EPRI

Greenhouse Gas Emissions Accounting for Electric Companies

A Compendium of Technical Briefing Papers and Frequently Asked Questions

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Technical Update, September 2021

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Greenhouse Gas Management Institute (GHGMI)

Electric Power Research Institute (EPRI)

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ABSTRACT

Corporate greenhouse gas (GHG) emissions accounting is a complex and inexact undertaking. Today, electric companies operating in the United States are required to report the "direct" GHG emissions from electric power generating facilities to federal and state regulatory agencies including the US EPA. Many companies also report their direct emissions and "indirect" emissions to a variety of external stakeholder organizations and entities interested in enhanced disclosure of corporate GHG emissions. In addition, many electric companies have adopted voluntary commitments to reduce their GHG emissions. To develop accurate emissions inventories and to track progress toward achieving these goals, companies need to understand both their direct and indirect GHG emissions and how to account for them, and how future activities may impact their corporate GHG emissions accounting.

This report is a compendium of briefing papers and Frequently Asked Questions (FAQ) developed to support a series of webcasts EPRI hosted in 2020 and 2021 as part of a project on Greenhouse Gas Emissions Accounting for Electric Power Companies. This project was designed to improve participants' understanding of voluntary corporate GHG emissions accounting as it applies to electric companies and combined utilities, and to expand electric companies' knowledge about key technical issues related to accounting for "scope 2" and "scope 3" indirect emissions.

This compendium explores a variety of key technical issues and nuances related to GHG emissions reporting and important technical considerations electric companies may want to address when developing their own GHG emissions inventories.

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PRIMARY AUDIENCE: Staff and managers of electric companies and combined electric and natural gas utilities who are responsible for company greenhouse gas emissions accounting and reporting; corporate environmental disclosures, including financial disclosures; and corporate sustainability.

SECONDARY AUDIENCE: Staff and managers of electric companies and combined electric and natural gas utilities who are responsible for corporate strategy, including sustainability, corporate reporting, and decarbonization goals. Other audiences include staff of organizations engaged in corporate environmental disclosure and policymakers focused on decarbonization and climate mitigation.

KEY RESEARCH QUESTION

Corporate greenhouse gas (GHG) emissions accounting is a complex and inexact undertaking. Today, electric companies operating in the United States may be required to report the "direct" GHG emissions from power generation to federal and state regulatory agencies. Many also report their direct emissions and their "indirect" emissions to a variety of external stakeholder organizations and entities interested in enhanced disclosure of corporate GHG emissions.

To develop their corporate GHG emissions inventories, electric companies typically rely on accounting guidance provided in formal protocols developed and maintained by non-profit organizations, such as the World Resources Institute (WRI) and The Climate Registry (TCR). Unfortunately, these protocols and related guidance documents can sometimes be ambiguous, inconsistent, and in other ways difficult for electric companies to understand and operationalize.

This report is a compendium of briefing papers and Frequently Asked Questions (FAQ) developed to support a series of webcasts EPRI hosted in 2020 and 2021 as part of an EPRI supplemental project on *Greenhouse Gas Emissions Accounting for Electric Power Companies*. This technical transfer project was designed to improve participants' understanding of voluntary corporate GHG emissions accounting as it applies to electric companies and combined utilities, and to expand electric companies' knowledge about key technical issues related to accounting for "scope 2" and "scope 3" indirect emissions.

RESEARCH OVERVIEW

EPRI hosted a series of technical webcasts designed to explore GHG emissions accounting challenges faced by electric companies and combined electric and natural gas utilities. In partnership with the non-profit organization, the Greenhouse Gas Management Institute (GHGMI), EPRI prepared a series of technical briefing papers to support these presentations. These briefing papers were designed to provide project participants with important background information on topics to be discussed during each of the webcasts. Throughout the course of this project, EPRI recorded questions asked by project participants and compiled them into a Frequently Asked Questions (FAQ) document.

This compendium is comprised of all of the technical briefing papers prepared by EPRI to support these webcasts and the FAQ. These briefing papers and the FAQ included in this report are incorporated here in their original format and do not include any additional editing or revisions to integrate them into this report.

KEY FINDINGS

- Several standards and guidelines exist today that provide guidance to electric companies on how to do GHG emissions accounting. These standards and guidelines differ depending on their context and purpose, so it is up to each company to determine how to apply them for their own purposes and needs.
- There are two foundational sets of GHG accounting protocols and guidance available today to guide electric companies who want to voluntarily account and report their GHG emissions. These were developed by the World Resource Institute and World Business Council for Sustainable Development (WRI/WBSCD) and The Climate Registry (TCR).
- Emissions "scopes" are used to classify "direct" and "indirect" GHG emissions to determine which GHG sources and activities should be included inside the boundary of an entity's (e.g., corporation or other organization) GHG inventory.
- Scope 2 emissions are associated with electricity, heat, steam, and cooling purchased by an electric company to power its own buildings or equipment connected to the electric grid. A second type of scope 2 emissions, relevant to companies that own and operate bulk transmission and local distribution (T&D) systems, relates to the transmission of electricity across the T&D system.
- Fifteen categories of scope 3 emissions have been defined for emissions reporting purposes separated into "upstream" and "downstream" designations, referring to the company's operational value chain (i.e., from inputs to company operations, to product use by customers, and disposal). Upstream refers to GHG emissions that occur within the value chain prior to an entity's operations. Downstream refers to GHG emissions that occur within the value chain subsequent to an entity's operations.
- By design, the categorization of scopes 1 and 2 emissions ensures against double counting of emissions between companies by ensuring that the same emissions are not attributed to two different companies. Scope 3 emissions do not prevent double counting.
- Most GHG emissions accounting programs and electric companies rely on a facility-based approach to calculate and report direct emissions of their generating resources. Unless an electric company fully serves its retail load with electricity generated by its own assets, this approach would undercount emissions associated with serving retail load. Load-based accounting approaches can be used to account for the emissions associated with purchased wholesale electricity used to serve load.
- Renewable energy certificates (RECs) are not appropriate environmental accounting instruments for either *consequential* or *attributional* GHG accounting. However, this remains a controversial topic and some accounting approaches provide methods that can be used to integrate RECs into corporate GHG accounting. Yet, as designed, RECs are well suited for renewable portfolio standard (RPS) compliance applications.

WHY THIS MATTERS

In addition to participating in mandatory and voluntary corporate GHG emissions reporting programs, many electric companies have adopted voluntary commitments to reduce their GHG emissions, both direct and indirect. To develop accurate emissions inventories and to track progress toward achieving these goals, companies need to understand both their direct and indirect GHG emissions and how to properly account for them, and how future activities may impact their corporate GHG emissions accounting.

Furthermore, electric and natural gas companies face growing pressures from shareholders, financial and corporate disclosure institutions, and environmental and sustainability organizations to disclose additional types of scope 1 direct GHG emissions (e.g., fugitive methane emissions from natural gas pipelines), and less well-defined scope 2 and scope 3 indirect emissions. When engaging in these reporting activities, it is important for these companies to have a strong understanding of the categorization of different types of GHG emissions, the methods used to estimate and report these emissions, and the technical challenges associated with tracking GHG emissions.

HOW TO APPLY RESULTS

Electric company staff engaged in corporate GHG emissions tracking, estimating, and reporting may use this resource as informative supplementary material when preparing their own corporate GHG emissions inventories. The briefing papers and FAQ included here explore key technical nuances of GHG emissions reporting and important technical considerations companies may want to address when developing their inventories.

This compendium does not address, in a comprehensive manner, the myriad technical issues and considerations an electric company must address when it develops a GHG emissions inventory and should not be considered a comprehensive treatise on all topics related to corporate GHG emissions accounting. This report also should not be considered a substitute for the information and guidance contained in the formal GHG emissions accounting protocols and guidance materials that have been developed over the past two decades which provide the foundation for existing mandatory and voluntary GHG emissions reporting programs in the United States and internationally.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Program 198 Strategic Sustainability Science
- Program 201 Energy, Environmental, and Climate Policy Analysis

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PROGRAM: Program 201 Energy, Environmental, and Climate Policy Analysis

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GREENHOUSE GAS EMISSIONS ACCOUNTING FOR ELECTRIC COMPANIES

About the Project

In June 2020, EPRI launched a supplemental project focused on *Greenhouse Gas Emissions Accounting for Electric Companies.* This project was designed to improve participants' understanding of voluntary corporate greenhouse gas (GHG) emissions accounting, as it applies to electric companies and combined utilities, and expand electric companies' knowledge about key technical issues related to accounting for "scope 2" and "scope 3" *indirect* emissions. To provide additional technical support, EPRI engaged the Greenhouse Gas Management Institute (GHGMI) as collaborators on this project.

This project included 14 participating electric companies. This project included a series of webcasts deigned to explore key technical issues associated with GHG accounting for electric companies. The webcast series began with an overview of GHG accounting principles and methods, followed by individual webcasts focused on scope 2 and scope 3 GHG emissions accounting methods and their technical accounting challenges. The fourth and fifth project webcasts focused on special topics related to GHG emissions accounting prioritized by the project participants. The project also organized and hosted a one-day technical workshop focused on technical challenges associated with scope 3 GHG emissions accounting for electric companies.

Table 1-1
List of briefing papers included in this compendium

Briefing Paper	Topic
01	Overview of Greenhouse Gas Accounting Principles and Methods
02	Scope 2 Emissions Accounting
03	Scope 3 Emissions Accounting
04	Special Topics: GHG Emission Factors, Renewable Energy, and Renewable Energy Certificates in GHG Emissions Accounting
05	Special Topics: The "Landscape" of Reporting Programs for Corporate GHG Emissions Accounting and Updates to The Climate Registry's Electric Power Sector Protocol

This compendium is organized as follows. This chapter provides an overview of EPRI's supplemental project. Chapters two through six include the original webcast briefing papers prepared by EPRI and GHGMI in advance of each of these technical webcasts. The webcast briefing papers are included here in their original format and do not include any additional editing or revisions to integrate them into this compendium. Throughout the course of this project, EPRI noted questions asked by project participants and compiled them into a Frequently Asked Questions (FAQ) document that is included here as Appendix A.

How to Use this Resource

Electric company staff engaged in corporate GHG emissions tracking, estimating, and reporting may use this resource as informative supplementary material when preparing their own corporate GHG emissions inventories. The briefing papers and FAQ included here explore key technical nuances of GHG emissions reporting and important technical considerations companies may want to address when developing their inventories.

This compendium should not be considered a substitute for the information and guidance contained in the formal GHG emissions accounting protocols and methodologies that have been developed over the past two decades which provide the foundation for existing mandatory and voluntary GHG emissions reporting programs in the United States and internationally. This compendium also does not address in a comprehensive manner the myriad technical issues and considerations an electric company must address when it develops a GHG emissions inventory and should not be considered a comprehensive treatise on all topics related to corporate GHG emissions accounting.

Other stakeholders that may be involved in tracking electric company GHG emissions or who are interested in the disclosure of these emissions may also use this resource to understand some of the questions, opportunities, and challenges that the electric sector faces with regard to developing their own GHG emissions inventories.

2. Briefing Paper for Webcast #1: Overview of Greenhouse Gas Accounting Principles and Methods

Introduction

This technical brief is the first in a series that will accompany a sequence of technical webcasts designed to explore greenhouse gas (GHG) emissions accounting challenges faced by electric power companies. This brief describes the basic elements of voluntary corporate GHG emissions accounting as it applies to electric companies operating in the United States today[1].

What is a Corporate GHG Inventory?

Like other corporations, an electric company can choose to report their GHG emissions by preparing a GHG inventory, which is an assessment of the GHG emissions and removals attributed to the company's operations over the course of a year. Several standards and guidelines exist today that provide guidance to electric companies on how to do credible GHG accounting. These standards and guidelines differ depending on their context and purpose, so it is up to each company to determine how to apply them given their purposes and needs. This paper highlights some of the key steps and decisions electric power sector entities need to make to design and implement a comprehensive corporate (aka "entity-level") GHG emissions inventory.

GHG accounting *frameworks* are defined principally by clearly drawing the system boundaries within which GHG emissions (and removals) are counted. GHG accounting frameworks can either be *attributional* in nature, meaning they focus on attributing GHG emissions — *direct* or *indirect* — to particular activities, or *causational*, meaning they focus on determining *net changes* in GHG emissions caused by a particular action, intervention, or activity such as an GHG "offset" project.

Many shareholder organizations and other sustainability stakeholders engaged in corporate carbon disclosure would like electric and natural gas companies to develop GHG emissions inventories that include complete organizational boundaries and apply an entity-level[2] accounting framework.

This approach is attributional. It combines emissions from the three GHG emissions "scopes" described further below.

Also, some GHG reporting programs for the electric power sector require only *facility-based accounting*, which is an attributional approach drawing the accounting boundary around individual sites or facilities; and so, does not necessarily represent an entire organizational boundary of a corporation.

Corporate GHG Reporting Programs and Standards

The United Nations Intergovernmental Panel on Climate Change (IPCC) developed internationally agreed upon guidelines in 2006 for national governments to use to develop national GHG inventories. They

[1] In addition to voluntary corporate GHG reporting efforts, there are several mandatory GHG emissions reporting programs that cover electric companies in the United States, including the mandatory CO_2 Cap-and-Trade program in California, and the Regional Greenhouse Gas Initiative in the Northeast United States. GHG emissions reporting under these mandatory reporting programs is beyond the scope of this briefing paper.

[2] Entity-level accounting frameworks provide standardize methods for estimating GHG emissions for an entire entity or organization.

encompass all major GHG emitting sectors (i.e., Energy; Industrial Process and Product Use; Agriculture, Forestry and Other Land Uses, and Other sources) and provide fundamental technical approaches to estimate GHG emissions. These methodologies are often referred to by other GHG accounting standards, including those highlighted below.

Today there are two basic sets of GHG accounting protocols and guidance available to guide electric companies who want to voluntarily account and report their GHG emissions.

The **World Resource Institute and World Business Council for Sustainable Development (WRI/WBSCD)** have developed the following important GHG accounting guidance documents:

- WRI/WBSCD Revised Corporate Standard (2004). The Corporate Standard provides requirements and guidance for preparing entity-level GHG inventories. The Corporate Standard is widely accepted and informs the development of many reporting programs.
- WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).[3] The Scope 2 Guidance is provided as a supplement to the Corporate Standard to estimate emissions associated with purchased or acquired electricity, steam, heat, and cooling (scope 2 emissions).
- WRI/WBSCD Corporate Value Chain (Scope 3) Standard (2011). The Corporate Value Chain Standard is a supplement to the Corporate Standard to assess scope 3 value chain emissions using a life-cycle analysis approach.

The Climate Registry (TCR) operates a voluntary GHG reporting program widely used by corporations and other entities. TCR has adopted the following specific protocols to guide electric and gas companies who choose to report their GHG emissions to the TCR:

- TCR General Reporting Protocol (GRP) v3 (2019). The GRP outlines GHG accounting principles and calculation methods for reporting an organizational carbon "footprint," or entity-level GHG inventory, specifically in the Climate Registry's online reporting program. It is a widely recognized standard that is available publicly.
- TCR Electric Power Sector Protocol (2009). A supplement to the TCR GRP that provides entity- and facility-level accounting guidance specifically for the electric power sector.

[3] It is important to be aware this guidance was published in 2015 with dissent. This guidance includes a controversial application of accounting for renewable energy certificates (RECs) and other "green" power purchasing claims in the accounting for indirect (scope 2) emissions. Numerous leading GHG accounting experts withdrew from the WRI/WBCSD working group that developed this guidance and publicly recommend companies not use this standard. Specifically, the application of RECs to claim a zero emission factor for scope 2 is contrary to evidence in the scientific literature that shows empirically a lack of environmental integrity with the use of some voluntary market RECs in environmental accounting.

GHG Inventory Principles

There are several generally agreed upon quality principles to be used by entities that develop a GHG inventory. In some cases, these principles are described using different "language" by each GHG accounting standard. Below is a summary of these general principles that draws upon the GHG guidelines and standards above.

Relevance. Ensure the GHG inventory appropriately reflects the GHG emissions of the company to serve the decision-making needs of both internal and external intended users of the information.

Completeness. *Account for and report on all GHG emissions sources/sinks and activities within the chosen inventory boundary. Disclose and justify any specific exclusions.*

Consistency (time series). Estimates for different inventory years (or other time period), gases, and source/sink categories are made in such a way that differences in the results between years and categories reflect real differences in emissions. Inventory trends, as far as possible, should be calculated using the same method and data sources in all years and should aim to reflect the real annual fluctuations in emissions or removals and not be subject to changes resulting from methodological differences.

Transparency. Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used. Provide sufficient detail so that someone else can understand how the inventory was prepared and is assured of its quality.

Accuracy. Ensure that the quantification of GHG emissions is systematically neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable. Achieve sufficient accuracy to enable users to make decisions with reasonable assurance as to the integrity of the reported information.

Comparability. This concept originated from territorial GHG reporting. Comparability ensures a GHG inventory is reported in a way that it can be compared to other inventories of the same type (i.e., nations using comparable inventories can make credible claims about how their emissions compare to each other). Being comparable requires using the same GHG accounting standard and emission reporting boundaries. Comparability as a principle is not generally applied to corporate reporting because of the variability in purposes and needs of corporate accounting. However, corporations participating the in the same reporting program (e.g., TCR) may desire having comparable inventories.

Basic Steps to Prepare an GHG Inventory

Step 1: Define Organizational Boundaries

First, a company must determine the appropriate organizational boundaries to use for its GHG inventory. In general, organization (aka "system") boundaries are defined along two dimensions: (i) the set of emissions-generating *activities* that are considered relevant for a particular accounting exercise, and (ii) the *scope* of relevant emissions associated with the covered activities. Relevant activities are those that occur within a company's organizational boundaries (e.g., stationary fuel combustion, mobile fuel combustion, waste disposal). There are three general approaches electric companies and others can use to define organizational boundaries (as defined in the TCR GRP). These are described below. Applying one of these approaches defines the relevant activities to be included in an entity-level GHG inventory.

- **Operational Control**: 100% of GHG emissions are included in the organizational boundaries from activities where the organization or its subsidiaries has the full authority to introduce and implement operating policies. The organization that holds the operating license for an activity typically has operational control.
- **Financial Control**: 100% of GHG emissions are included in the organizational boundaries from activities where the organization can direct the financial policies of the activity with an interest in gaining economic benefits from the activity. An organization has financial control over an activity if it has rights to the majority of benefits from the operation.
- **Equity Share**: GHG emission producing activities are included in the organizational boundaries based upon the organization's equity share in the operations. The company's percentage ownership of that operation (share of economic risks and rewards) should be equivalent to the share of GHG emissions for each activity.

