2, CH_4	Assume that all coke made onsite at iron and steel production facilities is used onsite. Multiply default emission factors by coke production to calculate CO_2 and CH_4 emissions	Governmental agencies responsible for manufacturing statistics, business or industry trade associations, or individual iron and steel companies	Table 4.1 and Table 4.2 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Iron and steel production		Multiply default emission factors by iron and steel production data		
Ferroalloy production	CO_2, CH_4	Multiply default emission factors by ferroalloy product type		Table 4.5 and Table 4.7 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Aluminum production	CO_2	Multiply default emission factors by aluminum product by different process	Aluminum production facilities	Table 4.10 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Magnesium production	CO_2	Multiply default emission factors by Magnesium product by raw material type	The magnesium production, casted/ handled data and raw material type may be difficult to obtain. Inventory compiler may consult industry associations such as the International Magnesium Association.	Table 4.19 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
	SF_6	Assume all SF_6 consumption in the magnesium industry segment is emitted as SF Estimate SF_6 by multiplying default emission factors by total amount of magnesium casted or handled.		Table 4.20 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
	HFC and other GHG emissions[63]	For HFC and other GHG gases, collect direct measurements or meaningful indirect data		Not applicable
Lead production	CO_2	Multiply default emission factors by lead products by sources and furnace type	Governmental agencies responsible for manufacturing statistics, business or industry trade associations, or individual lead and zinc producers	Table 4.21 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Zinc production	CO_2	Multiply default emission factors by zinc production		Table 4.24 from Chapter 4 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*

63. Others include fluorinated ketone and various fluorinated decomposition products e.g., PFCs

Table 9.6 **Non-energy product uses of fuels and other chemical products**

Types of fuels used	Examples of non-energy uses	Gases
Lubricants	Lubricants used in transportation and industry	CO_2
Paraffin waxes	Candles, corrugated boxes, paper coating, board sizing, adhesives, food production, packaging	
Bitumen; road oil and other petroleum diluents	Used in asphalt production for road paving	(NMVOC, CO)[64]
White spirit,[65] kerosene,[66] some aromatics	As solvent, e.g., for surface coating (paint), dry cleaning	

9.4 Calculating product use emissions

Products such as refrigerants, foams or aerosol cans can release potent GHG emissions. HFCs, for example, are used as alternatives to ozone depleting substances (ODS) in various types of product applications. Similarly, SF_6 and N_2O are present in a number of products used in industry (e.g., electrical equipment and propellants in aerosol products), and used by end-consumers (e.g., running shoes and anesthesia). The following methodological guide is listed according to the type of common product uses.

9.4.1 Non-energy products from fuels and solvent use

This section provides a method for estimating emissions from the use of fossil fuels as a product for primary purposes (but not for combustion or energy production). The main types of fuel usage and their emissions can be seen in Table 9.6.

Fuel and solvents are consumed in industrial processes. To estimate emissions on a mass-balance approach, cities need to know:

- Major fuel and solvent used within the city boundaries
- Annual consumption of fuels and solvent
- Emission factors for different types of fuel and solvent consumption

Cities should obtain facility-specific fuel/solvent consumption data and their respective uses with city-specific emission factors. If unavailable, IPCC methods are detailed in Table 9.7.

Equation 9.5 **CO_2 emissions from non-energy product uses**

$$CO_2 \text{ Emissions} = \sum_i (NEU_i \times CC_i \times ODU_i) \times 44/12$$

NEU_i	=	non-energy use of fuel i, TJ
CC_i	=	specific carbon content of fuel i, tonne C/TJ (=kg C/GJ)
ODU_i	=	ODU factor for fuel i, fraction
44/12	=	mass ratio of CO_2/C

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 3 Industrial Processes and Product Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol3.html

64. NMVOC and CO are not covered by the GPC, but are included in *IPCC Guidelines.*

65. Also known as mineral turpentine, petroleum spirits, or industrial spirit ("SBP").

66. Also known as paraffin or paraffin oils (UK, South Africa).

CO_2 emissions from all product uses can be estimated by following Equation 9.5.

In this equation, ODU represents the fraction of fossil fuel carbon that is *oxidized during use* (ODU), e.g., actual co-combustion of the fraction of lubricants that slips into the combustion chamber of an engine. The sources of data and default value links can be found in Table 9.7.

9.4.2 Calculating emissions from the electronics industry

This section includes methods to quantify GHG emissions from semiconductors, thin-film-transistor flat panel displays, and photovoltaic manufacturing (collectively termed "electronics industry"). Several advanced electronics manufacturing processes utilize fluorinated compounds (FC) for plasma etching intricate patterns, cleaning reactor chambers, and temperature control, all of which emit GHGs.

To estimate the fluorinated gas emissions from the electronics industry, cities need to know:

- Major electronic production industries within the city boundaries
- Annual production capacity of the industrial facility
- FC emission control technology used
- Gas fed-in and destroyed by the FC emission control system

Cities should contact electronic production facilities to obtain facility-specific emissions data. If facility-specific data are not available, cities can use IPCC methods outlined in Table 9.8.

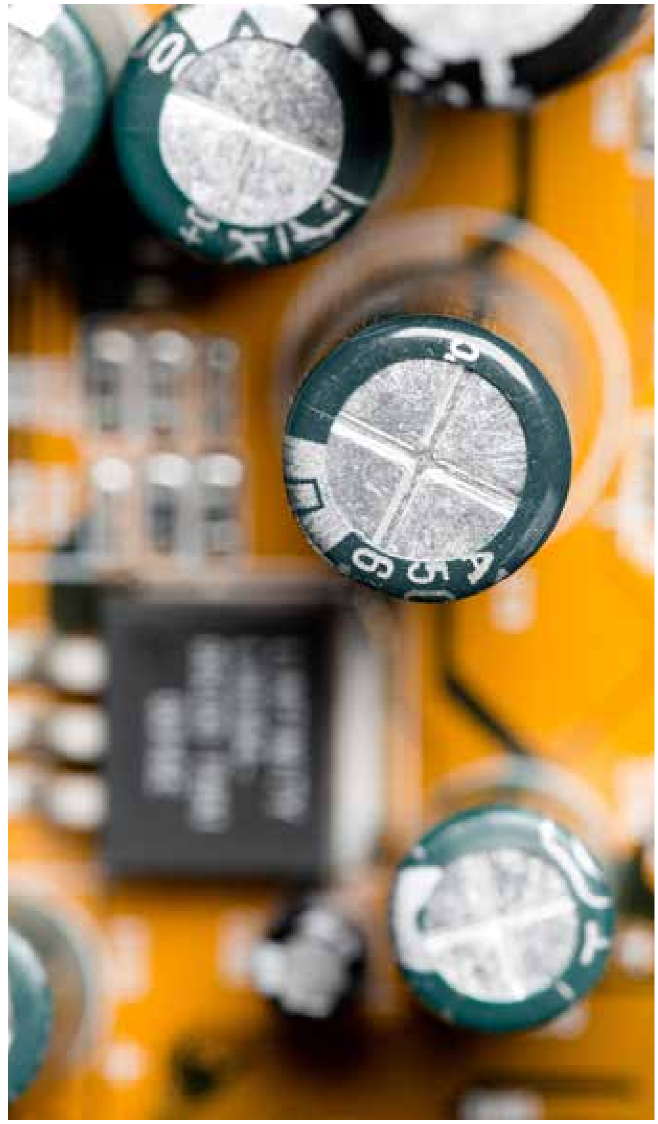


Table 9.7 Non-energy product emissions

Types of fuels used	Examples of non-energy uses	GHG emissions	Source of active data	Link to default emission factor calculation
Lubricants	Lubricants used in transportation and industry	CO_2	Basic data on non-energy products used in a country may be available from production, import and export data and on the energy/non-energy use split in national energy statistics.	Method 1, Chapter 5 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (p. 5.9)
Paraffin waxes	Candles, corrugated boxes, paper coating, board sizing, adhesives, food production, packaging			Chapter 5 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (section 5.3.2.2, page 5.12)

Table 9.8 Calculating emissions from the electronics industry

Electronics production processes	GHG emissions	Simplest approach for quantifying emissions	Source of active data	Link to default emission factor calculation
Etching and CVD cleaning for semiconductors, liquid crystal displays and photovoltaic	HFCs PFCs SF_6 NF_3	Generic emissions factors are multiplied by the annual capacity utilization and the annual manufacturing design capacity of substrate processes	Inventory compilers will need to determine the total surface area of electronic substrates processed for a given year. Silicon consumption may be estimated using an appropriate edition of the World Fab Watch (WFW) database, published quarterly by Semiconductor Equipment & Materials International (SEMI). The database contains a list of plants (production as well as R&D, pilot plants, etc.) worldwide, with information about location, design capacity, wafer size and much more. Similarly, SEMI's "Flat Panel Display Fabs on Disk" database provides an estimate of glass consumption for global TFT-FPD manufacturing	Table 6.2, Page 6.16 from Chapter 6 of Volume 3 of *2006 IPCC Guidelines for National Greenhouse Gas Inventories*
Heat transfer fluids		Generic emissions factors are multiplied by the average capacity utilization and design capacity		

9.4.3 Emissions from fluorinated substitutes for ozone depleting substances

HFCs and, to a very limited extent, PFCs, are serving as alternatives to ozone depleting substances (ODS) being phased out under the Montreal Protocol[67]. Current and expected application areas of HFCs and PFCs include[68]:

- Refrigeration and air conditioning
- Fire suppression and explosion protection
- Aerosols
- Solvent cleaning
- Foam blowing
- Other applications[69]

To estimate GHG emissions from these products, cities need to know:

- Major industry that uses fluorinated substitutes within the city boundaries
- Fluorinate gas purchase record by the major industry and their application

For accuracy, a city should contact a related facility to get plant-specific purchase and application data. Cities can use IPCC methods in Table 9.9 for default activity data and emission factors.

67. The Montreal Protocol on Substances that Deplete the Ozone Layer (a protocol to the Vienna Convention for the Protection of the Ozone Layer) is an international treaty designed to protect the ozone layer. It requires the reduction of production and consumption of substances that are responsible for ozone depletion.

68. IPPC.IPCC/TEAP special report on safeguarding the ozone layer and the global climate system: issues related to hydrofluorocarbons and perfluorocarbons. Intergovernmental Panel on Climate Change, 2005. http://www.ipcc.ch/publications_and_data/_safeguarding_the_ozone_layer.html.

69. HFCs and PFCs may also be used as ODS substitutes in sterilization equipment, for tobacco expansion applications, and as solvents in the manufacture of adhesives, coating and inks.

Table 9.9 Substitutes for ozone depleting substances

Substitutes for ozone depleting substances	GHG emissions	Simplest approach for quantifying emissions	Source of active data	Link to default emission factor calculation
Substitutes for ozone depleting substances	HFCs PFCs	Emission-factor approach: • Data on chemical sales by application • Emission factors by application Mass-balance approach: • Data on chemical sales by application • Data on historic and current equipment sales adjusted for import/export by application	Quantity of each chemical sold as substitutes for ozone-depleting substances. Data on both domestic and imported substitutes quantities should be collected from suppliers.	Users can search the IPCC Emissions Factor Database (EFDB) for datasets

Box 9.1 Calculating emissions from product use using a consumption-based approach

Product use emissions may also be calculated according to consumption activities within the city boundary. This approach estimates emissions based on where the products are purchased and/or used, rather than where they are produced.

Cities can apply both a bottom-up and top-down approach to estimate the consumption-based emissions from product use.

A bottom-up approach would involve identifying products purchased within the city boundary, the quantity and average lifetime of each product, as well as the average rate of emissions during use. A top-down approach, on the other hand, would take regional or national-level activity or emissions data and adjust to the inventory boundary using an appropriate scaling factor.

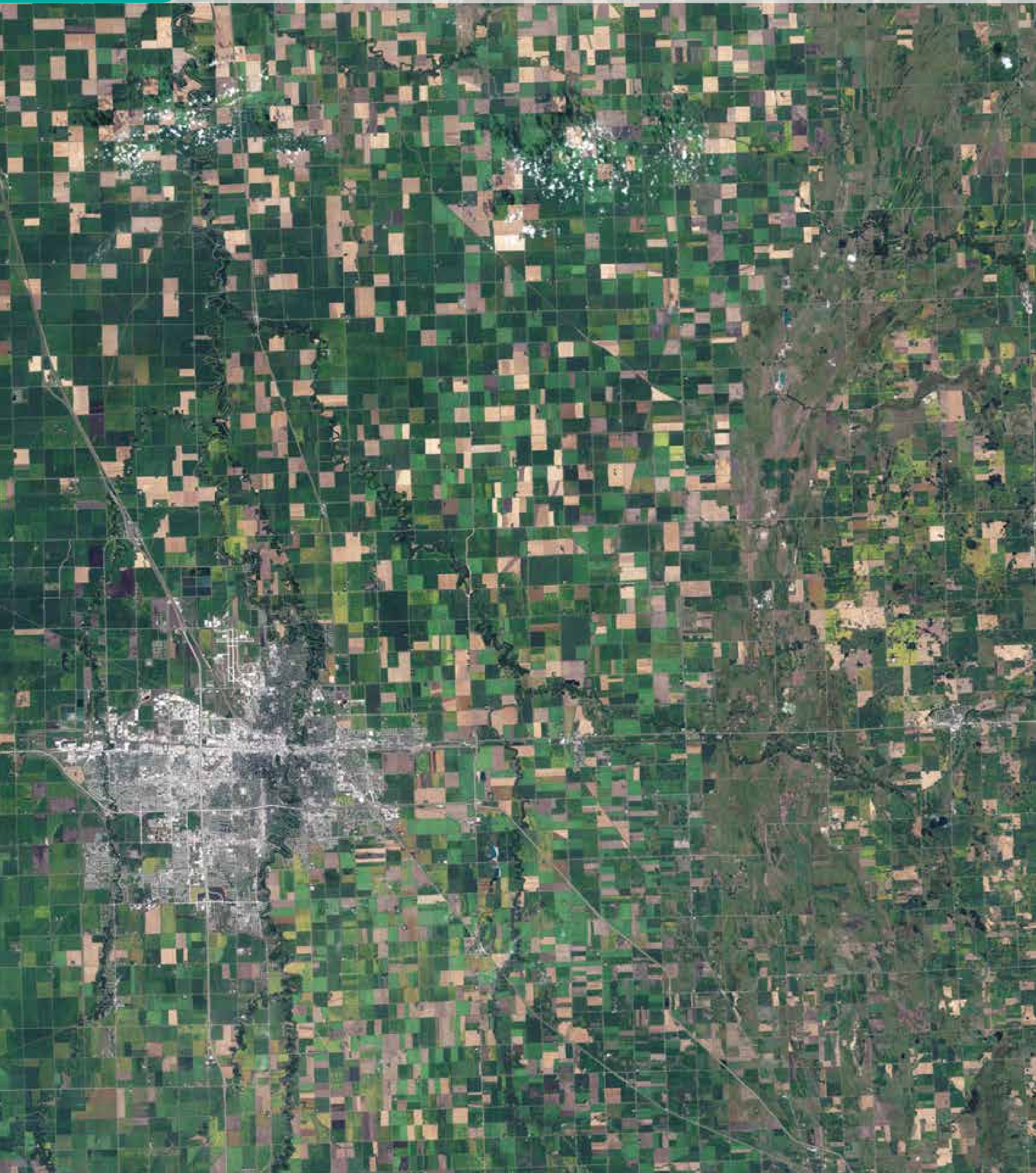
Case Study

Gibraltar used the consumption-based approach to calculate emissions from product use. With no industrial processes taking place within the city boundary and limited data on product use, Gibraltar used data from the National Atmospheric Emissions Inventory for the United Kingdom—which compiles estimates of emissions from UK sources, including crown dependencies and overseas territories, for submission to the UNFCCC—to calculate emissions from product use. Emissions were apportioned to the inventory boundary using a range of appropriate scaling factors:

Product use	Scaling factor
Aerosols	Population
Commercial refrigeration	GDP
Mobile air conditioning	Number of vehicles

Source: Ricardo-AEA (2014) A City-level Greenhouse Gas Inventory for Gibraltar.

10 Agriculture, Forestry and Other Land Use



The Agriculture, Forestry and Other Land Use (*AFOLU*) sector produces GHG emissions through a variety of pathways, including land-use changes that alter the composition of the soil, methane produced in the digestive processes of livestock, and nutrient management for agricultural purposes.

Requirements in this chapter

For BASIC+:

Cities shall report all GHG emissions resulting from the* AFOLU *sector within the city boundary in scope 1.

10.1 Categorizing *AFOLU* emissions by scope

Scope 1: In-boundary emissions from agricultural activity, land use and land use change within the city boundary
GHG emissions associated with the manufacture of nitrogen fertilizers, which account for a large portion of agricultural emissions, are not counted under *AFOLU*. *IPCC Guidelines* allocates these emissions to *IPPU*.

Scope 2: Not applicable
Emissions from use of grid-supplied energy in buildings and vehicles in farms or other agricultural areas shall be reported in *Stationary Energy* and *Transportation*, respectively.

Scope 3: Other out-of-boundary emissions
Emissions from land-use activities outside the city (e.g., agricultural products imported for consumption within the city boundary) are not covered in the GPC under BASIC/BASIC+ but may be reported as *Other Scope 3*.

10.2 Defining AFOLU activities

Given the highly variable nature of land-use and agricultural emissions across geographies, GHG emissions from *AFOLU* are amongst the most complex categories for GHG accounting. Some cities, where there are no measurable agricultural activities or managed lands within the city boundary, may have no significant sources of *AFOLU* emissions. Other cities may have significant agricultural activities and managed lands. Notation keys shall be used to indicate where sources do not occur, or where data gaps exist. *IPCC Guidelines* divides *AFOLU* activities into three categories:

- Livestock
- Land
- Aggregate sources and non-CO_2 emissions sources on land

These emission sources and their scope categorization are summarized in Table 10.1.

Multiple methodologies can be used to quantify *AFOLU* emissions. Guidance provided in this chapter is consistent with IPCC Tier 1 methodologies, unless otherwise specified. Tier 1 methodologies involve using default IPCC data, while Tier 2 methodologies involve using country-specific data. Country-specific data should be used if readily available, and if not, default IPCC data should be used. More complete guidance can be found in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* and the *IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry (2013).*

10.3 Calculating livestock emissions

Livestock production emits CH_4 through enteric fermentation, and both CH_4 and N_2O through management of their manure. CO_2 emissions from livestock are not estimated because annual net CO_2 emissions are assumed to be zero—the CO_2 photosynthesized by plants is returned to the atmosphere as respired CO_2. A portion of the C is returned as CH_4 and for this reason CH_4 requires separate consideration.

10.3.1 Enteric fermentation

The amount of CH_4 emitted by enteric fermentation is driven primarily by the number of animals, type of digestive system, and type and amount of feed consumed. Methane emissions can be estimated by multiplying the number of livestock for each animal type by an emission factor (see Equation 10.1).

