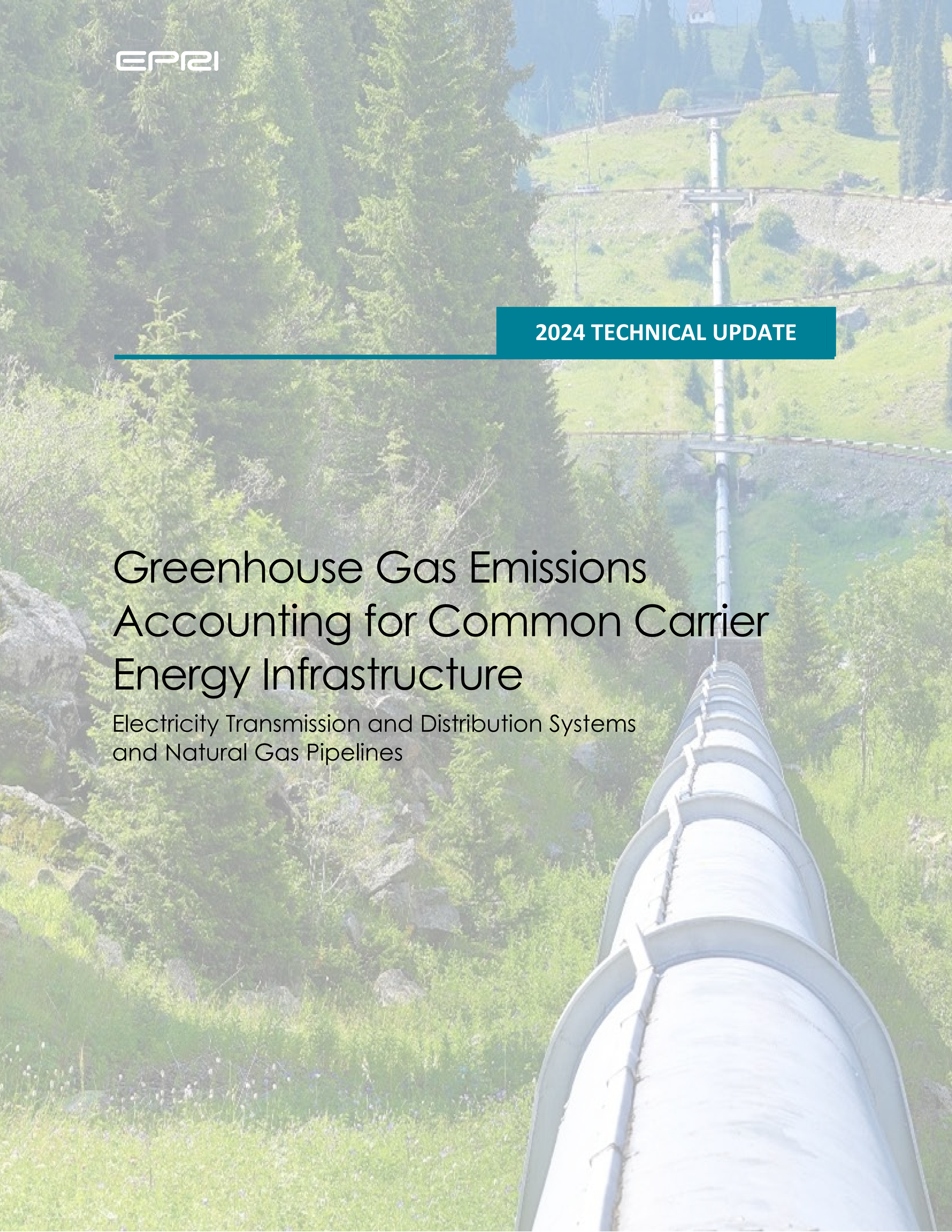

2024 TECHNICAL UPDATE

Greenhouse Gas Emissions Accounting for Common Carrier Energy Infrastructure

Electricity Transmission and Distribution Systems and Natural Gas Pipelines

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Electricity Transmission and Distribution Systems
and Natural Gas Pipelines

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ABSTRACT

Electric companies and combined electric and natural gas utilities emit greenhouse gases (GHG) from a wide range of activities. A myriad of voluntary and mandatory GHG accounting frameworks exist in the United States and internationally that a company may use to account for and report their GHG emissions. These frameworks use different GHG accounting methods, estimation techniques, and reporting guidelines and are often ambiguous. The major existing GHG accounting frameworks and guidance are intentionally generic and non-sector-specific, resulting in technical gaps for specific economic sectors. One of the areas lacking technical guidance in the energy sector relates to accounting for GHG emissions associated with "common carrier" energy infrastructure, such as natural gas pipeline and electric system transmission and distribution infrastructure.

This EPRI technical update report summarizes existing GHG accounting guidance from the perspective of entities that own common carrier energy infrastructure, both for voluntary and mandatory GHG accounting and reporting purposes. The report provides an overview of GHG accounting, emission sources associated with common carrier energy infrastructure, the setting of emissions reporting boundaries, and explores the different interpretations of existing voluntary GHG emissions accounting guidance relevant to reporting GHG emissions from common carrier natural gas and electricity infrastructure.

Keywords

Greenhouse gas emissions
Greenhouse gas accounting
Scope 2 emissions
Scope 3 emissions
Transmission line losses
Common carrier

GLOSSARY

CO_2	Carbon dioxide
EIA	United States Energy Information Administration
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas. Typically, GHG refers to the collection of all seven types of GHGs covered by the United National Framework Convention on Climate Change (UNFCCC/Kyoto Protocol) and include: carbon dioxide (CO_2), methane CH_4), nitrous oxides (N_2O), sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), perfluorocarbons (PFCs) and hydrofluorocarbons (HFCs).
GHGRP	GHG emissions reporting program operated by the U.S. EPA (see 40 CFR Part 98)
LCA	Life-cycle analysis and life-cycle assessment
LSE	Load-serving entity
MCF	Thousand cubic feet
MMBtu	Million British thermal units
Scope 1	Direct GHG emissions resulting from a company's owned or controlled equipment, facilities, or operational activities that emit (or remove) GHGs.
Scope 2	Scope 2 accounts for indirect GHG emissions from purchased electricity, steam, heating, and cooling that are generated by another entity and consumed by the reporting company. Also, generally includes emissions from electric company T&D system "line losses."
Scope 3	Scope 3 emissions are all other indirect GHG emissions not included in scope 2
SEC	United States Security Exchange Commission
SF_6	Sulfur Hexafluoride
T&D	Electric transmission and distribution systems
UNFCCC	United Nations Framework Convention on Climate Change
Wheeling	Electricity that passes from one system to another over transmission facilities of an intervening system without being purchased or sold (owned) by the transmission entity.
WRI	World Resources Institute

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1 INTRODUCTION

Electric companies and combined electric and natural gas utilities, and their value chain partners, emit greenhouse gases[1] (GHG) from a wide range of activities. Many of these companies' facilities are subject to mandatory facility-level GHG emission and fuel statistics reporting, and companies may also elect to voluntarily account for and report their corporate-wide GHG emissions.