Step 2: Identify GHG Sources to Include

Types of Greenhouse Gases

Typically, GHG inventories include emissions of the specific GHGs listed below to the extent they are associated with emitting activities. There are additional types[4] of GHGs that could be included, but these are not required to be reported by any of the aforementioned protocols.

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

To make it possible to compare the differential global warming impacts of each of these GHGs, the UN Intergovernmental Panel on Climate Change (IPCC) assesses the G*lobal Warming Potentials*

[4] These additional GHGs include: Trifluoromethyl Sulphur Pentafluoride (SF_5, CF_3); Halogenated Ethers (e.g., $C_4F_9OC_2H_5$, $CHF_2OCF_2OC_2F_4OCHF_2$, $CHF_2OCF_2OCHF_2$), and other halocarbons not covered by the Montreal Protocol including CF_3I, CH_2Br_2 $CHCl_3$, CH_3Cl, CH_2Cl_2.

(GWPs) of each GHG taking into account their different atmospheric lifespan and warming effect[5, 6].

By definition, CO_2 has a GWP equal to 1. By comparison, CH_4 has a GWP of ~30, and N_2O has a GWP close to 300. These GWPs can be used to convert emissions of each of these GHGs into universal units called "*carbon dioxide equivalents*," referred to as "CO_2e." For example, 1 metric ton ("tonne") of N_2O emissions has an equivalent warming effect of ~300 tonnes of CO_2e.

Direct vs Indirect Emissions

Corporate activities may cause *direct* (e.g., onsite combustion of fossil fuels) or *indirect* GHG emissions (e.g., purchasing goods produced using energy from combustion of fossil fuels). Direct emissions result from activities that physically release (or remove) GHGs to the atmosphere.

Indirect emissions result from other activities that are essential to a company's operations (e.g., fuel extraction and fuel transport to a power generation facility). Indirect emissions may occur "upstream" (e.g., associated with inputs to activities), coincident with activities (e.g., employee travel emissions), or "downstream" (e.g., associated with the use of products created by an entity's activities). Indirect emissions may also occur unintentionally from the entity's operations (e.g., a biomass-fueled combined heat and power plant may inadvertently cause deforestation to occur).

GHG Emission Scopes

Emissions "scopes" are used to classify direct and different types of indirect GHG emissions (**Table 2-1**). A complete entity-level GHG inventory typically includes all scope 1 emissions from activities inside the organizational boundary. Depending on the reporting purposes and the accounting protocol being used, some or all of scope 2 emission sources may be included. Scope 3 emissions typically are considered optional for entity-level reporting.

Table 2-1 Description of GHG Emission Scopes

Scope	Description
Scope 1	Emissions physically arising from sources or sinks directly owned or controlled by an entity.
Scope 2	Indirect emissions associated with electricity or heat that is purchased for use by an entity
Scope 3	All non-Scope 2 indirect emissions attributable to an entity's activities.

It is important to recognize emissions "scope" is a relative concept. Two different types of entities may classify the same GHG source within a different scope. For instance, electric customers would classify the electricity they purchase and consume from their load serving entity (LSE) as being in their scope 2 emissions. However, the electric company generating the power would classify these

[5] It is important to be aware that GWP values change over time as they are subject to continuous scientific study. Given this, it is important for companies reporting GHG emissions should follow program-specific GHG reporting guidance when selecting appropriate GWPs.

[6] GHG reporting programs often lag the most recent IPCC assessment report to allow time for scientific consensus to emerge around the updated GWPs. This practice reduces issues with time-series comparability and the burden to revise previously reported data until a new consensus is achieved.

emissions as scope 1 direct emissions. In this way, scope categorization helps to prevent double counting of emissions separately within scope 1 and 2 (but not scope 3). By reporting the same source of emissions under separate scopes, the electricity provider and end-use consumer can avoid making confusing and/or contradictory claims about responsibility for emissions from an GHG source. **Table 2-2** at the end of this document gives examples of GHG emission sources typical for energy sector entities organized by scopes.

For example, for an LSE that also generates electric power, scope 1 emissions would come from fuels combusted at its electricity generating facilities (even if the electricity is sold to another company for resale). For this LSE, scope 2 includes those indirect emissions associated with the amount of purchased electricity consumed and lost during transmission and distribution to customers (representing the emissions from electricity produced but not consumed by customers). And, scope 3 emission sources for an LSE can vary widely but will likely include wholesale purchased power for resale.

LSEs are particularly challenged by the need to properly account for the GHG emissions embedded in the electric power they purchase on a wholesale basis to meet their customers' electricity loads. This issue is an GHG accounting topic addressed by a recent EPRI-GHGMI report.[7]

Step 3: Calculate Emissions

Each GHG source included in a GHG inventory should be estimated using accurate and credible methods. The choice of specific methods depends on data availability and specific reporting requirements and the specific needs of individual entities. Detailed technical approaches to quantify emissions by source and sink category are provided in the guidance documents listed above.

In general, it is good practice to calculate GHGs separately for each company subsidiary, even if GHG emissions are eventually aggregated at the parent company level for reporting. This ensures information is available at the subsidiary level should it be requested or required in the future.

Most GHG emissions can be quantified by direct measurement or estimation. For example, it is common for CO_2 emissions from large electric power generation units to be measured directly using Continuous Emissions Monitors (CEMs). CEMs data provide highly accurate and real time emissions data. Alternatively, to estimate GHG emissions, one can calculate emissions by multiplying *activity data* (e.g., fuel combusted, kWh used, output from a process, hours of equipment operation) by an appropriate GHG emission factor (EF).

Emission factors relate a unit of activity (e.g., quantity of natural gas fuel consumed) to GHG emissions within a specific context (e.g., a CH_4 emission factor for natural gas-powered boilers in the U.S.). The EFs used to estimate emissions should be representative of the activities in terms of technology used and geography. The more specific the EF is to the circumstances of the activity being evaluated, the more appropriate its application.[8]

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[7] *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases*, EPRI, Palo Alto, CA: 2019. 3002015044.

[8] The IPCC 2006 guidelines provide guidelines to evaluate the appropriateness of emission factors in section 2.2.4.

Determining an appropriate EF to use to estimate an electric company's scope 2 emissions from purchased electricity for internal consumption is complex and will be discussed in more detail in this project. Often companies report these emissions based on average annual regional grid emissions factors published by the US EPA or other federal and state agencies that provide an average emissions rate for all electricity consumed across a large geographic region. While many entities rely on these regional average EFs to calculate and report their scope 2 emissions, they do have important shortcomings, including: (i) data reporting time lags that make it impossible for GHG reporting to accurately reflect the ongoing rapid change in the composition of the power generation fleet; and (ii) they do not reflect actual emissions at the time or location the emissions occurred and so may under or over-estimate actual emissions.

To produce activity data and establish EFs, companies need to undertake organized and systematic data collection efforts. For instance, an EF is likely to be more accurate if input fuel is analyzed for its carbon content. Often, activity data is collected by companies as part of their standard operations (e.g., through invoices or purchase orders).

Step 4: Reporting GHG Emissions

GHG reporting requirements vary depending on a reporting program's and entity's particular needs. Despite this, there are "good practices" to consider when reporting GHG emissions inventories. Following these practices will help ensure the accounting principles described above are followed.

All GHG inventory reports should include the minimum following information:

- Description of the system boundaries, including how the organizational boundaries were determined and which GHG emitting activities and sources/sinks are included.
- Explanation for why sources/sinks, facilities, or operations were excluded from the inventory, if applicable.
- Information on GHG emissions should be reported transparently by:
  - Separately reporting sources, gases, and scopes
  - Using metric tons as the unit of measure, and convert all GHGs to tonnes CO_2e using appropriate GWPs
  - Including a description of the methodologies and data used
  - Including an explanation of any recalculations to the time series if applicable
- As methods and data sources change over time, updates and changes relative to previous inventories should be documented.

Managing Inventory Quality and Verification

The primary objective of inventory quality management and verification is to enhance the credibility of a company's GHG inventory with the company's stakeholders. Some good practice procedures to manage inventory quality are to apply routine time series consistency and completeness checks, identify and address errors and omissions, and document and archive relevant GHG inventory records, including data management activities. It also can be helpful for companies to establish institutional arrangements (e.g., GHG inventory preparation team and budget) that identify who is responsible for, and a plan for how the GHG inventory will be prepared.

Verification of a GHG inventory is a systematic, independent, and documented process for the evaluation of a GHG report or attestation against agreed verification criteria. The purpose of verification is to create trust in the data by receiving an opinion by an independent and competent party. The decision to verify an GHG inventory is often optional, especially for a voluntary reporting program. Even if verification is mandatory, the type of verification required can vary widely from self-certification to engaging a certified third-party expert reviewer to audit an inventory. The choice to verify and methods will depend on a corporation's unique needs and the reporting requirements of particular programs.

GHG Accounting Challenges in the Electric Sector

This technical brief is the first in a series of papers and webinars designed to delve deeper into GHG accounting challenges that are unique to the electric power sector. This brief provides foundational knowledge on the basics of entity-level GHG accounting to form the basis for forthcoming topics that will explore these challenges, present alternative viewpoints, and exchange experience and knowledge.

Table 2-2 GHG Emissions Sources by Scope for the Energy Sector

Energy Sector	Scope 1 Emission Sources	Scope 2 Emission Sources	Scope 3 Emission Sources
Energy Generation	**Stationary combustion at electricity generating facilities:** ● Boilers and turbines used in the production of electricity, heat, or steam ● Fuel pumps ● Fuel cells ● Flaring **Mobile combustion:** ● Transportation of fuel by company owned vehicles **Fugitive emissions:** ● CH_4 leakage from transmission and storage facilities ● HFC emissions from LPG storage facilities ● SF_6 emissions from transmission and distribution equipment **Physical or chemical processing** ● SO_2 scrubbers	**Stationary combustion:** ● Emissions associated with electricity, heat or steam purchased for use by an entity. ● Consumption of electricity during transmission and distribution	**Purchased power for resale** **Stationary combustion:** ● Mining and extraction of fuels ● Energy for refining or processing fuels ● Process emissions Production of fuels ● SF_6 emissions **Mobile combustion:** ● Transportation of fuels/waste ● Employee business travel ● Employee commuting **Fugitive emissions:** ● Landfill waste decomposition ● Pipelines ● SF_6 emissions
Natural Gas Production	**Stationary combustion:** ● Process heaters ● Engines ● Turbines ● Flares ● Incinerators ● Oxidizers ● Production of electricity, heat, and steam **Process emissions:** ● Process and equipment vents ● Maintenance/turnaround activities ● Non routine activities **Mobile combustion:** ● Transportation of raw materials/products/waste by company owned vehicles **Fugitive emissions:** ● Leaks from pressurized equipment ● Wastewater treatment ● Surface impoundments	**Stationary combustion:** ● Consumption of purchased electricity, heat, or steam	**Stationary combustion:** ● Product use as fuel **Mobile combustion:** ● Transportation of raw materials / products / waste ● Employee business travel ● Employee commuting ● Product use as fuel **Process emissions:** ● Product use as feedstock ● Production of purchased materials **Fugitive emissions:** ● Landfill waste decomposition ● Production of purchased materials

Source: Adapted from Appendix D of the WRI Corporate Standard

3. Briefing Paper for Webcast #2: Scope 2 Emissions Accounting

Introduction

This technical brief is the second in a series that accompanies a sequence of technical webcasts exploring greenhouse gas (GHG) emissions accounting challenges faced by electric power companies. This brief describes accounting methods for scope 2 emissions for electric companies operating in the United States today.

GHG Scope Review

The first technical brief in this series introduced the concept of GHG emissions "scopes." Emissions scopes are used to classify *direct* and *indirect* GHG emissions to determine which GHG sources and activities should be included inside the boundary of an entity's (e.g., corporation or other organization) GHG inventory. A complete entity-level GHG inventory typically accounts for all scope 1 (direct) emissions and scope 2 emission sources. Scope 3 emission sources often are considered "optional" for voluntary reporting. Scope 2 and 3 emissions sources are indirect, meaning they are associated with a company's operations, but are not physically released to the atmosphere within the companies' boundaries. Scopes are a relative concept, and it is important to recognize scopes are in a sense linked together. For example, an electric power company's scope 1 emissions can be the "source" of scope 2 or 3 emissions reported by another company, such as a large commercial or industrial electric customer.

Defining Scope 2 Emissions

There are generally two types of scope 2 emissions that are relevant for electric companies. Both of these are described below.

Scope 2 Emissions for Purchases of Electricity, Heat, Steam and Cooling

First, scope 2 emissions are associated with electricity, heat, steam, and cooling purchased by an electric company to power its own buildings or equipment connected to the electric grid. These indirect emissions occur outside of the reporting boundary of the electric company and are emitted at a power generation site owned by another party. An electric company reporting these scope 2 emissions would account only for the GHG emissions associated with the portion of power generation they purchase from other entities and consume to power their own building and related infrastructure.

Most corporate entities, including electric and non-electric companies, will have this type of scope 2 emission, unless they supply 100% of the energy they consume in their operations sourced only from their own power generation sources and do not purchase any electricity, heat, steam, and cooling from other entities.

Scope 2 Emissions for T&D Line Losses

The second type of scope 2 emissions are relevant to companies that own and operate bulk transmission and local distribution (T&D) systems and relate to the transmission of electricity across the T&D system. When electricity (MWh) is transmitted from generation facilities to grid-connected end users through T&D systems, a portion of the electricity generated effectively is "lost" as it passes through wires and equipment. These are referred to as "T&D line losses" and a company may categorize the associated indirect emissions as scope 2 or scope 3 emissions depending on who owns and/or operates the T&D system. Typically, T&D line losses equal a small percentage (~3-7%) of the total amount of power transmitted and/or distributed across a power system.

Electric companies may account for T&D losses associated with wholesale power purchases within scope 2 or scope 3, depending on the specifics of the transactions, but in all cases they should seek not to double count the emissions. More information related to this topic can be found in EPRI 's GHG Emissions Accounting FAQ.

For power companies that both generate power and are responsible for providing energy to meet load, T&D lines losses do not have indirect emissions associated with them, as the emissions from the upstream generation of electricity are part of the company's reported scope 1 direct emissions. However, for an end-use customer, the indirect GHG emissions associated with these "line losses" count as a scope 3 emission source, while the indirect emissions associated with generating the power they purchase is considered scope 2.

In the case of a power generator who purchases electricity from an external third party to power its own operations (i.e., the power generator is acting as an end-user), the total amount of scope 2 emissions associated with these purchases is equal to the emissions associated with the power purchased and consumed by the company. The emissions associated with any "upstream" T&D line losses would be considered scope 3 emissions for the power company that bought and used the power.

If the same power generator transmits or distributes the purchased power to end-users rather than consuming the power in their own operations, they would not report scope 2 emissions associated with T&D line losses. In this case, the company would report the GHG emissions associated with the purchased power for resale as scope 3. The indirect emissions from T&D line losses that occur after the power has been purchased (i.e., through T&D to the end-user) are already accounted for within the total quantity of power purchased for end-users. In this case, the primary purpose of the power purchase is delivery for end-user consumption. The indirect emissions associated with delivery of purchased power for end-use consumption are typically labeled as scope 3 indirect.

Transmission and/or distribution companies who only own and operate T&D equipment (i.e., "wires only" companies) account for the indirect GHG emissions associated with T&D line losses as scope 2 emissions. These emissions are calculated based on **Equation 3-1.**

Equation 3-1: Calculating T&D Line Losses

Line losses (MWh) = Power Conveyed or Purchased (MWh) X (% Line losses)

Equation 3-1 also is relevant to end-use entities that do not generate the electricity, heat, steam, or cooling that they purchase to operate. The indirect emissions associated with the T&D line losses associated with this purchased electricity are considered to be scope 3 for these end users.

Figure 3-1 illustrates the two scope 2 emissions sources that are typically relevant to electric companies. In some cases, discussed below, T&D losses are not relevant because they are outside the corporation's accounting boundary, or they are already accounted for in an entity's scope 1 emissions.

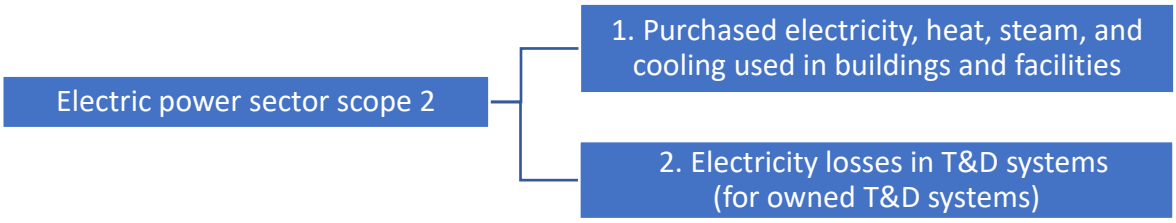

Figure 3-1 Potential scope 2 emissions for electric companies

Relating Accounting of Indirect T&D Emissions to Corporate Structure

The structure of an electric company's operations will influence the correct categorization of T&D losses. Below and summarized in **Table 3-1** is a discussion about accounting for T&D losses for four common forms of electric company entities:

- Vertically integrated companies (e.g., Investor-owned utilities, and some large public power agencies)
- Generation and transmission co-ops (G&Ts)
- Transmission and/or distribution companies ("wires only" companies)
- Independent power producers (IPPs)

Both vertically integrated power companies and G&Ts own and operate power generation facilities. Therefore, they report direct emissions from power generation at their facilities as scope 1. Even though these entities also own power lines, T&D losses from these companies' perspective are not indirect. However, if these companies also purchase some portion of electricity from another company and provide transmission services to deliver it (i.e., "wheel" it) across their lines to another unaffiliated party, without consuming it themselves, they should account for the scope 2 emissions associated with the T&D losses as the power is transmitted across their system. Accounting for the indirect emissions associated with losses that occur in the process of wheeling wholesale power within scope 2 is valuable as it distinguishes an emissions source that the wheeling electric company has a greater ability to impact (e.g., through improvements to the T&D system).

Transmission and/or distribution companies that only own and operate T&D equipment (i.e., "wires only" companies) account for indirect emissions associated with T&D losses as scope 2 emissions.

A company that only owns and operates power generation facilities, such as an IPP, typically does not have any scope 2 emissions associated with T&D losses, but they may have other scope 2 emissions associated with electricity or other forms of energy they purchase from a third party to operate their buildings and facilities. These entities account for all emissions from their own generation as scope 1, as they do not own or operate any transmission or distribution lines. Any T&D losses associated with electricity purchased by these entities would be categorized as scope 3 emissions.