Activity data on livestock can be obtained from various sources, including government and agricultural industry. If such data are not available, estimates may be made based on survey and land-use data. Livestock should be disaggregated by animal type, consistent with IPCC categorization: Cattle (dairy and other); Buffalo; Sheep; Goats; Camels; Horses; Mules and Asses; Deer; Alpacas; Swine; Poultry; and Other. Country-specific emission factors should be used, where available; alternatively, default IPCC emission factors may be used.[70]

10.3.2 Manure management

CH_4 is produced by the decomposition of manure under anaerobic conditions, during storage and treatment, whilst

Table 10.1 AFOLU Overview

GHG Emission Source	Scope 1	Scope 2	Scope 3
Agriculture, Forestry and Other Land Use	Emissions from agricultural, other land-use and land-use-change		
Livestock	V.1		
Land	V.2		
Aggregate sources and non-CO_2 emission sources on land	V.3		

- Sources required for BASIC+ reporting
- Sources included in Other Scope 3
- Non-applicable emissions

70. See *2006 IPCC Guidelines*, Volume 4, Chapter 10 "Emissions from Livestock and Manure Management.". Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4

Figure 10.1 Overview of AFOLU emission sources

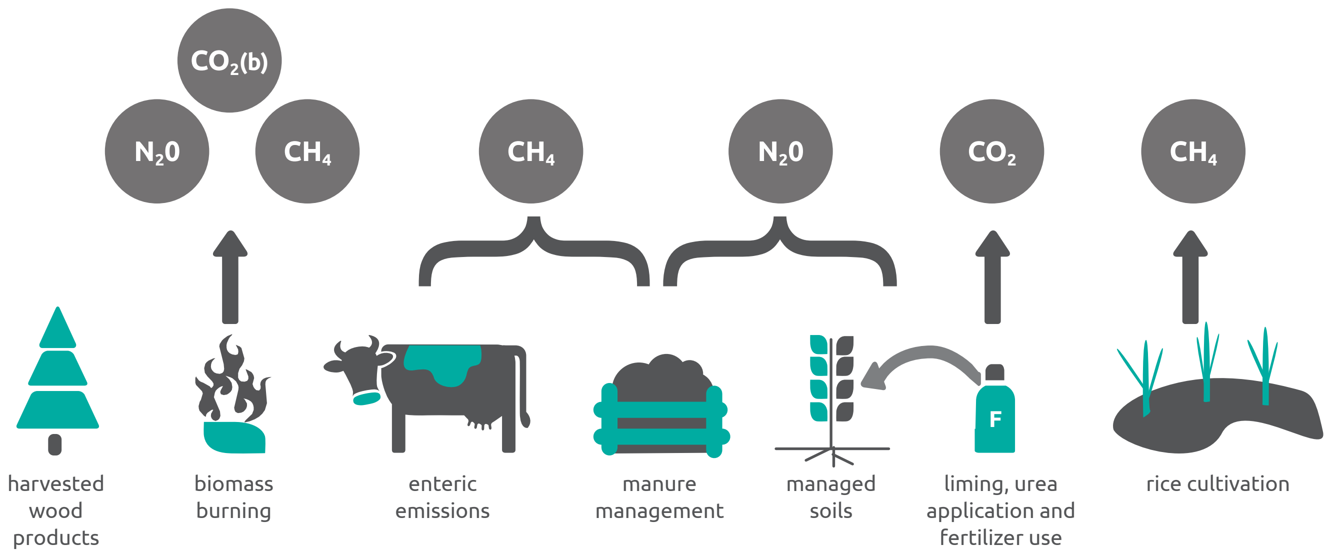


Table 10.2 Livestock emission sources and corresponding IPCC references

Category	Emission sources	2006 IPCC Reference
Livestock	Enteric fermentation	Volume 4; Chapter 10; Section 10.3
	Manure management	Volume 4; Chapter 10; Section 10.4-5

Equation 10.1 CH_4 emissions from enteric fermentation

$$CH_4 = N_{(T)} \times EF_{(Enteric,T)} \times 10^{-3}$$

Description			Value
CH_4	=	CH_4 emissions in tonnes	Computed
T	=	Species / Livestock category	User input
N	=	Number of animals (head)	User input
EF	=	Emission factor for enteric fermentation (kg of CH_4 per head per year)	User input or default values

Source: Adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 4, Agriculture, Forestry and Other Land Use. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html direct N_2O emissions occur via combined nitrification and denitrification of nitrogen contained in the manure. The main factors affecting CH_4 emissions are the amount of manure produced and the portion of the manure that decomposes anaerobically. The former depends on the rate of waste production per animal and the number of animals, and the latter on how the manure is managed. The emission of N_2O from manure during storage and treatment depends on the nitrogen and carbon content of manure, and on the duration of the storage and type of treatment. The term "manure" is used here collectively to include both dung and urine (i.e., the solids and the liquids) produced by livestock. Emissions associated with the burning of dung for fuel shall be reported under *Stationary Energy*, or under *Waste* if burned without energy recovery.

CH_4 emissions from manure management

CH_4 emissions from manure management systems are temperature dependent. Calculating CH_4 emissions from manure management, therefore, requires data on livestock by animal type and average annual temperature, in combination with relevant emission factors (see Equation 10.2).

Livestock numbers and categorization should be consistent with the method listed in Section 10.3.1 above. Average annual temperature data can be obtained from international and national weather centers, as well as academic sources. Country-specific temperature-dependent emission factors should be used, where available; alternatively, default IPCC emission factors may be used.[71]

N_2O emissions from manure management

Manure management takes place during the storage and treatment of manure before it is applied to land or otherwise used for feed, fuel, or construction purposes. To estimate N_2O emissions from manure management systems involves multiplying the total amount of N excretion (from all livestock categories) in each type of manure management system by an emission factor for that type of manure management system (see Equation 10.3). This includes the following steps:

1. Collect livestock data by animal type (T)
2. Determine the annual average nitrogen excretion rate per head ($Nex_{(T)}$) for each defined livestock category T
3. Determine the fraction of total annual nitrogen excretion for each livestock category T that is managed in each manure management system S ($MS_{(T,S)}$)
4. Obtain N_2O emission factors for each manure management system S ($EF_{(S)}$)
5. For each manure management system type S, multiply its emission factor ($EF_{(S)}$) by the total amount of nitrogen managed (from all livestock categories) in that system, to estimate N_2O emissions from that manure management system

Equation 10.2 CH_4 emissions from manure management

$$CH_4 = (N_{(T)} \times EF_{(T)} \times 10^{-3})$$

Description			Value
CH_4	=	CH_4 emissions in tonnes	Computed
T	=	Species / Livestock category	User input
$N_{(T)}$	=	Number of animals for each livestock category	User input
$EF_{(T)}$	=	Emission factor for manure management (kg of CH_4 per head per year)	User input or default values

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

71. See *2006 IPCC Guidelines*, Volume 4, Chapter 10, Tables 10A.1 to 10A-9

Emissions are then summed over all manure management systems. Country-specific data may be obtained from the national inventory, agricultural industry and scientific literature. Alternatively, data from other countries that have livestock with similar characteristics, or IPCC default nitrogen excretion data and default manure management system data may be used.[72]

N_2O emissions generated by manure in the system *pasture, range, and paddock* (grazing) occur directly and indirectly from the soil, and are reported under the category *N_2O emissions from managed soils* (see 10.5.4). N_2O emissions associated with the burning of dung for fuel are reported under *Stationary Energy* (Chapter 6), or under *Waste* (Chapter 8) if burned without energy recovery.

Note that emissions from liquid/slurry systems without a natural crust cover, anaerobic lagoons, and anaerobic digesters are considered negligible based on the absence of oxidized forms of nitrogen entering these systems combined with the low potential for nitrification and denitrification to occur in the system.

Equation 10.3 N_2O emissions from manure management

$$N_2O = [\Sigma_S\, [\Sigma_T\, (N_{(T)} \times Nex_{(T)} \times MS_{(T),(S)})] \times EF_{(S)}] \times 44/28 \times 10^{-3}$$

N_2O	=	N_2O emissions in tonnes
S	=	Manure management system (MMS)
T	=	Livestock category
$N_{(T)}$	=	Number of animals for each livestock category
$Nex_{(t)}$	=	Annual N excretion for livestock category T, kg N per animal per year (see Equation 10.4)
MS	=	Fraction of total annual nitrogen excretion managed in MMS for each livestock category
$EF_{(s)}$	=	Emission factor for direct N_2O-N emissions from MMS, kg N_2O-N per kg N in MSS
44/28	=	Conversion of N_2O-N emissions to N_2O emissions

Source: Equation adapted from 2006 IPCC Guidelines for *National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.4 Annual N excretion rates

$$Nex_{(T)} = N_{rate(T)} \times TAM_{(T)} \times 10^{-3} \times 365$$

$Nex_{(T)}$	=	Annual N excretion for livestock category T, kg N per animal per year
$N_{rate(T)}$	=	Default N excretion rate, kg N per 1000kg animal per day
$TAM_{(T)}$	=	Typical animal mass for livestock category T, kg per animal

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

72. See *2006 IPCC Guidelines* Volume 4, Chapter 10 "Emissions from Livestock and Manure Management", Tables 10.19, and 10.21. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4

Table 10.3 Land use categories and corresponding IPCC references

Category	Definition	2006 IPCC Reference
Forest land	All land with woody vegetation consistent with thresholds used to define forest land in national inventory	Volume 4; Chapter 4
Cropland	Cropped land, including rice fields, and agro-forestry systems where the vegetation structure falls below the thresholds for forest land	Volume 4; Chapter 5
Grassland	Rangelands and pasture land that are not considered cropland, and systems with woody vegetation and other non-grass vegetation that fall below the threshold for forest land	Volume 4; Chapter 6
Wetlands	Areas of peat extraction and land that is covered or saturated by water for all or part of the year	Volume 4; Chapter 7
Settlements	All developed land, including transportation infrastructure and human settlements of any size	Volume 4; Chapter 8
Other	Bare soil, rock, ice, and all land areas that do not fall into any of the other five categories	Volume 4; Chapter 9

Equation 10.5 Carbon emissions from land use and land-use change

$$\Delta C_{AFOLU} = \Delta C_{FL} + \Delta C_{CL} + \Delta C_{GL} + \Delta C_{WL} + \Delta C_{SL} + \Delta C_{OL}$$

ΔC	=	Change in carbon stock
AFOLU	=	Agriculture, Forestry and Other Land Use
FL	=	Forest land
CL	=	Cropland
GL	=	Grassland
WL	=	Wetlands
SL	=	Settlements
OL	=	Other land

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* , Volume 4 Agriculture, Forestry and Other Land Use, Section 2.2.1, eq 2.1. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

10.4 Calculating land use and land-use change emissions

IPCC divides land-use into six categories: forest land; cropland; grassland; wetlands; settlements; and other (see Table 10.3). Emissions and removals of CO_2 are based on changes in ecosystem C stocks and are estimated for each land-use category (see Equation 10.5). This includes both land remaining in a land-use category as well as land converted to another use. C stocks consist of above-ground and below-ground biomass, dead organic matter (dead wood and litter), and soil organic matter.

Estimating changes in carbon depends on data and model availability, and resources to collect and analyze information. The GPC recommends cities adopt a simplified approach that consists of multiplying net annual C stock change for different land-use (and land-use-change) categories by surface area.

Land-use categorization by surface area can be obtained from national agencies or local government using land zoning or remote sensing data. These categorizations will need to be aligned to the definitions provided in Table 10.3. Some lands can be classified into one or more

Equation 10.6 CO_2 emissions from land use and land-use change

$$CO_2 =$$
$$\Sigma_{LU}[\text{Flux}_{LU} \times \text{Area}_{LU}] \times 44/12$$

CO_2	=	GHG emissions in tonnes CO_2
Area	=	Surface area of city by land-use category, hectare
Flux	=	Net annual rate of change in carbon stocks per hectare, tonnes C per hectare per year
LU	=	Land-use category
44/12	=	Conversion of C stock changes to CO_2 emissions

categories due to multiple uses that meet the criteria of more than one definition. However, a ranking has been developed for assigning these cases into a single land-use category. The ranking process is initiated by distinguishing between managed and unmanaged lands. The managed lands are then assigned, from highest to lowest priority, in the following manner: Settlements > Cropland > Forest land > Grassland > Wetlands > Other land.

In addition to the current land use, any land-use changes within the last 20 years will need to be determined.[73] If the land-use change took place less than 20 years prior to undertaking the assessment, that land is considered to have been converted. In this case, assessment of GHG emissions takes place on the basis of equal allocation to each year of the 20-year period. Large quantities of GHG emissions can result as a consequence of a change in land use. Examples include change of use from agriculture (e.g., urban farms) or parks, to another use (e.g., industrial development). When the land use is changed, soil carbon and carbon stock in vegetation can be lost as emissions of CO_2.

Next, all land should be assigned to one of the categories listed in Table 10.4. Lands stay in the same category if a land-use change has not occurred in the last 20 years. Otherwise, the land is classified as *converted* (e.g., Cropland converted to Forest land) based on the current use and most recent use before conversion to the current use.

Average annual carbon stock change data per hectare for all relevant land-use (and land-use change) categories need to be determined and multiplied by the corresponding surface area of that land use (see Equation 10.6). Default data on annual carbon stock change can be obtained from the country's national inventory reporting body, United Nations Framework Convention on Climate Change (UNFCCC) reported GHG emissions for countries, IPCC, and other peer-reviewed sources.[74] Alternatively, annual carbon stock changes can be determined for different land-use categories by subtracting estimated carbon stocks in a previous year from estimated carbon stocks in the inventory year, divided by the total area of land in the inventory year. Default data on annual carbon stock changes can be obtained from the above listed sources. Finally, all changes in carbon stock

73. The use of 20 years as a threshold is consistent with the defaults contained in *IPCC Guidelines*. It reflects the time period assumed for carbon stocks to come to equilibrium.

74. For example: Watson, R.T., Noble, I.R., Bolin, B., Ravindranath, N.H., Verardo, D.J., and Dokken, D.J. (2000) Land Use, Land Use Change and Forestry (IPCC Special Report): Chapter 4. Web published

Table 10.4 Land use categories

	Forest land	Cropland	Grassland	Wetlands	Settlements	Other
Forest Land	Forest land remaining Forest land	Forest land converted to Cropland	Forest land converted to Grassland	Forest land converted to Wetlands	Forest land converted to Settlements	Forest land converted to Other land
Cropland	Cropland converted to Forest land	Cropland remaining Cropland	Cropland converted to Grassland	Cropland converted to Wetlands	Cropland converted to Settlements	Cropland converted to Other land
Grassland	Grassland converted to Forest land	Grassland converted to Cropland	Grassland remaining Grassland	Grassland converted to Wetlands	Grassland converted to Settlements	Grassland to Other land
Wetlands	Wetlands converted to Forest land	Wetlands converted to Cropland	Wetlands converted to Grassland	Wetlands remaining Wetlands	Wetlands converted to Settlements	Wetlands converted to Other land
Settlements	Settlements converted to Forest land	Settlements converted to Cropland	Settlements converted to Grassland	Settlements converted to Wetlands	Settlements remaining Settlements	Settlements converted to Other land
Other	Other land converted to Forest land	Other land converted to Cropland	Other land converted to Grassland	Other land converted to Wetlands	Other land converted to Settlements	Other land remaining Forest land

are summed across all categories (see Equation 10.5) and multiplied by 44/12 to covert to CO_2 emissions.

IPCC guidance provides the option of calculating all AFOLU GHG emissions consolidated by land-use category, because certain AFOLU data are not easily disaggregated by land-use category (e.g., CH_4 from rice cultivation could be counted in *cropland* or counted separately). Cities should make clear if any of the emission sources listed under Table 10.4 are included in Table 10.5.

10.5 Calculating emissions from aggregate sources and non-CO_2 emissions sources on land

Other sources of GHG emissions from land required for IPCC reporting are detailed below. This includes rice cultivation, fertilizer use, liming, and urea application, which can make up a significant portion of a city's AFOLU emissions. Rice cultivation is treated separately from other crops because it releases CH_4 emissions.

10.5.1 GHG emissions from biomass burning

Where biomass is burned for energy, the resulting non-CO_2 emissions shall be reported under scope 1 for *Stationary Energy* (see Chapter 6), while the CO_2 emissions are reported separately as biogenic CO_2. However, where biomass is burned without energy recovery, such as periodic burning of land or accidental wildfires, and these activities aren't included in 10.4, GHG emissions should be reported under *AFOLU*.

Country-specific factors should be used where available.; alternatively, default IPCC values may be used for M_B, CF and EF.[75]

75. These are listed in the *2006 IPCC Guidelines*, Volume 4 Agriculture, Forestry and Other Land Use, Chapter 2 General Methodologies Applicable to Multiple Land-Use Categories; Tables 2.4, 2.5 and 2.6. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4

Table 10.5 Aggregate sources and non-CO_2 emissions sources on land

Category	Emission sources	2006 IPCC Reference
Aggregate sources and non-CO_2 emissions sources on land	GHG emissions from biomass burning	Volume 4; Chapters 4-9
	Liming	Volume 4; Chapter 11; Section 11.3
	Urea application	Volume 4; Chapter 11; Section 11.4
	Direct N_2O from managed soils	Volume 4; Chapter 11; Section 11.2.1
	Indirect N_2O from managed soils	Volume 4; Chapter 11; Section 11.2.2
	Indirect N_2O from manure management	Volume 4; Chapter 10; Section 10.5.1
	Rice cultivation	Volume 4; Chapter 5; Section 5.5
	Harvested wood products	Volume 4; Chapter 12

Equation 10.7 GHG emissions from biomass burning

$$\mathbf{GHG} = A \times M_B \times CF \times EF \times 10^{-3}$$

GHG	=	GHG emissions in tonnes of CO_2 equivalent
A	=	Area of burnt land in hectares
M_B	=	Mass of fuel available for combustion, tonnes per hectare. This includes biomass, ground litter and dead wood. NB The latter two may be assumed to be zero except where this is a land-use change.
CF	=	Combustion factor (a measure of the proportion of the fuel that is actually combusted)
EF	=	Emission factor, g GHG per kg of dry matter burnt

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.8 CO_2 emissions from liming

$$\mathbf{CO_2} = ((M_{Limestone} \times EF_{Limestone}) + (M_{Dolomite} \times EF_{Dolomite})) \times 44/12$$

CO_2	=	CO_2 emissions in tonnes
M	=	Amount of calcic limestone ($CaCO_3$) or dolomite ($CaMg(CO_3)_2$), tonnes per year
EF	=	Emission factor, tonne of C per tonne of limestone or dolomite
44/12	=	Conversion of C stock changes to CO_2 emissions

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

10.5.2 Liming

Liming is used to reduce soil acidity and improve plant growth in managed systems, particularly agricultural lands and managed forests. Adding carbonates to soils in the form of lime (e.g., calcic limestone ($CaCO_3$), or dolomite ($CaMg(CO_3)_2$) leads to CO_2 emissions as the carbonate limes dissolve and release bicarbonate ($2HCO_3$-), which evolves into CO_2 and water (H_2O). Equation 10.8 sets out the formula for estimating CO_2 emissions from liming. The total amount of carbonate containing lime applied annually to soils in the city will need to be estimated, differentiating between limestone and dolomite.

Activity data may be obtained from regional or national usage statistics, or may be inferred from annual sales under the assumption that all lime sold within the city is applied to land within the city that year. Note, if lime is applied in a mixture with fertilizers, the proportion used should be estimated. Default emission factors of 0.12 for limestone and 0.13 for dolomite should be used if emission factors derived from country-specific data are unavailable.

10.5.3 Urea application

The use of urea ($CO(NH_2)_2$) as fertilizer leads to emissions of CO_2 that were fixed during the industrial production process. Urea in the presence of water and urease enzymes is converted into ammonium (NH_4+), hydroxyl ion (OH), and bicarbonate (HCO_3–). The bicarbonate then evolves into CO_2 and water.

A default emission factor of 0.20 for urea should be used if emission factors derived from country-specific data are unavailable.

Equation 10.9 CO_2 emissions from urea fertilization

$$CO_2 = M \times EF \times 44/12$$

CO_2	=	CO_2 emissions in tonnes
M	=	Amount of urea fertilization, tonnes urea per year
EF	=	Emission factor, tonne of C per tonne of urea
44/12	=	Conversion of C stock changes to CO_2 emissions

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.10 Direct N_2O from managed soils

$$N_2O_{Direct} = (N_2O\text{-}N_{N\ inputs} + N_2O\text{-}N_{OS} + N_2O\text{-}N_{PRP}) \times 44/28 \times 10^{-3}$$

N_2O_{Direct}	=	Direct N_2O emissions produced from managed soils, in tonnes
$N_2O\text{-}N_{N\ inputs}$	=	Direct N_2O-N emissions from N inputs to managed soils, kg N_2O-N per year
$N_2O\text{-}N_{OS}$	=	Direct N_2O-N emissions from managed inorganic soils, kg N_2O-N per year
$N_2O\text{-}N_{PRP}$	=	Direct N_2O-N emissions from urine and dung inputs to grazed soils, kg N_2O-N per year
44/28	=	Conversion of N (N_2O-N) to N_2O

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

10.5.4 Direct N_2O from managed soils

Agricultural emissions of N_2O result directly from the soils to which N is added/released and indirectly through the volatilization, biomass burning, leaching and runoff of N from managed soils. Direct emissions of N_2O from managed soils are estimated separately from indirect emissions, though using a common set of activity data. Tier 1 methodologies do not take into account different land cover, soil type, climatic conditions or management practices. Cities that have data to show that default factors are inappropriate for their country should utilize Tier 2 or Tier 3 approaches.