A myriad of voluntary and mandatory GHG accounting frameworks exist in the United States and internationally that a company may use to estimate and report their GHG emissions. These frameworks utilize different GHG accounting methods, estimation techniques, and reporting guidelines and are often ambiguous. One key challenge for companies trying to implement existing GHG accounting guidance is the existing flexibility related to defining emissions inventory accounting boundaries, which results in inventory reports across companies that are not temporally consistent or comparable across companies.[2]

In the United States, the potential expansion of corporate GHG reporting into the regulatory landscape (e.g., U.S. Security and Exchange Commission (SEC) Climate Disclosure Rule[3], California SB-253[4]) is increasing pressure on regulators and voluntary standards organizations to condense existing accounting and reporting guidance, and increasing pressure on reporting companies to build technically defensible emission inventories by properly applying applicable reporting guidance.

The major existing GHG accounting frameworks and guidance are designed to be intentionally generic and non-sector-specific, resulting in technical gaps for specific economic sectors. One of the areas lacking technical guidance in the energy sector relates to proper accounting and reporting of GHG emissions associated with "common carrier" infrastructure.

The term "common carrier" in this report refers to a company that owns transportation or transmission infrastructure, such as natural gas pipelines and electricity transmission and distribution (T&D) systems but does not own the natural gas or the electricity moving through their infrastructure.

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[1] The term "greenhouse gas" refers to the collection of all seven types of GHGs covered by the United National Framework Convention on Climate Change (NFCCC/Kyoto Protocol) and include carbon dioxide (CO_2), methane CH_4), nitrous oxides (N_2O), sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), perfluorocarbons (PFCs) and hydrofluorocarbons (HFCs).

[2] "Comparability" is an environmental reporting principle that is not included within GHG Protocol for corporate emission and removal inventories.

[3] The Enhancement and Standardization of Climate-Related Disclosures for Investors, Final Rule is available here: https://www.sec.gov/rules/2022/03/enhancement-and-standardization-climate-related-disclosures-investors#33-11275.

[4] Senate Bill 253: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB253.

The reporting of GHG emissions from the common carrier perspective has not been adequately addressed by existing voluntary guidance, leading to conflicting interpretations and a lack of comparability in GHG inventories across common carrier companies and entities that include common carrier subsidiaries. For example, several electric companies have expressed confusion about how to properly categorize and account for the indirect emissions associated with electric T&D system line losses.

As part of the research conducted for this report, the EPRI project team interviewed several staff members of electric and natural gas companies. Staff members that either work for, or have experience in, the electricity T&D systems in the Electric Reliability Council of Texas (ERCOT) region shared their interpretation and perspective that companies do not need to account for indirect GHG emissions from T&D line losses in their scope 2 emissions. The rationale provided for this view was based on ERCOT's requirement that power generators operating in the region "gross up" the amount of power they generate and sell in the region to make up for any T&D line losses. Based on their interpretation, this requirement accounts for the expected GHG emissions associated with T&D line losses and so does not obligate their companies to account for these emissions. Beyond ERCOT, other electric power companies have expressed the perspective that GHG emissions associated with T&D line losses should be accounted for as indirect scope 3 emissions rather than scope 2 emissions.

This EPRI technical update report summarizes existing GHG accounting guidance relevant to entities that own common carrier infrastructure, both for voluntary and mandatory GHG accounting and reporting purposes. Furthermore, this report explores the different interpretations of existing voluntary GHG accounting guidance to inform electric and combined utility companies' reporting practices to increase transparency and allow for a more streamlined approach when reporting to multiple programs.

Section two of this report provides an overview of GHG emissions accounting, including facility and entity-level GHG accounting, and accounting for direct scope 1 and indirect scopes 2 and 3 emissions.

Section three explores setting GHG reporting boundaries for voluntary corporate GHG reporting and mandatory reporting required by U.S. federal agencies relevant to common carrier energy infrastructure.

Section four identifies and describes important GHG emissions sources associated with electricity transmission and distribution systems and natural gas common carrier pipelines.

Section five explores several different options that may be used by electric companies and combined utilities to account for and report GHG emissions associated with common carrier infrastructure using the GHG Protocol.

Section six highlights other existing GHG accounting and reporting guidance applicable to electricity T&D system and natural gas pipeline common carriers.

Section seven provides key insights based on the information presented in this report.

2 BASICS OF GREENHOUSE GAS ACCOUNTING

A GHG emissions inventory is a quantification report representing the GHG emissions from sources, and removals by sinks, which are allocated (e.g., self-assigned) to a company. An emissions inventory includes GHGs from sources and sinks within an entity's accounting boundaries. These boundaries are further classified as including direct and indirect emissions, which are commonly referred to as "scopes" under the GHG Protocol (see Entity-Level Accounting section below). Existing voluntary and mandatory reporting standards guide the accounting and reporting of GHG emissions at both the entity- and facility-level. Determining emission sources to be accounted for and reported in a GHG emissions inventory depends on the reporting boundary established by the GHG accounting framework that is used. Table 1 lists common GHG accounting frameworks[5] and associated reporting boundaries.

Table 1. Common GHG emissions accounting frameworks

Accounting Framework	Activity Boundary	Emissions Reporting Boundary
Facility-level (or source-level) (e.g., electricity generators)	Individual site, facility, emission source	Direct emissions (may also include indirect)
Entity-level (e.g., corporations)	Organizational boundary (e.g., corporation)	Direct and indirect emissions
Jurisdictional (e.g., states, cities)	Geographic boundary	Direct emissions (may include indirect)[6]

The following section breaks down two types of GHG accounting commonly applicable to electric and combined utilities: facility-level and entity-level accounting.

Facility-Level Accounting

Facility-level GHG accounting (also referred to as source-based accounting or "point source" and "point of emissions") quantifies the direct emissions occurring at a specific facility, such as an electric generating unit (EGU). This is considered an allocational approach where direct emissions are allocated (i.e., responsibility is assigned) to the facility and/or sources in a facility. In the case of electric companies, for example, it can refer to a generating unit. The reporting boundaries for this type of accounting are defined by the physical footprint of an EGU, power plant, factory, warehouse, or pipeline. This type of accounting framework is most commonly used for regulatory purposes, which may include legal compliance in the form of performance standards or obligations under an emissions trading system, such as the mandatory California CO_2 emissions cap-and-trade program.

[5] Additional accounting frameworks include project-level, policy-level, and sectoral-level accounting.

[6] For example, the GHG Protocol's Global Protocol for Community-Scale Greenhouse Gas Inventories provide guidance for indirect emissions for limited sources on a sector-based approach for city-level GHG accounting.

In the United States, the U.S. Environmental Protection Agency (EPA) administers the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98) and mandates the reporting of GHG-related data from sources that emit above a specified emissions threshold. The GHGRP prescribes detailed methodologies that must be used to quantify and report GHG emissions from each source category on an annual basis. Under the GHGRP, electric companies and combined utilities are subject to various mandatory reporting, which can include:

- Subpart C[7]: General Stationary Fuel Combustion Sources
- Subpart D: Electricity Generation
- Subpart W: Petroleum and Natural Gas Systems
- Subpart DD: Electrical Transmission and Distribution Equipment Use
- Subpart LL: Suppliers of Coal-based Liquid Fuels
- Subpart MM: Suppliers of Petroleum Products
- Subpart NN: Suppliers of Natural Gas and Natural Gas Liquids

Though the GHGRP basically uses a source-based accounting framework, regulated fuel suppliers also are required to report specified (potential) indirect emissions. These entities (e.g., natural gas suppliers) must report GHG emissions that would result from the complete combustion or oxidation of supplied fuels. Hence, suppliers report estimated emissions occurring downstream and outside of their physical facility boundaries (i.e., indirect downstream emissions) through subpart MM and NN.