Table 3-1 T&D-related GHG Emissions Accounting by Type of Electric Company Entity

Corporate Structure	Does their GHG Inventory Include Scope 2 T&D losses?

Vertically Integrated Electric Company	1. No - for self-generated power, as these emissions are accounted for in Scope 1. T&D losses are not indirect for the company. 2. Yes - for wholesale power purchased from other parties and transmitted and/or distributed (e.g., wheeled) across the company's T&D system.
Generation and Transmission Co-op	Same as above. But line losses are limited to the bulk transmission system only, unless the G&T also owns / operates the local distribution system(s).
Transmission and/or Distribution companies	Yes. The inventory would include indirect GHG emissions associated with T&D line losses for all electricity flowing through company's system.
Independent Power Producer (IPP)	No. Company does not own or operate T&D equipment. Any indirect emissions associated with T&D line losses from purchased power for "own" use of electricity are categorized as scope 3.

Calculating Emissions from T&D Losses

To calculate the indirect GHG emissions associated with T&D losses, companies need to know how much power (MWh) is conveyed through their T&D systems, the "loss factor" for these systems, and the emission factor (EF) associated with the power generation.[9]

There are two methods for calculating line loss factors:

- ***Energy Balance Method.*** This method involves energy balance analysis, which calculates total energy flow into and out of the T&D system(s), then pairs those energy flows with fuel-specific EFs (for each fuel used to generate power flowing through the system) and determines a system-specific loss factor based upon these results.
- ***Aggregate Power Flow Method*.** This method simplifies the approach by applying default loss and emission factors.

To implement the Energy Balance Method and completely account for all power flows, a company would need to establish T&D system boundaries that extend from the "Point of Receipt" to the "Point of Delivery" for all company electricity transactions. The energy balance analysis should evaluate all power flows through the system (see TCR Electric Power Guidance v1.0 section 14.2.1 for identified power flows). The system average loss factor (**Equation 3-2**) equals the losses divided by the total energy flow into the system, expressed as a percentage.[10]

[9] See section beginning on page 56 of the TCR Electric Power Sector Guidance v1.0, 2009.

[10] Source: Equation 14a, TCR Electric Power Sector Guidance v1.0, 2009.

Equation 3-2 T&D System Loss Factor

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

Less analytically intensive options allow companies to model the loss factor using estimated losses from measured flow data or modeling calculations provided by a Balancing Authority. Companies in the United States also can use default average loss factors provided by the U.S. EPA's eGRID database[11] for five regions in the U.S.

With the T&D system loss factor identified, EFs can be applied to the respective power sources to calculate T&D system loss emissions. It is considered "best practice" for companies to strive to apply EFs specific to the equipment and fuels combusted to increase the accuracy of calculations.

Scope 2 grid EFs have been developed at many different jurisdictional levels (e.g., national, regional, utility), time scales (e.g., annual average, daily, hourly, real-time), and using a variety of different methodologies
(e.g., marginal or average rate). The general guidance for developing EFs is to develop and use the most detailed one feasible (e.g., specific to the location of the consuming equipment, specific fuels consumed, closer to real-time). In a future project webcast, we plan to explore these distinctions further, and discuss why they are relevant to electric power companies and electricity consumers.

Calculating Scope 2 Emissions from Purchased Electricity

Scope 2 emissions for electricity purchased and consumed by an electric company can be calculated as shown in **Equation 3-3**. by multiplying estimates of the amount of electricity purchased and consumed (MWhs) (e.g., from invoices, purchase orders, or metered records) by the appropriate EFs (e.g., supplier-specific, local grid, regional averages).

Equation 3-3 Calculating scope 2 emissions from purchased power (not for resale)

Scope 2 emissions* = *Electric energy consumption* (MWh) × *emission factor

Scope 2 emissions typically are limited to including only carbon dioxide (CO_2) associated with upstream indirect emissions resulting from fossil fuel combustion for generation of electrical energy.[12]

To calculate emissions from purchased electricity, the EF applied should be the "emission factor at generation" (EFG) as opposed to the "emission factor at consumption" (EFC), where the EFC is a function of EFG and T&D losses according to the series of equations shown below (**Figure 3-2**). The difference between the two is that an EFC includes T&D losses within its emissions rate while the EFG does not.

The EFG is preferred because T&D losses are accounted for separately from purchased electricity, steam, heat, and cooling. The use of an EFC is likely to result in double counting of T&D loss emissions that

[11] https://www.epa.gov/egrid/emissions-generation-resource-integrated-database-egrid

[12] Fossil fuel combustion for electrical energy generation may also result in small amounts of methane (CH_4) and nitrous oxide (N_2O) emissions. Further, some electrical transmission systems may utilize switchgear associated with fugitive emissions of sulfur hexafluoride (SF_6). Some geothermal power plants also release geologic sources of CO_2.

occur from delivering purchased energy: that is, it would be counted by the end-user through the EFC and also counted by the owner of the transmission and distribution lines. **Equation 3-4** is the one to apply in this case as follows:

Equation 3-4 Calculating scope 2 emissions from purchased power (EFG)

Indirect emissions from purchased electricity, steam, heat, and cooling = EFG × activity data (energy consumed)

$$EFG = \frac{\text{TOTAL } CO_2 \text{ EMISSIONS FROM GENERATION}}{\text{ELECTRICITY GENERATED}}$$

$$EFC = \frac{\text{TOTAL } CO_2 \text{ EMISSIONS FROM GENERATION}}{\text{ELECTRICITY CONSUMED}}$$

EFC and EFG are related as shown below.

$$\text{EFC} \times \text{ELECTRICITY CONSUMED} = \text{EFG} \times (\text{ELECTRICITY CONSUMED} + \text{T\&D LOSSES})$$

$$EFC = EFG \times \left(1 + \frac{\text{T\&D LOSSES}}{\text{ELECTRICITY CONSUMED}}\right)$$

Figure 3-2 Mathematical equations defining emissions factors at consumption and generation.[5]

Scope 2 Emissions for Combined Electric and Natural Gas Companies

Electric companies that also supply natural gas to end-use customers have another type of "T&D loss" to consider — fugitive methane (CH_4) emissions. Fugitive emissions occur when pressurized equipment in the natural gas supply chain leaks or is vented to the atmosphere. For example, methane leaks from joints, seals, valves, and gaskets in equipment used for producing, processing, transmitting, storing, and distributing natural gas to end users. These fugitive methane emissions may come from pipelines, meters, valves, wellheads (active and abandoned) and other equipment, if the equipment is within the operational boundaries of the natural gas company.

Because these emissions occur within the operational boundary of the entity, they are considered scope 1 direct emissions. While analogous in many ways to scope 2 T&D line losses associated with electricity, fugitive CH_4 emissions from natural gas transmitted via pipeline and distributed via local distribution pipes are not indirect, and so are not accounted for as scope 2 GHG emissions.

However, like any entity, natural gas related companies, must consider indirect scope 2 emissions associated with their purchased electricity, heat, steam, and cooling water. Combined electric and natural gas companies may provide electricity, heat, steam, or cooling from one part of the company to another, in which case the emissions are direct and counted within scope 1.

Scope 2 Emissions for Other Energy Distributors

Another entity that is responsible for a type of T&D energy loss would be owners and/or operators of steam, heat, and cooling distribution systems. If such entities are not also the generators of the energy (i.e., which would make this a direct scope 1 emission), the distribution system owner would account for scope 2 emissions associated with the energy losses from its equipment for the transmission and distribution of steam, heat, and cooling in an analogous manner for electricity T&D losses. End users would account for these losses similar to T&D line losses, as scope 3 emissions.

For instance, a company with a cogeneration plant that produces steam and utilizes another entity's distribution system to transfers steam to end users does not have scope 2 emissions from distribution

losses because the company will report GHG emissions from cogeneration as scope 1. In this same scenario, the company that owns or operates the distribution system would report emissions associated with distribution energy losses within its scope 2 because the emissions are occurring indirectly from the perspective of the distribution system's operation – at the cogeneration plant. If a single entity owned both the cogeneration plant and the distribution system, GHG emissions associated with losses from distribution would not be indirect and would be accounted for within the scope 1 direct emissions. Lastly, the end user who receives the cogeneration plant's energy would count the losses that occur through distribution as scope 3 emissions – the emissions are indirect from the end user (occurring at the cogeneration plant) and the end user does not own or operate the distribution system.

4. Briefing Paper for Webcast #3: Scope 3 Emissions Accounting

Introduction

This technical brief is the third in a series that accompanies a sequence of technical webcasts exploring greenhouse gas (GHG) emissions accounting challenges faced by electric power companies. **This brief describes accounting methods for scope 3 emissions for electric companies operating in the United States today.**

GHG Scope Review

The first technical brief in this series introduced the concept of GHG emissions "scopes." Emissions scopes are used to classify *direct* and *indirect* GHG emissions to determine which GHG sources and activities should be included inside the boundary of an entity's (e.g., corporation or other organization) GHG inventory. A complete entity-level GHG inventory typically accounts for all scope 1 (direct) emissions and scope 2 emission sources. Scope 3 emission sources often are considered "optional" for voluntary reporting. Scope 2 and 3 emissions sources are *indirect*, meaning they are associated with a company's operations, but emissions are not physically released to the atmosphere by assets owned or operated by the company. **Scope 3 emission are defined as any indirect emissions other than those covered by Scope 2.** The second technical brief in this series provides further detail on scope 2 issues.

Defining Scope 3 Emissions

The *Corporate Value Chain (Scope 3) Accounting and Reporting Standard*[13] (Scope 3 Standard) was released by the WRI/WBCSD Greenhouse Gas Protocol in 2011 to address the challenge of measuring and managing scope 3 emissions and is supplemental to the *Corporate Accounting Standard*.[14] The scope 3 Standard provides guidance for companies to prepare and publicly report a GHG emissions inventory that includes indirect emissions resulting from value chain activities (i.e., scope 3 emissions). The Scope 3 Standard is not intended for making comparisons between companies, quantifying GHG reductions or avoided emissions caused by a specific intervention, or accounting for life-cycle emissions at a product-level.[15]

A *value chain* is a model used in business to describe a series of coordinated activities required to deliver a product or service. For example, a supply chain is the upstream value chain for a manufacturer of consumer products. Often, multiple parties including suppliers, transporters, service companies,

[13] https://ghgprotocol.org/sites/default/files/standards/Corporate-Value-Chain-Accounting-Reporing-Standard_041613_2.pdf

[14] https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf

[15] *The Product Life Cycle Accounting and Reporting Standard* was also released in 2011 to quantify and publicly report an inventory of GHG emissions and removals associated with a specific product. https://ghgprotocol.org/sites/default/files/standards/Product-Life-Cycle-Accounting-Reporting-Standard_041613.pdf

professionals, retailers, and others are linked together to form a value chain. Scope 3 GHG accounting covers emission from sources along the value chain.

Including scope 3 emissions in a corporate GHG inventory is useful for understanding and influencing emissions across the entity's value chain. For a "typical" corporation not engaged in energy production or fuel combustion, a majority of its GHG emissions typically are associated with value chain activities and occur in entities other than their own. Companies can implement changes to impact their scope 3 emissions such as those from employee commuting by promoting carpooling and public transit use, or business travel through policies that reduce the need for travel by airplane.

By design, the categorization of scopes 1 and 2 emissions ensures against double counting of emissions between companies by ensuring the same emissions are not attributed to two different companies. Scope 3 emissions do not prevent double counting. For example, activities or products that lead to scope 3 emissions may be upstream inputs to a chain of companies and the same scope 3 emissions may be reported by some of those companies too.

The Scope 3 Standard defines 15 categories for reporting scope 3 emissions, separated into upstream and downstream designations (**Figure 4-1**). **Upstream refers to GHG emissions from purchased or acquired goods and services. Downstream refers to GHG emissions from the sale of goods and services by the reporting entity**.

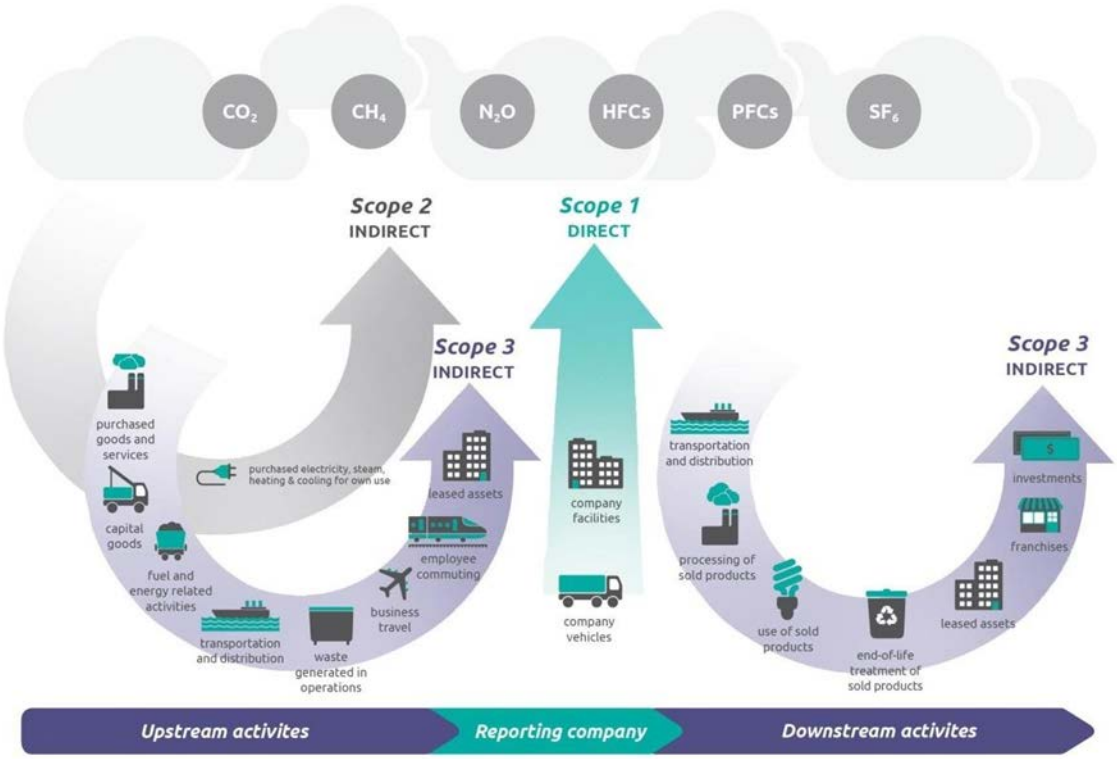

Figure 4-1 Upstream and Downstream Scope 3 Emissions Categories[16]

Three common scope 3 categories reported by many types of corporations are: (i) employee commuting; (ii) business travel; and (iii) waste generation in operations. Each are described below, as well as a scope 3 category particularly relevant for electric companies — fuel and energy-related activities.

Employee commuting

This category refers to emissions from travel by employees and other workers between their homes and their worksites in vehicles not owned or operated by the reporting company. The definition of commuting employees can be considered broadly as anyone commuting to facilities, owned, operated, outsourced, leased, or franchised by the company who contribute to or participate in the activities of the company, including: full time employees, part-time employees, contractors, volunteers, consultants, temporary or seasonal workers, interns, business service professionals, etc. All modes of transportation should be considered, including: cars, rail, air, public transit, marine, and others as may be appropriate.

Business travel

This category covers emissions from the transportation of employees for business-related activities in vehicles owned or operated by third parties, such as aircraft, trains, buses, and passenger cars including rental cars. Emissions associated with lodging for business travel (hotels) and lifecycle emissions associated with the manufacture of vehicles or infrastructure used for business travel may be included

[16] Source: Figure 1-1 in the Scope 3 Standard

but are considered optional. This category does not include business travel in vehicles owned, leased, or controlled or activities performed by traveling employees in facilities owned or controlled by the reporting company as these would be reported in the company's scope 1 or scope 2 emissions.

Waste generation in operations

This category refers to scope 3 emissions associated with waste processing services purchased from other companies. These emissions are considered scope 1 and 2 emissions of companies that provide waste processing services to the reporting company. This category does not account for emissions from waste generated as part of end-of-life processing after customers or consumers are finished with the reporting company's product or services (that is a separate downstream category).

Fuel and energy-related activities

This category covers scope 3 emissions related to **extraction and production of fuels and energy purchased by a reporting company** (that are not already reported in scopes 1 or 2). Specifically, it includes:

a. **Upstream emissions of purchased fuels** such as natural gas and coal (i.e., extraction, production, and transportation of fuels consumed by the reporting company[17]);
b. Upstream emissions of purchased electricity (extraction, production, and transportation of fuels consumed in the generation of electricity, steam, heating, and cooling consumed by the reporting company);
c. Upstream transmission and distribution (T&D) losses (electricity, steam, heating, and cooling energy that is lost in a T&D system) reported by end users.[18] (see **Table 4-1**)
d. **Generation of purchased electricity sold to end users or "wheeled" to third parties** (i.e., generation of electricity, steam, heating, and cooling that is purchased by the reporting company and resold to end users) **by an electric company or energy retailer**.

For guidance on defining and calculating emissions from all of the 15 scope 3 categories, refer to the Scope 3 Standard supplement, *Technical Guidance for Calculating Scope 3 Emissions*.[19]

[17] In some cases, electric companies may own mines or fuel wells (e.g., "mine-mouth" coal mines, natural gas E&P facilities etc.) that produce the raw fuel used by these companies to generate power. In these cases, the GHG emissions associated with the mining or drilling for fuel would be reported as scope 1 emissions.

[18] Note, the GHG Protocol Value Chain Standard does not appear to have considered wholesale power transactions in this category.

[19] https://ghgprotocol.org/sites/default/files/standards/Scope3_Calculation_Guidance_0.pdf

Table 4-1 T&D-related GHG Emissions Accounting by Role of Reporting Company

Reporting Entity Role	Emissions from Generation	Emissions from T&D loss
1. Company generates and sells wholesale electricity only	Scope 1	Scope 3
2. Company purchases wholesale electricity but does not consume it (does not own/operate T&D assets)	Scope 3	Scope 3
3. Company purchases wholesale electricity but does not consume it (owns/operates T&D assets)	Scope 3	Scope 2
4. Entity using the electricity	Scope 2	Scope 3

Use of sold products

For a natural gas company or combined electric and gas utility, the emissions resulting from the use and combustion of natural gas is included in the downstream scope 3 category "use of sold products" (i.e., emissions from the use of goods and services sold by the reporting company). Scope 3 emissions from the use of natural gas is based on the amount of gas sold to all customers. These emissions include those resulting from combustion of gas by end-use customers and any fugitive (e.g., methane) emissions occurring from customer-sided assets.