Three emission factors (EF) are needed to estimate direct N_2O emissions from managed soils. The first EF (EF_1) refers to the amount of N_2O emitted from the various synthetic and organic N applications to soils, including crop residue and mineralization of soil organic carbon in mineral soils due to land-use change or

Equation 10.11 Direct N_2O-N from managed soils

$$N_2O\text{-}N_{N\ inputs} =$$
$$(F_{SN} + F_{ON} + F_{CR} + F_{SOM}) \times EF_1$$
$$+ (F_{SN} + F_{ON} + F_{CR} + F_{SOM})_{FR} \times EF_{1FR}$$

$N_2O\text{-}N_{N\ inputs}$	=	Direct N_2O-N emissions from N inputs to managed soils, kg N_2O-N per year
F_{SN}	=	Amount of synthetic fertilizer N applied to soils, kg N per year
F_{ON}	=	Amount of animal manure, compost, sewage sludge and other organic N additions applied to soils (*Note:* If including sewage sludge, cross-check with Waste sector to ensure there is no double counting of N_2O emissions from the N in sewage sludge), kg N per year. See Equation 10.14
F_{CR}	=	Amount of N in crop residues (above-ground and below-ground), including N-fixing crops, and from forage/pasture renewal, returned to soils, kg N per year. See Equation 10.17
F_{SOM}	=	Annual amount of N in mineral soils that is mineralized, in association with loss of soil C from soil organic matter as a result of changes to land use or management, kg N per year. See Equation 10.18
EF_1	=	Emission factor for N_2O emissions from N inputs, kg N_2O–N (kg N input)-1
EF_{1FR}	=	Emission factor for N_2O emissions from N inputs to flooded rice, kg N_2O–N (kg N input)-1

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.12 Direct N_2O-N from managed inorganic soils

$$N_2O\text{-}N_{OS} =$$
$$(F_{OS,CG,Temp} \times EF_{2CG,Temp}) + (F_{OS,CG,Trop} \times EF_{2CG,Trop})$$
$$+ (F_{OS,F,Temp,NR} \times EF_{2F,Temp,NR}) + (F_{OS,F,Temp,NP} \times EF_{2F,Temp,NP})$$
$$+ (F_{OS,F,Trop} \times EF_{2F,Trop})$$

$N_2O\text{-}N_{OS}$	=	Direct N_2O-N emissions from managed inorganic soils, kg N_2O-N per year
F_{OS}	=	Area of managed / drained organic soils, ha (*Note:* the subscripts CG, F, Temp, Trop, NR and NP refer to Cropland and Grassland, Forest Land, Temperate, Tropical, Nutrient Rich, and Nutrient Poor, respectively)
EF_2	=	Emission factor for N_2O emissions from drained/managed organic soils, kg N_2O–N per hectare per year

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.13 Direct N_2O-N from urine and dung

$$N_2O\text{-}N_{PRP} =$$
$$(F_{PRP,CPP} \times EF_{3PRP,CPP}) + (F_{PRP,SO} \times EF_{3PRP,SO})$$

$N_2O\text{-}N_{PRP}$	=	Direct N_2O-N emissions from urine and dung inputs to grazed soils, kg N_2O-N per year
F_{PRP}	=	Annual amount of urine and dung N deposited by grazing animals on pasture, range and paddock, kg N per year (*Note:* the subscripts CPP and SO refer to Cattle, Poultry and Pigs, and Sheep and Other animals, respectively) See Equation 10.16
EF_{3PRP}	=	Emission factor for N_2O emissions from urine and dung N deposited on pasture, range and paddock by grazing animals, kg N_2O–N (kg N input)-1; (*Note:* the subscripts CPP and SO refer to Cattle, Poultry and Pigs, and Sheep and Other animals, respectively)

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

management. The second EF (EF_2) refers to the amount of N_2O emitted from an area of drained/managed organic soils, and the third EF (EF_{3PRP}) estimates the amount of N_2O emitted from urine and dung N deposited by grazing animals on pasture, range and paddock. Country-specific emission factors should be used where available; alternatively, default IPCC emission factors may be used.[76]

Sections (a)–(f) below show how to source and calculate activity data identified in the previous equations.

(a) Applied synthetic fertilizer (F_{SN})

Equation 10.14 N from organic N additions applied to soils

$$F_{ON} = F_{AM} + F_{SEW} + F_{COMP} + F_{OOA}$$

F_{ON}	=	Amount of organic N fertilizer applied to soil other than by grazing animals, kg N per year
F_{AM}	=	Amount of animal manure N applied to soils, kg N per year. See Equation 10.15
F_{SEW}	=	Amount of total sewage N applied to soils, kg N per year
F_{COMP}	=	Amount of total compost N applied to soils, kg N per year
F_{OOA}	=	Amount of other organic amendments used as fertilizer, kg N per year

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

The amount of synthetic fertilizer applied to soils may be collected from national statistics. If country-specific data are not available, data on total fertilizer use by type and by crop from the International Fertilizer Industry Association (IFIA) or the Food and Agriculture Organization of the United Nations (FAO) can be used.

76. Table 11.1 in the *2006 IPCC Guidelines*, Volume 4, Chapter 11 N_20 Emissions from Managed Soils, and CO_2 Emissions from Lime and Urea Application. Further equations will need to be applied to estimate the activity data, default values for which can also be found in the *2006 IPCC Guidelines*. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4

(b) Applied organic N fertilizer (F_{ON})

Equation 10.15 N from animal manure applied to soils

$$F_{AM} = N_{MMS\_Avb} \times [1 - (Frac_{FEED} + Frac_{FUEL} + Frac_{CNST})]$$

FAN	=	Amount of animal manure N applied to soils, kg N per year
N_{MMS_Avb}	=	Amount of managed manure N available for soil application, feed, fuel of construction, kg N per year
$Frac_{FEED}$	=	Fraction of managed manure used for feed
$Frac_{FUEL}$	=	Fraction of managed manure used for fuel
$Frac_{CNST}$	=	Fraction of managed manure used for construction

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

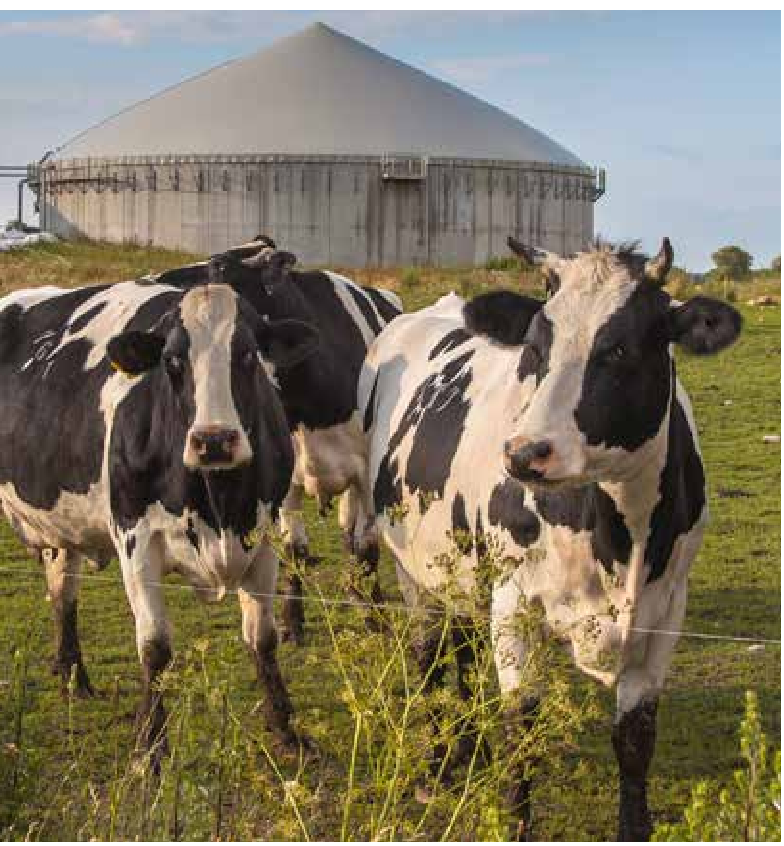
(c) Urine and dung from grazing animals (F_{PRP})

Equation 10.16 N in urine and dung deposited by grazing animals on pasture, range and paddock

$$F_{PRP} = \Sigma_T [(N_{(T)} \times Nex_{(T)}) \times MS_{(T,PRP)}]$$

F_{PRP}	=	Amount of urine and dung N deposited on pasture, range, paddock and by grazing animals, kg N per year
$N_{(T)}$	=	Number of head of livestock per livestock category
$Nex_{(T)}$	=	Average N excretion per head of livestock category T, kg N per animal per year
$MS_{(T, PRP)}$	=	Fraction of total annual N excretion for each livestock category T that is deposited on pasture, range and paddock

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html



(d) Crop residue N, including N-fixing crops and forage/pasture renewal, returned to soils (F_{CR})

Equation 10.17 N from crop residues and forage/pasture renewal

$$F_{CR} = \Sigma_T [Crop_{(T)} \times (Area_{(T)} - Area\ burnt_{(T)} \times CF) \times Frac_{Renew(T)} \times [R_{AG(T)} \times N_{AG(T)} \times (1 - Frac_{Remove(T)}) + R_{BG(T)} \times N_{BG(T)}]]$$

F_{CR}	=	Amount of N in crop residue returned to soils, kg N per year
$Crop_{(T)}$	=	Harvested dry matter yield for crop T, kg d.m. per hectare
$Area_{(T)}$	=	Total harvested area of crop T, hectare per year
$Area\ burnt_{(T)}$	=	Area of crop burnt, hectare per year
CF	=	Combustion factor
$Frac_{Renew(T)}$	=	Fraction of total area under crop T that is renewed. For annual crops $Frac_{Renew} = 1$
$R_{AG(T)}$	=	Ratio of above-ground residues dry matter ($AG_{DM(T)}$) to harvested yield for crop T. $R_{AG(T)} = AG_{DM(T)} \times 1000 / Crop_{(T)}$
$N_{AG(T)}$	=	N content of above-ground residues for crop T, kg N per kg dm
$Frac_{Remove(T)}$	=	Fraction of above-ground residues of crop T removed for purposes such as feed, bedding and construction, kg N per kg crop-N. If data for $Frac_{Remove(T)}$ is not available, assume no removal
$R_{BG(T)}$	=	Ratio of below-ground residues to harvested yield for crop T
$N_{BG(T)}$	=	N content of below-ground residues for crop T, kg N per kg dm
T	=	Crop or forage type

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

(e) Mineralized N resulting from loss of soil organic C stocks in mineral soils through land-use change or management practices (F_{SOM})

Equation 10.18 N mineralized in mineral soils as a result of loss of soil C through change in land use or management

$$F_{SOM} = \Sigma_{LU} [(\Delta C_{Mineral,LU} \times (1/R)) \times 1000]$$

F_{SOM}	=	Amount of N mineralized in mineral soils as a result of loss of soil carbon through change in land use or management, kg N per year
$\Delta C_{Mineral,LU}$	=	Loss of soil carbon for each land use type (LU), tonnes C (for Tier 1, this will be a single value for all land-uses and management systems)
R	=	C:N ratio of the soil organic matter
LU	=	Land-use and/or management system type

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

A default value of 15 for R, the C:N ratio, may be used for land-use change from Forest land or Grassland to Cropland, and a default value of 10 may be used for situations involving management changes on Cropland remaining Cropland.

(f) Area of drained/managed organic soils (F_{OS})
Data for the area of managed/drained organic soils may be collected from official national statistics and soil survey organizations, or expert advice may be used.

10.5.5 Indirect N_2O from managed soils

N_2O emissions also take place through volatilization of N as NH_3 and oxides of N (NO_x), and leaching and runoff from agricultural N additions to managed lands.

Equation 10.19 N_2O from atmospheric deposition of N volatilized from managed soils

$$N_2O_{(ATD)} = [(F_{SN} \times Frac_{GASF}) + ((F_{ON} + F_{PRP}) \times Frac_{GASM})] \times EF_4 \times 44/28 \times 10^{-3}$$

$N_2O_{(ATD)}$	=	Amount of N_2O produced from atmospheric deposition of N volatilized from managed soils in tonnes
F_{SN}	=	Amount of synthetic fertilizer N applied to soils, kg N per year
F_{ON}	=	Amount of animal manure, compost, sewage sludge and other organic N additions applied to soils (*Note:* If including sewage sludge, cross-check with Waste sector to ensure there is no double counting of N_2O emissions from the N in sewage sludge), kg N per year. See Equation 10.14
F_{PRP}	=	Annual amount of urine and dung N deposited by grazing animals on pasture, range and paddock, kg N per year (*Note:* the subscripts CPP and SO refer to Cattle, Poultry and Pigs, and Sheep and Other animals, respectively) See Equation 10.16
44/28	=	Conversion of N (N_2O-N) to N_2O
$Frac_{GASF}$	=	Fraction of synthetic fertilizer N that volatilizes as NH3 and NO_x, kg N volatilized per kg N applied
$Frac_{GASM}$	=	Fraction of applied organic N fertilizer materials (F_{ON}) and of urine and dung N deposited by grazing animals (F_{PRP}) that volatilizes as NH_3 and NO_x, kg N volatilized per kg N applied or deposited
EF_4	=	Emission factor for N_2O emissions from atmospheric deposition of N on soils and water surfaces, kg N_2O-N per kg NH_3-N and NO_x-N volatilized

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Activity data used in the above two equations is the same as the data used to estimate direct N_2O from managed soils. For Equation 10.20, only those amounts in regions where leaching/runoff occurs need to be considered.

Equation 10.20 N_2O from leaching/runoff from managed soils in regions where leaching/ runoff occurs

$$N_2O_{(L)} = [(F_{SN} + F_{ON} + F_{PRP} + F_{CR} + F_{SOM}) \times Frac_{LEACH-(H)} \times EF_5] \times 44/28 \times 10^{-3}$$

$N_2O_{(L)}$	=	Amount of N_2O produced from leaching and runoff of N additions to managed soils in regions where leaching / runoff occurs, in tonnes
$Frac_{LEACH-(H)}$	=	Fraction of all N added to/mineralized in managed soils in regions where leaching/ runoff occurs that is lost through leaching and runoff, kg N per kg if N additions
EF_5	=	Emission factor for N_2O emissions from N leaching and runoff, kg N_2O-N per kg N leached and runoff

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Default emission, volatilization and leaching factors should be used in the absence of country-specific data.[77]

10.5.6 Indirect N_2O from manure management

Indirect emissions result from volatile nitrogen losses that occur primarily in the forms of NH_3 and NO_x. Calculation is based on multiplying the amount of nitrogen excreted (from all livestock categories) and managed in each manure management system by a fraction of volatilized nitrogen (see Equations 10.21 and 10.22). N losses are then summed over all manure management systems.[78]

Equation 10.21 Indirect N_2O emissions due to volatilization of N from manure management

$$N_2O = (N_{volatilization-MMS} \times EF_4) \times 44/28 \times 10^{-3}$$

N_2O	=	Indirect N_2O emissions due to volatilization of N from manure management in tonnes
$N_{volatilization-MMS}$	=	Amount of manure nitrogen that is lost due to volatilization of NH_3 and NO_x, kg N per year. See Equation 10.22
EF_4	=	Emission factor for N_2O emissions from atmospheric deposition of N on soils and water surfaces, kg N_2O-N per kg NH_3-N and NO_x-N volatilized

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

77. Default factors can be found in the *2006 IPCC Guidelines*, Volume 4, Chapter 11, N_20 Emissions from Managed Soils, and CO_2 Emissions from Lime and Urea Application, Table 11.3. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4

78. IPCC default nitrogen excretion data, default manure management system data and default fractions of N losses from manure management systems due to volatilization are listed in the *2006 IPCC Guidelines*, Volume 4, Chapter 10, Annex 10A.2, Tables 10A-4 to 10A-8 and Table 10.22. A default value of 0.01 kg N_2O-N (kg NH3-N + NO_x-N volatilized)$^{-1}$ may be used for EF_4.

Equation 10.22 N losses due to volatilization from manure management

$$N_{volatilization\text{-}MMS} = \Sigma_S [\Sigma_T [(N_{(T)} \times Nex_{(T)} \times MS_{(T,S)}) \times (Frac_{GasMS} \times 10^{-2})_{(T,S)}]]$$

$N_{volatilization\text{-}MMS}$	=	Amount of manure nitrogen that is lost due to volatilization of NH_3 and NO_x, kg N per year
S	=	Manure management system (MMS)
T	=	Livestock category
$N_{(T)}$	=	Number of head of livestock per livestock category
$Nex_{(T)}$	=	Average N excretion per head of livestock category T, kg N per animal per year
$MS_{(T,S)}$	=	Fraction of total annual N excretion for each livestock category T that is managed in manure management system S
$Frac_{GasMS}$	=	Percent of managed manure nitrogen for livestock category T that volatilizes as NH_3 and NO_x in the manure management system S, %

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

10.5.7 Rice cultivations

Anaerobic decomposition of organic material in flooded rice fields produces methane (CH_4), which escapes to the atmosphere primarily by transport through rice plants. The amount of CH_4 emitted is a function of the number and duration of the crop grown, water regimes before and during cultivation period, and organic and inorganic soil amendments. CH_4 emissions are estimated by multiplying daily emission factors by cultivation period of rice and harvested areas (see Equation 10.23).

The disaggregation of harvested area should cover the following three water regimes, where these occur within the city boundary: irrigated, rain-fed, and upland. However, it is good practice to account for as many different factors influencing CH_4 emissions from rice cultivation (i, j, k etc.), where such data are available. The daily emission factor for each water regime is calculated by multiplying a baseline default emission factor by various scaling factors to account for variability in growing conditions (see Equation 10.24).

Equation 10.23 CH_4 emissions from rice cultivation

$$CH_{4Rice} = \Sigma_{i,j,k}(EF_{i,j,k} \times t_{i,j,k} \times A_{i,j,k} \times 10^{-6})$$

CH_{4Rice}	=	Methane emissions from rice cultivation, Gg (i.e., 1000 metric tonnes) CH_4 per year
$EF_{i,j,k}$	=	Daily emission factor for i, j and k conditions, kg CH_4 per hectare per year
$t_{i,j,k}$	=	Cultivation period of rice for i, j and k conditions, number of days
$A_{i,j,k}$	=	Harvested area of rice for i, j and k conditions, hectares per year
i,j,k	=	Represent different ecosystems, water regimes, type and amount of organic amendments, and other conditions under which CH_4 emissions from rice may vary (e.g. irrigated, rain-fed and upland)

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.24 Adjusted daily emission factors

$$EF_i = EF_c \times SF_w \times SF_p \times SF_o$$

EF_i	=	Adjusted daily emission factor for a particular harvested area (kg CH_4 per hectare per day)
EF_c	=	Baseline emission factor for continuously flooded fields without organic amendments (kg CH_4 per hectare per day)
SF_w	=	Scaling factor to account for the differences in water regime during the cultivation period
SF_p	=	Scaling factor to account for the differences in water regime in the pre-season before cultivation period
SF_o	=	Scaling factor should vary for both type and amount of organic amendment applied

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Equation 10.25 Adjusted CH_4 emission scaling factors for organic amendments

$$SF_o = (1 + \Sigma_i ROA_i \times CFOA_i)^{0.59}$$

SF_o	=	Scaling factor should vary for both type and amount of organic amendment applied
ROA_i	=	Application rate or organic amendment i, in dry weight for straw and fresh weight for others, tonne per hectare
$CFOA_i$	=	Conversion factor for organic amendment i

Source: Equation adapted from *2006 IPCC Guidelines for National Greenhouse Gas Inventories* Volume 4 Agriculture, Forestry and Other Land Use available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

Activity data are based on harvested area, which should be available from a national statistics agency or local government, as well as complementary information on cultivation period and agricultural practices, which may be estimated from industry or academic sources. Country-specific emission factors should be used where available and may be obtained from the national inventory, agricultural industry and scientific literature. Alternatively, IPCC default values should be used. The IPCC default value for EF_c is 1.30 kg CH_4 per hectare per day.[79]

10.5.8 Harvested wood products (HWP)

Harvested wood products (HWP) include all wood material that leaves harvest sites and constitutes a carbon reservoir (the time carbon is held in products will vary depending on the product and its uses). Fuel wood, for example, may be burned in the year of harvest, and many types of paper are likely to have a use life less than five years, including recycling. Wood used for panels in buildings, however, may be held for decades to over 100 years. Discarded HWP can be deposited in solid waste disposal sites where they may subsist for long periods of time. Due to this storage in products in use and in SWDS, the oxidation of HWP in a given year could be less, or potentially more, than the total amount of wood harvested in that year.

IPCC Guidelines allow for net emissions from HWP to be reported as zero, if it is judged that the annual change in carbon in HWP stocks is insignificant. The term “insignificant” is defined as being less than the size of any key category. If, however, it is determined that the annual change in carbon in HWP stocks is significant, the Tier 1 methodology outlined in *2006 IPCC Guidelines* should be followed.

79. Defaults values for SFw and SFp and CFOAi are listed in the *2006 IPCC Guidelines*, Volume 4, Chapter 5, Tables 5.12, 5.13, and 5.14. Available at: www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html

PART III
Tracking Changes and Setting Goals

11 Setting Goals and Tracking Emissions Over Time

This chapter shows how inventories can be used as the basis for goal setting and performance tracking. Further guidance on setting a mitigation goal and tracking progress over time can be found in the *GHG Protocol Mitigation Goal Standard*,[80] which has been designed for national and sub-national entities, as well as cities.

11.1 Setting goals and evaluating performance

Developing GHG inventories, setting goals, and tracking progress are part of an interconnected process. Setting reduction or "mitigation" goals can help cities focus efforts on key emission sources, identify innovative mitigation solutions, demonstrate leadership and reduce long-term costs (see Box 11.1 for an example of NYC's goal setting and performance tracking).

The type of goal provides the basis against which emissions and emissions reductions are tracked and reported. Users with a multi-year goal shall report whether the goal is an average, annual, or cumulative multi-year goal. In general, there are four goal types:

1. Base year emissions goals
2. Fixed level goals
3. Base year intensity goals
4. Baseline scenario goals

80. See www.ghgprotocol.org/mitigation-goal-standard

Box 11.1 Setting goals and tracking progress—New York City

New York City, U.S. aims to reduce GHG emissions by 30% below 2005 levels by 2030, and 80% by 2050.[81] To help determine where to best direct mitigation efforts, as well as track the effectiveness of actions taken and measure progress, the city conducts and publishes an annual assessment and analysis of GHG emissions. The plan states:

> *"Regular, accurate data allow us to assess the impact of policy measures, infrastructure investments, consumer behavior, population and weather on GHG emissions, and focus our programs to ensure that we are implementing the most effective GHG mitigation strategies."*

In 2012, GHG emissions were 19% lower than in 2005. The reduced carbon intensity of the city's electricity supply proved to be the main driver. Next, New York City plans to expand their inventory to map neighborhood-level emissions to better target policies and provide communities with information to help them reduce their GHG emissions.