Entity-Level Accounting

Entity-level GHG accounting quantifies the emissions from an entity's activities. An entity can be a corporation, municipality, or other organization. In the case of an electric company, for example, it refers to all facilities and operations owned or controlled by the company.

Corporate Accounting

In 2001, the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) released the GHG Protocol Corporate Standard (revised in 2004), henceforth referred to as the 'GHG Protocol' (GHGP), to guide entities on how to conduct GHG emissions accounting that includes organizational boundaries and applies an entity-level GHG accounting framework. This approach allocates direct and indirect GHG emissions from activities to entities. The GHG Protocol is ubiquitously referenced worldwide by organizations conducting corporate GHG inventories and serves as a basis for other corporate GHG disclosure programs.[8]

[7] Subpart to Title 40 Protection of Environment, Chapter 1 Environmental Protection Agency, Subchapter C Air Programs, Part 80 Regulation of Fuels and Fuel Additives.

[8] The Climate Registry's General Reporting Protocol and Carbon Footprint Registry are based on the GHG Protocol and provide additional guidance and requirements for public disclosure in their voluntary reporting program.

Direct and Indirect Emissions

The concept of *direct* and *indirect* emissions is based on a delineated corporate inventory boundary and was introduced by the GHG Protocol along with the concept of scopes. Direct emissions, referred to as scope 1 emissions, are emissions from sources that are owned or controlled by a reporting company. Indirect emissions[9] are emissions that occur at sources *not* owned or controlled by a reporting company yet responsibility for reporting emissions from them is still allocated to the reporting company. Indirect emissions can be either scope 2 or scope 3. Table 2 identifies and briefly describes these emissions accounting scopes.

Table 2. Corporate GHG emissions accounting[10] scopes and descriptions

Scope	Scope Description
Scope 1	Direct GHG emissions resulting from a company's owned or controlled equipment, facilities, or operational activities that emit (or remove) GHGs.
Scope 2	Scope 2 accounts for indirect GHG emissions from purchased or acquired electricity, steam, heating, and cooling that are generated by another entity and consumed by the reporting company. Also, generally includes emissions associated with electric company T&D system "line losses."
Scope 3	Scope 3 emissions are all other indirect GHG emissions not included in scope 2.

Scope 1 Direct Emissions

Direct emissions, referred to as scope 1, result from a company's owned or controlled equipment, facilities, or operational activities that emit (or remove) GHGs. For example, an electric utility's scope 1 emissions may include emissions associated with combusting natural gas in the turbines it owns to generate power, fugitive SF_6 emissions from company-owned switchgear and mobile emissions associated with company-owned vehicles.

A complete entity-level GHG inventory includes all scope 1 emissions and, depending on the reporting purposes and the accounting protocol being used, all relevant scope 2 emission sources. Scope 3 emissions currently are considered optional for voluntary reporting, but stakeholders increasingly are requesting information and data related to companies' scope 3 emissions. In addition, the federal Securities and Exchange Commission (SEC) recently published final regulations that will require publicly-listed companies to report "material" scope 1 and 2

[9] Indirect emissions for corporate inventorying are different from national GHG inventories. In national GHG inventories, as defined by the Intergovernmental Panel on Climate Change (IPCC) Guidelines, indirect emissions refer to releases of pollutants that later result in the release of GHGs to the atmosphere through biological or atmospheric chemical reactions.

[10] As defined by the GHG Protocol Corporate Standard (2004).

emissions.[11] The State of California also is working on implementing new statutory requirements to enhance public disclosure of corporate GHG emissions and "climate risk."[12]

Scope 2 Indirect Emissions from Purchased Electricity, Heat, Steam, and Cooling[13]

Scope 2 emissions account for emissions from the generation of electricity, heat, steam, and cooling that is purchased or acquired (i.e., brought into the organization boundary of the reporting company).[14] Within scope 2 emissions, there are two predominant categories relevant to electric companies and combined utilities: (i)) indirect emissions from electric power purchased or acquired and consumed; and (ii)) indirect emissions associated with electricity "consumption" associated with transmitting electricity across company-owned T&D systems. The Climate Registry's Electric Power Sector Protocol (2009)[15] (henceforth called the 'EPS Protocol') contains sector-specific reporting guidance which has contributed to a more consistent GHG accounting interpretation and reporting of these emissions categories by electric companies and combined utilities. The EPS Protocol also provides additional guidance to address other accounting issues specific to electric companies where the GHG Protocol lacks complete guidance.

Primarily, scope 2 accounts for indirect emissions from electricity, heat, steam, and cooling that are generated by another entity and consumed by the reporting company to power its buildings and equipment connected to the electric grid. These indirect emissions occur outside of the organizational boundary of the reporting company but inside the organizational boundary of the energy generator (i.e., they are directly emitted by a power plant owned or operated by another party). An electric company reporting these scope 2 emissions would account for the GHG emissions associated with the portion of power that they purchase (or acquire) from other entities and consume to power their buildings and related infrastructure. Most corporate entities, including electric and non-electric companies, will have this type of scope 2 emissions unless they supply 100% of the energy consumed in their operations from their own power generation sources and do not purchase any electricity, heat, steam, or cooling from other entities.

[11] The Enhancement and Standardization of Climate-Related Disclosures for Investors, Final Rule published 3/8/2024. See 17 CFR Parts 210-249.

[12] CA law SB-253 (GHG Acct) requires companies operating in CA with more than $1B in annual gross revenue to account and disclosure Scopes 1, 2 & 3 emissions from global operations. SB-261 (Carbon Disclosure) requires public and privately-owned California-based companies – with more than $500 million in annual gross revenues – to disclose climate-related financial risks.

[13] Much of the information presented in this section comes from *Greenhouse Gas Emissions Accounting for Electric Companies: A Compendium of Technical Briefing Papers and Frequently Asked Questions.* EPRI, Palo Alto, CA: 2021. 3002022366.

[14] Identifying Scope 2 Emissions and Setting the Scope 2 Boundary, Scope 2 Guidance, (GHG Protocol, 2016)

[15] https://theclimateregistry.org/registries-resources/protocols/.

The second type of scope 2 emissions is unique to electric companies that own and operate T&D systems. When electricity (MWh) is transmitted from generation facilities to grid-connected end users through T&D systems, a portion of the electrical energy generated is lost due to the resistance and other losses in wires and equipment, referred to as "T&D line losses." Within a GHG inventory, 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, in the United States, T&D line losses are between three and seven percent (3-7%) of the total amount of electrical energy transmitted and/or distributed across a power system.

Electric companies may account for emissions from T&D line losses associated with wholesale power purchases within scope 2 or scope 3, depending on the specifics of the transactions, with the goal of not double counting the emissions across scopes within a reporting company's GHG inventory.

For power companies that both generate power and are responsible for providing energy to meet end-use load, scope 2 emissions do not include T&D line losses because these indirect emissions typically are accounted for and reported within the company's scope 1 direct emissions. However, for an end-use customer, the indirect GHG emissions associated with these "line losses" are reported as a scope 3 emission source, while the indirect emissions associated with generating the power they purchase are considered scope 2. Transmission and/or distribution companies who only own and operate T&D equipment, referred to as "wires only" companies, account for the indirect GHG emissions associated with T&D line losses as scope 2 emissions.