Electricity Emissions Factors for Indirect Emissions Accounting

The calculation method for indirect emissions associated with electricity is the same regardless of which scope the emissions fall under (scope 2 or 3). It is based on the quantity of electrical energy (e.g., MWh) times an emission factor (e.g., tonnes CO_2/MWh). Accounting methods for scope 2 and 3 electricity emissions may require different types of emission factors. The two main types are described below.

When electricity is consumed off of a distribution grid the source of energy cannot be traced in a physical sense from a specific generator to an individual consumer. **Grid average emission factors** generally are used because all operating generators contribute to the electrical potential for the entire system at each moment. Grid average emission factors are derived by dividing the total emissions from all the generation resources supplying a defined transmission and distribution grid system area by the total amount of electricity supplied over a given time period. This resulting ratio, which we refer to as an emission factor (EF), reflects the average indirect emissions for each unit of electrical energy consumption by those end users within the distribution area. Such an emission factor is also referred to as a location-based factor.

A grid *average* EF represents the average of the GHG emissions associated with the power generation facilities dispatched onto a grid over a defined period of time.[20] Typically, electric companies need to use

[20] Because an entity-level GHG emissions inventory is an *attributional* accounting for emissions they rely on the use of grid *average* EFs. However, for "consequential analysis" of the potential impacts of GHG emissions reduction interventions it may be appropriate in some cases to use a "marginal" EF that more closely approximates the GHG EF at the specific time electric power is generated and dispatched onto the grid. Marginal EFs represent the marginal GHG emission source being dispatched on the grid for each hour or sub-hourly time period.

grid-related EFs for two reasons associated with accounting for their emissions: (i) to calculate their scope 2 indirect emissions associated with any electricity they purchase from third parties and consume in company-owned facilities and operations; as well as (ii) to calculate their scope 3 emissions associated with purchasing wholesale power from third parties for resale to other electric companies or for delivery to end-use customers.

During our recent scope 2 technical webcast, we discussed how addressing item (i) above requires an electric company to obtain an appropriate GHG EF for their grid or from their third-party electricity provider to determine their scope 2 indirect emissions. This situation is identical to an end-use customer requesting an EF from their load-serving entity (LSE) to calculate their scope 2 emissions. Below we discuss the development of EFs that can be used by electric companies to calculate scope 3 emissions associated with purchasing wholesale power from third parties for resale or to deliver to end-users.

Emissions Associated with Serving Retail Electric Load

Accounting of emissions associated with serving the electric load of end-use customers is of particular interest to electric companies and to end-use consumers. To serve retail load, most electric companies rely on a combination of electricity generated by their own resources and wholesale electricity market purchases. Accounting of emissions associated with serving retail load thus overlaps both Scope 1 (emissions from the company's own resources) and Scope 3 (emissions associated with the company's wholesale electric purchases). For electric companies that own or operate T&D assets, it may also include accounting of emissions associated with T&D losses (Scope 2). While formal GHG accounting methods have evolved considerably in recent years, accounting for the GHG emissions associated with purchased power for resale to end-use consumers is complex and continues to be an uncertain area of GHG accounting.

GHG Accounting Considerations for Wholesale Power

Most electric power companies are familiar with calculating and reporting the direct emissions of their generating resources. Unless an electric company fully serves its retail load solely with electricity generated by its own assets, such a *facility-based approach* would undercount emissions associated with serving retail load. Some method is needed to account for emissions associated with purchased wholesale electricity used to serve load. This is particularly important to the types of end-use customers described above who want to actively reduce their GHG emissions, but their largest source of GHG emissions are their scope 2 indirect emissions associated with their electricity usage. These entities as well as retail end-use customers often request their electricity provider to provide them with the scope 2 EF associated with the electricity delivered to them.

Choosing an appropriate method needs to account for a number of factors. First is the ability to identify specific resources, other than the electric company's own assets, used to serve retail load. Most bilateral contracts are not helpful in assigning specific resources to load, because most do not specify the resource type – only the price, delivery point, MW quantity, and duration. Renewable power purchase agreements (PPAs) often are considered the exception, but there may be others that identify a particular resource (specified PPAs). Renewable Energy Credits (RECs) are sometimes used as proxy for a physical transaction of energy between an energy generator and an electric company (or consumer). Implicitly or explicitly, these contractual arrangements typically are used to claim the right to use a resource-specific EF (zero for

many renewable resources[21]) associated with a certain amount of generation (as discussed further above).

A further consideration is whether the company operates within an organized electricity market. Determining emissions associated with serving retail load is less straight-forward for companies operating in organized markets because while resources are owned and contracted by electric companies, they are dispatched by the market operator based on market conditions. Power purchased from the market is *undifferentiated* and electric companies typically do not have any control the source of power purchased from the wholesale market.

Lastly, power generation resources differ in their ability to respond to dispatch instructions from a market operator. For instance, the availability of wind and solar PV depends on weather conditions; coal-fired steam resources operate inefficiently at levels below 70-80% of the resource's maximum capacity and need several hours to ramp up or down. Conversely, natural gas resources generally are considered fully dispatchable in that they can quickly ramp up or down. Certain accounting methods consider the dispatchability of an owned or contracted resource in distinguishing whether the resource can be attributed to a specific electric company or collective energy market for emissions accounting purposes.

Methods to Account for Emissions Associated with Serving Retail Load

There is no definitive method for accounting of scope 3 emissions associated with serving retail load and the existing voluntary GHG accounting protocols have not directly addressed this issue. However, several different GHG accounting methods have been developed over time in the absence of more definitive guidance. These differ in terms of what generation is attributed to an electric company's portfolio, how the quantity of system (undifferentiated) wholesale electricity purchases is quantified, and the EF used to quantify emissions associated with wholesale power purchases.

The **simplified portfolio method** is the simplest, and least accurate method. For each calendar year the electric company would total up the generation from its own resources and deduct this amount from its total retail load. The remainder represents the quantity of wholesale electricity purchases used to serve load. Emissions associated with these purchases are then calculated by multiplying this quantity by an annual regional grid-averaged EF. The simplified portfolio approach likely overestimates the scope 3 emissions associated with retail load for electric companies that contract for a substantial volume of "clean" or renewable electricity.

The **specified portfolio method** differs from the simplified portfolio method in that a resource-specific EF is used where known (e.g., for renewable energy) for each specified wholesale electricity purchase. Undifferentiated wholesale purchases are calculated by deducting the total generation of the electric company's own resources and resources under specified PPAs from total annual load. Emissions from these resources are calculated using resource-specific EFs. An annual grid-average emission factor is used for the remaining quantity of undifferentiated system energy purchases. The accuracy of the specified

[21] Zero-emissions resources include wind, solar, hydro, and nuclear that do not emit GHG when they generate electric power. Renewable resources generally are considered "climate-neutral," although some, such as biogas or landfill gas, do emit GHGs. However, because they do not result in a net increase in GHGs, they are effectively treated as zero emission. Also, hydropower resources may emit methane from decaying matter in reservoirs that needs to be accounted for in some cases.

portfolio method depends on the extent to which actual generation by the utility's portfolio of owned resources and specified PPAs matches its load profile throughout the year, and on the accuracy of the EF assigned to undifferentiated system energy purchases.

Net short accounting methods differ from the two portfolio approaches in that net short methods distinguish between *dispatchable* and *non-dispatchable* resources.[22] Non-dispatchable resources (e.g., coal, variable renewable energy) that are owned or contracted by an electric company are considered part of the company's portfolio of resources, and emissions are attributed to this generation using resource-specific EFs. All other generation needed to meet retail load (regardless of whether owned by the electric company) is treated as serving the organized wholesale market. The quantity of undifferentiated system energy purchases is calculated by summing the generation of the company's owned and contracted "non-dispatchable" resources and deducting this quantity from total annual load. Because non-dispatchable resources are considered assigned to the owning or contracting utility, the system EF used to calculate emissions for the other system energy purchases is a "residual" EF that represents the grid-averaged EF of "dispatchable" resources only (i.e., gas). A net short method may be applied on an annual basis, or more granularly (e.g., hourly).

[22] A good example of a "dispatchable resource" in this context is a single-cycle natural gas combustion turbine. These generators have a fast start time and so are typically used as "peaking" units. While not as quick to start, natural gas combined cycle units can operate efficiently over a wide range of power generation output and can change their output level quickly (aka "ramping"), on the order of minutes. In contrast, many renewable resources, such as wind and solar PV, are "non-dispatchable" because their availability depends entirely on weather conditions. Nuclear generators typically operate at a steady output level, and so are also often considered to be "non-dispatchable." In contrast, hydropower resources and coal-fired resources fall somewhere in the middle, but in many cases have limited dispatchability. Hydropower resources technically are dispatchable as they can release water and generate power at the direction of the operator; however, they are subject to environmental laws and regulations that often requires the operator to maintain a minimum level of water flow, which limits their dispatchability. Coal resources also have limited dispatchability, typically around 20-30% of the resource's maximum capacity. However, this flexibility is not immediately available, as it typically takes a coal-fired steam generator several hours to ramp up or down.

Table 4-2 Approaches to Account for Emissions Associated with Serving Retail Load

Approach	Emissions Accounted	Emission rate for PPAs	Calculation of Volume of System Power Purchases	Emission Rate used for System Power Purchases
Facility-based	Utility's Own Resources	Not applicable	Not applicable	Not applicable
Simplified Portfolio	Utility's own resources and wholesale purchases	All purchases attributed the same emission rate	Total annual load minus total annual generation of utility's owned resources	Annual generation-weighed grid average of all resources on the system
Specified Portfolio	Utility's own resources and specified contracts	Emission rate of the specified resource	Total annual load minus total annual generation of utility's owned resources and specified contracts	Annual generation-weighed grid average of all resources on the system
Annual Net Short	Non-dispatchable owned and contracted resources in	Emission rate of the specified resource	Total annual load minus total annual generation of utility's non-dispatchable owned resources and specified contracts	Annual generation-weighted average of residual system resources
Hourly Net Short	Non-dispatchable owned and contracted resources in	Emission rate of the specified resource	Hourly load minus hourly annual generation of utility's non-dispatchable owned resources and specified contracts	Hourly generation-weighted average of residual system resources

5. Briefing Paper for Webcast #4: Special Topics: GHG Emission Factors, Renewable Energy, and Renewable Energy Certificates in GHG Emissions Accounting

Introduction

This technical brief is the fourth in a series that accompanies a sequence of technical webcasts exploring greenhouse gas (GHG) emissions accounting challenges faced by electric power companies. **This brief discusses the selection and use of emission factors (EFs), including factors provided by electric companies in the United States to consumers whose electric load they serve, as well as GHG accounting issues associated with renewable energy purchasing claims.**

Emission Factors

According to the U.S. Environmental Protection Agency (US EPA), EFs are defined as, "*a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant*."[23] Typically, EFs are expressed as the mass of GHG pollutant per unit of the emission producing activity, such as kilograms of carbon dioxide (CO_2) emitted per kilograms of bituminous coal combusted.

Direct emissions measurement (either source-specific emission tests or continuous emissions monitoring (e.g., CEMS) generally produces more representative results than estimation performed using an EF.[24] However, in many situations, it is impractical to directly measure all emissions from a source (e.g., diffuse methane (CH_4) leaks along a natural gas pipeline network). When direct emissions measurement is not possible, the use of EFs becomes the appropriate alternative. To estimate emissions, an EF is multiplied by corresponding activity data such as the hours of operation of a piece of machinery, or the mass of coal combusted, or the amount of electricity consumed. The basic formula is:

Equation 5-1 Formula for estimating GHG emissions using an emission factor

$$\textit{Emission factor} \times \textit{Activity data} = \textit{GHG emissions}$$

Emission factors may be quantified in a handful of ways. They can be developed using an understanding of stoichiometry for processes that strictly follow simple chemical reactions or apply mass balance calculations, or they can be developed empirically producing statistical sample measurements. Numerous studies have been published for most emission sources in peer-reviewed scientific research (see "Resources for Emission Factors"). EFs also can be established based upon expert judgement by evaluating all the available evidence to produce a representative average emissions rate for a specific industry or technology.

[23] https://www.epa.gov/air-emissions-factors-and-quantification/basic-information-air-emissions-factors-and-quantification

[24] In the case of carbon dioxide emissions from fuel combustion, both direct measurement and estimation based on EFs derived from fuel carbon content analysis can produce equally accurate results.

Emission factors also vary in the breadth of activity or activities they cover. Typically, in GHG accounting, EFs address a single source category, such as CO_2 emissions resulting from the combustion of gasoline in light-duty on-road vehicles. However, some factors serve as integrated values across multiple sources and processes. These broader factors are often developed for environmental life cycle analysis (e.g., upstream CO_2 and CH_4 emissions associated with gasoline consumption – which incorporates emissions occurring from unrefined fossil fuel extraction, fuel processing, transportation, fugitive releases, as well as combustion). Examples of single source emission factors are presented in **Table 5-1**.

Table 5-1 Examples of GHG Emission Factors relevant to Load Serving Entities (LSEs)

Emission Source	Emission Factor Units	Considerations
Stationary combustion	• kg CO_2 / short ton • kg CO_2 / Btu • kg CO_2 / scf • kg CO_2 / gallon	CO_2 EFs are generally estimated based on sample measurements of the average carbon content of the fuel and then applied to activity data collected in energy units (e.g., MJ or Btu) rather than units of mass or volume.[25] Fuel type and characteristics combusted must match the EF selected and appropriate units of mass. CEMS data can be used as an alternative method for quantifying stationary combustion emissions.
Mobile combustion	• kg CO_2 / gallon • kg CO_2 / scf	
SF_6 switchgear	Fraction of SF_6 (leaked) / year	Default EFs exist for SF_6 production as well as use in electrical equipment (installation, use, retirement). EFs can be gauged by tracking how much SF_6 gas is purchased or the through use of default emission (leak) factors.
Fugitive CH_4 (gas transmission & storage)	Gg CO_2e / million m^3 of marketable gas	These EFs typically set a default rate for fugitive CH_4 emissions assuming typical steady-state leak rates and typical frequency of intermittent leak rates across a range of equipment (e.g., valves, compressors).

Global Warming Potentials

As identified in the examples above, EFs typically are expressed in units of mass (e.g., grams, metric tons, pounds) of specific gaseous chemical species, such as CO_2, CH_4, SF_6, and others. However, GHG emissions generally are reported in terms of *CO_2 equivalent* (CO_2e) units. Carbon dioxide equivalence provides a way to compare and combine gases using the Global Warming Potential (GWP) – that is, the "warming effect" – for different GHGs. Specifically, GWPs are a quantified measure of the globally averaged relative atmospheric radiative forcing impacts of a particular GHG. It is defined as the cumulative radiative forcing – including both direct and indirect effects – integrated over a period of time from the emission of a unit mass of gas relative to a reference gas (IPCC 1996). Carbon dioxide was chosen by the IPCC as the reference gas and its GWP is set equal to a value of one. GWP values provide a relatively easy method to compare the impacts of emissions and reductions of different gases.[26]

[25] The carbon content of fuels is correlated to their energy content, so use of activity data in energy units should produce more accurate emission estimates.

[26] For more information on GWPs and how they are determined read this blog post by Michael Gillenwater.

The most commonly applied GWP integration time period is 100 years. One challenge with selecting appropriate GWP values relates to the fact that the IPCC, who publishes GWP values, updates them every 5 or 6 years in conjunction with the Panel's scientific assessment reports (e.g., AR4, AR5). GWP values necessarily need to be updated as our scientific understanding of the impacts of different GHGs improves.

Entities make commitments based on GWP values while these revisions are taking place. For example, a company or country may commit to reduce its combined GWP-weighted GHG emissions by 10% by a certain time. Then, if GWP values are updated, the relative importance of the specific GHGs also changes, which could make the goal more or less burdensome. The larger the fraction of non-CO_2 GHGs reported, the greater the potential impact GWP value revisions (because the GWP value of CO_2 is fixed at 1 by definition). GHG reporting programs usually specify which vintage of GWP values they expect reporting entities to use.

Resources for Emission Factors

Databases exist containing EFs for nearly all recognized GHG emissions sources and removal sinks. The IPCC maintains the emission factor database (EFDB) that compiles emission factors from scientific research and is overseen by an expert editorial board.

Primarily for regulatory reporting applications, the US EPA also provides a database of air pollutant (GHGs and other pollutants) EFs, which also includes information on how to develop EFs and how to use emissions estimation tools.

The GHG Protocol program offers calculation tools for corporate GHG inventories that provide EF guidance and worksheets in a series of multi-sector tools (including electricity, stationary combustion, transportation, among others) and stationary combustion (including guidance on calculating direct emissions and an Excel tool).

The Climate Registry (TCR) provides a default EF document to those entities who report to it. The document is updated annually and can be downloaded here.[27]

Electric Power Grid Emissions Factors

Emissions factors are also applied to electricity taken from the power grid to estimate indirect GHG emissions for purchased electricity, that is either consumed by an entity (i.e., scope 2) or resold by an electric company to its customers (i.e., scope 3).

There are different types of grid EFs. The most commonly used is an ***annual grid-averaged EF***. This type is a generation-weighted EF averaging all GHG emissions (or CO_2 only) associated with all power generation resources in a defined grid region (usually the interconnection) across a single calendar year. This type of EF can blur significant seasonal and/or intra-day (peak/off-peak) differences in the emission intensity of system power (i.e., *undifferentiated* electric power taken from the grid). For instance, a grid average EF would likely overestimate the emission intensity of the system mix during periods of high

[27] Online at https://www.theclimateregistry.org/?s=general+reporting

renewable generation and underestimate the emission intensity during peak load periods with little or no renewable power available.

Some Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) publish GHG intensity data for their footprint. The US EPA's eGRID program also publishes emission intensities for grid sub-regions throughout the United States. One challenge in using grid EFs databases like eGRID is that publishing lags several years behind the current reporting period. This lag is particularly problematic for recent years, as the overall power generation mix has been changing rapidly in certain regions of the country.

Although not commonly used, ***residual EFs*** represent another approach to estimating emissions associated with system power purchases used to serve retail electric load. Residual EFs are calculated using the generation-weighted average of resources used to generate power in a given grid region that are not attributed to individual electric company (i.e., LSE) portfolios. For instance, the *net short accounting methods* discussed in Technical Brief #3 use a residual EF based only on generation of "dispatchable"[28] resources in the grid region. While accurate calculation of a residual EF would require knowledge of which non-dispatchable resources are owned or contracted to electric companies in the region, a reasonable approximation may be achieved using an EF for natural gas resources operating in the grid region, as these are typically the only fully dispatchable resources available for load following.