Source: PlaNYC website www.nyc.gov/html/planyc

Base year emissions goals represent a reduction in emissions relative to an emissions level in a historical base year. They are framed in terms of a percent reduction of emissions compared to a base year emissions level, and therefore correspond to an absolute reduction in emissions.

Fixed level goals represent a reduction in emissions to an absolute emissions level in a target year. For example, a fixed level goal could be to achieve 200 Mt (million tonnes) CO_2e by 2020. The most common type of fixed level goals are carbon neutrality goals, which are designed to reach zero net emissions by a certain date (though such goals often include the purchase and use of offset credits to compensate for remaining emissions after annual reductions). Fixed level goals do not include a reference to an emissions level in a baseline scenario or historical base year.

81. New York City Mayor's Office of Long-Term Planning and Sustainability (2014). "Inventory of New York City Greenhouse Gas Emissions." 2014. http://www.nyc.gov/html/planyc/downloads/pdf/NYC_GHG_Inventory_2014.pdf

Figure 11.1 Example of a base year emissions goal

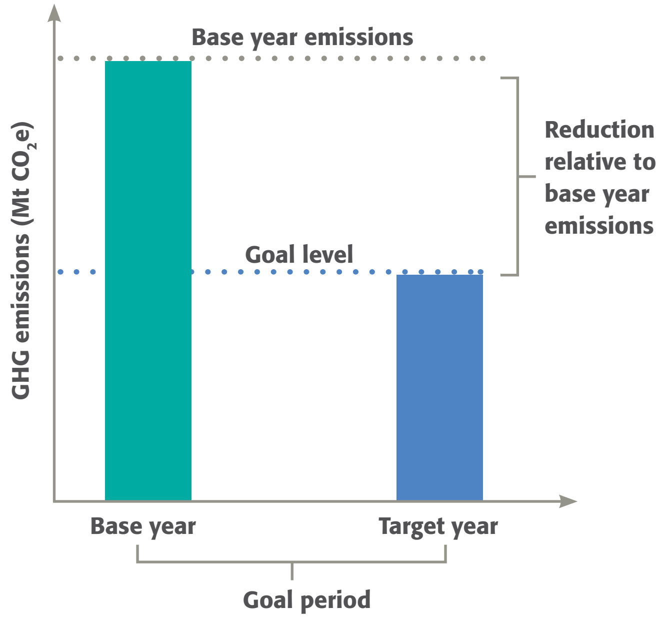
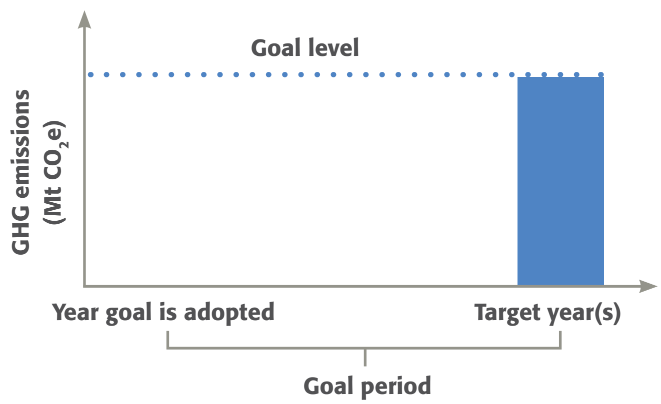
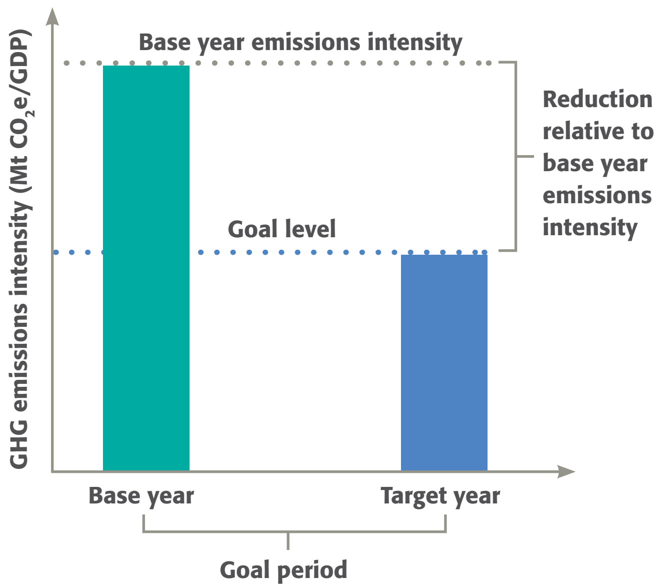


Figure 11.2 Example of a fixed-level goal



Base year intensity goals represent a reduction in emissions intensity relative to an emissions intensity level in a historical base year. Emissions intensity is emissions per unit of output. Examples of units of output include GDP, population, and energy use. Intensity goals are framed in terms of a percent reduction of emissions intensity compared to a base year emissions intensity, and therefore correspond to an absolute reduction in emissions intensity.

Figure 11.3 Example of a base year intensity goal



Baseline scenario goals represent a reduction in emissions relative to a baseline scenario emissions level. They are typically framed in terms of a percent reduction of emissions from the baseline scenario, rather than an absolute reduction in emissions. A baseline scenario is a set of reasonable assumptions and data that best describe events or conditions that are most likely to occur in the absence of activities taken to meet a mitigation goal (i.e. business-as-usual).

All goal types, except for fixed level goals, require a base year GHG inventory and a GHG inventory in the target year for evaluation of results. To estimate the business-as-usual (BAU) baseline, additional historical data series may be used, including GDP, population, sectoral energy intensity, among others. Although GPC does not provide guidance on how to estimate the BAU baseline, it is advisable to have historical city inventories for a cross-check analysis. Table 11.1 gives examples of different goal types and minimum inventory need.

Figure 11.4 Example of a baseline scenario goal

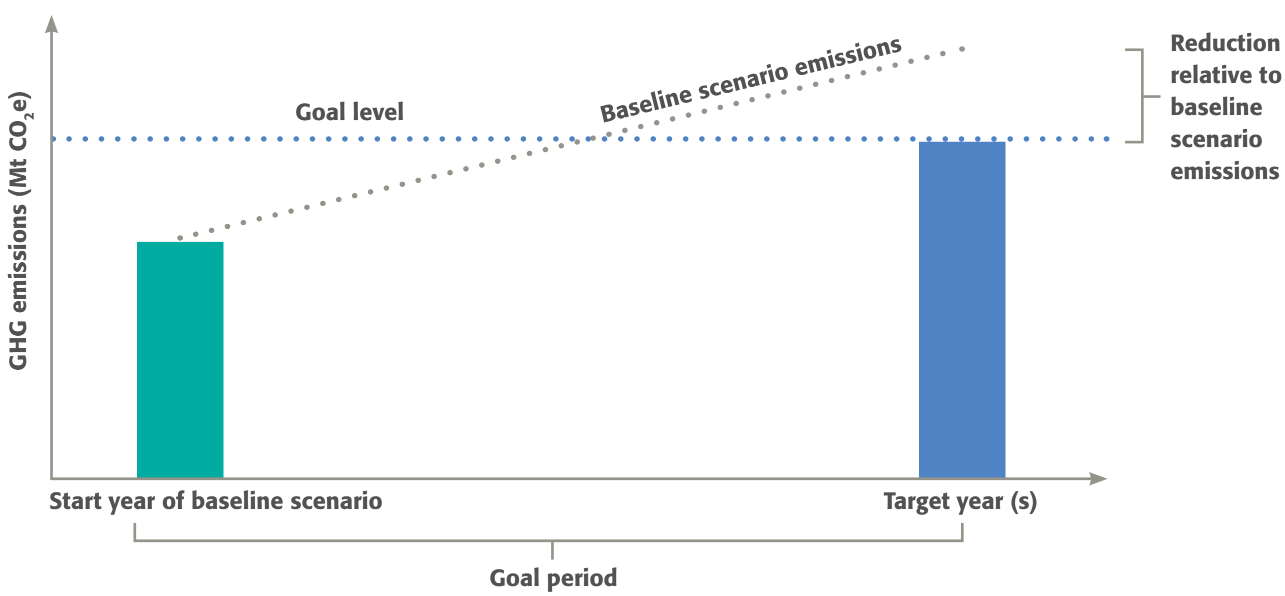


Table 11.1 Examples of city goal types and inventory need

Goal type		Example	Minimum inventory need
Base year emissions goals	Single-year goal	London (UK): By 2025 60% GHG emissions reduction on 1990 levels	Inventory for 1990 and 2025
	Multi-year goal	Wellington (New Zealand): Stabilize from 2000 by 2010, 3% GHG emissions reduction by 2012, 30% by 2020, 80% by 2050	Inventory for 2000, 2010, 2012, 2020 and 2050
Fixed level goals		Carbon-neutral is another type of fixed level goal type. Melbourne (Australia) set a target to achieve zero net carbon emissions by 2020, and plans to achieve the goal through internal reductions and purchasing offsets.	Inventory for 2020. In the case of Melbourne, current inventory required to determine quantity of offsets necessary to cover remainder of emissions, as well as GHG inventory in 2020.
Base year intensity goals	Per capita goal	Belo Horizonte (Brazil): 20% GHG emissions reduction per capita until 2030 from 2007 levels	Inventory for 2007 and 2030
	Per GDP goal	China is the major country adopting GHG emissions reduction per unit of GDP goal for cities. For example, Beijing: 17% reduction per unit of GDP in 2015 from 2010 levels.	Inventory for 2010 and 2015
Baseline scenario goals		Singapore pledged to reduce GHG emissions to 16% below business-as-usual (BAU) levels by 2020 if a legally binding global agreement on GHG reductions is made. In the meantime, Singapore started implementing measures to reduce emissions by 7% to 11% of 2020 BAU levels.	Inventory for 2020 and a projected BAU inventory for 2020

11.2 Aligning goals with the inventory boundary

Mitigation goals can apply to a city's overall emissions or to a subset of the gases, scopes, or emission sectors identified in the inventory boundary (Chapter 3). The results of a compiled GHG inventory, along with a mitigation assessment and any of the city's specific mitigation interests, should determine which parts of the inventory boundary are included or excluded in the goal. Cities may choose to set a sectoral goal as a way to target a specific sector, sub-sector, or group of sectors. For example, a city may establish a goal to reduce emissions from the *IPPU* sector by 20%. Cities may also include additional operations such as city-owned waste facilities or city-owned energy generation facilities that are located outside the inventory boundary.

Cities may follow the *GHG Protocol Mitigation Goals Standard* to set goals separately for each scope, in order to minimize double counting the same emissions in the same goal. If cities choose to set a combined scope 1 and 2 goal, then cities should use the BASIC/BASIC+ framework, or include an adjusted scope 2 total reflecting energy consumption net of energy production occurring in the city.

To avoid double counting scope 1 and scope 2 emissions in a GHG goal, cities can set separate goals for scope 1 and scope 2. If cities seek to set a target that combines scope 1 and scope 2, they may set a target based on BASIC or BASIC+ total. Alternatively, they can have a separate target for scope 2 emissions "net" of energy produced within the city. For this, cities may perform adjustments to scope 2 activity data and regional emission factors (following the location-based method) and report this total separately. These procedures are elaborated upon in Box 11.2.

Use of transferable emissions units

Cities may designate a portion of their mitigation goals to be met using transferable emissions units such as offset credits generated from emissions reduction projects. To ensure transparency and prevent "double counting" of emissions reductions, cities shall document any sold GHG offsets from projects located within the inventory boundary as well as any credits purchased from projects located outside of the city boundary for the purpose of goal attainment. These shall be reported separately (see Section 4.4).

11.3 Tracking emissions over time and recalculating emissions

Tracking emissions over time is an important component of a GHG inventory because it provides information on historical emissions trends, and tracks the effects of policies and actions to reduce city-wide emissions. All emissions over time should be estimated consistently, which means that as far as possible, the time series should be calculated using the same methods, data sources and boundary definitions in all years. Using different methods, data or applying different boundaries in a time series could introduce bias because the estimated emissions trend will reflect real changes in emissions or removals as well as the pattern of methodological refinements.

If cities set an emissions goal, they should identify a base year for that goal. To clarify how emissions will be tracked over time, cities should report base year emissions. Cities should also identify a base year recalculation policy, including the significance threshold for recalculating base year emissions. For example, a city may identify a 5% threshold to determine if the applicable changes to base year emissions warrant recalculation.

Cities may undergo significant changes, which will alter a city's historical emissions profile and make meaningful comparisons over time difficult. In order to maintain consistency over time, historic emissions data from a base year inventory will have to be recalculated. Cities should recalculate base year emissions if they encounter significant changes such as:

Box 11.2 Adjustments to identify energy consumption emissions net of energy production

To determine emissions from grid-supplied energy consumption net of in-city energy production, cities may subtract energy generated in the city from total scope 2 emissions and/or adjust regional emission factors to subtract energy generated in the city.

To adjust the activity data to identify grid-supplied energy consumption net of in-city energy production, a city may follow the equation below.

Grid-supplied energy consumption of net in-city prodution (MWh) =
Grid-supplied energy consumption (MWh) - In-city grid-supplied energy production (MWh)

If a city generates and delivers to the grid more energy than it uses from the grid (e.g. the city is a net generator compared with consumption), it should report zero net energy consumption emissions (shall not be negative emission). If a city uses more grid-supplied energy than it produces, then it would deduct the MWh hours of generation from its MWhs of production, and multiply the remaining MWhs by a location-based emission factor. If all emissions from electricity generation are accounted for, any residual consumption will be served by electricity generated outside of the city boundaries.

Even with an adjustment of activity data, there may be further double counting in the form of the location-based emission factors (applied to any consumption net of production). Because these factors represent an average of all energy generation in the region, they will therefore inherently include emissions from any energy generation located in the city. Cities may attempt to address this by also adjusting the emission factor, which would require the city to identify the total emissions and total generation (in MWh) represented in the regional grid average emission factor as shown below:

$$\textbf{Adjusted emission factor} = \frac{\text{Total regional emissions (tonnes } CO_2e) - \text{emissions from city generation (tonnes } CO_2e)}{\text{Total generation (MWh)} - \text{city generation (MWh)}}$$

From there, a city may deduct the emissions and generation produced in-boundary.

- **Structural changes in the inventory boundary**. This may be triggered by adjustment in a city's administrative boundary, or changes in inclusion or exclusion of activities within the city boundary. For example, a category previously regarded as insignificant has grown to the point where it should be included in the inventory. But no emissions recalculations are needed for activities that either did not exist in the base year, or reflect a natural increase or decrease in city activities (known as "organic growth").
- **Changes in calculation methodology or improvements in data accuracy**. A city may report the same sources of GHG emissions as in previous years, but measure or calculate them differently.

Changes resulting in significant emission differences should be considered as recalculation triggers, but any changes that reflect real changes in emissions do not trigger a recalculation.

Sometimes the more accurate data input may not be reasonably applied to all past years, or new data points may not be available for past years. The city may then have to back cast these data points, or the change in data source may simply be acknowledged without recalculation. This acknowledgement should be made in the report every year in order to enhance transparency; otherwise, new users of the report in the two or three years after the change may make incorrect assumptions about the city's performance.

- **Discovery of significant errors.** A significant error, or a number of cumulative errors that are collectively significant, should also be considered as a reason to recalculate emissions.

Cities should *not* recalculate base year emissions for organic growth (e.g., changes in the level or type of city activities). Cities should also note that emission factors for electricity and GWP are specific to every year, and their changes do not count as methodology changes. To isolate the role of changing activities compared with changing emission factors, cities may track activity data separately—for instance, tracking energy use separately to see the impact of energy efficiency policies.

These recalculation triggers are summarized in Table 11.2.

Whether recalculation is needed depends on the significance of the changes. Determining a significant change may require taking into account the cumulative effect on base year emissions of a number of small changes. The GPC makes no specific recommendations as to what constitutes "significant." However, some GHG programs do specify numerical significance thresholds, e.g., the California Climate Action Registry, where the change threshold is 10% of the base year emissions, determined on a cumulative basis from the time the base year is established.

In summary, base year emissions—and emissions for other previous years when necessary—should be retroactively recalculated to reflect changes in the city that would otherwise compromise the consistency and relevance of the reported GHG emissions information. Once a city has determined its policy on how it will recalculate base year emissions, it should apply this policy in a consistent manner.

Table 11.2 Example of recalculation triggers

Goal type	Example	Recalculation needed (if significant)	No recalculation needed
Changes in inventory boundary	A community is included in or set aside from a city's administrative boundary	X	
	Change in goal boundary from BASIC to BASIC+, or from 6 GHGs to 7 GHGs	X	
	Shut down of a power plant		X
	Build of a new cement factory		X
Changes in calculation methodology or improvements in data accuracy	Change in calculation methodology for landfilled MSW from Methane Commitment Approach to the First Order Decay Method	X	
	Adoption of more accurate activity data instead of a scaled-down national figure	X	
	Change in global warming potential factors used		X
	Change in electricity emission factor due to energy efficiency improvement and growth of renewable energy utilization		X
Discovery of significant errors	Discovery of significant mistake in units conversion in formula used	X	

12 Managing Inventory Quality and Verification

The GPC does not require that cities verify their inventory results, but recommends that cities choose the level and type of verification that meets their needs and capacity. This chapter outlines how cities can establish inventory management plans to ensure data quality improvements over time and preparation for verification procedures.

12.1 Managing inventory quality over time

To manage inventory quality over time, cities should establish a management plan for the inventory process. The design of an inventory management plan should provide for the selection, application, and updating of inventory methodologies as new research becomes available, or the importance of inventory reporting is elevated. The GPC focuses on the following institutional, managerial, and technical components of an inventory. It includes data, methods, systems and documentation to ensure quality control and quality assurance throughout the process:

- **Methods:** These are the technical aspects of inventory preparation. Cities should select or develop methodologies for estimating emissions that accurately represent the characteristics of their source categories. The GPC 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.
- **Data:** This is the basic information on activity levels and emission factors. 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 city 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 city-wide processes related to quality.

- **Documentation:** This is the record of methods, data, processes, systems, assumptions, and estimates used to prepare an 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. Cities should seek to ensure the quality of these components at every level of their inventory design.

Quality control

Quality control (QC) is a set of technical activities, which measure and control the quality of the inventory as it is being developed. They are designed to:

- Provide routine and consistent checks to ensure data integrity, correctness, and completeness
- Identify and address errors and omissions
- Document and archive inventory material and record all QC activities

QC activities include accuracy checks on data acquisition and calculations, and the use of approved standardized procedures for emission calculations, measurements, estimating uncertainties, archiving information and reporting. Higher tier QC activities include technical reviews of source categories, activity and emission factor data, and methods.

Quality assurance

Quality assurance (QA) activities include a planned system of review procedures conducted by personnel not directly involved in the inventory compilation/ development process. Reviews, preferably performed by independent third parties, should take place when an inventory is finalized following the implementation of QC procedures. Reviews verify that data quality objectives were met and that the inventory represents the best possible estimates of emissions and sinks given the current state of scientific knowledge and data available.

See Table 12.1 for an outline of procedures for ensuring QA/QC.

12.2 Verification

Cities may choose to verify their GHG emissions inventory to demonstrate that it has been developed in accordance with the requirements of the GPC, and provide assurance to users that it represents a faithful, true, and fair account of their city's GHG emissions. This can be used to increase credibility of publicly-reported emissions information with external audiences and increase confidence in the data used to develop climate action plans, set GHG targets and track progress.

Verification involves an assessment of the completeness, accuracy and reliability of reported data. It seeks to determine if there are any material discrepancies between reported data and data generated from the proper application of the relevant standards and methodologies, by making sure that reporting requirements have been met, estimates are correct and data sourced is reliable.

To enable verification, the accounting and reporting principles set out in Chapter 2 need to be followed. Adherence to these principles and the presence of transparent, well-documented data (sometimes referred to as an audit trail) are the basis of a successful verification.

While verification is often undertaken by an independent organization (third-party verification), this may not always be the case. Many cities interested in improving their GHG inventories may subject their information to internal verification by staff who are independent of the GHG accounting and reporting process (self-verification). Both types of verification should follow similar procedures and processes. For external stakeholders, third-party verification is likely to significantly increase the credibility of the GHG inventory. However, self-verification can also provide valuable assurance over the reliability of information.