In the case of a power generator that 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 is equal to the emissions associated with the 3rd party generating the energy (MWhs) purchased and consumed by the company. In addition, the emissions associated with any *upstream* T&D line losses would be considered scope 3 emissions for the electric 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 its own facilities – they would report scope 2 emissions associated with T&D line losses that occur within their system's boundaries.

In the case of a wires-only company that purchases power for resale, the emissions associated with line losses occurring within their organizational boundary could be an area of inadvertent double counting of emissions between scope 2 and scope 3. See Appendix B for more information on scope 2 and scope 3 accounting scenarios for wires-only load-serving entity (LSE) to end-use consumers.

In both cases above, to avoid double counting between scope 2 and scope 3, the reporting company may report the indirect GHG emissions associated with the purchased power for resale under scope 3, category 3, activity D (purchased power for resale to end-use customers) based on the total amount of power delivered to end-users. The indirect emissions from T&D line losses that occur within the company's boundaries after the power has been purchased until it is delivered to the end-user) would be reported as scope 2 emissions. In the event the reporting company opts to report scope 3, category 3, activity D based on the total amount of power purchased, the company would need to be careful to not also report scope 2 emissions associated with line losses, as this could lead to double counting across scope 2 and scope 3.

Corporate Structure and Accounting for Indirect T&D Emissions

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

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

Table 3. T&D-related greenhouse gas emissions accounting by type of electric company

Corporate Structure	Does the 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 vertically integrated 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 company	Yes. The company's emissions inventory would include scope 2 indirect GHG emissions associated with T&D line losses for all electricity flowing through T&D company's system.
Independent Power Producer (IPP)	No. The IPP 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 electric companies and generation and transmission cooperatives (G&Ts) own and operate power generation facilities. Consequently, 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 transmitting and distributing power generated by the company's facilities are not considered to be 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 party, they should account for the T&D losses associated with transmitting the power across their system as scope 2 indirect emissions. 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 may have a greater ability to impact (e.g., through improvements to the T&D system).

Wires-only companies account for indirect emissions associated with T&D losses as scope 2 emissions. An electric 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 and consume from third parties 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 T&D lines. Any indirect emissions from T&D losses associated with electricity purchased by these entities would be categorized as scope 3 emissions.

Scope 3 Value Chain Accounting

Scope 3 emissions are all other indirect emissions not included in scope 2. Scope 3 emissions broadly can be classified into *upstream* or *downstream* activities that comprise an entity's value chain. Upstream activities involve a company's supply chain and include inputs to a company's production. Downstream emissions relate to activities associated with selling goods and services to intermediate and end-use customers and may include emissions associated with a reporting company's franchises and investments.

Entity-level value chain GHG accounting is focused primarily on allocating indirect emissions to a company. Value chain accounting also can be applied to a specific product (i.e., "product-level" accounting) or any other type of entity (e.g., an entire industry sector). Life-cycle assessment (LCA) methodologies typically are used to estimate value chain emissions.

Scope 3 Standard

The prevailing guidance for value chain accounting for corporate GHG inventories is the Corporate Value Chain (Scope 3) Standard developed by the GHG Protocol (henceforth referenced as the Scope 3 Standard). The Scope 3 Standard categorizes value chain indirect emissions into upstream and downstream from the perspective of the reporting company, based on financial transactions:[16]

- **Upstream emissions** are indirect GHG emissions related to purchased or acquired goods and services.
- **Downstream emissions** are indirect GHG emissions related to sold goods and services. Downstream emissions also include emissions from products that are distributed but not sold (i.e., without receiving payment). The Scope 3 Standard also includes any other indirect emissions not included in scope 1 and scope 2 due to consolidation approaches (e.g., leased assets, franchises, investments).

[16] Conventionally within the energy sector, upstream and downstream may have different meanings than are applied for GHG accounting through the Scope 3 Standard.

Double Counting of Emissions

Two different types of entities may classify the same GHG source within a different scope. For instance, electric customers would classify the indirect emissions related to the electricity they purchase and consume as scope 2 emissions. However, the electric company generating this power would classify the emissions as scope 1. In this way, scope categorization helps prevent double counting of emissions within and across scope 1 and 2 (but not scope 3).

By reporting the same source of emissions under separate scopes, an electricity provider and end-use consumer can avoid making confusing and contradictory claims about responsibility for emissions from a GHG source. For example, for an LSE that also generates electric power, scope 1 emissions are a result of fuel combustion at its electricity-generating facilities. This LSE's scope 1 emissions inherently account for any indirect emissions associated with the T&D system line losses from transmitting the power from the generator to end-use customers. If this LSE were not a power generator, these emissions would be accounted for separately as scope 2 T&D line losses. See Table 4 for an example of how scope 1 and scope 2 avoid double counting from a scenario including an IPP, T&D company, and electricity end user.

It is important to acknowledge that double counting of emissions between numerous companies is an inherent trait of the existing scope 3 emissions reporting framework. Scope 3 reporting's purpose is to allow reporting entities to assess their value chain emissions and identify priority areas for emission reduction interventions. Further, scope 3 reporting does not assume the sum of parts equals a whole (i.e., individual emission sources globally equals total global emissions). For example, in a scenario where every corporate entity reports emissions from the use of sold products, no information can be deduced for the total emissions of sold products because some products are sold multiple times and some sold products are used to produce other products, and in these ways, the emissions would be counted multiple times and equate to a greater value than the actual total emissions occurring from the use of sold products.

Table 4. Example of emission source classification by scope for electricity generation, T&D line losses and end-use consumption by entity

Scenario: IPP generates a "gross" amount of electricity (e.g., 1,000 MWh) purchased by a T&D company that is an LSE which delivers 965 MWh of "net" energy to end-use customers.			
Entity	**Scope 1**	**Scope 2**	**Scope 3**
Independent Power Producer (IPP)	1,000 $mtCO_2$ (Assumes 1,000 MWh purchased has an EF of 1 mt CO_2 /MWh)	N/A	Scope 3, category 3, activity A: Upstream emissions associated with fuel purchased for combustion.
T&D Company	N/A	35 $mtCO_2$ (Assumes T&D line losses of 3.5%)	Scope 3, category 3, activity B: Upstream emissions of purchased electricity (in this scenario, the electricity consumed as T&D line losses reported in scope 2). Scope 3, category 3, activity C: NA[17] Scope 3, category 3, activity D: Upstream emissions associated with the generation of purchased electricity resold to end users.
End-users	N/A	965 $mtCO_2$	Scope 3, category 3, activity B: Upstream emissions of purchased electricity reported in scope 2 (e.g., fuel extraction, production, transportation). Scope 3, category 3, activity C: Upstream emissions associated with T&D line losses.
Mass-balance check[18]	1,000 $mtCO_2$	1,000 $mtCO_2$	NA

[17] For simplification purposes, scope 3, category 3, activity C: Upstream T&D losses (i.e., before entering the T&D company's system) are assumed to be non-existent in this scenario, but are likely to be relevant in real grid scenarios.

[18] The mass-balance check in this example confirms that all scope 1 emissions are reported as indirect emissions in other organization's scope 2 estimates.

3 DEFINING EMISSIONS REPORTING BOUNDARIES

Boundaries for GHG reporting may be defined by regulations and may differ across reporting programs based on the intended application of GHG accounting. This section identifies the relevant reporting boundaries related to common carrier infrastructure, voluntary corporate inventorying, and mandatory facility-level reporting through the EPA GHGRP. The GHGRP reporting boundaries are specific and conclusive, while voluntary reporting programs and the GHG Protocol provide a more flexible approach to setting accounting boundaries.