Marginal EFs are a third type. In theory, a marginal EF represents the emission rate of the marginal generating resource dispatched on the system. Because the marginal resource at any given point in time depends on load and grid conditions, marginal EFs by their very nature change frequently.

These three types of grid emission factors (average, residual and marginal) are used for different applications. Grid-averaged and residual emission factors are used for *attributional GHG accounting*, which includes preparing corporate GHG emissions inventories. The purpose of attributional environmental accounting frameworks is to allocate (i.e., assign responsibility for) aggregate emissions across a population (e.g., countries or organizations). For instance, a grid-average emission factor would be appropriate to calculate the allocation of corporate scope 2 emissions associated with electricity consumption to each company consuming electricity from the grid. Conversely, a residual emission factor may be appropriate for an electric company to estimate the emissions associated with wholesale power purchases necessary to serve their retail electric load.

In contrast, marginal EFs are used for *consequential* GHG accounting, where the goal is to estimate *changes in emissions or removals* caused by specific interventions. Consider an energy efficiency project that potentially reduces emissions by reducing demand for electricity. In evaluating the emission reductions caused by this example energy efficiency project, a marginal EF would be appropriate to apply to estimate the emissions avoided through reduced output from the last-to-be-dispatched

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[28] In this context, "dispatchable" is defined as those resources operating in a wholesale power market that can ramp quickly and have lower marginal costs, such as natural gas combined cycle turbines and single cycle peaking units. These units can more easily control their output and respond to system operator instructions. In contrast, generation resources that cannot easily control their output (i.e., renewables) and baseload generation (e.g., nuclear, coal, and hydro) that typically run at a constant output are considered under load-based accounting methods to be "non-dispatchable" resources. For more information, please see the EPRI report, *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases* (3002015044).

generator(s) corresponding to the reduced electrical load. However, a marginal factor would be inappropriate to use for attributional environmental accounting, such as corporate GHG inventories, because emissions from marginal generation units cannot be allocated and claimed by all companies simultaneously.

Additionality is a concept relevant to consequential GHG accounting (and to the forthcoming discussion of "green power" below). Additionality is a determination, typically *ex ante*, of whether a specified intervention (e.g., a new subsidy policy or energy efficiency program) will cause an environmental change, such as a reducing GHG emissions. Additionality assessments result in a binary (i.e., yes or no) eligibility determination. The concept of additionality is most often applied in the context of GHG emission reduction credits (i.e., carbon offset credits), and is not applicable to preparing corporate GHG inventories or other forms of attributional environmental accounting.[29]

Renewable Energy, Renewable Portfolio Standards, and Electric Company GHG Accounting

Growing deployment and generation of renewable energy (RE) power generation resources (e.g., wind and solar) is an important means to reduce the environmental impacts – including reducing GHG emissions – associated with power generation and consumption. To drive more rapid renewables deployment, many states have adopted regulatory programs establishing renewable portfolio standards (RPS) or other programs requiring procurement and tracking of RE resources by electric companies.

Renewable Energy Certificates (RECs)

Some of these regulations specify the creation of tradable *Renewable Energy Certificates* (RECs) that typically record the generation of 1 MWh by a "renewable" resource, as defined by the program. RECs are described as being "*bundled RECs*" when they are transferred in conjunction with the electricity from the underlying RE generator. Or they may be referred to as "*unbundled RECs*" when they are sold separately from the underlying RE power.

RECs originally were designed and intended to be used as a tradable instrument solely for tracking compliance with RPS procurement targets.[30] The creation of RECs by metered generation from renewable resources, as well as REC transfers and retirement for RPS regulatory programs, are recorded in designated tracking systems, such as the Midwest Renewable Energy Tracking System (M-RETS). The use of RECs in regulatory compliance schemes enables accounting of wholesale RE procurement without the need to track the underlying electricity or verify the underlying renewable Power Purchase Agreements (PPAs).

Appropriate accounting for the purchase of RE (MWhs) and RECs is complex and depends on the context and purpose for the accounting. Electric companies may seek to account for their own wholesale RE

[29] Corporations may purchase GHG emissions offset credits, but the accounting for these credits should always occur separately from their corporate GHG emissions inventory. First, an entity assesses the emissions it is deemed responsible for through *attributional* accounting, and then it may separately claim to have offset some or all of those emissions by retiring offset credits.

[30] Gillenwater (2008). "Redefining RECs (Part 1): Untangling attributes and offsets". *Energy Policy*.

purchases as part of demonstrating RPS regulatory compliance[31] and to facilitate RE purchasing goals of their end-use customers. These activities are discussed in more detail below.

Corporate Green Marketing Claims

Many end-use customers, especially corporate entities, have made a variety of environmental and RE purchasing claims. For example, in late 2016, Google announced that in 2017 that it would reach 100% RE for global operations, including data centers and offices.[32]

One common form of retail consumer claim is based on a financial arrangement referred to as a "virtual" renewable PPA, where the entity purchases only unbundled RECs without purchasing the underlying electricity (MWhs). This approach is problematic for several reasons. First, unbundled RECs may or may not be registered to a specific generation resource actually serving load in the same grid region where the end-use consumer is physically connected. Even when these claims are based on bundled RECs, the RECs themselves do not represent the physical delivery or consumption of electricity. A fundamental principle of *attributional* environmental accounting is that emissions should be allocated based upon *physical processes* (e.g., combustion of a fuel) and physical matter or energy transfers (e.g., purchase and use of steel).[33] The use of RE contractual arrangements, such as RECs, by retail electricity consumers, in all but special circumstances, do not reflect this principle.[34,35]

Corporations and other retail electricity customers also purchase bundled RECs to claim progress toward achieving voluntary procurement goals. These REC transactions are often tracked in a similar fashion to those for RPS compliance, but such "consumer" commitments are not subject to regulatory participation and compliance mandates.

In addition to bundled or unbundled RECs, other contractual approaches also are used by corporate retail electricity consumers, such as commercial and industrial entities, to make RE purchasing claims. These approaches include "physical" renewable PPAs, under which a RE generator sells both electricity and RECs to the buyer specified in the PPA[36]. Some end-use customers may also choose to enroll in an electric

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[31] Typically, RPS regulatory requirements stipulate an LSE deliver a percentage (e.g., 50%) of specified renewable energy resources to their end-use consumers by a specified date (e.g., 2030).

[32] https://sustainability.google/progress/projects/announcement-100/. In September 2020, Google announced in 2020 a new goal of powering its entire business with 100% renewable energy for "every hour of every day of the year" by 2030.

[33] If the principle of physical connection is relaxed, then the attribution of emissions to entities in attributional accounting can become arbitrary and meaningless, representing immaterial reallocation of emissions and leading to GHG accounting that does not reflect physical emissions to the atmosphere that result from an entity's activities.

[34] The University of Edinburgh Centre for Business, Climate Change and Sustainability compiles a webpage of research on this topic.

[35] Some consumers use RE contractual arrangements to implicitly or explicitly make consequential emission reduction claims, akin to those associated with GHG emission offset credits. Such claims are also problematic due to overlapping policy interventions such as the production tax credit (PTC). For example, if a RE generation facility accessed a PTC incentive and generates RECs, it is not clear whether the REC or PPA, and not the PTC, caused the additional renewable capacity investment.

[36] For more information on some of the types of contractual mechanisms used by corporate end-use consumers to purchase RE, see "*Achieving our 100% Renewable Energy Purchasing Goal and Going Beyond*," Google, December 2016 (available online here:

utility-sponsored "green" tariff program, where the RE is designated for that particular customer, rather than all of the utility's customers.

In addition to making "green power" purchasing claims, some electricity end use customers may further seek to account for RE purchases to quantify their corporate scope 2 GHG emissions or to claim GHG emission reductions. However, there are serious limitations to using REC purchases or other renewable power procurement approaches in these ways.

It is important to understand specifically what the different types of environmental claims associated with RE represent before considering the extent to which it may be appropriate for a corporate end-use customer or an electric company to use a RE contractual arrangement and rely on this arrangement to claim the RE purchase in their GHG inventory or report a reduction in their GHG emissions.

"Buying" Renewable Energy and GHG Emissions Accounting

The marketing messages broadcast by voluntary green power programs (e.g., Green-e) and green power marketers to end-use consumers often includes the implicit assertion that end-users who purchase "green power" are taking *physical* delivery of RE (an *attributional* accounting claim) as well as causing additional RE generation to deploy on the grid (a *consequential* accounting claim). However, in recent years, environmental accounting experts have challenged these *retail* green power claims and found them to be highly problematic when made on an *attributional* basis.[37] Further, some experts have demonstrated in the peer-review scientific literature that voluntary REC markets do not influence RE investment or generation, thereby rejecting *consequential* accounting claims associated with most kinds of contractual arrangements.[38,39] This issue continues to be controversial.

RECs and some other RE contractual arrangements often are used as a proxy for the *physical* transaction of energy between a renewable energy generator and an end-use consumer. Implicitly or explicitly, RECs and other contractual arrangements are then often also used to claim the right to use a "zero" EF for the RE referenced in these arrangements.

While it can be legally appropriate to use RECs and/or other RE contractual arrangements for load serving entities (LSEs) to demonstrate RPS compliance as discussed above, it remains controversial for end-use customers to use these approaches to track progress toward achieving corporate RE purchasing commitments. Furthermore, it is inappropriate to use these arrangements for environmental accounting purposes, including preparing corporate GHG inventories, as these arrangements are not an appropriate proxy for the actual physical flow of electric power between producers and consumers.

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https://static.googleusercontent.com/media/www.google.com/en//green/pdf/achieving-100-renewable-energy-purchasing-goal.pdf

[37] https://scope2openletter.wordpress.com/

[38] Gillenwater, Lu, and Fischlein (2014). "Additionality of wind energy investments in the US voluntary green power market." *Renewable Energy*.

[39] Gillenwater (2013). "Probabilistic decision model of wind power investment and influence of green power market." *Energy Policy*.

As currently applied in practice and in major GHG protocols,[40] RECs are appropriate environmental accounting instruments for neither consequential nor attributional GHG accounting. With this growing realization and in response to the accumulating research evidence, many end-user companies are responding by moving away from the use of RECs to claim zero EFs or GHG emission reductions. Yet, as designed, RECs are well suited for RPS compliance applications. Unfortunately, research is currently lacking on how to understand the influence of alternatives, such as PPAs, on RE investment or how to properly integrate them into attributional (corporate) GHG accounting.

Electric Company Portfolio Emissions Intensity for Serving End-use Load

Technical Brief #3 introduced the *specified portfolio approach* to accounting for emissions associated with an electric company's wholesale PPAs. One problem using this approach to account for scope 3 emissions associated with serving load is that it may create a mismatch between claimed renewable power generation and the electric company's actual load profile. This problem may be minor when the portion of grid electricity supplied by renewable resources is small, but would increase as renewable generation increases (because the approach allows excess renewable generation during low load periods to be counted against grid emissions associated with serving load during periods when renewable generation is not available).[41] This problem would be exacerbated if an electric company were to count unbundled RECs as part of the portfolio of energy used to serve its consumer's load, because as explained above, the purchase of unbundled RECs does not involve the actual purchase of electricity (MWhs). The *net short approaches* discussed in Technical Brief #3 address this problem and make it possible for an electric company to account for its renewable purchases.

Electric companies may choose to calculate an *emission intensity* (tonne CO_2e/MWh) associated with serving customer load that reflects the combined EFs of its own power generation resources and GHG emissions associated with a company's net wholesale power purchases. In calculating such a "portfolio" GHG emission intensity metric, the company should try to avoid double counting of both specific generation and associated emissions in the EF used to apply to *undifferentiated* wholesale electricity purchases. For example, use of a grid-average EF based on *all* generation resources in the grid region to calculate an electric company's portfolio emission intensity could double count resources (and associated emissions) claimed by other individual electric company portfolios. Use of a residual EF for grid system purchases (or a proxy of based on natural gas generation) can avoid this outcome.

[40] For example, GHG Protocol Scope 2 Standard and The Climate Registry's revised Electric Power Sector Protocol.

[41] See Technical Brief #3. This problem is exacerbated if an electric company counts unbundled RECs in its portfolio.

6. Briefing Paper for Webcast #5: Special Topics: The "Landscape" of Reporting Programs for Corporate GHG Emissions Accounting and Updates to The Climate Registry's Electric Power Sector Protocol

Introduction

This technical brief is the fifth in a series that accompanies a sequence of technical webcasts exploring greenhouse gas (GHG) emissions accounting challenges faced by electric power companies. This brief describes the "landscape" of reporting programs for corporate GHG emissions accounting as it applies to electric companies operating in the United States[42]. **This brief also highlights the Climate Registry's (TCR) Electric Power Sector (EPS) protocol which provides the most specific and targeted guidance to electric companies about reporting their GHG emissions.**

Landscape of Reporting Programs

Several reporting programs exist today that provide guidance to electric companies on how to do credible GHG accounting. Where these programs are mandatory, entities within the policy's jurisdiction must comply with the reporting requirements. However, many programs are voluntary and present a different challenge to companies navigating this landscape. These programs differ depending on their scope and purpose, and it is up to each company to determine whether and how to apply the voluntary program's standards and guidance. Companies must make this determination based upon their own goals and needs.

Protocols, Standards, and Methodologies

Terminology within this realm is important to define. For reporting purposes, a program is defined as an entity that generally fulfills three functions (Broekhoff et al, 2019):

1. Defining eligibility rules;
2. Defining measurement, reporting, verification, and certification rules; and
3. Registration services to transparently track emissions.

Protocols and *methodologies* are two terms for the same concept: "[they] cover GHG accounting rules and program requirements for monitoring, reporting, verification, and certification" (Broekhoff et al, 2019[43]).

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[42] In addition to voluntary corporate GHG reporting efforts, there are several mandatory GHG emissions reporting programs that cover electric companies in the United States, including the mandatory CO_2 Cap-and-Trade program in California and the Regional Greenhouse Gas Initiative in the Northeast United States. GHG emissions reporting under these mandatory reporting programs is beyond the scope of this briefing paper.

[43] Broekhoff, D., Erickson, P., and Piggot, G. (2019). *Estimating consumption-based greenhouse gas emissions at the city scale – A guide local governments*. Stockholm Environment Institute: Stockholm, Sweden. https://www.sei.org/wp-content/uploads/2019/03/estimating-consumption-based-greenhouse-gas-emissions.pdf

Standards may include protocols or methodologies and additional guidance materials. Standards provide guidance and specific requirements for GHG quantification, monitoring, and reporting. Standards do not represent the entirety of a program, as exhibited by standalone standards that do not include key registry and report tracking systems. Standalone standards may be considered guidance material (e.g., WRI/WBCSD GHG Protocol) or they may provide auditable and/or certifiable requirements (e.g., ISO 14064).

GHG Accounting Frameworks and Boundaries

As discussed in the earlier Technical Brief, *Overview of Greenhouse Gas Accounting Principles and Methods,* GHG accounting *frameworks* are defined principally by clearly drawing the system boundaries within which GHG emissions (and removals) are counted. GHG accounting frameworks can either be *attributional* in nature, meaning they focus on attributing GHG emissions — *direct* or *indirect* — to particular activities or entities, or *causational*,[44] meaning they focus on determining *net changes* in GHG emissions caused by a particular action, intervention, or activity such as the emission reduction credit price signal associated with a proposed GHG "offset" project.

Table 6-1 GHG Accounting Frameworks

Accounting Framework	Activity Boundaries	Scope Boundaries	Type of Accounting
Facility-based (or source-based)	Individual site or facility	Direct emissions	**Attributional**
Entity-level	Organizational boundaries (corporation or other entity)	Direct and selected indirect emissions	**Attributional**
Sectoral	Defined economic sector boundaries (within a single jurisdiction or across multiple jurisdictions)	Usually direct; sometimes will include indirect	**Attributional**
Jurisdictional or territorial	Jurisdictional or territorial geographic boundaries	Usually direct; sometimes will include indirect	**Attributional**
Value chain (in the electricity sector, load-based accounting)	Multiple (can be incorporated into any of the above frameworks)	Indirect	**Attributional or causational**
Project- and policy-based	Activities associated with a defined project or policy action	Direct and indirect	**Causational**

[44] Also referred to as *consequential* accounting.

Catalogue of Various GHG Reporting Programs and Protocols

Many shareholder organizations and other sustainability stakeholders engaged in corporate carbon disclosure would like electric companies to develop GHG emissions inventories that include complete organizational boundaries and apply an entity-level[45] accounting framework. This approach is attributional. It combines emissions from the three GHG emissions "scopes".

Some GHG reporting programs for the electric power sector require only *facility-based accounting*, which is an attributional approach that draws the accounting boundary around individual sites or facilities; and so, does not necessarily represent an entire organizational boundary of a corporation.

The **World Resource Institute and World Business Council for Sustainable Development (WRI/WBSCD)** have developed the following influential GHG accounting guidance documents:

- WRI/WBSCD Revised Corporate Standard (2004). The Corporate Standard provides requirements and guidance for preparing entity-level GHG inventories. The Corporate Standard is widely accepted and informs the development of many reporting programs.
- WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).[46] The Scope 2 Guidance is provided as a supplement to the Corporate Standard to estimate emissions associated with purchased or acquired electricity, steam, heat, and cooling (Scope 2 emissions).
- WRI/WBSCD Corporate Value Chain (Scope 3) Standard (2011). The Corporate Value Chain Standard is a supplement to the Corporate Standard to assess Scope 3 value chain emissions using a life-cycle analysis approach.

The Climate Registry (TCR) is a non-profit organization that operates a voluntary GHG reporting program widely used by corporations and other entities, including electric power companies. TCR has adopted the following specific protocols to guide electric and gas companies who choose to report their GHG emissions to the TCR:

- TCR General Reporting Protocol (GRP) v3 (2019). The GRP outlines GHG accounting principles and calculation methods for reporting an organizational carbon "footprint," or entity-level GHG inventory, specifically in the Climate Registry's online reporting program. It is a widely recognized standard based on the WRI/WBSCD Corporate Standard that is available publicly.

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[45] Entity-level accounting frameworks provide standardized methods for estimating GHG emissions for an entire entity, such as a corporation or other organization.