Table 12.1 Example QA/QC procedures

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 calculations
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 calculations)
Check the aggregation of data across source categories, sectors, etc.
Check consistency of time series inputs and calculations
Others

12.3 Parameters of verification

Verifiers should be selected based on previous experience and competence in undertaking GHG verifications, understanding and familiarity with the GPC, and their objectivity, credibility, and independence. However, before commencing with verification, a city should clearly define its goals and decide whether they are best met by self-verification or third-party verification. Verification criteria for a GHG emissions inventory should include the following:

- Inventory boundary is clearly and correctly defined
- All required emission sources are included and notation keys have been used appropriately
- Calculations are consistent with the requirements of the GPC
- Data are time- and geographically-specific to the inventory boundary and technology-specific to the activity being measured
- Data are sourced from reliable and robust sources and referenced appropriately
- All assumptions are documented

The verification process may also be used to examine more general data management and managerial issues, such as selection and management of GHG data, procedures for collecting and processing GHG data, systems and processes to ensure accuracy of GHG data, managerial awareness, availability of resources, clearly defined responsibilities, and internal review procedures. To enhance transparency and credibility, the objectives and remit of verification should be made publicly available.

12.4 Verification process

Verification will usually be an iterative process, where an initial review—highlighting areas of non-compliance and/or queries relating to the assessment—offers an opportunity to make any necessary updates to the GHG inventory before the verification report is produced and conformity with the GPC is determined.

Verification can take place at various points during the development and reporting of GHG inventories. Some cities may establish a semi-permanent internal verification team to ensure that GHG data standards are being met and improved on an on-going basis. Verification that occurs during a reporting period allows for any issues to be addressed before the final report is prepared. This may be particularly useful for cities preparing high-profile public reports.

All relevant documentation should be made available to support the GHG inventory during the verification process. Cities are responsible for ensuring the existence, quality and retention of documentation so as to create an audit trail of how the GHG inventory was compiled. Assumptions and calculations made, and data used, for which there is no available supporting documentation cannot be verified.[82]

If, following verification, the GHG inventory is deemed to be fully compliant with the principles and requirements set out in the GPC, then the city will be able to make a claim of conformity. However, if the verifiers and city cannot come to an agreement regarding outstanding areas of non-compliance, the city will not be able to make a claim of conformity.

The process of verification should be viewed as a valuable input to a path of continuous improvement. Whether verification is undertaken for the purposes of internal review, public reporting or to certify compliance with the GPC, it will likely contain useful information and guidance on how to improve and enhance a city's GHG accounting and reporting practices.

82. If a city issues a specific base year against which it assesses future GHG performance, it should retain all relevant historical records to support the base year data. These issues should be kept in mind when designing and implementing GHG data processes and procedures.

Appendices

Appendix A
Overview of GHG standards and programs

Appendix A summarizes the main features of existing GHG accounting and reporting standards and compares those features with the GPC. Some of the most commonly used or referenced standards include:

1. *1996/2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC Guidelines)*
2. *International Local Government GHG Emissions Analysis Protocol (IEAP)*
3. *International Standard for Determining Greenhouse Gas Emissions for Cities (ISDGC)*
4. *Baseline Emissions Inventory/Monitoring Emissions Inventory methodology (BEI/MEI)*
5. *U.S. Community Protocol for Accounting and Reporting of Greenhouse Gas Emissions (USA Community Protocol)*
6. *PAS 2070: Specification for the assessment of greenhouse gas emissions of a city*
7. *GHG Protocol Corporate Standard*

National GHG inventory methods

IPCC Guidelines, developed for national GHG inventories, provide detailed guidance on emission and removal categories, calculation formulae, data collection methods, default emission factors, and uncertainty management. Both national- and city-level GHG inventories represent geographically explicit entities, and can share similar boundary setting principles and emission calculation methodologies. A key difference between city-level accounting and national-level accounting is that due to relatively smaller geographic coverage, "in-boundary" activities for a country can become transboundary activities for a city. This means that scope 2 and scope 3 emissions may account for a larger percentage in a city and should not be neglected. Another important difference is that statistical data at the city level may not be as comprehensive as national-level data, thus requiring more data collection from the bottom-up.

Corporate GHG inventory methods

The *GHG Protocol Corporate Standard*[83] established the "scopes" framework for corporate accounting, dividing emissions into scope 1, 2 and 3 to fully cover all the relevant corporate activities and avoid double counting within the same inventory. The scopes framework is widely adopted for corporate inventories and has been adapted in the GPC to fit the geographic inventory boundaries of cities. Table A.1 shows the application of scopes terminology for corporate and city-level inventories.

83. See *GHG Protocol Corporate Standard*, 2004.

Table A.1 Scope definitions for corporate and city inventories

	Corporate	City
Scope 1	All direct emissions from sources that are owned or controlled by the company	GHG emissions from sources located within the city boundary
Scope 2	Energy-related indirect emissions from generation of purchased electricity, steam and heating/cooling consumed by the company	GHG emissions occurring as a consequence of the use of grid-supplied electricity, heat, steam and/or cooling within the city boundary
Scope 3	All other indirect emissions that are a consequence of the activities of the company	All other GHG emissions that occur outside the city boundary as a result of activities taking place within the city boundary

Some standards use frameworks or requirements that differ from the GPC, including:

- **IEAP** requires two levels of reporting: city-wide emissions, and emissions from the operations of local government;
- **ISDGC** requires that upstream GHG emissions embedded in food, water, fuel and building materials consumed in cities be reported as additional information items. It recommends cities or urban regions with populations over 1 million persons to use its reporting standard, and cities with populations below 1 million may use less detailed reporting tables such as BEI/MEI;
- **BEI/MEI** only requires mandatory quantification of CO_2 emissions due to final energy consumption. Reporting of emissions from non-energy sectors and non-CO_2 emissions are not mandatory. It was specifically designed for the signatory cities participating in the EU Covenant of Mayors Initiative to track their progress toward the goal set under the initiative, and therefore doesn't cover interactions with other policies, such as EU ETS, in its framework;
- **U.S. Community Protocol** introduces the concepts of "sources" and "activities" rather than the scopes framework, where "sources" is equivalent to scope 1, and "activities" is equivalent to 2 and 3, with some overlap in scope 1. Activities are recognized as those processes which can be managed for emissions reductions regardless of where the emissions occur. The U.S. Community Protocol uses different emission categories than *IPCC Guidelines* and also provides a reporting framework with Five Basic Emissions Generating Activities and some additional and voluntary reporting frameworks (see table A.2);
- **PAS 2070** provides two methodologies to assess city GHG emissions. These recognize cities as both consumers and producers of goods and services. The direct plus supply chain (DPSC) methodology captures territorial GHG emissions and those associated with the largest supply chains serving cities and is consistent with the GPC. The consumption-based (CB) methodology uses input-output modeling to estimate direct and life cycle GHG emissions for all goods and services consumed by residents of a city.

Some other important features, including primary audience, use of the "scopes" framework, inclusion of transboundary emissions and emission sources categories are also compared and summarized below.

Primary audience

The standards reviewed are developed for accounting and reporting of city-level, national-level and corporate or organizational-level inventories. Most of the standards were developed for global use, while two standards were designed to target specific groups. The BEI/MEI was designed for EU cities that participated in the Covenant of Mayors Initiative to track their progress to achieve their SEAP goal. The U.S. Community Protocol was designed as a management framework to guide U.S. local governments to account for and report their GHG emissions associated with the communities they represent, with an emphasis on sources and activities over which U.S. local governments have the authority to influence.

Adoption of "scopes" framework and inclusion of transboundary emissions

All standards reviewed adopt the scopes framework except for the U.S. Community Protocol, which includes two central categories of emissions: 1) GHG emissions that are produced by community-based "sources" located within the community boundary, and 2) GHG emissions produced as a consequence of community "activities". To better illustrate these two concepts using the scopes framework, emissions from sources refer to scope 1 emissions, emissions from activities refer to processes that take place within the community boundary which result in transboundary emissions. All standards cover both in-boundary and transboundary emissions, except for the BEI/MEI method, which only considers scope 1 and scope 2 emissions.

Emission source categories

2006 IPCC Guidelines divide emissions sources into four sectors: *Energy, IPPU, Waste* and *AFOLU*. All other reviewed standards generally followed this division method, except for some minor adaptations, which include using two major categories—*Stationary* and *Mobile*—instead of *Energy*, and adding an additional major category of Upstream Emissions. IPCC categories of emission sources is a good practice for cities to follow for their inventories due to three main reasons:

1. the IPCC offers full coverage of all emissions/removals across all aspects of people's social and economic activities.
2. It clearly defines and divides those emission sources which easily cause confusion (e.g., energy combustion in cement production and emissions from the production process itself shall be categorized under *Energy* and *IPPU* separately; use from waste-generated energy shall be categorized under *Energy* rather than *Waste*; and CO_2 emissions from biomass combustion shall be accounted for but reported separately as an information item because the carbon embedded in biomass is part of the natural carbon cycle).
3. Consistency with national inventories is conducive for cities to conduct longitudinal comparison and analysis.

Despite minor adaptations when it comes to sub-categories, similarities can also be observed. The Stationary Energy sector is usually divided into residential, commercial/institutional, industrial and others, and the Mobile Energy sector is usually divided by transportation types into on-road, railways, aviation, waterborne and other. Classifications in the Waste sector are highly consistent with IPCC Guidelines, consisting of MSW, biological treatment, incineration and wastewater.

Gases covered

Most standards cover the GHG gases specified by the Kyoto Protocol, which now include seven gases. The BEI/MEI methodology only requires reporting of CO_2 emissions.

Detailed guidance on calculations methodologies

IPCC Guidelines, LEAD, U.S. Community Protocol and GPC provide detailed chapters/sections on the calculation formulae and data collection methods for different emissions sectors. PAS 2070 provides a detailed case study of how London, United Kingdom, used its methodologies. Other standards only provide general requirements on accounting and reporting of GHG emissions.

Calculation tools

No specific tool is required to be used in order to achieve conformance with the GPC. WRI developed an Excel-based tool to help Chinese cities calculate emissions. The China tool was designed to take Chinese conditions into consideration, embedding computing functions and default local emission factors, while keeping emissions sources categories consistent with national inventory. The U.S. Community Protocol provides an Excel-based "Scoping and Reporting Tool" to assist cities in scoping out their inventory and showing calculation results. The Excel table does not have computing functions but only records emissions results in CO_2e and utilizes "notation keys" to indicate why a source or activity was included or excluded.

Guidance on setting reduction targets

Only the *GHG Protocol Corporate Standard* and GPC provide guidance on how to set an emissions reduction goal for a company or city.

Table A.2 **Review of existing standards on GHG accounting and reporting**

Program/platform	Author	Target audience	Consistency with major IPCC emission sources categories	Adoption of in-boundary /out-of-boundary framework	In-boundary emissions
Global Protocol for Community-Scale GHG Emissions Inventories (GPC)	C40 ICLEI WRI (2014)	Communities worldwide	Yes	Yes	Yes
1996/2006 IPCC Guidelines for National Greenhouse Gas Inventories	IPCC (1996/2006)	National governments	NA	Yes[84]	Yes
International Local Government GHG Emissions Analysis Protocol (Version 1.0)	ICLEI (2009)	Local governments and communities	Yes[85]	Yes	Yes
International Standard for Determining Greenhouse Gas Emissions for Cities (Version 2.1)	UNEP UN-HABITAT World Bank (2010)	Communities	Yes	Yes	Yes
Baseline Emissions Inventory/ Monitoring Emissions Inventory Methodology	The Covenant of Mayors Initiative[87] (2010)	Cities in the EU	Yes/No[88]	Yes	Yes
U.S. Community Protocol for Accounting and Reporting of Greenhouse Gas Emissions (Version 1.0)	ICLEI USA (2012)	Cities and communities in the U.S.	No[89]	No	Yes
PAS 2070: 2013	BSI (2013)	Cities	Yes	Yes	Yes
Bilan Carbone	ADEME[90] (since 2001)	Companies, local authorities, and regions, in France	No		
Manual of Planning against Global Warming for Local Governments	Ministry of Environment, Japan (2009)	Sub-national governments	Yes[91]	Yes	Yes

84. IPCC emission sources categories include all in-boundary emissions and international aviation and water-borne related out-of-boundary emissions

85. Sub-category (government) not consistent with IPCC categorization

86. Upstream embedded GHG emissions

87. The Joint Research Centre (JRC) of the European Commission

Out-of-boundary emissions	Gases	Detailed guidance on calculation methodologies	Guidance on setting reduction targets	Other information
Yes	Seven gases	No	Yes	• Divides in-boundary and transboundary emissions into scopes 1, 2, and 3 • Provides BASIC, BASIC+ reporting levels • Pilot tested by 35 pilot cities
Yes	Six gases	Yes	No	• Provides detailed guidance on emission/removal categories, calculation formula, data collection, default emission factors, and uncertainty management

Yes	Six gases	Yes	No	• Requires two levels of reporting:
				  • Local government operations (LGO)
				  • Community-wide

Yes[86]	Six gases	No	No	• Simplified description, with a lot of reference to other standards (e.g., IPCC Guidelines) • Suggests cities or urban regions with populations over 1 million persons to use this reporting standard and cities with populations below 1 million to use less detailed reporting tables, such as BEI/MEI
No	CO_2; other gases optional	No	No	• Designed especially for the Covenant of Mayors Initiative in the EU as one of the main measures for signatory cities to achieve their SEAP targets • Only requires quantification of CO_2 emissions due to final energy consumption • Considers interactions with other policies such as EU ETS
Yes	Six gases	Yes	No	• Created the concepts of "sources," which could be interpreted as in-boundary emissions, and "activities", which could be interpreted as both in-boundary and out-of-boundary emissions • Provides various reporting frameworks including the Five Basic Emissions Generating Activities, local government significant influence, community-wide activities, household consumption, in-boundary sources, government consumption, full consumption-based inventory, life cycle emissions of community businesses, and individual industry sectors

Yes	Six gases	Yes	No	• Provides two methodologies to assess city GHG emissions:
				  • Direct plus supply chain methodology, which is consistent with GPC
				  • Consumption-based methodology
				• Worked case study of the application of PAS 2070 provided for London, United Kingdom

	Six gases		Yes	
Yes	Six gases	Yes	Yes	

88. Does not include industry energy, air transport, water-borne sources, and includes waste but not agriculture, forestry and industrial processes

89. Basic emission generating activities—no carbon sinks

90. Managed by the Association Bilan Carbone (ABC) since 2011

91. Sectors: industry, residential, commercial, transport, IPPU, waste, LUCF

Table A.3 Comparison of emissions sources categories

IPCC classification		GPC classification (Scope 1)	
	Energy		**Stationary Energy**
1A4b	Residential	I.1	Residential buildings
1A4a	Commercial/institutional	I.2	Commercial and institutional buildings/facilities
1A2	Manufacturing industries and construction	I.3	Manufacturing industries and construction
1A1	Energy industries	I.4	Energy industries
1A4c	Agriculture/forestry/fishing/fish farms	I.5	Agriculture, forestry, and fishing activities
1A5a	Non-specified	I.6	Non-specified sources
1B1	Solid fuels (fugitive emissions)	I.7	Fugitive emissions from mining, processing, storage, and transportation of coal
1B2	Oil and natural gas (fugitive emissions)	I.8	Fugitive emissions from oil and natural gas systems
			Transportation
1A3b	Road transportation	II.1	On-road transportation
1A3c	Railways	II.2	Railways
1A3d	Water-borne navigation	II.3	Water transport
1A3a	Civil aviation	II.4	Aviation
1A3e	Other transportation	II.5	Off-road transportation
4	**Waste**		**Waste**
4A	Solid waste disposal	III.1	Solid waste disposal
4B	Biological treatment of solid waste	III.2	Biological treatment of waste
4C	Incineration and open burning of waste	III.3	Incineration and open burning
4D	Wastewater treatment and discharge	III.4	Wastewater treatment and discharge
2	**IPPU**		**IPPU**
2A 2B 2C 2E	Mineral industry Chemical industry Metal industry Electronics industry	IV.1	Industrial processes
2D 2F 2G 2H	Non-energy products from fuels and solvent use Product uses as substitutes for ozone depleting substances Other product manufacture and use Other	IV.2	Product use
3	**AFOLU**		**AFOLU**
3A	Livestock	V.1	Livestock
3B	Land	V.2	Land
3C 3D	Aggregate sources and non-CO_2 emissions sources on land Other	V.3	Aggregate sources and non-CO_2 emissions sources on land

Appendix B
Inventories for local government operations

Introduction

Local government operations (LGO) and their key functions vary worldwide, but there are several essential community services that typically fall under the responsibility of local governments, including: water supply, residential waste collection, sanitation, mass transit systems, roads, primary education and healthcare. These local government operations represent activities over which the city has either direct control or strong influence, presenting an opportunity to measure and manage emissions, and demonstrate to tax payers a responsible and efficient use of resources by city leadership.

To guide local governments on calculating and reporting GHG emissions from their operations, ICLEI created the *International Local Government GHG Emissions Analysis Protocol* (IEAP) in 2009. It focuses on the specificities of LGOs, tailoring general guidance on corporate GHG accounting to the needs of cities. This appendix summarizes the guidance given in IEAP for local government operations, with slight changes to ensure consistency with the GPC and promote comparability of local government operations' GHG emissions inventories with national and subnational GHG inventories. For additional guidance please refer to the IEAP chapters which address local government operations.[92]

Other standards and guidelines have also provided similar guidance on a local or national level, including the U.S.-focused *GHG Protocol U.S. Public Sector Protocol* and the *Local Government Operations Protocol* written by the California Air Resources Board, The Climate Registry and ICLEI—Local Governments for Sustainability USA.

Purpose of an LGO inventory

An LGO inventory accounts for GHGs from operations, activities and facilities that governments own or operate, including those from municipal fleets or buildings, or from waste management services provided by the municipality to the community. Emissions from local government operations are typically a subset of city-wide emissions, though rare exceptions can occur. One such exception is if the local government is the operator or owner of facilities that are simultaneously located outside of its geopolitical boundary and serve other communities.

The majority of emissions from local government operations are a subset of community emissions, typically ranging from 3–7% of total city-wide emissions. Although this is a relatively small fraction of the city's emissions, it clearly shows that local governments must use their influence over operations that are not under their direct control (e.g., improving the energy performance of private buildings through the municipal building code). GHG reduction targets can be set for both LGO performance and city-wide emissions.

An LGO inventory can be used to:

- Develop a baseline (and base year) against which GHG developments can be compared
- Regularly reflect and report a true account of emissions generated by LGO
- Identify problem areas in local government operations through facility and activity benchmarking, e.g. identify opportunities to improve energy efficiency in municipal buildings or water supply
- Demonstrate leadership in climate change mitigation by setting a GHG reduction target for LGO
- Increase consistency and transparency in GHG accounting and reporting among institutions

Conducting an LGO inventory

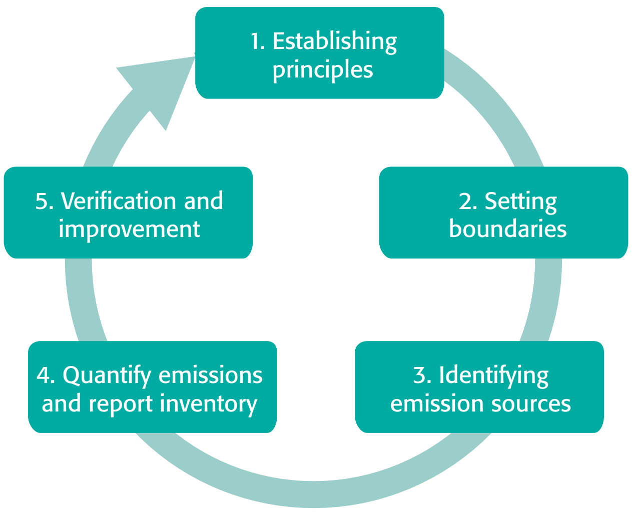
Overall, an LGO inventory follows the five steps described in Figure B.1. This appendix only illustrates the special requirements for LGO emissions inventory in steps 1, 2 and 3.

92. Available online at: http://www.iclei.org/details/article/international-local-government-greenhouse-gas-emissions-analysis-protocol-ieap.html

Accounting and reporting principles

An LGO inventory draws on the same accounting and reporting principles as a city-wide inventory: Relevance, Completeness, Consistency, Transparency and Accuracy, as well as the same procedures for inventory quality control and quality assurance.

Figure B.1 Major steps for LGO inventories



Setting boundaries

Facilities controlled or influenced by local governments typically fall within a city's geographical boundary (see GPC Chapter 3 on inventory boundaries). In some cases, such as electricity use and waste disposal, emissions can occur outside the geographic boundary of the city territory. Regardless of where the emissions occur, however, all LGO emissions must be included in the analysis.

To measure the impact of an emissions reduction measure in LGOs for future years, the corresponding emission source must be included in the base year inventory. For example, if the local government wishes to consider a measure which addresses employee commuting in its mitigation action plan, then emissions from employee commuting need to be included in the base year inventory and following inventories.