There are also other mandatory reporting requirements for electric companies and combined utilities through the Federal Energy Regulatory Commission (FERC), such as FERC Form-1, the Energy Information Administration (EIA) Form-176, and other state-level regulatory agencies.

Voluntary Corporate Reporting Boundaries

When conducting a corporate GHG inventory, the first step is to establish *organizational boundaries*. These boundaries determine which activities and operations are owned or controlled by the company, and therefore which sources and sinks are allocated to the organization for reporting and included in the GHG inventory.

There are two general consolidation approaches to define organizational boundaries: control (operational or financial) and equity share. The selection of a consolidation approach defines GHG-emitting (or removing) assets that constitute the organization.

- **Operational Control**: 100% of GHG emissions are included in the organizational boundaries from assets and activities for which the organization, or its subsidiaries, has the authority to introduce and implement operating decisions. 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 assets and activities for which the organization can direct the financial policies with an interest in gaining economic benefits from the activity. An organization has financial control over an activity if it has the rights to the majority of the benefits from its operation.
- **Equity Share**: Emitting assets and activities are included in the organizational boundaries based upon the organization's equity share in them. 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 under this approach.

The majority of companies conducting GHG inventories apply the operational control approach, but electric companies are outliers as an industry group as many utility companies apply the equity share approach.[19] Ultimately, each company may choose how they approach establishing their organizational boundaries based on their company structure, historical and

[19] Kasperzak R, Kureljusic M, Reisch L, Thies S. Accounting for Carbon Emissions—Current State of Sustainability Reporting Practice under the GHG Protocol. *Sustainability*. 2023; 15(2):994. https://doi.org/10.3390/su15020994

industry practices, and alignment with their objectives for compiling an inventory. Table 5 provides an example of emissions reporting based on different consolidation approaches.

Table 5. Example comparing control and equity share approaches to consolidate emissions for natural gas pipelines owned by two or more entities

<table>
<tr><th colspan="3">Example 1: Natural Gas Pipelines Owned by Two or More Entities</th></tr>
<tr><td colspan="3">Within a corporate inventory, if a facility is owned by multiple entities, the emission reporting related to the direct and indirect emissions from a facility would be reported based on the consolidation approach that each partial owner has selected. For this example, let us assume the pipeline facility calculated the following emissions for each emissions scope.</td></tr>
<tr><th>Scope 1</th><th>Scope 2</th><th>Scope 3</th></tr>
<tr><td>1,500 mt CO_2e</td><td>500 mt CO_2e</td><td>5,000 mt CO_2e</td></tr>
<tr><td colspan="3">In the case of a natural gas pipeline that is owned by two entities (e.g., Entity A and Entity B) with 50/50 split ownership while Entity A exercises control of the facility, direct and indirect emissions associated with the pipeline would be reported as follows:</td></tr>
<tr><th>Entity</th><th>Control Approach</th><th>Equity Share</th></tr>
<tr><td>A</td><td>Scope 1: 1,500 mt CO_2e
Scope 2: 500 mt CO_2e
Scope 3: 5,000 mt CO_2e</td><td>Scope 1: 725 mt CO_2e
Scope 2: 250 mt CO_2e
Scope 3: 2,500 mt CO_2e</td></tr>
<tr><td>B</td><td>Scope 1: null
Scope 2: null
Scope 3 (Category 15): 7,000 mt CO_2e</td><td>Scope 1: 725 mt CO_2e
Scope 2: 250 mt CO_2e
Scope 3: 2,500 mt CO_2e</td></tr>
<tr><td colspan="3">In a case where Entity A and Entity B do not coordinate GHG emissions reporting and choose different consolidation approaches, emissions either could be under- or over-counted as shown in this example. The GHG Protocol recommends entities that co-own assets coordinate their approach to GHG inventorying.</td></tr>
</table>

The next step is to identify which company activities result in GHG emissions or removals and to categorize these identified sources and sinks within scope 1 if they occur directly from controlled activities (or a proportion of the emissions from a jointly owned source if applying the equity share approach), within scope 2 if they occur indirectly through energy consumption, or within scope 3 if they occur indirectly and are not included in scope 2. These sources and sinks define the company's operational boundaries for GHG inventory purposes.

EPA's GHG Reporting Program Boundaries

In addition to regulatory requirements in the U.S. to report GHG emissions through the EPA's GHGRP for facilities that emit more than 25,000 mt CO_2e per year,[20] the GHGRP also includes the following subparts that identify reporting requirements related to common carrier infrastructure:

- Subpart DD identifies requirements for reporting the emissions of SF_6 and perfluorocarbons (PFCs) related to electric T&D across electric power systems.[21]
- Subpart NN identifies requirements for suppliers of natural gas transported through common carrier infrastructure (but may not be purchased or owned by the pipeline owner).[22]

The reporting requirements in Subpart DD apply to all fugitive emissions resulting from equipment transmitting and distributing electricity through the reporting company's T&D equipment including self-generated, purchased, and non-purchased electricity.[23]

The reporting requirements in subpart NN apply to the owner or operator of natural gas distribution pipelines (local distribution companies) and do not include interstate or intrastate pipelines. These entities, as well as natural gas liquids fractionators,[24] must report under Subpart NN when they exceed the natural gas distribution threshold of 460,000 scf to "non-major industrial" end-users during a calendar year.[25]

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[20] EPA, 2009. Mandatory Greenhouse Gas Reporting: § 98.2 Who must report? Environmental Protection Agency. Accessed: February 26th, 2024. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98.

[21] https://www.epa.gov/ghgreporting/electronic-transmission-and-distribution-infosheet.

[22] https://www.epa.gov/sites/default/files/2018-02/documents/nn_infosheet_2018_2.pdf.

[23] Note that the regulation defines a facility as "the electric power system, comprising all electric transmission and distribution equipment insulated with or containing SF_6 or PFCs that is linked through electric power transmission or distribution lines and functions as an integrated unit, that is owned, serviced, or maintained by a single electric power transmission or distribution entity (or multiple entities with a common owner), and that is located between (1) the point(s) at which electric energy is obtained by the facility from an electricity generating unit or a different electric power transmission or distribution entity that does not have a common owner, and (2) the point(s) at which the customer or another electric power transmission or distribution entity that does not have a common owner receives the electric energy."

[24] Entities that separate natural gas liquids into their constituent products (ethane, propane, normal butane, isobutane, or pentanes plus) for downstream supply.

[25] EPA, 2009. Mandatory Greenhouse Gas Reporting: Subpart NN–Suppliers of Natural Gas and Natural Gas Liquids. Environmental Protection Agency. Accessed: December 4th, 2023. URL: https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=be77ce6e756f0befaa0dd95743e3342e&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl

EIA Form-176

Similar to EPA's GHGRP, natural gas transported via pipelines must be reported regardless of its ownership by the owner or operator of the pipelines, companies, plants, or facilities identified below as required by EIA Form-176. The instructions for the form specify the following entities are required to report to the Energy Information Administration (EIA):

(1) Interstate natural gas pipeline companies

(2) Intrastate natural gas pipeline companies

(3) Natural gas distribution companies

(4) Underground natural gas storage operators

(5) Synthetic natural gas plant operators

(6) Field, well, or processing plant operators that deliver natural gas directly to consumers (including their own industrial facilities) other than for lease or plant use or processing.

(7) Field, well, or processing plant operators that transport gas to, across, or from a state border through field or gathering facilities.