[46] It is important to be aware that this guidance was published in 2015 with dissent (see letter here). Also see EPRI Technical Brief #4 on *GHG Emission Factors, Renewable Energy, and Renewable Energy Certificates in GHG Emissions Accounting* Brief for further discussion. This guidance includes a controversial application of accounting for renewable energy certificates (RECs) and other "green" power purchasing claims in the reporting of indirect (Scope 2) emissions. Numerous leading GHG accounting experts withdrew from the WRI/WBCSD working group that developed this guidance and publicly recommend companies not use this standard. Specifically, the application of RECs to claim a zero-emission factor for Scope 2 is contrary to evidence in the scientific literature that shows empirically a lack of environmental integrity with the use of some voluntary market RECs in environmental accounting.

The TCR Protocol and associated reporting software also facilitates facility-level reporting for organizations.

- TCR Electric Power Sector Protocol (2009). A supplement to the TCR GRP that provides entity- and facility-level accounting guidance specifically for the electric power sector. TCR published recent updates to the guidance on December 1, 2020.

The United States Environmental Protection Agency (US EPA) GHG Reporting Program (GHGRP) requires that GHG data be reported by large GHG emitters operating in the United States. This program applies at a facility-level as a mandatory reporting regime for emission sources >25,000 tonnes CO_2e per year, or supply products that when used will result in >25,000 tonnes CO_2e per year. The emissions calculation methodologies are specified under federal regulations and are, in general, based upon the methodological tier available to apply (e.g., for fossil fuel combustion, Tier 1 would apply a default emission factor while Tier 3 would apply measurement of the fuel characteristics). The reported information is used for public policy purposes, such as the Affordable Clean Energy rule (formerly the Clean Power Plan).

CDP (formerly the Climate Disclosure Project) is a non-profit organization that developed the Global Disclosure Platform for investors, companies, cities, states, and regions to report environmental impacts and GHG emissions. CDP works with its members to improve emission reduction goals and reported climate data. CDP provides guidance and gathers information through annual questionnaires.[47] Sector-specific questions are identified for high-impact sectors including the electric sector. CDP assesses reported information and releases rankings like the "A-list" of high performing companies. The CDP questionnaire defers to the WRI/WBCSD GHG Protocol for GHG methodological and reporting guidance.

One CDP methodology developed through the **Assessing Low-Carbon Transition (ACT)** initiative targets electric utilities' company alignment with low-carbon transition. Through this methodology, electric companies are guided through a process to consider each asset within their power generation portfolio for alignment with low-carbon transition. The results are evaluated to set goals and develop a transition plan. ACT provides ratings to assess a company's progress towards achieving this transition plan, current and past action, and the cohesiveness of these plans and actions. In particular, ACT provides guidance to address the difficulties associated with asset "lock-in" that will impact emissions over the lifespan of generation units.[48]

The **Science Based Target Initiative (SBTi)** is a cooperative initiative by WRI, CDP, the United Nations Global Compact, and the World Wildlife Foundation (WWF) to establish GHG emission reduction goals based upon scientifically informed targets. The SBTi has issued guidance to help companies identify the quantity of GHG emissions they must reduce and the necessary timeframe to achieve those reductions. SBTi then assesses each company's submitted science-based targets for approval against the SBTi criteria. Those companies that receive SBTi's "approval" are permitted to claim that their climate action

[47] To gain access to the guidance materials provided by CDP you must create a free account and then follow this link to locate the appropriate materials.

[48] CDP. ACT – Executive Summary Report. Available at: https://www.cdp.net/en/reports/downloads/1759

is in line with "science-based targets". SBTi provides specific guidance for electric utilities through their Power Sector guidance.

Over the past several years, **EPRI** has been engaged in a project to understand climate scenarios and goal setting activities and has published a series of studies[49] to develop public technical resources that can serve as a scientific foundation for informed dialogue and decision-making related to electric company climate policy scenario analysis and emissions goals. We encourage all of the project participants to review these materials.

Ceres, a non-profit that seeks to transform the economy and build a sustainable future, initiated the **Global Reporting Initiative (GRI)** for corporate climate reporting and disclosures in 1997. The GRI is now used globally to report corporate GHG emissions through application of GRI 305: Emissions 2016. GRI 305 also bases its reporting guidance on the WRI/WBCSD Corporate Standard and the Corporate Value Chain Standard, for reporting emissions from Scopes 1, 2, and 3. The GRI 305 also includes guidance for reporting GHG emissions intensity, reduction of GHG emissions (causational-project level accounting), emissions from ozone-depleting substances (ODS), and nitrogen oxides (NO_x), sulfur oxides (SO_x), and other significant air emissions.

Additionally, through the Ceres Investor Network and the Ceres Company Network, Ceres works with companies and investors to set ambitious climate goals, track their achievement, and leverage their member's goals to push for climate reporting within public policy.

The **Edison Electric Institute (EEI)** and the **American Gas Association (AGA)** developed a corporate environmental, social, and governance (ESG) reporting template to assist electric companies in providing consistent data to the financial sector. The template is tailored to utility operators and incorporates specific guidance for natural gas companies.[50] Member organizations and companies of both EEI and AGA have access to these standardized reporting templates that are used for voluntarily reporting GHG emissions (and other ESG factors) to investors.

EPRI's *Sustainability Benchmarking for Utilities* is a research collaborative project comprised of 30 or so electric power companies that provides participants an opportunity to 1) benchmark company data on industry-specific benchmarking metrics using an online platform and 2) share and learn from leading companies' practices and industry subject matter experts.

A recently published free EPRI report shares summary results and insights from EPRI's annual benchmarking efforts[51]. This report addresses why electric power companies are interested in sustainability benchmarking, how different company characteristics impact benchmarking, and how the Benchmarking Project can help companies better manage and measure performance on industry priority sustainability issues, including reducing GHG emissions. It also provides an overview of aggregated results from the 2019 benchmarking effort for ten core metrics and presents four case studies from

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[49] See *(I) Grounding Decisions: A Scientific Foundation for Companies Considering Global Climate Scenarios and Greenhouse Gas Goals*, EPRI, 2018 (3002014510), and (II) – *A Technical Foundation for Company Climate Scenarios and Emissions Goal,* EPRI 2018 (3002014515).

[50] EEI. ESG/Sustainability Template – Version 2. Available at: https://www.eei.org/issuesandpolicy/Finance%20and%20Tax/ESG_Template_Version_2_Qualitative.pdf

[51] *Sustainability Benchmarking for Utilities: 2019 Public Report*. EPRI, Palo Alto, CA: 2020. 3002018172.

project participants that demonstrate how companies have used their benchmarking experience to enhance their sustainability efforts.

Other efforts exist targeting the investment risk associated with fossil fuel energy sources including the **Securities and Exchange Commission's Regulations S-K** that requires the reporting of climate risks, and the **Task Force on Climate-related Financial Disclosures (TCFD)** that provides recommendations for how to account for these risks and encourages voluntary reporting. These reporting programs touch on GHG emission reporting but are most relevant to investment firms and, for this reason, are only mentioned briefly.

Within this landscape of reporting programs and guidance, the TCR EPS is a foundational document that provides granular and specific GHG accounting and reporting guidance to power generators and load serving entities (LSEs). The following sections introduce TCR, the EPS, and its recent protocol update.

The Climate Registry[52]

The Climate Registry (TCR) is a non-profit organization based in California. TCR was established in 2007 and was formed to continue the work of the California Climate Action Registry (CCAR). Created by the State of California in 2001, CCAR's mission was to promote and protect businesses' early actions to manage and reduce their GHG emissions. Through the state mandate, CCAR established protocols to guide emissions inventories and managed an online reporting tool, the Climate Action Registry Reporting Tool (CARROT), to serve as a central database for emissions reports. CCAR accepted its last emissions inventory reports for 2009 in December 2010 and officially transitioned its members to TCR.

Since 2007, TCR has designed and operated voluntary and compliance GHG reporting programs globally. TCR is most well-known for assisting a broad range of companies and other organizations, including electric companies, in measuring, reporting, and verifying (MRV) GHG emissions and removals related to their operations. TCR operates a proprietary web-based GHG reporting platform and provides protocols, training, and technical support to its members and other organizations.

TCR members report their GHG emissions to the *Carbon Footprint Registry* using the Climate Registered Information System (CRIS), an online reporting platform (www.cris4.org) that enables the calculation, reporting, and analysis of emissions data.

In 2020, TCR also revamped its *Climate Registered™ recognition program* to provide more flexible recognition opportunities and new incentives for reporting entities. The program now offers five tiers of recognition with unique benefits connected to each tier. Recognition is available for organizations at all points on the reporting spectrum—from those who have just started to build their capacity to those who exemplify true excellence in reporting and reducing GHG emissions. Actions such as reporting and verifying an emissions inventory, setting a public GHG reduction goal, and reporting GHG-related performance metrics, can earn organizations a certificate or plaque, visibility in TCR's marketing platforms, and the opportunity to use a designated Climate Registered™ logo to communicate their

[52] For more information, please see https://www.theclimateregistry.org/

leadership[53]. As shown in Appendix A, a number of electric companies, including EPRI Members, have been recognized by TCR for their GHG emissions reporting.

TCR's **General Reporting Protocol (GRP)** provides the basic framework for the program's participating organizations to report GHG emissions in TCR's Carbon Footprint Registry. TCR also develops sector-specific methodological and reporting protocols, including for the electric power industry.

The Electric Power Sector (EPS) Protocol

TCR developed the Electric Power Sector Protocol (EPS) (2009[54]) as a supplemental annex to the GRP that provides more specific GHG accounting and reporting guidance to electric power companies.[55] It defines more specific requirements for EPS organizations to report to TCR and is designed to be used in conjunction with the GRP.[56] The EPS Protocol provides detailed guidance on reporting GHG emissions from:

- Stationary combustion, including allocation of emissions from combined heat and power (CHP);
- Mobile combustion;
- Indirect emissions from electricity consumption, including transmission and distribution losses;
- Indirect emissions from imported heat, steam, cooling, and electricity from CHP;
- Fugitive and process emissions; and
- Scope 3 emissions from purchased wholesale power delivered to customers.

The protocol also provides guidance to calculate and report the various power generation and deliveries metrics described below.

EPS: Power Generation Metrics

The EPS Protocol provides a methodology for power generators that deliver power to the grid on a net annual basis[57] to report standardized power generation metrics that reflect the *carbon intensity* of individual generating units or facilities, as well as the company's entire generation portfolio. The purpose of developing and reporting standardized metrics for the electric power sector is to:

1. Provide a basis for consistent comparison between industry members, regardless of an entity's size; and
2. Track an entity's carbon intensity performance over time as a complement to reporting of absolute GHG emissions.

Power generation metrics are reported at the unit ***or*** facility-level ***and*** for all owned and controlled facilities combined. All power generation metrics are based on the CO_2 emissions directly related to

[53] Appendix A includes a complete list of the organizations TCR recognized in 2019 in its Climate Registered recognition program.

[54] EPRI staff member Adam Diamant participated in the TCR working group that developed the original 2009 EPS Protocol.

[55] Updates and clarifications to the protocol are occasionally published on the TCR website. The latest updates and clarifications to the protocol were published on 1 December 2020.

[56] In some instances, the EPS Protocol provides alternative provisions to those of the GRP.

[57] Facilities with low or no GHG emissions from generation (i.e., wind, hydro) may also report power generation metrics.

power generation and are proportional to power output (i.e., exclude upstream emissions and emissions from ancillary equipment and operations at the power generating facility). In terms of organizational boundaries, generation metrics are based on the equity share of net power generated and the equivalent emissions associated with that share of the generation in units of CO_2/MWh. The five types of power generation metrics that may be reported to TCR are listed in **Table 6-2**.

Table 6-2 Summary of Required Power Generation Metrics

Reference	Metric	Comment	Units
EPS Metric G-1	Fossil Generation	Fossil CO_2/ Net Fossil Generation	MT CO_2/MWh
EPS Metric G-2	Biofuels Generation	Biogenic CO_2/ Net Biogenic Generation	MT CO_2/MWh
EPS Metric G-3	Geothermal Generation	Geothermal CO_2/ Net Geothermal Generation	MT CO_2/MWh
EPS Metric G-4	Anthropogenic Generation	Anthropogenic CO_2/ Net Generation	MT CO_2/MWh
EPS Metric G-5	Biogenic Generation	Biogenic CO_2/ Net Generation	MT CO_2/MWh

EPS Update December 2020

On 12/1/2020, TCR published updates and clarifications to its methodologies for developing power generation metrics in the EPS protocol. These metrics originally were envisioned, in part, as a resource to help electric companies identify the carbon intensity of wholesale power purchased from specific generation facilities, to aid in the development of their electricity deliveries metrics. Several EPS members provided feedback that the metrics were not being used for this purpose and were mostly redundant to mandatory reporting of electricity generation.

In response, TCR changed reporting of power *delivery* metrics from *required* to *optional*. TCR also incorporated an additional biogenic generation metric for unit or facility-level generation and all owned or controlled generation combined, due to the inclusion of indirect biogenic emissions in WRI's Scope 2 Guidance and TCR's GRP v2.1.

TCR further clarified that facility-level power generation metrics do not apply to generating facilities with negative net generation (i.e., the facility consumes more electricity that it generates), because the emissions rate would not accurately represent the emissions rate of the unit when it is generating electricity. Lastly, TCR also clarified that system average metrics do not include facilities with negative net generation.

EPS: Electricity Deliveries Metrics

Reporting power deliveries metrics (i.e., carbon intensities) helps to make it possible for LSEs to monitor trends in the carbon intensity of the wholesale electricity they acquire and sell to their customers. Also, some electric companies and industry observers are interested in comparing the environmental *performance* of electric companies of different sizes, which can be difficult to do solely on the basis of absolute (i.e., total) GHG emissions.

In some cases, a larger electric company may have greater absolute GHG emissions (i.e., tons CO_2) than a smaller electric company, but the larger company may have a lower carbon intensity per MW of power delivered (CO_2/MWh) than the smaller one. Standardized carbon-intensity metrics provide a means to do this on a consistent basis. Power deliveries metrics reported under the EPS Protocol also are a source of emission factors (EF) that electricity wholesale and/or retail customers can use to calculate their own Scope 2 "*market-based*" emissions.

Metrics represent the emissions intensity of delivered electricity either: (A) across the LSE's entire portfolio (described as an LSE's "single-system average" in the EPS Protocol), or (B) attributed to specific customer groups.

Under the EPS Protocol, power deliveries metrics must be verified by a third-party to ensure customers and stakeholders are using accurate data as a basis for decision marking and in their own GHG inventories. LSEs are required to report anthropogenic CO_2 and biogenic CO_2 emissions in separate metrics. Methane (CH_4) and nitrous oxide (N_2O) metrics may be reported separately, although since the quantity of CH_4 and N_2O is expected to be very small for most fuel sources, LSEs may use simplified methods to calculate these metrics.

Options A and B are intended to provide the flexibility for companies to report portfolio-wide emissions or separately report emissions associated with individual power products (i.e., wholesale sales, retail sales and special power products).

The simplest TCR metric to calculate includes all sources of power (i.e., generated and purchased or exchanged) flowing into the LSE's entire portfolio (i.e., the single system average as defined in the EPS Protocol), where the anthropogenic and biogenic CO_2 metrics for the LSE's portfolio would be the metrics used for power delivered to all customers. The two types of portfolio-wide (i.e., system-average) metrics are listed in **Table 6-3** below.

Table 6-3 EPS Protocol Option A – Single-system

Single System-Average Anthropogenic Metric	Single System-Average Biogenic CO_2 Metric

Product-specific metrics are further broken down by the EPS Protocol into defined categories, including wholesale power, special power,[58] and retail power. LSEs may develop multiple product-specific metrics (i.e., reporting multiple special power products.) The six types of product-specific metrics are listed in **Table 6-4**.

[58] The power assigned to the wholesale product and each special product must be clearly tied to specific sources of generation and/or specific power purchases delivered to a specific customer group. The power and emissions assigned to each of these products are set aside and deducted from the remaining power mix delivered to retail customers.

Table 6-4 EPS Protocol Option B – Product-specific

Product-Specific A-W (Anthropogenic Wholesale Deliveries)	**Product-Specific B-W (Biogenic CO_2 Wholesale Deliveries)**
Product-Specific A-SP (Anthropogenic Special Power Deliveries)	**Product-Specific B-SP** (Biogenic CO_2 Special Power Deliveries)
Product-Specific A-R (Anthropogenic Retail Deliveries)	**Product-Specific B-R** (Biogenic CO_2 Retail Deliveries)

LSEs can develop anthropogenic and biogenic CO_2 metrics using both options. When an LSE reports product-specific metrics, any of the LSE's end-use customers who also report to TCR are required to apply the LSE's more granular EFs to compile their inventories (in accordance with the requirements in the GRP).

The recently published updates and clarifications to the EPS Protocol provide additional guidance for several new reporting options: biogenic CO_2 deliveries metrics, and CH_4 and N_2O deliveries metrics. The update also removed a previous limitation to report either portfolio-wide metrics (Option A) *or* product-specific metrics (Option B), to provide additional reporting options and transparency. However, to prevent double counting between the two methods, TCR only will publish the most granular factors to its website and encourages all organizations that develop both types of metrics to explain to customers that only the more granular metrics should be used for their Scope 2 accounting.

Market-Based Scope 2 Accounting

The recent EPS Protocol update also amended the entirety of Section 19.3 to incorporate principles of *market-based Scope 2 accounting*, based on the GHG Protocol's Scope 2 Guidance and TCR's GRP v2.1.

Under the market-based method for Scope 2 accounting, organizations claim EFs conveyed through contractual instrument transactions between the reporting organization and the electricity or product provider. Supplier-specific EFs, as defined in this EPS section, are one of the tools organizations may use to calculate their market-based Scope 2 totals. The key changes to this section of the EPS include: incorporation of eligibility criteria for energy attribute certificates from GRP v3.0.; clarification that accounting for sold energy attribute certificates in deliveries metrics is required; clarified step-by-step methods for calculating deliveries metrics adjusted for certificate sales and purchases; and an update that LSEs may optionally disclose metrics unadjusted for certificate purchases.

Electric Power Sector Reporters in the Carbon Footprint Registry

While the EPS Protocol is available to the public, additional reporting resources and trainings, technical reporting and verification support, a proprietary web-based reporting tool, and access to a collaborative network of climate leaders are available only to members who formally join the Carbon Footprint Registry.[59]

[59] Please contact Michelle Zilinskas (mzilinskas@theclimateregistry.org) or info@theclimateregistry.org to discuss the benefits and options for TCR membership and to request updates or clarifications to the EPS Protocol.