Where facilities are jointly used by multiple levels of government, the local government should account for all quantified GHG emissions from the facilities over which it has financial and/or operational control. Where such disaggregated activity data is not available, or not applicable due to the nature of the facilities, local governments should account for its proportion of GHG emissions based on the local governments' equity share or ownership of the facilities. Both methods for consolidation of facility level GHG emissions are recognized as valid by ISO 14064-1:2006 (greenhouse gases - guidance at the organization level).

Emissions from contracted services

These emissions should be included in an LGO inventory if they contribute to an accurate understanding of local government emissions trends, or if they are particularly relevant to developing a comprehensive GHG management policy. Determining whether to include emissions from a contractor in an LGO inventory should be based on three considerations:

1. Is the service provided by the contractor a service that is normally provided by local government? If so, the local government must include these emissions to allow accurate comparison with other local governments.
2. In any previous emissions inventory, was the contracted service provided by the local government and, therefore, included in the earlier inventory? If so, these emissions must be included to allow an accurate comparison to the historical base year inventory.
3. Are the emissions resulting from the contractor a source over which the local government exerts significant influence? If so, these emissions must be included in order to provide the most policy relevant emissions information.

Transferable emission units (e.g. offsets)

A local government should document and disclose information, in alignment with the GPC for city-wide inventories, for any transferable emissions units sold from projects included in the LGO inventory or purchased to apply to an LGO inventory. This ensures transparency and prevents double counting of emissions reductions.

Identify emission sources and sinks

After setting boundaries for an LGO inventory, a local government should identify the emission sources and sinks associated with each included activity or facility. Local governments should note that the scopes definition for categorizing LGO activities will differ from the scopes definition used for city-wide inventories. The categorization of GHG emissions according to scope for local government operations in IEAP is based on the degree of control, whereas a city-wide inventory uses the scopes based on the geographic boundaries of the territory which is under the jurisdiction of the local government. For LGO inventories, IEAP requires local governments to report emissions according to scope and according to the following sectors:

- Stationary Energy
- Transportation
- Waste
- Industrial Processes and Product Use (IPPU)
- Agriculture, Forestry and other Land Use (AFOLU)

Considering the activities usually performed by local governments, the GHG emissions inventory should be further disaggregated into the following categories, when applicable:

- Electricity or district heating/cooling generation
- Street lighting and traffic signals
- Buildings
- Facilities (only energy consumption from facilities operation), which can include:
  - Water supply facilities (collection, treatment and distribution)
  - Wastewater facilities (drainage, treatment and disposal)
  - Solid waste facilities (processing, treatment and disposal)
  - Any other facilities which are part of the local government operations and are not included in the other stationary energy categories mentioned above
- Vehicle fleet (which can be further disaggregated, for example, to single-out the solid waste collection fleet)
- Employee commute
- Wastewater and solid waste (only emissions from biodegradation)
- Other (this sector recognizes the diversity of local government functions and allows for consideration of any sources of emissions not included elsewhere)

Local government GHG inventories help inform city governments in their decision-making process. When local governments aggregate emissions from different sources, it may aggregate the energy emissions from the operation of waste management facilities (GPC's *Stationary Energy* sector) with emissions from the biodegradation of waste during treatment and disposal (GPC's *Waste* sector), but this aggregation result should not be directly used for reporting under GPC and *IPCC Guidelines*.

Not all local governments provide the same functions, and consequently some governments will not have any emissions from some sectors. The *Other Scope 3* sector recognizes the diversity of local government functions and allows for consideration of any sources of emissions not included elsewhere.

A local government's influence over city activity might change through time as well. One emission source within a local government operation might not be included in the government operation the next year. Ensure inventories contain the same emission source coverage when conducting LGO inventory comparisons.

Appendix C
Methodology reference

This table serves as a brief summary of the methodologies outlined in Part II of the GPC, and includes a general overview of activity data and emission factors used.

Please note that this table is not exhaustive. Cities may use alternative methodologies, activity data and emission factors as appropriate. Methods used to calculate emissions shall be justified and disclosed.

Table C.1 Methodology reference

Sectors	Emission sources	Scope	Approaches	Activity data	Emission factors
Stationary Energy	Fuel combustion within the city boundary	1	Fuel consumption	Amount of fuel consumption	Mass GHG emissions per unit of fuel
	Consumption of grid-supplied energy consumed within the city boundary	2	Grid-energy consumption	Amount of grid-supplied energy consumption	Mass GHG emissions per unit of grid-supplied energy (grid specific emission factor)
	Transmission and distribution losses from grid-supplied energy	3	Loss rate based approach	Amount of energy transmitted and average loss rate of the grid	Mass GHG emissions per unit of grid-supplied energy
	Fugitive emissions from fossil fuels extraction and processing	1	Direct Measurement	Direct measurement of GHG emissions	
			Production-based estimation	Quantity of production in fuel extraction and processing	Mass GHG emissions per unit of fossil fuel production
Transportation	Fuel combustion for in-boundary transportation	1	ASIF model (Activity, Share, Intensity, Fuel)	Distance traveled by type of vehicle using type of fuel	Mass GHG emissions per unit distance traveled by type of vehicle using type of fuel
			Fuel sold method	Amount of fuel sold	Mass GHG emissions per unit of sold fuel
	Consumption of grid-supplied energy for in-boundary transportation	2	Grid-energy consumption model	Amount of electricity consumed	Mass GHG emissions per unit of grid-supplied energy (grid specific emission factor)
	Emissions from transboundary transportation	3	ASIF model (Activity, Share, Intensity, Fuel)	Distance traveled or fuel consumed by type of vehicle using type of fuel	Mass GHG per unit distance traveled or fuel consumed by type of vehicle using type of fuel
	Transmission and distribution losses from grid-supplied energy	3	Loss rate based approach	Amount of energy transmitted and average loss rate of the grid	Mass GHG emissions per unit of grid-supplied energy

Table C.1 Methodology reference (continued)

Sectors	Emission sources	Scope	Approaches	Activity data	Emission factors
Waste	Solid waste disposal	1 and 3	First Order of Decay method (GPC recommended)	Amount of waste received at landfill site and its composition for all historical years	Methane generation potential of the waste
			Methane Commitment method	Amount of waste disposed at landfill site in inventory year and its composition	Methane generation potential of the waste
	Biological treatment of waste	1 and 3	Waste composition based approach	Mass of organic waste treated by treatment type	Mass GHG emission per unit of organic waste treated, by treatment type
	Incineration and open burning	1 and 3	Waste composition based approach	Mass of waste incinerated and its fossil carbon fraction	Oxidation factor, by type of treatment
	Wastewater	1 and 3	Organic content based approach	Organic content of wastewater per treatment type	Emission generation potential of such treatment type
IPPU	Industrial processes occurring in the city boundary	1	Input or output based approach	Mass of material input or product output	Emission generation potential per unit of input/output
			Direct Measurement	Direct measurement of GHG emissions	
	Product use occurring within the city boundary	1	Input or output based approach	Mass of material input or product output	Emission generation potential per unit of input/output
			Direct Measurement	Direct measurement of GHG emissions	
			Scaling approach	National or regional level activity or emissions data	Emission factor or scaling factor
AFOLU	Livestock emission sources	1	Livestock based approach	Number of animals by livestock category and manure management system	Emission factor per head and nitrogen excretion per manure management system
	Land uses emission sources	1	Land area based approach	Surface area of different land use categories	Net annual rate of change in carbon stocks per hectare of land
	Aggregate sources and non-CO_2 emission sources on land	1	See details in corresponding chapters		

Abbreviations

AFOLU	Agriculture, forestry and other land use
BOD	Biochemical oxygen demand
C40	C40 Cities Climate Leadership Group
CCHP	Combined cooling, heat and power (trigeneration)
CDD	Cooling degree days
CEM	Continuous emissions monitoring
CH_4	Methane
CHP	Combined heat and power (cogeneration)
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOC	Degradable organic carbon
EF	Emission factor
EFDB	Emission factor database
FAO	Food and Agriculture Organization of the United Nations
FOD	First order decay
GDP	Gross domestic product
GHG	Greenhouse Gas
GPC	Global Protocol for Community-scale Greenhouse Gas Emission Inventories
GWP	Global warming potential
HDD	Heating degree days
HFCs	Hydrofluorocarbons
ICLEI	ICLEI - Local Governments for Sustainability
IPCC	Intergovernmental Panel on Climate Change
IPPU	Industrial processes and product use
ISIC	International Standard Industrial Classification
ISO	International Organization for Standardization
LGO	Local Government Operations
MC	Methane commitment
MMS	Manure management system
MSW	Municipal solid waste
N_2O	Nitrous oxide
NF_3	Nitrogen trifluoride
NMVOCs	Non-methane volatile organic compounds
ODU	Oxidized during use
ODS	Ozone depleting substances
PFCs	Perfluorocarbons
QA	Quality assurance
QC	Quality control
SF_6	Sulphur hexafluoride
SWD	Solid waste disposal
SWDS	Solid waste disposal sites
T&D	Transmission and distribution
TAZ	Traffic analysis zone
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UN-HABITAT	United Nations Human Settlement Programme
US EPA	United States Environmental Protection Agency
US FMC	United States Federal Maritime Commission
VKT	Vehicle kilometers traveled
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute
WWTP	Wastewater treatment plant

Glossary

Activity data	A quantitative measure of a level of activity that results in GHG emissions. Activity data is multiplied by an emission factor to derive the GHG emissions associated with a process or an operation. Examples of activity data include kilowatt-hours of electricity used, quantity of fuel used, output of a process, hours equipment is operated, distance traveled, and floor area of a building.
Allocation	The process of partitioning GHG emissions among various outputs.
Base year	A historical datum (e.g., year) against which a city's emissions are tracked over time.
BASIC	An inventory reporting level that includes all scope 1 sources except from energy generation, imported waste, *IPPU*, and *AFOLU*, as well as all scope 2 sources.
BASIC+	An inventory reporting level that covers all BASIC sources, plus scope 1 *AFOLU* and *IPPU*, and scope 3 in the *Stationary Energy* and *Transportation* sectors.
Biogenic emissions (CO_2(b))	Emissions produced by living organisms or biological processes, but not fossilized or from fossil sources.
City	Used throughout the GPC to refer to geographically discernable subnational entities, such as communities, townships, cities, and neighborhoods.
City boundary	See geographic boundary.
CO_2 equivalent	The universal unit of measurement to indicate the global warming potential (GWP) of each GHG, expressed in terms of the GWP of one unit of carbon dioxide. It is used to evaluate the climate impact of releasing (or avoiding releasing) different greenhouse gases on a common basis.
Double counting	Two or more reporting entities claiming the same emissions or reductions in the same scope, or a single entity reporting the same emissions in multiple scopes.
Emission	The release of GHGs into the atmosphere.
Emission factor(s)	A factor that converts activity data into GHG emissions data (e.g., kg CO_2e emitted per liter of fuel consumed, kg CO_2e emitted per kilometer traveled, etc.).
Geographic boundary	A geographic boundary that identifies the spatial dimensions of the inventory's assessment boundary. This geographic boundary defines the physical perimeter separating in-boundary emissions from out-of-boundary and transboundary emissions.
Global warming potential	A factor describing the radiative forcing impact (degree of harm to the atmosphere) of one unit of a given GHG relative to one unit of CO_2.
Greenhouse gas inventory	A quantified list of a city's GHG emissions and sources.
Greenhouse Gases (GHG)	For the purposes of the GPC, GHGs are the seven gases covered by the UNFCCC: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6); and nitrogen trifluoride (NF_3).

In-boundary	Occurring within the established geographic boundary.
Inventory boundary	The inventory boundary of a GHG inventory identifies the gases, emission sources, geographic area, and time span covered by the GHG inventory.
Out-of-boundary	Occurring outside of the established geographic boundary.
Proxy data	Data from a similar process or activity that is used as a stand-in for the given process or activity without being customized to be more representative of that given process or activity.
Reporting	Presenting data to internal and external users such as regulators, the general public or specific stakeholder groups.
Reporting year	The year for which emissions are reported.
Scope 1 emissions	GHG emissions from sources located within the city boundary.
Scope 2 emissions	GHG emissions occurring as a consequence of the use of grid-supplied electricity, heat, steam and/or cooling within the city boundary.
Scope 3 emissions	All other GHG emissions that occur outside the city boundary as a result of activities taking place within the city boundary.
Transboundary emissions	Emissions from sources that cross the geographic boundary.

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Attachment Item 14B

Recognitions

Pilot Testing Cities

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Revised Assembly Bill 1110 Implementation Proposal for Power Source Disclosure

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ABSTRACT

The Power Source Disclosure Program requires retail electricity suppliers to disclose information annually through a Power Content Label to their end-use customers about the fuel mix of the electricity products the customers were sold the previous calendar year. Passed in 2016, Assembly Bill 1110 (Ting, Chapter 656, Statutes of 2016) directs the California Energy Commission to update the Power Source Disclosure program to require an electricity retail supplier to disclose to its customers the unbundled renewable energy credits and greenhouse gas emission intensities associated with the electricity portfolios offered to its customers.

The Energy Commission plans to initiate a rulemaking to amend the Power Source Disclosure Program regulation in accordance with AB 1110. The Revised *Assembly Bill 1110 Implementation Proposal for Power Source Disclosure* draft staff paper details a proposed approach to modifying the Power Source Disclosure Program to implement AB 1110. This updated proposal reflects changes made in response to stakeholder comments made during and following a public workshop on July 14, 2017.

Keywords: Power Source Disclosure, PSD, power content label, greenhouse gas, GHG, emissions, emissions intensity factor, power mix, fuel mix, renewable energy credit, REC

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ACRONYMS AND ABBREVIATIONS

ACS	Asset-controlling supplier
CARB	California Air Resources Board
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
EIA	Energy Information Agency
EIM	Electricity Imbalance Market
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
LSE	Load-serving entity
MRR	Mandatory Reporting Regulation
MWh	Megawatt-hour
N_2O	Nitrous oxide
POU	Publicly owned utility
PSD	Power Source Disclosure Program
REC	Renewable energy credit
RPS	Renewables Portfolio Standard
WREGIS	Western Renewable Energy Generation Information System

EXECUTIVE SUMMARY

The Power Source Disclosure Program is a consumer information program that requires the reporting and disclosure of the electricity sources used to serve retail customers during the previous calendar year. Passed in 2016, Assembly Bill 1110 (Ting, Chapter 656, Statutes of 2016) modifies the Power Source Disclosure Program by also requiring the reporting and disclosure of the greenhouse gas (GHG) emissions intensity associated with the electricity serving retail customers.

The California Energy Commission will initiate a rulemaking to amend the PSD regulations in accordance with AB 1110. As part of the Energy Commission's pre-rulemaking, Energy Commission staff developed the *Revised Assembly Bill 1110 Implementation Proposal for Power Source Disclosure* draft staff paper, which details a proposed approach to modifying the Power Source Disclosure Program to implement AB 1110. This staff paper was developed in consultation with the California Air Resources Board (CARB) and with consideration of feedback received from the California Public Utilities Commission (CPUC) and from stakeholders.

To maintain consistency with CARB's key GHG emissions reporting and compliance programs, staff proposes a method to construct a retail supplier's GHG emissions intensity factor for the Power Source Disclosure Program largely based on data reported through and methods used by the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, also called the Mandatory Reporting Regulation. In addition, the draft staff paper includes proposed operational definitions for key terms, proposed guidance for classifying renewable energy resources and for disclosing unbundled renewable energy credits, a proposed adjustment mechanism for qualifying publicly owned utilities to generate emissions credits for qualifying GHG-free electricity, proposed new reporting requirements, and an updated Power Content Label and reporting template.

Energy Commission staff held a workshop on July 14, 2017, to solicit feedback from stakeholders on the initial draft staff paper. Staff developed this updated draft staff paper to address public comments received and to provide additional clarity on staff's implementation proposal for AB 1110.

Summary of Revisions

The updated draft staff paper proposes substantive changes to the following subjects:

- *Directly Delivered Electricity Procurements.* Distinguishes between directly delivered and firmed-and-shaped electricity procurements, and reaffirms that firmed-and-shaped procurements will be assigned the GHG emissions intensity of the associated substitute electricity.

- *Self-Consumption and Grid Losses.* Proposes that self-consumption, defined as electricity consumed by a retail supplier and grid losses from transmission, distribution, power wheeling, and transmission-interconnected energy storage, be attributed proportionally to non-renewable electricity sources, consistent with current practice under Power Source Disclosure Program and with California's Renewables Portfolio Standard.

- *Line Loss Adjustment Factor for Imports*. Removes the provision in the original proposal to use CARB's line loss adjustment factor for electricity imports. This revision is to prevent the creation of additional accounting complexities that arise due to differences between net procurement and actual retail sales for a given electricity portfolio.

- *Biogenic CO_2*. Proposes that CO_2 from biogenic sources should be disclosed in a footnote on the Power Content Label, but not included in the overall GHG emissions intensity of an electricity portfolio, consistent with CARB's GHG Emission Inventory's treatment of biogenic sources.

- *Publicly Owned Utility Emissions Adjustment Credits.* Amends the proposal to allow banking of historical emissions credits for eligible generation that occurred on or after January 1, 2017.

- *Power Mix of Asset Controlling Suppliers*. Allows specified purchases of system power from an asset controlling supplier (such as Bonneville Power Administration) to be claimed as the mix of fuel types comprising the asset controlling supplier's system resources.

- *"Eligible Renewable" Definition*. Clarifies that a generating facility must be certified under California's Renewables Portfolio Standard to be classified as "eligible renewable" in power mix reporting.

- *Other Minor Changes*. Includes programmatic changes intended to streamline reporting and improve data collection and validation.

Introduction

The Power Source Disclosure Program

The Power Source Disclosure (PSD) Program is a consumer information program. Retail suppliers of electricity are required to disclose information annually to their end-use customers about the power mix, which is the mix of resource types comprising the electricity portfolio sold to the customers during the previous calendar year. To complete this requirement, retail suppliers report to the California Energy Commission their gross electricity procurement sources, resales of electricity, and the net electricity used to serve retail load for the previous calendar year. The Energy Commission uses this information to generate California's total power mix, which is provided to retail suppliers. Each retail supplier then discloses the power mix associated with its electricity portfolios, as well as California's overall power mix, on a Power Content Label to allow consumers to compare.

Assembly Bill 1110

Passed in 2016, AB 1110 modifies the PSD Program by further requiring retail suppliers to disclose the GHG emissions intensity associated with the electricity portfolios used to serve retail load. A GHG emissions intensity, sometimes referred to as an emissions factor, is the rate of emissions resultant from one megawatt of generation. Retail suppliers are required to begin disclosing the GHG emissions intensity associated with their electricity products on the Power Content Label in 2020 for the 2019 reporting year. AB 1110 also requires the Energy Commission to determine a format for disclosing unbundled renewable energy credits (RECs) as a percentage of annual retail sales.

To implement these modifications, the Energy Commission must:

- Adopt guidelines for the reporting and disclosure of the GHG emissions intensity associated with retail sales and unbundled RECs based on the requirements of AB 1110.
- Adopt a method, in consultation with CARB, for calculating the GHG emissions intensity corresponding to each purchase of electricity by a retail supplier to serve its customers.
- Establish guidelines for adjusting a GHG emissions intensity for a reporting year for any local publicly owned utility (POU) that demonstrates it generated quantities of electricity in previous years in excess of its total retail sales and wholesale sales from specified sources that do not emit any GHGs.

AB 1110 Implementation Process

To implement the changes introduced by AB 1110, the Energy Commission anticipates initiating a formal rulemaking process in accordance with the California Administrative

Procedures Act (APA) in late 2018, which commences with the publication of a notice of proposed action and proposed regulations. The Energy Commission will have one year from the date on which staff initiate the formal rulemaking process to adopt proposed regulations at an Energy Commission business meeting and submit the regulations to the Office of Administrative Law for review.[1]

In advance of this process, staff is conducting pre-rulemaking activities with the public to identify and develop proposed changes to the regulation. Energy Commission staff held a workshop on February 21, 2017, to initiate pre-rulemaking activities and solicit input on several scoping questions under consideration for the AB 1110 implementation process.

After evaluating stakeholder feedback, staff developed a proposal for implementing AB 1110, presenting it at a public workshop on July 14, 2017, to solicit stakeholder feedback. This revised version of the staff draft paper addresses public comment received on the initial staff draft paper presented at a public workshop on July 14, 2017. The revised staff paper was developed in consultation with the California Air Resources Board (CARB) and with consideration of feedback received from stakeholders and the California Public Utilities Commission (CPUC).

Based on comments that staff receives on this updated version, staff plans to develop the proposal into draft regulatory language, which staff anticipates providing for stakeholder feedback in early 2018. Following this public engagement, staff aims to initiate the formal APA rulemaking process in late 2018.

Guiding Principles

The PSD Program is a consumer transparency program. With the passage of AB 1110, the PSD Program is intended to provide a snapshot of the electricity resource typesoh and GHG emissions characteristics of the electricity portfolios sold to retail customers. Several statutory principles guide the development of this implementation proposal:

- Present information disclosed to customers on the Power Content Label in a manner that is accurate, reliable, consistent, and simple to understand.[2]
- Rely on the most recent verified GHG emissions data in developing GHG emissions intensities for specified and unspecified sources of power, while ensuring that these intensities are made available to retail suppliers with sufficient notice to permit timely reporting under PSD.[3]

1 More information about the California state government rulemaking process can be found at http://www.oal.ca.gov/rulemaking_process/regular_rulemaking_process/.