(8) Liquefied natural gas (LNG) storage operators, both peaking facilities and marine terminals

(9) Producers of high-Btu renewable natural gas that inject into an interstate or intra-state pipeline, or who deliver to a natural gas distributor.[26]

Though this reporting is for natural gas data only and is not GHG-related, its mandatory nature and definition of operations for natural gas common carrier infrastructure helps illustrate the various reporting frameworks entities owning common carrier pipelines must report to. It also identifies data that is already being gathered because of this reporting requirement that would support GHG accounting.

[26] EIA. Annual Report of Natural and Supplemental Gas Supply and Disposition Form EIA-176: Instructions. U.S. Department of Energy. Federal Energy Administration Act of 1974. Available: https://www.eia.gov/survey/form/eia_176/instructions.pdf.

4 EMISSION SOURCES IN THE SECTOR

This section summarizes existing guidance for reporting indirect emission sources for common carriers as identified by the GHG Protocol, including Scope 2 Guidance and the Scope 3 Standard, where appropriate. Additionally, it notes where guidance is unclear, ambiguous, and subject to interpretation regarding accounting and reporting indirect emissions.

Electricity Transmission and Distribution Systems

The GHG Protocol provides guidance and information for the accounting of emission sources occurring in the value chain of T&D line owners in cases where the owner or operator of a T&D system **does not generate electricity**. However, for indirect emissions associated with all electricity flowing through their systems, including electricity that is not purchased or sold to another entity, the guidance remains unclear. Figure 1 provides a simplified illustration of the value chain from the perspective of an organization operating an electricity T&D system.

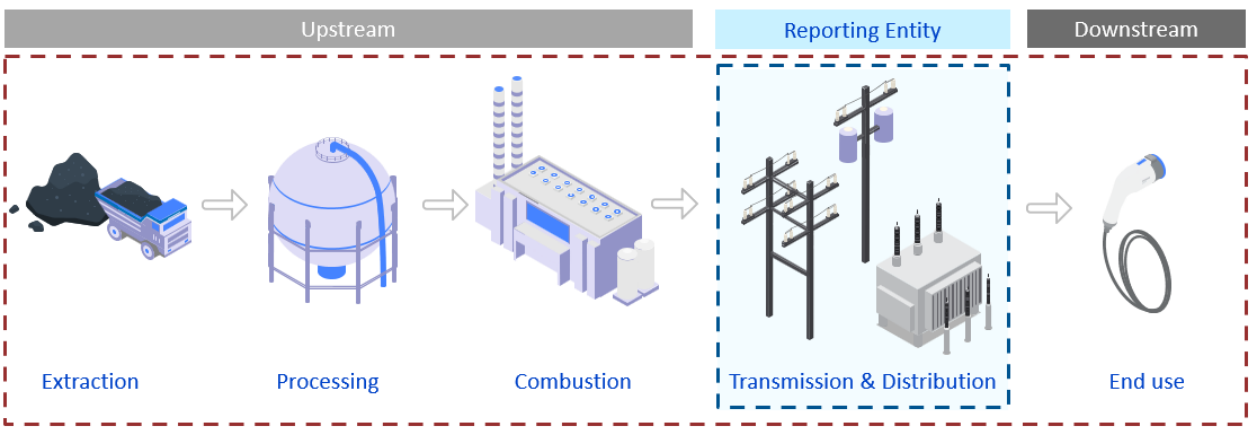

Figure 1. Simplified value chain of T&D systems with upstream and downstream sources

Table 6 summarizes the emission sources related solely to the operations of T&D systems and categorizes them according to the GHG Protocol and Scope 3 Standard. Other emission sources associated with managing T&D systems are dependent on other operation-specific activities and are out of the scope of this report (e.g., direct emissions from stationary and mobile combustion, indirect emissions from waste disposal, and purchased goods).

Table 6. Relevant greenhouse gas emission sources for electricity T&D system owners

Emission Source	A. T&D owner that generates and/or purchases the electricity	B. T&D owner that does not generate or purchase the electricity
Direct Emission Sources		
Scope 1, fugitive: SF_6 emissions from T&D systems	Yes.	**Scope 1, fugitive:** SF_6 emissions from T&D systems
Scope 1: other direct: emissions from T&D-related operations (e.g., from stationary combustion, fugitive)	Yes.	**Scope 1: other direct:** emissions from T&D-related operations (e.g., from stationary combustion, fugitive)
Upstream Indirect Emission Sources		
Scope 2: purchased or acquired electricity, heat, steam, and cooling	Yes, only for emissions from non-self-generated electricity "consumed" by the T&D systems as line losses.	Yes, for emissions associated with electricity "consumed" by the T&D systems as line losses.
Scope 3, category 1: purchased goods and services	Yes, upstream emissions related to purchased fluorinated gases (e.g., SF_6 refilling), outsourced maintenance services, etc.	
Scope 3, category 3: all upstream emissions from: **a.** Purchased fuels **b.** Purchased electricity **c.** T&D losses **d.** Purchased electricity sold to end users	**a.** Yes, purchased fuel combusted at T&D sites. **b.** Yes, purchased and consumed electricity (i.e., line losses) that is not self-generated (excluding combustion). **c.** Yes, line losses in T&D systems that are not owned/operated by the reporting organization.[27] **d.** Yes, emissions from purchased electricity that is sold to end users.	**a.** Yes, purchased fuel combusted at T&D sites. **b.** Yes, purchased and consumed electricity (i.e., line losses) that is not self-generated (excluding combustion). **c.** Yes, line losses in T&D systems that are not owned/operated by the reporting organization.[28] **d.** **Ambiguous for electricity that is transmitted via common carriers.** Not directly addressed by GHG Protocol standards.[29]
Scope 3, category 5: waste generated from operations	Yes, for any waste disposed of and sent to third-party treatment facilities.	
Downstream Indirect Emission Sources		
Other scope 3 categories	Scope 3 categories that may be applicable include end-of-life treatment of sold products (category 12), and investments (category 15).	

[27] Line loss emissions that occur prior to entering T&D system they own. For example, when battery energy storage systems (BESS) losses occur before power is metered and injected into their T&D systems.

[28] Ibid.

[29] The Climate Registry's Electric Power Sector Protocol addresses this scenario. Refer to Section 6.

While the Scope 3 Standard does not specifically address electric power only transmitted through T&D lines (and not generated, purchased, or sold) by the reporting organization (as in scenario B in Table 6 above), the GHG Protocol's Scope 2 Guidance, which supersedes the Scope 3 Standard, provides a figure illustrating the energy value chain. As seen in Figure 2, the "utility/energy distributor" would account for emissions from fuel production and power generation (i.e., upstream emissions) under scope 3, and T&D losses under scope 2. Though the term "energy distributor" is not defined explicitly in the Scope 2 Guidance, one can infer this term refers to entities that own and maintain T&D systems but do not generate or purchase electricity. Alternatively, the guidance may be using "energy distributor" as an umbrella term for entities transacting energy on behalf of end users.