2019 TCR Climate Registered Recognition Recipients[60]

In 2019, the following members earned Climate Registered™ recognition:

ALL STAR:

Xcel Energy, Northern States Power, Public Service Company of Colorado, Southwestern Public Service Company, California Department of Water Resources

GOLD:

3Degrees
American Licorice Co
Aquarium of the Pacific
Black & Veatch
Blue Source, LLC
California Public Employees Retirement System
City of Woodland
Clif Bar & Company
Columbia University
Copper Mountain Solar 1 LLC
DAK Americas LLC
Delta Air Lines
Denver Water
Dignity Health (formerly Catholic Healthcare West prior to 2012)
Driftwood Dairy
Eastern Municipal Water District
Environmental Science Associates
Enwave Seattle (formerly Seattle Steam Company)
Exelon
Fetzer Vineyards
Harrison Industries
Heising-Simons Foundation
Marin Sanitary Services
Massachusetts Department of Environmental Protection
Metropolitan Water District of Southern California
Mithun
New York Power Authority
Nexant, Inc.
Nuclear Energy Institute
Pacific Gas and Electric Corporation
Port of Portland
Qualcomm Inc
Redhorse Corporation
Rodney Strong Vineyards
Sacramento Municipal Utility District
San Diego Gas & Electric
San Francisco Public Utilities Commission, Power Enterprise
San Lorenzo Valley Water District
Seattle City Light
Sonoma Clean Power
Sonoma Water
South Bay Recycling
South Bayside Waste Management Authority
South San Francisco Scavenger Company Inc.
Southern California Gas Co.
Specialty Solid Waste and Recycling
Stanford University
Termoelectrica de Mexicali, S. de R.L. de C.V.
Terra Global Capital LLC
The Cadmus Group, Inc
The Climate Registry
The David and Lucile Packard Foundation
The Tower Companies
Turlock Irrigation District
United States Postal Service
University of California, Davis
University of California, Irvine
University of California, Los Angeles
University of California, Office of the President
University of California, San Francisco
University of California, Santa Barbara
Waste Connections, Inc.
West Basin Municipal Water District
Yale University
Zone 7 Water Agency
New York State Metropolitan Transportation Authority

[60] The Climate Registry, 2019 Impact Report, p8.

A. Frequently Asked Questions (FAQ)

Table of Contents

Purpose

This document is a curated list of questions, organized by topic area, that have come up over the course of the supplemental project, *Greenhouse Gas Emissions Accounting for Electric Power Companies*. Much of the material covered in this FAQ was sourced from the briefing papers prepared for each webcast identified in **Table A-1**. For more detailed information, please consult the briefing papers included in this Compendium.

Audience

The primary audience for this FAQ is the electric power companies participating in this EPRI supplemental project. This FAQ attempts to address questions and provide answers that are of interest to the project participants and take into consideration these entities' principal activities. This FAQ does not include answers that may be relevant or complete for other entities that are not electric power companies or combined electric and natural gas utilities.

Table A-1 List of project briefing paper topics

Briefing Paper	Topic
01	Introduction to Corporate Greenhouse Gas (GHG) Emissions Accounting
02	Scope 2 Emissions
03	Scope 3 Emissions
04	Special Topics: GHG Emission Factors, Renewable Energy, and Renewable Energy Certificates (RECs) in GHG Emissions Accounting
05	Special Topics: The "Landscape" of Reporting Programs for Corporate GHG Emissions Accounting and Updates to The Climate Registry's Electric Power Sector Protocol

Frequently Asked Questions

General Questions

How should an electric company account for the GHG emissions associated with "in" service territory versus "out of" service territory electricity purchases?

In answering this question, it is important to first define "who" is consuming the power and what is meant by "in" versus "out of" service territory electricity purchases. Regarding the former, electric companies may purchase electricity to serve either company or end-user (customer) electricity load. Emissions associated with electricity, heat, or steam that is purchased and then consumed by the electric company to power its own facilities are considered scope 2 emissions. The emissions associated with electricity an electric company purchases from others to meet end-user load inside its "service territory" are considered scope 3.

Regarding from "where"[61] the electricity originates, if the power purchased and consumed is generated by facilities inside the electric company's organizational boundaries (i.e., by a wholly-owned subsidiary), these emissions would be considered scope 1 regardless of who is consuming the electricity. Because these emissions are included in the company's scope 1 calculations, they can be excluded from the scope 2 accounting. If the purchased power is generated by facilities outside of the company's organizational boundaries[62], the emissions "embedded" in the purchased power would be considered either scope 2 or scope 3, depending on who ultimately consumes the electricity (see above).

[61] It is best to define "where" in terms of organizational boundaries as opposed to geographic location. Electric companies may purchase electricity from other entities physically located within their service territories, but not included in their organizational boundaries. To be included in an electric company's organizational boundaries, the entity that owns the generating facility should be under the operational or financial control of the electric company. Emissions producing activities also may be included within organizational boundaries based on the electric company's equity share in the operations. The company's percentage ownership of that operation should be equivalent to the share of GHG emissions for each activity.

[62] This purchased power may be delivered via power purchase agreements (PPAs) or other market mechanisms.

The discussion above applies to categorization of scopes as is done under typical "source-based" accounting. This differs under a "load-based" accounting approach that attempts to account for the GHG emissions associated with serving retail load (which cuts across scopes 1 and 3).

Table A-2 provides a matrix that shows how to determine the appropriate accounting for purchased electricity.

Table A-2 Matrix for determining accounting for purchased electricity.

		Electricity Consumer	
		Electric Company	*End-User (Customer)*
Origin of purchased electricity	*Company-owned (including subsidiaries)*	Scope 1	Scope 1
	Third Party	Scope 2	Scope 3

Scope 2 Emissions

How should an electric company calculate the scope 2 emissions associated with electricity purchased from an entity outside of its organizational boundaries?

There are several ways this can be done. To calculate the scope 2 emissions, the company purchasing the power ideally would use an appropriate emissions factor (EF) (CO_2/MWh) associated with the delivered power. This kind of EF potentially can be obtained from the entity that generated and delivered the power.

If the power was purchased in a "specific" bilateral transaction where the generating resource was known, then a reporting company could use a specific EF associated with the source of electricity specified in the contract. However, if the power is "grid" power (aka "system" or "unspecified" power), the electric company purchasing the power would need to use an appropriate grid- averaged emissions factor provided by the entity generating the power, or use a more general average regional grid EF, such as those available from EIA, USEPA's eGRID, and other sources. The accounting for these scope 2 emissions covers power purchased by the electricity company outside of its organizational boundaries that is consumed by the company in its operations.

How would an electric company account for the GHG emissions embedded in the power the company purchases from others to power company-owned buildings and facilities, if these facilities are not powered by the electric company's own generators?

This is a textbook example of scope 2 emissions accounting. Any emissions associated with purchased electricity used to power company-owned facilities or used by the company for its own direct consumption would be counted as scope 2. Ideally, the electric company would obtain an emission factor for the purchased electricity from the power distribution company and use that to estimate their scope 2 emissions.

Why is scope 2 emissions reporting typically limited to include only carbon dioxide (CO_2) associated with upstream indirect emissions resulting from fossil fuel combustion for generation of electrical energy? What about the other GHG emissions (e.g., CH_4, N_2O, SF_6)?

Both electricity generation and transmission activities emit other GHGs including CH_4, N_2O and SF_6. Emissions of these non-CO_2 gases and CO_2 are considered scope 2 for entities that purchase and consume the electricity, but do not generate it. Limiting scope 2 emissions reporting estimates to only CO_2 (as opposed to including other GHGs too) is a matter of practicality and is consistent with *de minimus*[63] guidelines. Typically, non-CO_2 emissions are comparatively small relative to CO_2 for upstream power generation, so scope 2 reporting often does not address them. However, there are no restrictions on entities reporting non-CO_2 GHGs in their scope 2 reporting, and entities are encouraged to do so when this information can be readily obtained.

In contrast to calculating scope 2 CO_2 emissions, a reporting entity that would like to report on indirect CH_4 and N_2O emissions would need to understand details about not just the fuels but also the combustion technologies, conditions, and any associated emissions controls. They could also include upstream SF_6 emissions associated with the transmission of the purchased power. In contrast, accurate CO_2 estimates can be produced with only the information about the type of fuel consumed (e.g., coal, natural gas) and its carbon content. Reporting non-CO_2 emissions in a scope 2 inventory is proper for the sake of completeness. These estimates will typically rely on default factors for the non-CO_2 emissions instead of directly monitoring the release of these gasses, which would increase the cost of quantification.

Some electric companies may receive calls from activist investors and other parties encouraging them [the electric company] to focus their emissions reduction efforts to reduce their *scope 2 indirect emissions*. How can an electric company respond to these well-meaning inquiries?

Scope 2 emissions are considered a special category of indirect emissions and encompass emissions associated with the purchase of electricity by the reporting entity for its own consumption. Electric companies that own electricity generation units typically have large direct (scope 1) emissions inventories due to the emissions released from these owned units. If electric companies use some of these electricity generation units to power their own facilities, buildings, or assets, the emissions from this electricity would not be counted as scope 2 since they are already counted in the company's scope 1 inventory. Emissions from electricity consumed by the company are only counted as scope 2 if the electricity is not generated by company-owned generation facilities. Even if these electricity generators purchase some electricity for company consumption, the emissions associated with those purchases are likely to be very small relative to the emissions associated with company-owned electricity generation. In addition, the company's scope 2 emissions typically will be much smaller than the downstream scope 3 emissions associated with serving end-user load.

The structure and business product of a corporate entity affects the amount of direct and indirect emissions the entity produces. For "wires only" power companies that do not own any power generation assets it may make sense to focus attention on reducing scope 2 emissions as these are likely to be the largest source of emissions for the company. However, it may be difficult for a "wires only" company to reduce these emissions as they do not own the power generation sources feeding their transmission and distribution systems.

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[63] *De minimus* refers to a source or set of emissions that are relatively small and do not need to be included in an entity's GHG inventory. It is tied to the materiality of a source or set of emissions. GHG reporting protocols and programs have different thresholds for *de minimus* designations. Companies typically have to develop preliminary estimates in order to justify *de minimus* exclusions.

For companies that do not generate, but purchase electricity, emissions associated with this purchased electricity may comprise a very large share of the company's GHG emissions inventory. For these non-electric companies, reducing their scope 2 emissions is likely to be an important way to reduce their overall emissions.

Furthermore, in addition to implementing energy efficiency measures, another key way these companies can reduce their scope 2 emissions is by encouraging their load serving entity (LSE) to change its generation mix to reduce its scope 1 direct emissions. As a result, these companies may be interested in understanding how their LSE plans to reduce the carbon intensity of its power mix in the future. Over time, as the power sold by the LSE and larger grid becomes less carbon intensive, this will reduce these companies' scope 2 emissions.

How are fugitive emissions of methane from electric company-owned pipelines, compressor stations and other equipment accounted for within the GHG emission scopes?

Natural gas emissions associated with "leaky" electricity generation equipment contributes GHG emissions to the atmosphere. While many parties jump to the conclusion that these "fugitive" GHG emission should be accounted for as scope 2 emissions, this is incorrect. Fugitive emissions from natural gas electricity generating systems are "direct" emissions and so are accounted for as scope 1 emissions by the entity that includes the natural gas facilities within their organizational boundary.

How are scope 2 emissions accounted for in the charging and the use of batteries (energy loss)? What about the scope 3 emissions from manufacturing and disposal of batteries?

The accounting for GHG emissions for battery energy storage systems is an issue that has recently become of interest, and, to date, we are not aware of any specific studies that directly address this issue.

Based on the fundamental principles of "attributional" GHG accounting, we can offer the following guidance on this question. Below are some preliminary thoughts about the appropriate ways to account for battery energy storage in the specific situations discussed below. As part of this project, EPRI is doing further research on this topic and plans to publish a technical brief on *Greenhouse Gas Emissions Accounting for Batteries Energy Storage Systems (BESS)* later this year.

The configuration of the battery and its integration with the transmission and distribution grids impacts how indirect emissions associated with BESS are categorized. For a third-party owner of a battery energy system, the GHG emissions (or electricity losses) associated with the charging and discharging of batteries that are connected to the grid (i.e., "in front of the meter") would be considered scope 2 for the company that owns the battery. Accounting for these emissions is similar to how "wires only" companies account for T&D line losses associated with power they purchase from generators and transmit to third parties or end-use customers.

In circumstances in which an electric power company owns the battery system and charges it from power generation units it owns, there would be no indirect emissions associated with charging / discharging the battery system because they are captured in the company's scope 1 emissions. This is similar to how scope 2 emissions for electricity generators typically are already accounted for in the company's scope 1 emissions inventory.

Owners of batteries, including electric companies, may also be interested in lifecycle GHG emissions accounting associated with the production and disposal of batteries. In most cases, these emissions would be considered scope 3 for the owner and operator of the battery.

The accounting guidance provided above is limited to "source-based accounting", scope 1 and 2 emissions, for power generation companies and T&D wires companies and may not be appropriate guidance for load-based accounting of these emissions.

Why doesn't leasing vehicles cause scope 2 emissions to go up? Isn't that also purchasing energy from some other entity?

The GHG emissions associated with burning of fuel in owned vehicles are scope 1 emissions since these emissions result from the direct combustion of the fuel in the vehicles. Typically, the owners and/or lessees that have operational control of vehicles would also account for these emissions as scope 1 emissions. Consequently, leasing vehicles rather than owning them typically does not alter a company's scope 2 GHG emissions. However, in cases in which an equity-based consolidation approach to organizational boundaries is applied, leased assets may be considered a scope 3 emissions source.

When the GHG accounting protocols were being developed, there was a desire to distinguish between "*direct*" and "*indirect*" emissions. Emissions scopes were created to categorize direct and indirect emissions. Within the indirect category, it was decided to have special designation (scope 2) for purchased energy (i.e., electricity, heat, steam, cooling) as it represents a significant indirect source of GHG emissions for many reporting entities, and the largest opportunity for many entities to reduce their GHG emissions.

While scope 2 includes emissions associated with indirect consumption of other forms of purchased energy beyond electricity, including heat, steam, and cooling purchased by a company to power its own buildings or equipment, scope 2 does not include liquid fuels burned for transportation.

Transmission and distribution line losses

How does a reporting entity account for "line losses" associated with the transmission and distribution of electricity?

When electric power is transmitted from generation facilities to end-uses through transmission and distribution (T&D) systems, a portion of it is "lost" as it passes through the wires and other equipment. These are referred to as "T&D line losses" and a company may categorize the associated indirect emissions as scope 2 or scope 3 emissions depending on who owns and/or operates the T&D system. This is an additional category of scope 2 emissions beyond purchased electricity consumed by the reporting entity. Typically, T&D line losses equal a small percentage (~3-7%) of the total amount of power transmitted and/or distributed across a power system (in the United States).

Accounting for the emissions associated with these losses is dependent on the structure of an electric's company's operations (see **Table A-3**), which include:

- Vertically integrated companies (e.g., Investor-owned utilities, and some large public power agencies)
- Generation and transmission co-ops (G&Ts)

- Transmission and/or distribution companies ("wires only" companies)
- Independent power producers (IPPs)

Table A-3 T&D-related GHG Emissions Accounting by Type of Electric Company Entity

Electric Company Corporate Structure	Does GHG Inventory Include Scope 2 T&D losses?
Vertically Integrated Electric Company[1]	3. No - for self-generated power, as all emissions are accounted for in scope 1. T&D losses are not indirect for the company. 4. Yes - for wholesale power purchased from other parties and transmitted and/or distributed (e.g., wheeled) across the company's system.
Generation and Transmission Co-op	Same as above. But line losses are limited to the bulk transmission system only, unless the G&T also owns / operates the local distribution system(s).
Transmission and/or Distribution companies[1]	Yes. The inventory would include indirect GHGs emissions associated with T&D line losses for all electricity flowing through the company's system.
Independent Power Producer	No. Company does not own or operate T&D equipment. Any indirect emissions associated with T&D line losses from purchased power for "own" use of electricity are categorized as scope 3.

Both vertically integrated power companies and G&Ts own and operate power generation facilities. Therefore, they report direct emissions from power generation at their facilities as scope 1. Even though these entities also own power lines, T&D losses from these companies' perspective are not indirect. However, if these companies also purchase some portion of electricity from another company and transmit it (e.g., "wheel" it) across their lines, without consuming it themselves, they should account for the scope 2 emissions from the T&D losses associated with the power being transmitted across their system.

Transmission and/or distribution companies that only own and operate T&D equipment (i.e., "wires only" companies) account for indirect emissions associated with T&D losses as scope 2 emissions. If these companies also consume the power that flows through their T&D systems, they would report the emissions associated with the generation of that electricity in their scope 2 inventory as well.

A company that only owns and operates power generation facilities, such as an IPP, typically does not have any scope 2 emissions associated with T&D losses, but they may have other scope 2 emissions associated with any electricity or other forms of energy they purchase from a third party to operate their buildings and facilities. These entities account for all emissions from their own generation as scope 1, as they do not own or operate any transmission or distribution lines. Any T&D losses associated with electricity purchased by these entities would be categorized as scope 3 emissions.

Emissions accounting for T&D line losses is also relevant to emissions accounting associated with wholesale power transactions. **Table A-4** describes the scope categorization for emissions from T&D line losses associated with electricity purchased through wholesale power transactions.

Table A-4 T&D-related GHG Emissions Accounting by Role of Reporting Company for Wholesale Power Market Transactions

Reporting Entity Role	Emissions from Generation	Emissions from T&D loss
5. Company generates and sells wholesale electricity only	Scope 1	Scope 3
6. Company purchases wholesale electricity but does not consume it (does not own/operate T&D assets)	Scope 3	Scope 3
7. Company purchases wholesale electricity but does not consume it (owns/operates T&D assets)	Scope 3	Scope 2
8. Entity using the electricity	Scope 2	Scope 3

Electric companies may account for T&D losses associated with wholesale power purchases within scope 2 or scope 3, depending on the specifics of the transactions, but in all cases, they should seek to not double count the emissions.

For power companies that both generate power and are responsible for providing energy to meet load, T&D lines losses do not have indirect emissions associated with them, as the emissions from the upstream generation of electricity are part of the company's reported scope 1 direct emissions. However, for an end-use customer, the indirect GHG emissions associated with these "line losses" count as a scope 3 emissions source, while the indirect emissions associated with generating the power they purchase is considered scope 2.

In the case of a power generator who purchases electricity from an external third party to power its own operations (i.e., the power generator is acting as an end-user), the total amount of scope 2 emissions associated with these purchases is equal to the emissions associated with the power purchased and consumed by the company. The emissions associated with any "upstream" T&D line losses would be considered scope 3 emissions for the power company that bought and used the power.