2 Public Utilities Code 398.1 (a), http://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=2.3.&article=14.

3 Public Utilities Code 398.4 (k)(2)(C).

- Ensure there is not double-counting of GHG emissions or environmental attributes.[4]
- Minimize the reporting burden on retail suppliers.[5]

Another consideration guiding staff implementation of AB 1110 is appropriate alignment with other state energy and GHG emissions programs. As intended by the bill's author,[6] the Energy Commission aims to develop a GHG emissions intensity method that is consistent, to the extent possible, with CARB-administered programs, including the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, also called the Mandatory Reporting Regulation (MRR), and the Cap-and-Trade Program.

MRR lays out the reporting requirements applicable to all stationary sources of GHG emissions and fuel suppliers with GHG emissions equal to or in excess of 10,000 metric tons of CO_2-equivalent (CO_2e) per year, as well as to all electricity importers. This regulation provides the data underpinning California's Cap-and-Trade Program. MRR requires entities to report annual emissions and associated information for in-state electricity generation and electricity imports.[7]

The Cap-and-Trade Program is a market-based program designed to reduce GHG emissions covering 85 percent of the state's economy. The Cap-and-Trade Program sets a firm cap on GHG emissions, and this cap declines every year to ensure that the state meets the GHG emissions reduction targets of Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) and Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016). The Cap-and-Trade Program requires that all covered entities retire GHG allowances equal to the entities' GHG emissions during a compliance period, typically three years. Covered entities may also apply a limited number of offset credits toward the compliance obligation. The Cap-and-Trade Program allows for a trading market for regulated entities and voluntary participants to buy and sell GHG emissions allowances. Under the Cap-and-Trade Program, market forces create incentives to reduce GHG emissions below allowable levels through investments in clean technologies.

MRR data also serve as one of the bases for CARB's GHG Emission Inventory, an accounting of the state's estimated annual anthropogenic GHG emissions, including emissions from imported electricity resources, that is used to track progress toward California's GHG reduction goals. CARB developed the GHG Emission Inventory to

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4 Public Utilities Code 398.4 (k)(2)(E).

5 Public Utilities Code 398.5 (d).

6 Ting, Phil, California State Assembly Member, Nineteenth District, "Legislative Intent—Assembly Bill No. 1110," August 28, 2016, *California State Assembly Daily Journal*, http://docketpublic.energy.ca.gov/PublicDocuments/16-OIR-05/TN215755_20170203T095647_Jordan_Scavo_Comments_Assemblymember_Ting's_Letter_to_the_Daily.pdf.

7 The greenhouse gases represented in MRR emissions reporting include CO_2, methane (CH_4), and nitrous oxide (N_2O) from geothermal generators and generators that combust fossil fuels and biogenic fuels. There is a one-year lag between the most recent available MRR data and PSD's current reporting year.

conform to international GHG emissions accounting guidelines developed by the International Panel on Climate Change (IPCC).[8] The GHG Emission Inventory is a public GHG emissions accounting system that provides an annual accounting of California's GHG emissions, which is similar to the purpose of AB 1110.

[8] "California Greenhouse Gas Emissions for 2000-2014-Trends of Emissions and Other Indicators," *California GHG Emission Inventory, 2016 Edition*, CARB, https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2014/ghg_inventory_trends_00-14_20160617.pdf.

PSD Program Definitions

Electricity Portfolio and Electricity Offering

Energy Commission staff proposes that the terms *electricity portfolio* and *electricity offering* be considered synonymous with the term *electric service product* as it is used in the PSD regulations. All three terms mean a portfolio of electricity sources serving load of some or all retail customers in a retail supplier's service area over a calendar year.

Furthermore, staff proposes to clarify that each electricity portfolio offered to a retail supplier's customers should be disclosed separately in annual filings and on power content labels.

Electricity Sources Serving Private Contracts

Some retail suppliers have private contracts with individuals or organizations to provide electricity. The electricity resources procured to fulfill these private contracts are not available to the retail supplier's general customer base. These electricity portfolios are still subject to the reporting requirements under the PSD Program. However, reporting and disclosing every private contract separately may be cumbersome.

Therefore, staff proposes that a retail supplier's default electricity portfolio shall include the aggregated generation sources and associated GHG emissions from private contracts, rather than reporting these separately for each private contract.

Annual Sales

The statutes governing the PSD Program stipulate that the power mix should be based on *annual sales*, an undefined term in statute.[9] In the past, the PSD Program has informally interpreted annual sales to mean *retail sales* as defined in the *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities* and applied in the Renewables Portfolio Standard (RPS) Program.[10] Staff proposes that annual sales should be interpreted to mean retail sales and be defined as follows:

> "Sales of electricity by a retail supplier to end-use customers and their tenants over the course of a calendar year, measured in megawatt hours (MWh). Retail sales do not include self-consumption, defined as consumption by a retail supplier; electricity produced for onsite consumption (self-generation) that was not sold to the customer by the retail supplier; or losses due to transmission, distribution, power wheeling, and transmission-interconnected energy storage."

9 Public Utilities Code 398.4 (g).

10 *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Utilities*, http://www.energy.ca.gov/2016publications/CEC-300-2016-002/CEC-300-2016-002-CMF.pdf.

Greenhouse Gases Covered Under the PSD Program

Targeted Gases

Energy Commission staff proposes to limit the calculation of the GHG emissions intensity associated with retail suppliers' electricity portfolios to include only the GHGs typically associated with electricity generation emissions: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). These are the tracked GHGs under MRR, the EPA's Greenhouse Gas Reporting Program, and the IPCC's GHG inventory guidelines.[11]

Excluded Emissions

Although the terms are sometimes conflated, not all renewable electricity resources are GHG-free resources. Under MRR, geothermal generators and generators that use biogenic fuels, such as biomass and all in-state and new out-of-state sources of biomethane,[12] are required to report their GHG emissions.

The Cap-and-Trade Program exempts certain GHG emissions from the determination of a participating entity's compliance obligation. In particular, biogenic CO_2, meaning CO_2 emitted from combustion of biogenic fuels and fugitive emissions from geothermal generators (CO_2 and CH_4,) are exempted from the determination of compliance obligations.

Biogenic CO_2 emissions from the electricity sector are estimated in CARB's GHG Emission Inventory, but disclosed separately from other GHG emissions and not included under the statewide GHG emissions total or CARB's Scoping Plan sectoral GHG emissions targets.[13] This is consistent with IPCC GHG inventory accounting that attributes biogenic CO_2 to the Agriculture, Forestry, and Other Land-Use sector; in order to avoid double-counting, IPCC guidance states that biogenic CO_2 should not be counted in the electricity sector GHG emissions accounting.[14]

[11] See CARB's *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, https://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-2016-unofficial-2017-10-10.pdf ; EPA's *Greenhouse Gas Reporting Program, Subpart C*, https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=be77ce6e756f0befaa0dd95743e3342e&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl; *2006 IPCC Guidelines for National Greenhouse Gas Inventories: Volume 2, http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html.*

12 See sections 95852.1, 95852.1.1 , and 95852.2 of the Cap-and-Trade Regulation for further details on what biomass and biomethane is exempt from a compliance obligation.

13 See CARB's "Scoping Plan Categorization," https://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_scopingplan_00-15.xlsx

[14] "Frequently Asked Questions," IPCC Task Force on National Greenhouse Gas Inventories, http://www.ipcc-nggip.iges.or.jp/faq/faq.html.

Fugitive GHG emissions from geothermal generators vary depending on the local geologic conditions and generator system design. Because of this degree of variability, fugitive GHG emissions from geothermal generators are not used to determine a compliance obligation under the Cap-and-Trade Program. However, these emissions are reported under MRR and counted in the GHG Emission Inventory.

Staff proposes that retail suppliers report to the PSD Program all GHG emissions, including those from geothermal and biogenic sources. For consistency with electricity sector GHG accounting practices under CARB's Cap-and-Trade Program and GHG Emission Inventory and IPCC guidance, staff proposes that reported geothermal emissions under MRR be included in the overall GHG emissions intensity for each electricity portfolio. Staff proposes that biogenic CO_2 associated with an electricity offering be disclosed on the power content label separately in a footnote, but not be used in calculating the electricity offering's overall GHG emissions intensity. CH_4 and N_2O emissions associated with biogenic fuels will still be included in an electric service product's GHG emissions intensity. The proposed approach provides an accurate and transparent reporting of the renewable and emissions attributes associated with electricity serving retail customers, while aligning with existing emissions accounting protocols used by California and other national and international organizations.

This approach will treat biogenic and geothermal electricity sources differently for GHG emissions intensity calculations but will not alter the way the retail supplier's power mix is calculated, as biomass, eligible biomethane, and geothermal electricity generators will still be classified as eligible renewable energy resources.

Data Sources and GHG Emissions Intensity Calculations

Generator-Specific GHG Emissions Intensities

MRR collects and disseminates the most robust generator-level GHG emissions data available for implementation of AB 1110. Therefore, Energy Commission staff proposes to use the most recent publicly available MRR data on an annual basis to develop generator-specific emissions intensities.

Publicly available GHG emissions data reported under MRR are derived from several reporting methods. Most in-state electricity generators directly report GHG emissions to MRR.[15] Out-of-state electricity generators do not directly report their GHG emissions to MRR; however, the MRR program calculates generator-specific GHG emission intensities based on federal data from the US EPA and Energy Information Agency so electricity importers can report the quantity of imported electricity and report GHG emissions associated with their electricity imports. MRR data, therefore, will provide generator-specific GHG emissions intensities for out-of-state generators (expressed in metric tons of CO_2e/MWh), and total GHG emissions for in-state generators (expressed in metric tons of CO_2 equivalent or CO_2e).

Staff proposes to calculate generator-specific GHG emissions intensities by dividing total GHG emissions of CO_2e by the annual net generation reported to EIA.[16] Staff further proposes to adopt the out-of-state generator-specific GHG emissions intensities that CARB staff calculates and publishes as part of the MRR reporting tools for electricity importers.[17]

Generator Data Not Covered Under MRR

Some small generators do not meet the reporting threshold under MRR. For these cases, staff will calculate GHG emissions by multiplying the heat content of fuel consumed for electricity production[18] by stationary fuel emission factors[19] published by the EIA. When

[15] Small generators with an annual capacity less than 1 MW or that emit fewer than 10,000 MT of CO_2e a year are not required to report under MRR.

[16] Annual net generation data is published by EIA on Form 923.

[17] See CARB's Mandatory Reporting Regulation reporting tools Workbook 1: EPE Importers and Exporters, https://www.ccdsupport.com/confluence/display/calhelp/Reporting+Form+Instructions#EPE.

[18] "Annual Electric Utility Data," Energy Information Agency, Form EIA-923, https://www.eia.gov/electricity/data/eia923/.

[19] "Carbon Dioxide Emission Coefficients," Energy Information Agency, https://www.eia.gov/environment/emissions/co2_vol_mass.php ; EIA's factors are based on stationary fuel combustion emissions factors published by the Environmental Protection Agency. See "Emission Factors for

calculating GHG emissions for such generators, staff proposes to convert emissions of CO_2, CH_4, and N_2O to CO_2e using global warming potentials in a manner consistent with MRR.[20]

Generator Data Not Covered Under MRR

Some small generators do not meet the reporting threshold under MRR. For these cases, staff will calculate GHG emissions by multiplying the heat content of fuel consumed for electricity production[21] by stationary fuel emission factors[22] published by the EIA. When calculating GHG emissions for such generators, staff proposes to convert emissions of CO_2, CH_4, and N_2O to CO_2e using global warming potentials in a manner consistent with MRR.[23]

Furthermore, staff is aware that a small number of generators may have discrete generating units that are owned or contracted to separate retail suppliers. These generators may have only supplied aggregated GHG emissions data under MRR. Staff is consulting with CARB to develop a better an optimal treatment for such cases, which may involve using either MRR or EIA data. As a default option for situations in which electricity deliveries from discrete generating units within one generator can be demonstrated to be attributable to separate retail suppliers, staff proposes to calculate GHG emissions intensities for each generating unit using the heat content of fuel consumed for electricity production and stationary fuel combustion factors provided by EIA.

Cogeneration Facilities

Cogeneration plants produce GHG emissions through both the generation of electricity and useful heat for industrial processes. MRR collects total GHG emissions from these cogeneration facilities, which includes emissions associated with both heat and electricity generation.

For cogeneration facilities, staff proposes to include in the electricity portfolio's GHG emissions intensity only the portion of GHG emissions associated with electricity

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Greenhouse Gas Inventories," Environmental Protection Agency, https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf.

[20] Direct Global Warming Potential, Second Assessment Report (SAR) 100 Year Values, IPCC, https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

[21] "Annual Electric Utility Data," Energy Information Agency, Form EIA-923, https://www.eia.gov/electricity/data/eia923/.

[22] "Carbon Dioxide Emission Coefficients," Energy Information Agency, https://www.eia.gov/environment/emissions/co2_vol_mass.php ; EIA's factors are based on stationary fuel combustion emissions factors published by the Environmental Protection Agency. See "Emission Factors for Greenhouse Gas Inventories," Environmental Protection Agency, https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf.

[23] Direct Global Warming Potential, Second Assessment Report (SAR) 100 Year Values, IPCC, https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html.

generation. Using fuel consumption data reported to EIA,[24] staff will calculate this portion by dividing the heat content of the fuel consumed for electricity generation by the heat content of the total fuel consumed by the cogeneration facility. That portion of GHG emissions attributable to electricity production will then be multiplied by the facility's total GHG emissions and divided by the facility's total electricity generation to calculate a cogenerator's GHG emissions intensity for a given year.

GHG Emissions Intensity of an Electricity Portfolio

For each procurement claim from a specified resource, reporting entities will multiply the GHG emissions intensity of the generator at which the electricity was generated by the total amount of procurement from that generator to obtain the GHG emissions associated with that procurement.

Procurement of unspecified sources of electricity will be assigned a default GHG emissions intensity, as discussed in a subsequent section of this paper.

An electricity portfolio's GHG emissions intensity should be calculated by dividing the sum of all GHG emissions associated with its specified and unspecified electricity sources by the retail sales of that electricity portfolio.

As stated above, in order to reconcile total procured generation with retail sales, an electricity portfolio's total GHG emissions, for the purpose of calculating its GHG emissions intensity, will exclude GHG emissions associated with a retail supplier's self-consumption, as well as losses as a result of transmission, distribution, power wheeling, and transmission-interconnected energy storage. This method differs from GHG emissions accounting under MRR , since MRR does not calculate an electric power entity's GHG emissions of generation based on retail sales.

Incorporating GHG Emissions Intensities into Annual Reports

Retail suppliers will provide line item generator data for each procurement on Schedule 1 of the annual report, including EIA identification numbers (IDs). Using formulas built into Schedule 1, generator-specific GHG emissions intensities will auto-populate based on the EIA ID entered for each line item of procurement. The electricity portfolio's overall GHG emissions intensity will also be automatically calculated on Schedule 1.

Timing of GHG Emissions Intensity Updates

Staff proposes to update the PSD Program annual reporting forms with the most recently available GHG emissions intensities for known electricity generators by April 1 of each year.

24 Cogeneration facility heat content numbers as made available through EIA's Form 923 reporting process will be used for this calculation.

Due to the availability date of new GHG emissions data from MRR, the generator-specific emissions intensities will be based on data from an earlier year than the reporting year under the PSD Program, as is also the case for the Cap-and-Trade Program's use of MRR data. This data lag is unavoidable, given the statutory requirements of AB 1110. CARB staff analysis of MRR data, however, indicates that generators' year-to-year emissions intensities do not vary significantly.

RECs and PSD Program Accounting

RECs in Power Mix Accounting

The current PSD regulations instruct retail suppliers to report eligible renewable energy generation based on the year it was generated. The current regulations do not, however, offer specific guidance on how the procurement and retirement of the associated RECs would affect how the eligible renewable energy generation is reflected in the power mix for each electricity portfolio. Some stakeholders have requested eligible renewable energy generation to be reported for the year the associated REC is retired, consistent with how RECs are reported for California's RPS Program. The RPS Program is constructed with multiyear compliance periods that allow retail suppliers to reconcile annual REC retirements at the end of the period and among compliance periods, as RECs have a 36-month period in which they can be retired. However, the PSD Program requires retail suppliers to report annually on the electricity portfolios they sold to retail customers the previous year. Due to differences in reporting time frames, there would be a mismatch between how eligible renewable electricity is accounted for in the PSD Program and the RPS Program. These programmatic differences prevent eligible renewable energy resource reporting under the PSD Program to align with the reporting of REC retirements for the RPS Program.

Furthermore, reporting eligible renewable energy generation in the year the associated REC is retired would result in discrepancies between annual electricity procurements and annual retail sales, as renewable electricity generation would be reported according to the REC retirement year, while nonrenewable generation would still be reported according to the year in which it was generated.

Finally, the purpose of the original PSD Program and AB 1110 is to provide transparency to customers about the electricity they consume. Reporting eligible renewable electricity for the year corresponding to the actual generation year of electricity (and the associated RECs) more closely aligns with this purpose of the PSD Program.

As such, staff proposes that electricity from eligible renewable energy sources be reported according to the year in which it was generated. Staff further proposes that a retail supplier's electricity transactions may be classified only as an eligible renewable resource in the power mix if the REC and procured electricity were transacted together (either directly or through firming-and-shaping as Portfolio Content Category 1 or 2 products under RPS regulations for POUs).

Finally, and in accordance with Public Utilities Code 398.4 (h), staff proposes to clarify that eligible renewable generators must be certified under California's RPS Program to be classified as "Eligible Renewable" in the power mix. Renewable facilities that do not meet this requirement will be classified as "Other" in the power mix.[25]

RECs in GHG Emissions Accounting

California has several landmark climate and energy policies and programs that aim to reduce GHG emissions and advance renewable energy in California, including the RPS Program, the MRR, and the Cap-and-Trade Program. Staff from the Energy Commission, CARB, and the California Public Utilities Commission (CPUC) recently issued a joint letter reaffirming California's definition and usage of a REC under its principal energy policies and programs.[26]

The letter states:

> "Public Utilities Code section 399.12 (h) defines a 'Renewable energy credit' as:
>
> > 'a certificate of proof associated with the generation of electricity from an eligible renewable energy resource, issued through the accounting system established by the Energy Commission pursuant to Section 399.25, that one unit of electricity was generated and delivered by an eligible renewable energy resource.'
>
> It goes on to specify that a REC:
>
> > 'includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.'
>
> The definition of a REC reflects the renewable and environmental attributes identified by CPUC Decision 08-08-028, which states:
>
> > 'A REC includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, including any avoided emission of pollutants to the air, soil or water; any avoided emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, or any other greenhouse gases…'

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25 The "Other" classification under Power Source Disclosure is a blanket classification that also captures uncommon electricity generation fuels such as petroleum.

26 Courtney Smith, Rajinder Sahota, and Edward Randolph, "Public Comment on June 15, 2015 Workshop on RECs, the Oregon Renewable Portfolio Standard, and energy imports into California via the western Energy Imbalance Market," August 2, 2017, Public Comments on Renewable Energy Certificates Associated with Energy Imported into the California Energy Imbalance Market, pg. 8-11, http://www.oregon.gov/energy/energy-oregon/Documents/2017-Public-Comments-RECs-EIM.pdf

> Decision 08-08-028 further provides, '[a]lthough the avoided GHG emissions attribute is included in the definition of the REC, under a cap, the avoided GHG emissions attribute should … have zero value' (p.23). Accordingly, the REC may not be used for GHG emissions reduction purposes.
>
> CARB has codified in the design of the California Cap-and-Trade Program that a REC does not confer avoided emissions value under the Program, as the total GHG emissions allowed under the cap are fixed. If renewable energy is generated rather than fossil-fuel based energy, emissions are not avoided because the cap on emissions does not change. Rather, the generation of renewable energy instead of fossil-fuel based energy makes available allowances that can be used by other entities.
>
> Under both California's Cap-and-Trade Program and MRR, entities must report the electricity generated in-state or imported into California from specified sources, irrespective of whether the electricity is also associated with RECs. CARB then assigns emission factors to specified resources based on fuel type."

The joint letter expresses a consistent understanding of the role of RECs in GHG emissions accounting. Although a REC includes all renewable and environmental attributes associated with electricity production, including avoided emissions, a REC is not an emissions reduction credit and cannot be used for that purpose. Existing GHG emissions accounting protocols in California track actual emissions attributable to the state.

To be consistent with existing state policy, staff proposes to calculate GHG emissions intensities according to delivered electricity. Staff further proposes not to use RECs to track or reduce GHG emissions under PSD.