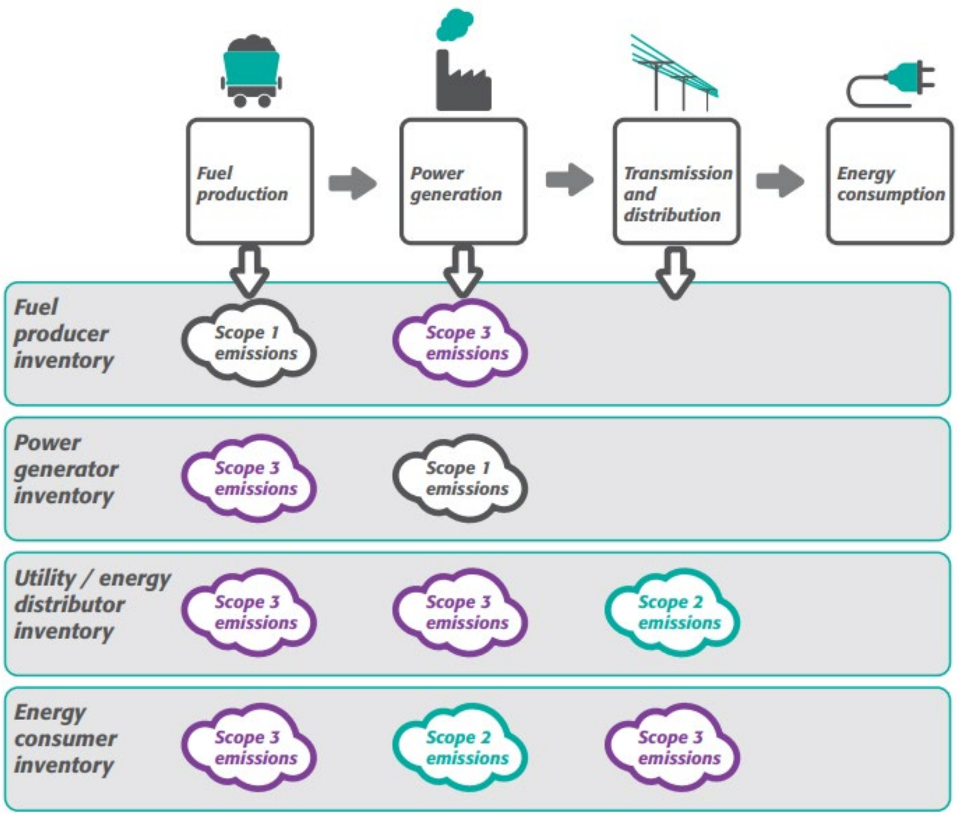

Figure 2. Accounting for electricity emissions throughout the supply chain.
Source: Scope 2 Guidance (GHG Protocol, 2016)

This binary ambiguity results in different emission profiles for a T&D company that does not generate or purchase electricity, as compared to a company that does generate or purchase electricity. Table 7 illustrates how emissions reporting significantly varies based on this ambiguity. As shown in Table 7, both the energy distributor and wires-only entities would report scope 2 T&D line losses equal to 337,500 mt CO_2e. However, the energy distributor in this example also would report scope 3, category 3 emissions equal to 7,962,500 mt CO_2e, while the wires-only company would report scope 3, category 3 emissions equal to just 36,000 mt CO_2e. For a detailed illustration of scope 2 and scope 3 accounting options for these entities see Appendix B.

The ambiguous nature of the existing guidance on how to account for T&D-related emissions is a contentious topic and is being considered further in the revision process of the GHG Protocol.[30] The GHG Protocol stakeholder feedback summary report specifically mentions stakeholders' requests for greater clarification on how to address line losses for wires only companies.

Table 7. Example emissions reporting from the perspective of "energy distributors"

Emissions by scope (mt CO_2e)	**B. Electric Company does not generate or purchase the electricity**	
	Reports all indirect emissions from electricity flowing through own system (energy distributor)	**Reports only indirect emissions associated with own system's line losses (wires only entity)**
Aggregate scope 2 (line losses): **337,500** mt CO_2e	**337,500** mt CO_2e	**337,500** mt CO_2e
Scope 3, category 3: Based on the following assumptions: 1. Upstream power generation (power flowing through owned lines): **7,500,000 mt CO_2e** 2. Upstream fuel production (power flowing through owned lines): **800,000 mt CO_2e** 3. **4.5%** T&D system line loss factor	Scope 3, category 3[31] = 7,500,000 – 337,500 + 800,000 = **7,962,500** mt CO_2e	Scope 3, category 3 = 800,000 x (4.5%) = **36,000** mt CO_2e

[30] Greenhouse Gas Protocol Standards Update Process, Detailed Summary of Responses from Scope 2 Guidance Stakeholder Survey July 2023. See: https://ghgprotocol.org/sites/default/files/2023-07/Scope%202%20Survey%20Feedback%20Draft%20Summary.pdf.

[31] Line losses emissions already account for emissions from electricity generation and hence are subtracted from 7,500,000 to avoid double counting.

Natural Gas Common Carrier Pipelines

The GHG Protocol does not provide specific guidance and information for the treatment of indirect emission sources occurring in the value chain of natural gas pipeline owners where the owner does not own or control the natural gas flowing through their systems. Figure 3 provides a simplified illustration of the value chain from the perspective of an organization that only owns and operates interstate natural gas pipelines and/or local distribution pipelines.[32]

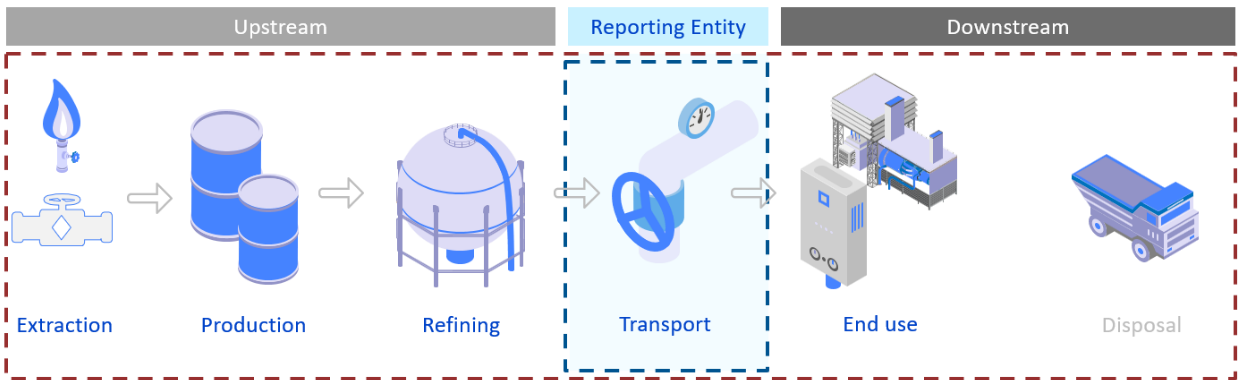

Figure 3. Simplified value chain of pipeline systems with upstream and downstream sources.

Note that disposal activities include any byproduct or residues disposed of from the reporting entity's operations, but these may be limited or not applicable for natural gas.

In the absence of specific guidance, the existing guidance for electric T&D systems can be interpreted as being analogous to natural gas pipelines as both types of infrastructure operate as common carriers for the distribution of undifferentiated energy commodities. **The main value chain difference is that the largest emission sources in the natural gas value chain occur downstream from pipelines as opposed to upstream as is the case for electric T&D systems.** Reporting similarities derive from the nature of operating as a common carrier and being responsible[33] for the handling and delivery of goods and any losses occurring within their systems.

Table 8 summarizes emission sources according to the categorization by the GHG Protocol and the Scope 3 Standard for the operations of natural gas pipeline systems (e.g., energy used by equipment within the pipeline network to move natural gas). Other emission sources may apply and are associated with managing pipelines and other operation-specific activities that are beyond the scope of this report.