If the same power generator transmits or distributes the purchased power to end-users rather than consuming the power in their own operations, they would not report scope 2 emissions associated with T&D line losses. In this case, the company would report the GHG emissions associated with the purchased power for resale as scope 3. The indirect emissions from T&D line losses that occur after the power has been purchased (i.e., through T&D to the end-user) are already accounted for within the total quantity of power purchased for end-users. In this case, the primary purpose of the power purchase is delivery for end-user consumption. The indirect emissions associated with delivery of purchased power for end-use consumption are typically labeled as scope 3 indirect.

How would an electric company account for the GHG emissions associated with wholesale electricity it purchases and "wheels" (i.e., resells and transports) across its T&D infrastructure without consuming it?

In these situations, the key distinctions to be made are (i) who generates the electricity that is sent through the T&D lines; (ii) who owns the T&D lines, and (iii) the difference between "wheeling" wholesale electricity to another electric company and retail power delivery to an end-use-customer.

First, an electric company needs to distinguish between the GHG emissions associated with the **generation** of the wheeled power – within scope 3 – and the **transmission losses** associated with that wheeled power – within scope 2.

For companies that purchase wholesale electricity which they do not consume and transport it across T&D lines that they own or operate, the indirect emissions associated with T&D losses are reported as scope 2 or scope 3 depending on whether the purchased power is being "wheeled" to another entity or distributed to an end-use-customer, as described below.

If an electric company purchases wholesale power to deliver to an end-use-customer (at retail), then the primary purpose of the power purchase is delivery for consumption. The indirect emissions associated with delivery for consumption power transactions are typically labeled as scope 3 indirect.

This case is distinguished from "wheeling" wholesale power in which the transaction's primary purpose is for the wheeling electric company to provide a transmission service for a separate load serving entity. Accounting for the indirect emissions associated with losses that occur in the process of wheeling wholesale power within scope 2 is valuable as it distinguishes an emissions source that the wheeling electric company has a greater ability to impact (e.g., through improvements to the T&D system).

Using this approach, the estimation of scope 3 emissions associated with wholesale power purchases should be calculated based on the amount of power that will not double count indirect emissions reported as scope 2 (e.g., for wheeled power, scope 3 should be calculated based on the amount of power delivered to the node of a separate load serving entity).

Another way to properly account for these emissions would be for an electric company to report all the indirect emissions (scope 2 and 3) associated with electric power it purchases wholesale based upon the amount of power that is **delivered to all customers**, including both end-use customers and other electric companies. Using this approach, the GHG emissions associated with the quantity of power delivered would be accounted for as **Scope 3 emissions**. Then, the T&D line losses associated with indirect emissions would be counted as **scope 2 emissions**. This approach avoids any double counting. Note that the scope 3 portion is based on the amount of power "delivered," not the gross amount purchased in the wholesale market.

A last approach to properly account for these emissions would be to report all the indirect emissions associated with purchased wholesale power as **scope 3.** Then, separately calculate the T&D line losses that occur across the reporting company's T&D system as **scope 2**. Using this approach, the company would be accepting and acknowledging that some double counting is occurring between its scope 2 and 3 for T&D losses from purchased wholesale power. The only case in which there would be no double counting using this approach is if the power being wheeled is being bought and resold at the same "node" in the power system.

For companies that purchase wholesale electricity without consuming it directly[64] and that flows through T&D lines that they do not own or operate, the emissions associated with T&D losses are reported as scope 3 emissions.

How are T&D line loss factors calculated?

There are two methods for calculating line loss factors:

- ***Energy Balance Method.*** This method involves energy balance analysis, which calculates total energy flow into and out of the T&D system(s), then pairs those energy flows with fuel-specific emissions factors (for each fuel used to generate power flowing through the system), and determines a system-specific loss factor based upon these results.
- ***Aggregate Power Flow Method*.** This method simplifies the approach by applying default loss and emission factors.

To implement the Energy Balance Method and completely account for all power flows, a company would need to establish T&D system boundaries that extend from the "Point of Receipt" to the "Point of Delivery" for all company electricity transactions. The energy balance analysis should evaluate all power flows through the system (see TCR Electric Power Guidance v1.0 section 14.2.1 for identified power flows). The system average loss factor (**Equation A-1**) equals the losses divided by the total energy flow into the system, expressed as a percentage.[65]

Equation A-1 T&D System Loss Factor

$$\textbf{T\&D System Loss Factor [\%]} = (\textbf{Total Power Flows onto System [MWh]} - \textbf{Total Power Flows out of System [MWh]}) / \textbf{Total Power Flows onto System [MWh]}$$

Less analytically intensive options allow companies to model the loss factor using estimated losses from measured flow data or modeling calculations provided by a Balancing Authority. Companies in the United States also can use default average loss factors provided by the U.S. EPA's eGRID database[66] for six regions in the U.S. or other average loss factors that may be available from other sources.

How are line losses incorporated into grid-based emission factors?

Grid-based emission factors, such as those found in the U.S. EPA eGRID database, do not include line losses. These emission factors are associated with emissions from the generation of electricity and are calculated prior to line losses.

[64] In these situations, companies are generally purchasing wholesale electricity from electric power markets and reselling it to end-use customers.

[65] Source: Equation 14a, TCR Electric Power Sector Guidance v1.0, 2009.

[66] https://www.epa.gov/egrid/emissions-generation-resource-integrated-database-egrid

Scope 3 Emissions

What are some examples of sources for emission factors for upstream fuel purchases?

Emission factors (EFs) for upstream and downstream scope 3 emissions are no different than EFs used for emission sources that are within scope 1 or 2. The only difference is that the activity data to which these EFs are applied come from entities that are, accordingly, upstream or downstream from the reporting company.

Alternatively, companies can base emission estimates for scope 3 on established life-cycle assessment databases, which include a library of default EFs, especially for common purchased commodities (e.g., steel or concrete). You can find a listing of such databases here:

- https://ghgprotocol.org/life-cycle-databases
- https://lca-net.com/services-and-solutions/input-output-databases-life-cycle-assessment/

Electric companies that generate electricity purchase fuel, such as coal and natural gas, to generate electricity. Emissions associated with the mining and extraction of the fuels used to generate electricity are considered upstream scope 3 emissions for electricity generators.

What categories of scope 3 emissions do the upstream process emissions associated with the purchase of coal and natural gas fall under?

Process emissions refer to emissions from physical or chemical processes such as CO_2 from the calcination step in cement manufacturing, CO_2 from catalytic cracking in petrochemical processing, or perfluorocarbon (PFC) emissions from aluminum smelting.[67] The production and extraction of fossil fuels may generate process emissions through, among other activities, process vents, equipment vents, and maintenance/turnaround activities, which would be considered scope 1 for the company producing or extracting the fuels and scope 3 for the company purchasing the fuel for use in their own operations, such as the generation of electricity.

Depending on the source of these emissions, they could be identified as one of the following scope 3 categories: purchased goods and services, capital goods, fuel and energy-related activities, or upstream transportation and distribution.

Should the emissions associated with the provision of end-use electricity from non-regulated retail service providers be included in a scope 3 emissions inventory?

Yes. Provided that the electricity is not generated by company owned or operated power generating units (in which case it would be counted within scope 1), and that the electric company is responsible for transmitting and/or distributing the electricity to the end-user, then the associated emissions should be considered scope 3.

Why are the emissions associated with the purchase of wholesale power for resale to end-use customers categorized as scope 3 (including treatment of line losses)?

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[67] See the GHG Protocol Corporate Standard for more information: https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf

The emissions associated with the purchase of wholesale electricity that is resold to end-use customers is considered scope 3 for the entity that purchased and resold the electricity to the end-use customer and scope 2 for the end-use customer that is consuming the electricity.

Line losses associated with the transportation of the purchased power across the T&D system are also considered scope 3 to the electric company as long as they do not own and/or operate the T&D infrastructure. If they do own and/or operate this infrastructure (and did not generate the power being transmitted, i.e., a "wires-only" company), the emissions associated with the line loss would be considered scope 2 for that company.

Emission Factors for Greenhouse Gas Emissions Accounting

What emission factor should a company apply to renewable power generation when the REC is unbundled and sold separately from the generation? How does this affect the company's GHG emissions accounting?

Accounting of electricity generated by an electric company (MWh) and the emissions (tCO_2eq) produced by sources owned by the electric company should be undertaken separately. Renewable energy certificates (RECs) originally were designed as regulatory compliance tracking instruments and were not intended to be used as emissions accounting instruments. The inclusion of renewable resources in an electric company's generation portfolio does not by itself guarantee a decrease in an electric company's scope 1 emissions or the emissions rate for that company.

Furthermore, when a REC is "unbundled" from the renewable generation and sold separately, the purchaser does not receive a physical flow of electricity from the seller. These transactions are not an appropriate proxy for the actual physical flow of electric power between producers and consumers. In other words, the emission rate of the generation does not transfer to the energy purchaser with the REC transaction *if* the transaction does not also include the delivery of electricity.[68] In this case, it would be prudent to apply a grid average emission factor to account for the electricity consumed. Additionally, to prevent double counting of the renewable energy, as a portion of the grid-average and claimed by an entity purchasing the unbundled REC, the grid average emissions factor must exclude all renewable sources for which RECs have been sold to make an emissions claim.

However, if a company is doing load-based accounting, it would account for its emissions on the basis of the energy it consumes and not the energy associated with the RECs. The "net short" load-based accounting approach allows a company to fully account for the benefits of the renewable generation it owns or contracts for through a PPA. For more information, please see EPRI report, *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases*[69].

[68] In California, any renewable energy delivered to the grid is counted as zero emissions, reflecting the physical reality of the power flow based on a contract for delivery. The zero emission attribute goes with the electricity, not the REC.

[69] https://www.epri.com/research/products/000000003002015044

How often are marginal emission factors updated and who updates them?

We are not aware of a readily available source for marginal GHG emission factors. Typically, these are developed based on analysis of the specific power system involved or developed through power system modeling with production cost or capacity expansion modeling tools.

It is important to understand that marginal EFs are constantly changing in reality as the generation mix of the "grid" changes constantly on an incremental basis as the power plant dispatch to the grid changes to always ensure that power supply equals load.

Load-Based Emissions Accounting for Wholesale Power Purchases

What is the relationship between emissions scopes developed as a part of corporate GHG accounting protocols and load-based accounting methods?

Emissions scopes were developed to facilitate source-based accounting approaches and are used to classify direct and indirect types of GHG emissions. Source-based accounting methods account for emissions at the source of their release and attempt to answer the question, "*How much GHG emissions are released by activities over which the reporting entity has direct control or indirectly through activities that are essential to company operations, but not directly controlled by the company?*" Virtually all mandatory regulatory pollution reporting programs in the US and internationally, including GHG reporting where it is mandatory, is done using source-based accounting. Source-based accounting can be applied to any entity or sector that wishes to inventory GHG emissions.

Load-based accounting approaches, by contrast, are only applicable to the electric sector. These methods were developed to help account for emissions associated with purchased power used to serve retail load and to resolve difficulties with accurately attributing the source of the electrons drawn from the grid. These approaches adopt a different perspective and are aimed at answering the question, "*How much GHG emissions are embedded in the electric power an electric company delivers to its end-use customers?"* The value derived from load-based accounting could be used by a company to set an emissions reduction target[70] and can be used to develop an emissions factor (EF) to provide to the company's end-use customers to use it to report their own scope 2 indirect emissions associated with their use of electricity delivered by the company.

Separating emissions totals from load-based accounting methods into the scopes developed for source-based accounting methods is not a straightforward task. This is because it is impossible to determine the source of the electricity drawn from the grid to serve end-use customers. Companies that operate in wholesale power markets and both generate and purchase wholesale power invariably deliver electricity to their customers that includes a mix of "scope 1" (self-generated) and "scope 3" (power generated by other market participants purchased by the reporting entity) emissions sources.

For companies operating in wholesale power markets, in particular, the use of a source-based or load-based accounting approach may yield different emissions totals.

[70] Some electric companies have tied emissions reduction targets to their direct sources of emissions (usually electricity generation), while others have tied their targets to reductions in emissions associated with electricity delivered to their end-use customers. The former relies on a source-based accounting approach, while the latter employs a load-based accounting approach.

How is "dispatchability" defined within a load-based accounting approach? How does this differ from other uses of dispatchability within the electric power sector?

Under the "net short" load-based accounting approach, "dispatchable" resources are those resources operating in a wholesale power market that can ramp up and down quickly and typically have lower marginal costs, such as natural gas turbines and other peaking units. These units can more easily control their generation output and are typically used by power system operators to balance supply and demand on the grid in real time. In contrast, generation resources that cannot easily control their output (i.e., renewables) and "baseload" generation (e.g., nuclear, coal, and hydro[71]) that typically run at a constant output are considered to be "non-dispatchable" resources when using this accounting method.

This distinction differs from the more traditional meaning of term "dispatchable" generation, which refers to sources of electricity that can be easily turned on or off by power grid operators and effectively used for load following purposes.

How would an electric company account for the GHG emissions embedded in the wholesale power purchased on the western Energy Imbalance Market (EIM)?

This question applies to entities that purchase from the EIM but operate inside California and those who purchase power and operate outside of California. CAISO provides data and emission factors associated with the entire EIM footprint and more specific emission factors for EIM deliveries sold to California[72].

Also, there are several methods an electric company could use to account for emissions embedded in wholesale power purchases that are used to serve the company's retail customers. For a detailed description of these methods, please see the EPRI report, *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases (3002015044).*

Natural Gas Operations

How do natural gas companies account for the GHG emissions associated with providing natural gas to end-use customers or for transporting natural gas through pipeline systems that they own and operate? How does the company account for emissions if they own the pipeline, but not the natural gas flowing through it?

Companies that distribute natural gas to end-use customers for space or water heating and cooking in residential homes account for the emissions associated with the burning of that natural gas as scope 3 emissions – within the product use category. These same GHG emissions would be counted as scope 1

[71] Although hydropower often is considered to be a dispatchable power generation technology, in this context we consider it to be "non-dispatchable," as hydro dispatchability often is limited due to environmental constraints.

[72] GHG emissions from unspecified imports, including EIM transfers serving CAISO load, are based on the unspecified emission rate established by CARB of 0.428 $mtCO_2/MWh$. For dispatches of CAISO internal resources, the resource-specific CO_2 emission rate was used. For more information, see the CAISO Greenhouse Gas Emission Tracking Methodology Report or the CEC Power Source Disclosure Resources for Retail Suppliers.

by the end-use customer. **Table A-5** shows GHG emissions accounting for sale and delivery of natural gas to end-use customer by reporting entity.

Fugitive methane (CH_4) emissions associated with leakage from the company's natural gas pipeline system are reported as scope 1 emissions for the company that owns the pipeline distribution system. Although these losses appear analogous to T&D line losses reported as scope 2 emissions, they are not because company-owned assets (e.g., pipelines) in this case are directly emitting CH_4 into the atmosphere.

If the company only transports natural gas through its pipeline system but does not own the natural gas that is being sold to end-use customers, it still reports the fugitive methane emissions[73] associated with transmission of the natural gas through its pipeline system as scope 1. In this case, though, the emissions associated with the final combustion of the natural gas fuel would be scope 3 for the company that contracts with the owner of the pipeline to transport its natural gas to the end-use customer, and also may be reported as scope 3 by the company that physically distributes the gas through its pipeline system. In this case, both the owner of the natural gas and the pipeline owner could report these scope 3 emissions. By its very nature, scope 3 allows for double counting of emissions across various entities across a given value chain.

The original owner / seller of the gas to the end-use customer (who contracted with the pipeline owner for transport) would report scope 3 emissions associated with the final transport and combustion of the gas.

Table A-5 Emissions accounting for sale and delivery of natural gas to end-use customer by reporting entity

Reporting Entity Role	Emissions from burning of natural gas for end-use energy[74]	Methane emissions from pipeline transport of natural gas
Company owns and sells natural gas to end-use customer, but does not own the pipeline system through which the gas is transported	Scope 3	Scope 3
Company owns and sells natural gas to end-use customer and owns the pipeline system through which the gas is transported	Scope 3	Scope 1
Company only owns the pipeline system through which the gas is transported and does not own the gas being transported	N/A[75]	Scope 1

[73] These fugitive methane emissions would be reported as scope 2 for the end-use customer that purchases the natural gas and causes them to occur indirectly through transport.

[74] In this case, the emissions associated with burning the natural gas are considered direct for whomever directly combusts the natural gas for energy use. In the case of residential natural gas furnaces, for example, the emissions associated with burning the natural gas for space heating are considered scope 1 for the homeowner because he or she combusts the fuel directly in his or her home.

[75] These emissions would be reported as scope 3 for the company that owns and sells the gas to the end-use customer.

Emissions offsets and energy efficiency initiatives

If a company incentivizes the use of efficiency products such as compact fluorescent lights (CFLs), how would this show up in an electric company's scope 3 emissions accounting?

Emissions associated with electricity consumed by an electric company's end-use customers are considered scope 3 for the electric company if the company did not generate the power delivered to these customers, but rather purchased it and resold it to the customer. If the reporting company did generate the electric power and delivered it directly to the customer through transmission and distribution assets that it owns and operates, the GHG emissions would be accounted for in the company's scope 1 inventory.

More efficient electric technologies such as CFLs reduce an end-use customer's electricity consumption compared to less efficient technologies used for the same purpose. If a customer uses less electricity overall as a result of using a device with greater efficiency, this could in theory reduce the GHG emissions associated with serving load by reducing the overall amount of electricity used to serve end-use customers.

Companies should use *consequential* emissions accounting methods (also called causational or project-level accounting) to demonstrate the impact of a particular program or policy aimed at reducing emissions, such as deploying energy efficiency devices to end-use customers. These methods attempt to estimate the change in GHG emissions caused by a specific emissions mitigation intervention and require the company to develop projections of both the baseline emissions that would have occurred absent the intervention and the reduced emissions relative to the baseline produced by the intervention. These methods differ from the attributional or absolute accounting methods discussed in detail in this supplemental project.

What emission factors can be used to verify emission reductions attributable to a utility-sponsored energy efficiency program?

Verification of emission reductions associated with a particular intervention, including an energy efficiency program, fall under the realm of *consequential / causational* emissions accounting (see above). Marginal emission factors, which represent the emission rate of the marginal electricity generation resource at a given time, are appropriate to use in these situations. Marginal emission factors are not appropriate for use in attributional GHG emissions accounting (e.g., the preparation of corporate GHG inventories).

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