RPS Adjustment Under the Cap-and-Trade Program

To give retail suppliers credit for the cost associated with investing in out-of-state renewable electricity resources to meet RPS Program requirements, the Cap-and-Trade Program provides the RPS adjustment, which provides an optional adjustment to an entity's compliance obligation based on the retirement of RECs associated with electricity from RPS-eligible resources that is not delivered to California.[27] The RPS adjustment is not recognition of avoided emissions or the emissions characteristics of the RECs that were transacted as part of imported electricity. The RPS adjustment does not change the GHG emissions associated with any electricity imports.

Unbundled RECs Under the PSD Program

[27] The RPS adjustment reduces an electricity importer's total emissions according to the quantity of eligible retired RECs (in MWh) multiplied by the default emissions factor for unspecified electricity.

Unbundled RECs are renewable energy credits from an eligible renewable energy resource that are not procured as part of the same contract or ownership agreement with the underlying energy from that eligible renewable energy resource, including RECs that were originally procured as a bundled product but were subsequently resold separately from the underlying energy.

AB 1110 requires the Energy Commission to determine the format for disclosing the portion of annual sales derived from unbundled RECs.[28] The current PSD regulations provide no formal guidance regarding how to report or reflect unbundled RECs on the Power Content Label.

The past practice of some load-serving entities (LSEs) has been to report unbundled REC purchases as electricity purchases in their PSD Program filings and to reflect unbundled RECs in the power mix for each electricity portfolio on the Power Content Label. However, such reporting produces accounting discrepancies under the PSD Program, as the inclusion of unbundled RECs inflates the reported total electricity procurement for an electricity portfolio. To reconcile retail sales with an inflated total electricity procurement, retail suppliers have reduced the amount of electricity procured from unspecified or other non-renewables sources.

This has led to concerns that the Power Content Label does not reflect the actual generating sources comprising an electricity portfolio or that unbundled RECs are being used to misrepresent the actual sources of electricity used to serve customers. In implementing AB 1110, this proposal aims to address the perceived marketing concerns pertaining to the reflection of unbundled RECs in the Power Content Label.

Since unbundled RECs do not represent electricity procurement, Energy Commission staff proposes that unbundled RECs should not be classified as a renewable energy resource or as any other category for the power mix. Staff also proposes that unbundled RECs not be included in the GHG emissions intensity calculations, since RECs, including unbundled RECs, cannot be used for emissions reduction purposes.

Retail suppliers will report their unbundled RECs procured as part of each electricity portfolio separate from electricity procurements in their PSD Program filings. As a footnote on the Power Content Label, retail suppliers will disclose the quantity of unbundled RECs retired in the reporting year as a percentage of retail sales.

Retirement of Unbundled RECs

Staff proposes that retail suppliers will report their unbundled RECs in the year in which the REC is retired. This approach differs from staff's proposed approach to RECs associated with directly delivered or firmed-and-shaped electricity transactions, in

[28] See Section 398.4 (h) (7) of the Public Utilities Code, https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PUC&division=1.&title=&part=1.&chapter=2.3.&article=14.

which the transactions are reported in the year the electricity is delivered, as described above. This is because unbundled RECs can be bought and sold more than once before ultimately being retired, which could result in double-counting. RECs from directly delivered or firmed-and-shaped electricity transactions, on the other hand, cannot be resold without the environmental attribute becoming that of an unbundled REC, minimizing the concern of double-counting these resources.

Procurement Types and PSD Program Accounting

This proposal is predicated on a few category designations for procurement. The type of procurement thus determines how a transaction will be treated under the PSD Program with respect to the power mix and GHG emissions intensity calculation. Consistent with current practices under the PSD Program, procurements will be classified as specified or unspecified, with specified procurements further distinguished as either directly delivered or firmed-and-shaped.

The table below summarizes how each type of procurement is treated for power mix and GHG emissions accounting.

Table 1: Procurement Types and Accounting Treatment

Procurement Type	Power Mix Accounting	GHG Emissions Intensity Accounting
Specified – Directly Delivered	Assigned the resource type of the generator	Assigned the GHG emissions intensity of the generator
Specified – Firmed-and-Shaped	Assigned the resource type of the generator that produced the REC	Assigned the GHG emissions intensity of the substitute power. If unknown, assigned the default GHG emissions intensity for unspecified electricity[29]
Specified – Null Power	Classified as Unspecified Electricity	Assigned the GHG emissions intensity of the generator
Unspecified	Designated as Unspecified Electricity	Assigned the default GHG emissions intensity for unspecified electricity

Source: Energy Commission staff

29 If the source of the substitute electricity is known, the retail supplier may use the generator-specific GHG emissions intensity from the substituted electricity in the firmed-and-shaped procurement transaction.

Specified Sources of Electricity

Specified sources of electricity are electricity transactions that are traceable to specific generation sources by any auditable contract trail or equivalent, such as a tradable commodity system, that provides commercial verification that the electricity source has been sold once and only once to a retail consumer. A specified source must have been specified prior to contract execution or trade confirmation. A source is also considered specified on the basis of ownership with evidence of direct delivery (see below) via continuous physical transmission.

Directly Delivered Procurements

Procurement claims that meet one of the following criteria will be considered directly-delivered sources of electricity: have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or be scheduled from the generation source into a California balancing authority via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink located in the state of California (usually via e-tag),[30] or have an agreement to dynamically transfer electricity to a California balancing authority.

Power Mix. Directly delivered procurements will be assigned the power mix resource type of the generator from which the electricity was derived.

However, directly delivered procurements from renewable generators must be transacted with the associated RECs to be classified as an eligible renewable resource in the power mix. Otherwise, the procurements will be classified as null power (discussed further below).

GHG Emissions Intensity. Directly delivered procurements will be assigned the GHG emissions intensity of the generator from which the electricity was derived.

Firmed-and-Shaped Procurements

Firmed-and-shaped procurements are electricity products that are bundled products in which RECs are matched with incremental substitute electricity imported from outside a California balancing authority and in addition to a retail supplier's resource portfolio prior to the contract or ownership agreement for the renewable resource.[31]

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[30] The use of another source to provide real-time ancillary services required to maintain an hourly or subhourly import schedule into a California balancing authority shall be permitted, but only the fraction of the schedule actually generated by the specified generation source shall count toward this specified procurement of electricity.

[31] For the full definition, see Section 3203 (b) of the *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities.*

As discussed above, RECs are not used to track or adjust GHG emissions under CARB's GHG emissions programs. In the case of firmed-and-shaped procurements, MRR requires GHG emissions of the substitute power actually delivered into California to be reported.

Power Mix. For the power mix, staff proposes that firmed-and-shaped electricity procurements be assigned the resource type of the generator from which the RECs were derived. This proposal aligns with current practice under PSD. It should be noted that this exception for firmed-and-shaped procurements, in which the fuel type of the transacted REC is used to determine the procurement's power mix category, is meant to reflect a retail supplier's procurement decisions for meeting its RPS obligation, and the inclusion of firmed-and-shaped procurements in PSD's power mix is still predicated on transactions for actual electricity as part of the bundled product.

GHG Emissions Intensity. To determine the GHG emissions of firmed-and-shaped transactions, staff proposes requiring reporting entities to use the GHG emissions intensities of the generator that produced the substitute electricity. For cases in which the source of the substituted electricity is unknown, reporting entities will be required to use the default GHG emissions intensity of unspecified electricity in reporting the emissions associated with that product.

Staff proposes not to provide any adjustments to retail sellers' GHG emissions intensity based on the retirement of RECs transacted through firmed-and-shaped electricity products. A main purpose of the PSD Program is to bring additional transparency regarding the GHG emissions intensity associated with electricity portfolios sold to retail customers in California. As such, staff concludes that any adjustments to GHG emissions for the retirement of RECs from firmed-and-shaped electricity products would prevent a more accurate accounting of the GHG emissions associated with a retail supplier's electricity portfolios used to serve retail customers.

Null Power

Under the current PSD regulations, null power, which is electricity generated from a renewable resource that has been disassociated from its RECs, is classified as unspecified electricity for the power mix on the Power Content Label.

CARB's GHG emissions programs track emissions associated with electricity generation, so null power has no meaning under MRR and the electricity is reported at the GHG emissions rate associated with its electricity generator. In the absence of meeting the specified power requirements, imported electricity is reported as unspecified.

Power Mix. Staff proposes that null power will continue to be classified as unspecified electricity, since it was not procured with its associated RECs.

GHG Emissions Intensity. In alignment with CARB GHG emissions accounting, specified transactions for null power will be assigned the GHG emissions rate of the specified source from which the electricity was generated or the unspecified emissions intensity if the electricity is imported and does not come from a specified source.

Specified System Mixes of Asset-Controlling Suppliers

Asset-controlling suppliers (ACS), such as Powerex and Bonneville Power Administration, have system mixes composed primarily of large hydroelectric plants with a small portion comprised of other generation sources. Under the current PSD regulations, a retail supplier that procures specified electricity from an ACS through a transaction that can be traced to a specific generator can report it according to the resource characteristic of the specific generator; otherwise, procurements from mixed electricity sources must be classified as unspecified electricity. However, MRR contains provisions that allow an ACS to be assigned a GHG emissions intensity that reflects the ACS's system mix of specified resources for the reporting year. Under MRR, there is a two-year lag in the ACS-specific GHG emissions factor data and MRR reporting data. (For example, 2019 data reported in 2020 will use an emissions factor based on the ACS's 2017 generation and emissions.)

Staff proposes that specified procurements of system mix electricity from an ACS (but not procurements for unspecified electricity from an ACS) will be assigned the ACS-specific GHG emissions factor as determined under MRR. For the power mix, specified purchases from an ACS will no longer be reported as unspecified power. Instead, retail suppliers will be allowed to assign the ACS-specific system GHG emissions factor for its system mix as determined under MRR.

Energy Commission staff will post resource mix factors and system GHG emissions intensity factors for specified procurements of ACS system power by April 1 of each year. Retail suppliers will use these resource factors to determine the system mix breakdown of a specified purchase from an ACS. Each line item of resource-specific ACS electricity will be assigned the overall GHG emissions intensity of the ACS's system mix.

Unspecified Sources of Electricity

Unspecified sources of electricity are procurements that cannot be traced to specific generation sources through an auditable contract trail or an equivalent verification process. More specifically, electricity is unspecified when the source was not explicitly identified at the time the contract was executed which is the case, for example, when buying power on the Intercontinental Exchange or similar platform, or contracting for power from unknown sources via a broker.

Power Mix. As is the case under the current PSD program, unspecified sources will be categorized in the power mix as "Unspecified."

Greenhouse Gas Emissions Intensity. Energy Commission staff proposes that emissions from unspecified electricity should be treated in a manner consistent with MRR. The current MRR assigns unspecified power a default emissions factor of 0.428 MT CO_2e/MWh. If CARB updates its default GHG emissions factor for unspecified power, it will be reflected in the PSD Program.

In-State Unspecified Electricity

CARB's default emissions factor for unspecified electricity applies only to imports of unspecified power as most in-state generation reports actual emissions under MRR. However, Energy Commission staff is not aware of a simple and reliable method of distinguishing between in-state and imported sources of unspecified electricity purchased through open market transactions. Furthermore, Energy Commission staff analysis indicated that the average GHG emissions factor of in-state marginal generation did not substantially deviate from CARB's GHG default emissions for imported sources of unspecified electricity.

Therefore, Energy Commission staff proposes applying CARB's default emissions factor to all sources of unspecified electricity.

Spot Market Purchases Through the Energy Imbalance Market

The Energy Imbalance Market (EIM) [32] is a real-time electricity trading market managed by the California Independent System Operator (CAISO). A retail supplier's CAISO spot market purchases for unspecified electricity may include electricity transacted through the EIM. Staff proposes that unspecified electricity, including any electricity that may be transacted through the EIM, be assigned CARB's default emissions factor of 0.428 MT CO_2e.

CARB and the CAISO are currently performing analysis of the EIM to determine a method for determining the GHG emissions attributable to EIM transactions. If the results of that analysis yield a method for more accurately reflecting GHG emissions attributed to EIM transactions, Energy Commission staff will consider incorporating that method under PSD through a public process.

32 An *Energy Imbalance Market* is a real-time wholesale energy market that allows participating balancing authority areas to buy and sell the final few megawatts of power to satisfy demand during the hour it's needed. (See https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx .)

GHG Emissions Adjustments

Adjustment due to Self-Consumption and Grid Losses

AB 1110 specifies that GHG emissions should be reported for each generation source, but that the GHG emissions intensity should be determined based on retail sales. However, Energy Commission staff anticipates that there will be discrepancies between a retail supplier's reported annual procurement and retail sales. For discrepancies stemming from some portion of a retail supplier's total procurement being used to serve a retail supplier's self-consumption (generation consumed by the retail supplier) or lost due to transmission, distribution, power wheeling, and transmission-interconnected energy storage, staff proposes that a retail supplier's non-renewable sources of electricity should be reduced pro-rata.

Staff has concluded that such an approach best aligns with RPS procurement strategies, since RPS sets renewable procurement targets based on retail sales, and specific sources of renewable generation are procured exclusively to meet retail sales (and not to serve self-consumption or system losses).

After a retail supplier provides the relevant data on Schedule 1 of the PSD Program annual report, the pro-rata reduction of each non-renewable procurement to account for self-consumption and transmission, distribution, power wheeling, and storage losses will be applied automatically by an embedded Excel formula and be reflected in the calculated GHG emissions. A retail supplier that also serves as a balancing authority should not report electricity used to cover transmission losses for wheeled power as part of its retail sales.

Emissions Adjustment for Excess GHG-Free Generation of Publicly Owned Utilities

AB 1110 requires the Energy Commission to develop guidelines for adjustments to a GHG emissions intensity for a reporting year for any POU that demonstrates it generated GHG emission-free electricity in excess of its retail sales and wholesale sales of specified sources.

Qualifying Requirements

Energy Commission staff understands that this GHG emissions adjustment provision was intended to address the unique contractual circumstances of excess Hetch Hetchy hydroelectric generation owned by the San Francisco Public Utilities Commission.

Any POU that wishes to apply for this adjustment must demonstrate that it generated GHG-free electricity in excess of its retail sales and wholesale sales of specified sources in a given year. To verify a POU's eligibility for the adjustment, staff proposes requiring each applying POU to demonstrate qualifying generation amounts by submitting all associated contracts for the sale of the qualifying generation.

Adjustment Mechanism

Staff proposes allowing a qualifying POU to annually generate emissions credits, denominated in megawatt hours, equal to the quantity of eligible generation in excess of its retail sales and wholesale sales of specified sources for a given year multiplied by the default emissions factor for unspecified electricity. In effect, only excess electricity sold as unspecified electricity will be eligible for emissions credits. These emissions credits can be applied by the POU to reduce a POU's current or future reported annual GHG emissions and thereby reduce or eliminate the GHG emissions intensity of its electricity offerings on the Power Content Label for the reporting year. Each emissions credit can be applied only once.

Consistent with the *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities*, staff proposes a 20-year life for each emissions credit generated to capture the annual fluctuation of hydroelectric output. This means that an eligible POU could bank emissions credits for up to 20 years after the year in which the credit was generated[33] for later use in reducing annual emissions as reflected on the Power Content Label.

For example, if a POU generated 1,000 MWh of qualifying GHG-free electricity in 2019 that was in excess of its 2019 retail sales and wholesale sales of specified sources, it will be credited for 428 MT CO_2e (1,000 MWh x 0.428 MT CO_2e/MWh) of adjustment credits that could be used for the retail supplier's 2019 PSD report or any PSD report through the retail supplier's 2040 PSD report.

To generate retroactive GHG emissions credits from zero-emission electricity generated prior to the first year in which GHG emissions intensities must be reported (2019), a POU eligible for this adjustment will be allowed to submit historical data for generation that occurred no earlier than the effective date of AB 1110, January 1, 2017.

[33] Credits would expire on an annual basis. The year following the reporting year (for example, 2020 for 2019 generation data) would be the first year in the 20-year banking period for a specific credit.

Other Proposed Program Changes

Energy Commission staff proposes a number of other programmatic changes to the PSD regulations.

First, to streamline reporting, retail suppliers will be required to provide EIA IDs and RPS IDs[34] on the annual report for any generators that have been assigned those numbers. RPS Retail suppliers will no longer be asked to provide either WREGIS (Western Renewable Energy Generation Information System) or FERC (Federal Energy Regulatory Commission) IDs. Nearly all generators will have EIA IDs, and all eligible renewables will have RPS IDs. For the few generators that have neither ID, retail suppliers should contact Energy Commission staff to determine an appropriate method of identifying the generator in question.

Second, the current Schedules 3 and 4 of the annual report pertaining to power pools will be eliminated. Staff analysis indicates that no retail supplier has used these forms since 2012, which suggests these forms are very likely obsolete.

Third, Section 1394 (b)(2) of the current PSD regulations will be clarified to establish an October 1 due date for a retail supplier that is a public agency to submit the minutes from the public meeting in which the governing board approved the annual report to the Energy Commission.

Fourth, the auditing procedures in Appendix A will be simplified to provide more discretion for auditors to perform their work in accordance with industry standards and their professional judgement.

34 The RPS ID is a unique identifier assigned to each generator that applies for RPS certification.

Proposed New Reporting Requirements

Energy Commission staff aims to minimize new reporting requirements. Under the AB 1110 implementation proposal outlined above, a retail supplier reporting under PSD will need to make the following changes to Schedule 1 of its annual filing to the Energy Commission:

- Mark whether line items are firmed-and-shaped procurements (Column K)
- Disclose EIA and RPS IDs, rather than EIA, WREGIS, or FERC IDs (Columns I and J)
- Specific attribution of self-consumption and grid losses will no longer be reported; self-consumption and grid losses will be automatically reconciled against retail sales as described on page 21 of this document (Column O)

Proposed Power Content Label

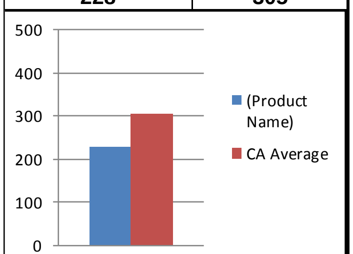
The proposed annual Power Content Label builds upon the existing label by adding GHG emissions intensity of the product near the top and the percentage of the electricity portfolio associated with retired unbundled RECs in footnote 4. The chart on the label that compares the electricity portfolio's GHG emissions intensity to the statewide GHG emissions intensity of electricity serving California load will be rendered automatically through embedded formulas in the Power Content Label. Although retail suppliers will report GHG emissions denominated in metric tons CO_2e/MWh, the GHG emissions intensity of the electricity portfolio will be converted to kilograms of CO_2e/MWh for disclosure to customers. (This conversion will be performed automatically on the PSD reporting form.) Staff will create variants of the proposed label so that a retail supplier could display multiple electricity portfolios on a single Power Content Label.

Figure 1: Proposed Power Content Label

(ENTITY NAME & ELECTRICITY PORTFOLIO NAME)

2019 POWER CONTENT LABEL

Greenhouse Gas Emissions Intensity (in kg CO_2e/MWh)[1]	
(Product Name)	CA Average
228	**305**



Energy Resources	Power Mix	CA Total Mix
Eligible Renewables[2]	**31%**	**22%**
Biomass & biowaste	3%	3%
Geothermal	5%	4%
Eligible hydroelectric	0%	1%
Solar	0%	6%
Wind	23%	8%
Coal	**0%**	**6%**
Large Hydroelectric	**10%**	**5%**
Natural Gas	**40%**	**44%**
Nuclear	**0%**	**9%**
Other	**0%**	**0%**
Unspecified Electricity[3]	**20%**	**14%**
TOTAL[4]	**100%**	**100%**

[1] Greenhouse gas emissions intensity represents the carbon dioxide (CO_2) equivalent of greenhouse gases resulting from each megawatt hours of electricity generated for this product. CO_2 emissions from biogenic fuels are not reflected in the GHG emissions intensity above. Including biogenic CO_2 changes the emissions intensity to **295 kg CO_2e/MWh** in this product, and **353 kg CO_2e/MWh** for the statewide average. For more detail, visit www.energy.ca.gov/pcl/

[2] Eligible renewables are resources that are eligible under California's Renewables Portfolio Standard. For more, visit www.energy.ca.gov/portfolio/documents/rps_certification.html

[3] Unspecified electricity is electricity that was purchased through open market transactions and is not traceable to a specific generation source or sources. For more information, visit www.energy.ca.gov/pcl/

[4] Unbundled renewable energy credits (RECs), which are products that represent the environmental attributes of renewable energy without the underlying electricity, are not reflected in the power mix or GHG emissions intensities above. This retail supplier has retired unbundled RECs that approximate **12%** of this electricity porfolio's retail sales, whereas **11%** of California's total retail sales have retired unbundled RECs associated with them. For more information, visit www.energy.ca.gov/pcl/

For specific information about this electricity portfolio, contact:	**(Entity Name)**	(Entity Phone Number) (Entity Website)
For general information about the Power Content Label, consult:	**California Energy Commission**	1-844-217-4925 www.energy.ca.gov/pcl/

Source: California Energy Commission staff