Overview of Greenhouse Gas Emissions Accounting for Electric Power Companies

This Program 201 back-pocket-insight (BPI) describes the basic elements of voluntary corporate greenhouse gas (GHG) emissions accounting as it applies to electric companies operating in the United States. It is based on 2021 research completed by P201.[1]

What is a Corporate GHG Inventory?

A GHG inventory is an assessment of the GHG emissions and removals attributed to a company's operations over the course of a year. Several standards and guidelines exist today that provide guidance to electric companies on doing credible GHG accounting.[2, 3]

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*[4] accounting framework. This approach is attributional, as it attributes *direct* or *indirect* GHG emissions to particular activities*.* It includes emissions from the three GHG emissions "scopes" described below.

Organizational Boundaries

First, a company must determine the *organizational boundaries* to use for its GHG inventory. In general, these boundaries are defined along two dimensions: (i) the set of relevant *emissions-generating activities*, 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).

Types of Greenhouse Gases

Typically, GHG inventories include accounting for several different GHGs to the extent they are associated with relevant emitting activities. These GHGs include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and nitrogen trifluoride (NF_3). Other more unusual GHGs also may be included in some inventories.

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

Direct and Indirect Emissions

Corporate activities may cause *direct* and *indirect* GHG emissions. Different emissions *scopes* are used to classify direct and indirect GHG emissions.

Direct emissions, referred to as "*scope 1,*" result from company activities that physically release (or remove) GHGs to the atmosphere, such as burning natural gas to generate electric power and fugitive SF_6 emissions from transformers.

Indirect emissions can be either *scope 2* or *scope 3* and result from other indirect activities that are essential to a company's operations (e.g., fuel extraction and fuel transport to a power generation facility).

Scope 2 emissions refer to indirect emissions associated with electricity or heat purchased by an entity for its own use. For example, a large component of many electricity customers' total GHG emissions are scope 2 emissions associated with their consumption of electricity to operate their businesses.

For transmission and distribution "wires-only" electric companies that do not also generate electric power, scope 2 includes the emissions associated with transmission system "line losses" from transmitting electricity from generators to load-serving entities (LSEs). This specific type of scope 2 emissions is unique to these types of electric companies.

A complete entity-level GHG inventory typically includes all scope 1 emissions and, depending on the reporting purposes and the accounting protocol being used, some or all scope 2 emission sources. Typically, scope 3 emissions are considered optional for entity-level reporting, but increasingly stakeholders and others are requesting this information.

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 as scope 2 emissions. However, the electric company generating the power would classify the emissions as scope 1. In this way, scope categorization helps prevent double counting of emissions within scope 1 and 2 (but not scope 3).

---

1 *Greenhouse Gas Emissions Accounting for Electric Companies: A Compendium of Technical Briefing Papers and Frequently Asked Questions*. EPRI, Palo Alto, CA: 2021. 3002022366.

2 See WRI/WBSCD Revised Corporate Standard (2004), WRI/WBSCD GHG Protocol Scope 2 Guidance (2015),and WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).

3 See The Climate Registry (TCR) General Reporting Protocol (GRP) v3 (2019) and TCR Electric Power Sector Protocol (2009).

4 Entity-level accounting frameworks provide standardized methods to estimate GHG emissions for an entire entity or organization.

5 By definition, CO_2 has a GWP equal to 1. 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 GHGs into universal units called "carbon dioxide equivalents (CO_2e)." For example, 1 metric ton ("tonne") of N_2O emissions has an equivalent warming effect of ~300 tonnes of CO_2e.

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 a GHG source.

For example, for an LSE that also generates electric power, scope 1 emissions would come from fuels combusted at its electricity generating facilities. This LSE's scope 1 emissions also include those indirect emissions associated with the transmission system line losses associated with moving the power from the generator to end-use customers. If this LSE was not also a power generator, these emissions would be accounted for separately as Scope 2 transmission line losses. An electric company's scope 3 emissions can vary widely and may include emissions associated with wholesale electric power purchased for resale to customers, upstream and downstream emissions associated with fuel production and extraction, employee travel, waste and many other categories.

Calculating Emissions

Each GHG source included in a GHG inventory should be estimated using accurate and credible methods. 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). 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.).

Determining an appropriate EF to use to estimate an entity's scope 2 emissions associated with purchased electricity for internal consumption is complex and will be discussed in a future P201 BPI. Often companies report these emissions based on average annual regional grid EFs 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 make it impossible to accurately reflect the ongoing rapid change in the composition of the power generation fleet; and (ii) they do not accurately reflect actual emissions at the time or location the emissions occurred and so may under or over-estimate actual emissions.

Reporting GHG Emissions

GHG reporting requirements vary depending on a reporting program's and reporting entity's particular needs. Despite this, there are "good practices" to consider when reporting GHG emissions inventories, including:

- Providing a description of the system boundaries, including how the organizational boundaries were determined and which GHG emitting activities and sources/sinks are included.
- Explaining why any sources/sinks, facilities, or operations may have been excluded from the inventory.
- Transparently reporting information on GHG emissions, by separately reporting sources, gases, and scopes, using metric tons as the unit of measure, and converting all GHGs to tonnes CO_2e using appropriate GWPs.
- Also, it is important to document methods and data sources that may have changed over time, and any updates and changes relative to previous inventories.

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. Some good practices 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 is a systematic, independent, and documented process for evaluating a GHG inventory report or providing attestation against agreed verification criteria. The purpose of verification is to create trust in the data by receiving an opinion from an independent and competent 3rd party. The decision to verify a GHG inventory often is optional, particularly for a voluntary reporting program, but is good practice and is becoming more common.

Project Contacts

Adam Diamant (adiamant@epri.com; 650-855-2077)
Laura Fischer, (lfischer@epri.com; 202-495-8144)

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com