[32] From a GHG accounting perspective, emissions reporting for interstate natural gas pipelines is similar to local distribution pipelines.

[33] Via mandates, legal responsibility, legislative act etc.

Table 8. Relevant emission sources for natural gas pipeline owners

Emission Source	A. Owns, controls, and/or purchases the natural gas	B. Does not own, control, or purchase natural gas
Direct Emission Sources		
Scope 1, fugitive: CH_4 emissions from pipeline systems	Yes.	
Scope 1, other direct: emissions from pipeline-related operations (e.g., stationary combustion, fugitive)	Yes.	
Upstream Indirect Emission Sources		
Scope 2: purchased or acquired electricity, heat, steam, and cooling	Yes, only for emissions from non-self-generated electricity.	
Scope 3, category 1: purchased goods and services	Yes, upstream emissions from purchased natural gas for distribution.	***Ambiguous for natural gas transported by common carriers****;* it is not directly addressed by the Scope 3 Standard.
Scope 3, category 2: capital assets	Yes, upstream emissions from purchased capital assets (e.g., infrastructure).	
Scope 3, category 3: all upstream emissions from: **a.** Purchased fuels **b.** Purchased electricity **c.** T&D losses **d.** Purchased electricity sold to end users	**a.** Fugitive emissions related to purchased fuel combusted on site remain ***ambiguous.***[34] Non-purchased fuels fugitive emissions are not directly addressed by Scope 3 Standard. **b.** Purchased electricity that is not self-generated (not including combustion). **c.** Not applicable. **d.** Not applicable.	
Scope 3, category 5: waste generated from operations	Yes, for any waste disposed of and sent to third-party treatment facilities.	
Downstream Indirect Emission Sources		
Scope 3, category 11: Use of sold products	Yes, downstream emissions associated with natural gas sold to end users.	***Ambiguous for natural gas transported by common carriers***; it is not directly addressed by the Scope 3 Standard.
Scope 3, other categories	Scope 3 categories that may be applicable include end-of-life treatment of sold products (category 12) and investments (category 15).	

[34] Although this category is for "purchased fuels," pipeline leaks could be interpreted as analogous to T&D line losses (reported under category 3, activity c).

Scope 3 Ambiguous Emission Sources

Although the Scope 3 Standard delineates that downstream emissions also include indirect emissions from products which are distributed but not sold, the standard is not clear whether *distributed products* apply to products not owned or produced by the reporting company. For upstream indirect emissions, the language is inflexible and restricts reporting[35] of indirect emissions to *purchased* or *acquired* goods and services and does not clarify whether it should include emissions from distributed products that are not *purchased* or *acquired* (i.e., owned), or consumed by the reporting company.

For common carriers who do not purchase, acquire, or control the goods flowing through their systems and are financially structured based on a flow rate fee (e.g., $/MWh, $/mcf), the reporting company's GHG inventory compilers often resort to either (i) subjective interpretation of the GHG Protocol, or (ii) seeking additional sector-specific GHG reporting guidance. These two approaches commonly cause reporting across companies to be inconsistent in their accounting decisions and therefore not comparable in their reporting. This is an issue that extends beyond the power sector.

The next sections of this report explore how GHG inventory compilers may use existing guidance to inform their GHG reporting.

[35] Unintentionally or intentionally.

5 OPTIONS TO REPORT COMMON CARRIER INDIRECT EMISSIONS UNDER THE GHG PROTOCOL

Accounting for and reporting emissions associated with products that are distributed but not sold, such as natural gas and electricity transported via common carrier infrastructure, presents challenges for owners of this type of infrastructure because the available GHG accounting guidance to address this situation is not definitive.

This section presents alternative approaches that electric companies and combined utilities may use to account for, and report emissions associated with the transport of products that are distributed but not sold via common carrier infrastructure based on different interpretations of the GHG Protocol.

Option 1: Expand the Boundary and Report Ambiguous Emission Sources within Categories 3 and 11

To account for and report emissions from electricity and natural gas products that are distributed but not sold (i.e., the *ambiguous* emission sources identified in Tables 7 and 8 in Section 4), common carriers can establish their reporting boundaries to include *all* electricity and natural gas the company transports and delivers within its value chain. If a company takes this approach, it may report indirect emissions from these sources under scope 3 category 3 (fuel and energy-related emissions) for T&D companies, or category 11 (use of sold products), for natural gas common carrier companies. For example, a natural gas pipeline owner would estimate and report end-use emissions from combustion of the total amount of natural gas transported through their systems in category 11.

Option 2: Report Outside of the 15 Categories, but within Scope 3

Alternatively, common carriers could provide GHG-related information about their operations under the Scope 3 Standard's guidance for *optional reporting*. The Scope 3 Standard provides a comprehensive list of *optional* information that reporting companies may choose to report as supplemental information or as an addendum to the scope 3 emissions inventory, including:

- **Emissions from scope 3 activities not included** in the list of scope 3 categories (e.g., transportation of attendees to company-hosted conferences/events), reported separately (e.g., in an "other" scope 3 category);
- **Qualitative information** about emission sources not quantified;
- **Performance indicators** and intensity ratios related to operations; or
- **Information on supplier's** or partner's engagement, data availability, and performance.

In the case of identified ambiguous sources, reporting companies can provide information related to these sources outside of their scope 3 inventory as optional (i.e., additional) information.

Existing mandatory reporting guidelines and sector-specific guidance help reporting companies identify what *optional* information is relevant within their sector and is not covered by the Scope 3 Standard. For example, a reporting company may choose to report emissions reported under the GHGRP Subpart NN, as an "other" category. Additionally, reporting companies can report performance indicators or intensity ratios based on GHG risk exposure (e.g., regulatory penalties, reputational harm, and supply chain partners burdened by these same risks).[36]

Reporting Optional Performance Indicators

Another approach common carriers could use to report on the GHG emissions associated with their activities would be to report energy-related GHG performance metrics[37] (representing emissions per unit of output). The kinds of performance metrics are ubiquitous in GHG-related literature and are often used to communicate estimates of emissions "embedded" in energy products. These metrics can be developed for a product's entire life cycle or portions of it. Commonly, GHG emissions intensity metrics are found in three main forms:

1. **Entity-level.** Communicates an entity's emissions normalized for its output (e.g., mt CO_2e/MWh generated). Typically, these metrics account only for direct emissions.
2. **Product-level**. Communicates the average per unit emissions and removals that occur during a product's cradle-to-grave life cycle (e.g., mt CO_2e/product unit, mt CO_2e/MWh of electricity produced).
3. **Delivery-level.** Communicates upstream emissions until a specified product's point of delivery (e.g., mt CO_2e/MMBtu natural gas delivered). This is communicated from the reporting entity's perspective. For example, an entity in the energy value chain can communicate to its immediate downstream customer[38] the upstream emissions of delivered electricity and natural gas.

Figure 4 shows the relationship among all three types of metrics with a normalized output of one MMBtu. Reporting organizations can choose which performance metric(s) can be accurately and consistently reported to fulfill their stakeholders' expectations.

[36] See Appendix A for a list of criteria that can be used to determine the "relevancy" of emission sources.

[37] Definition of performance GHG accounting and relationship to physical GHG accounting at https://ghginstitute.org/2023/03/01/what-is-greenhouse-gas-accounting-furnishing-definitions.

[38] End users of electricity, natural gas retailers, etc.

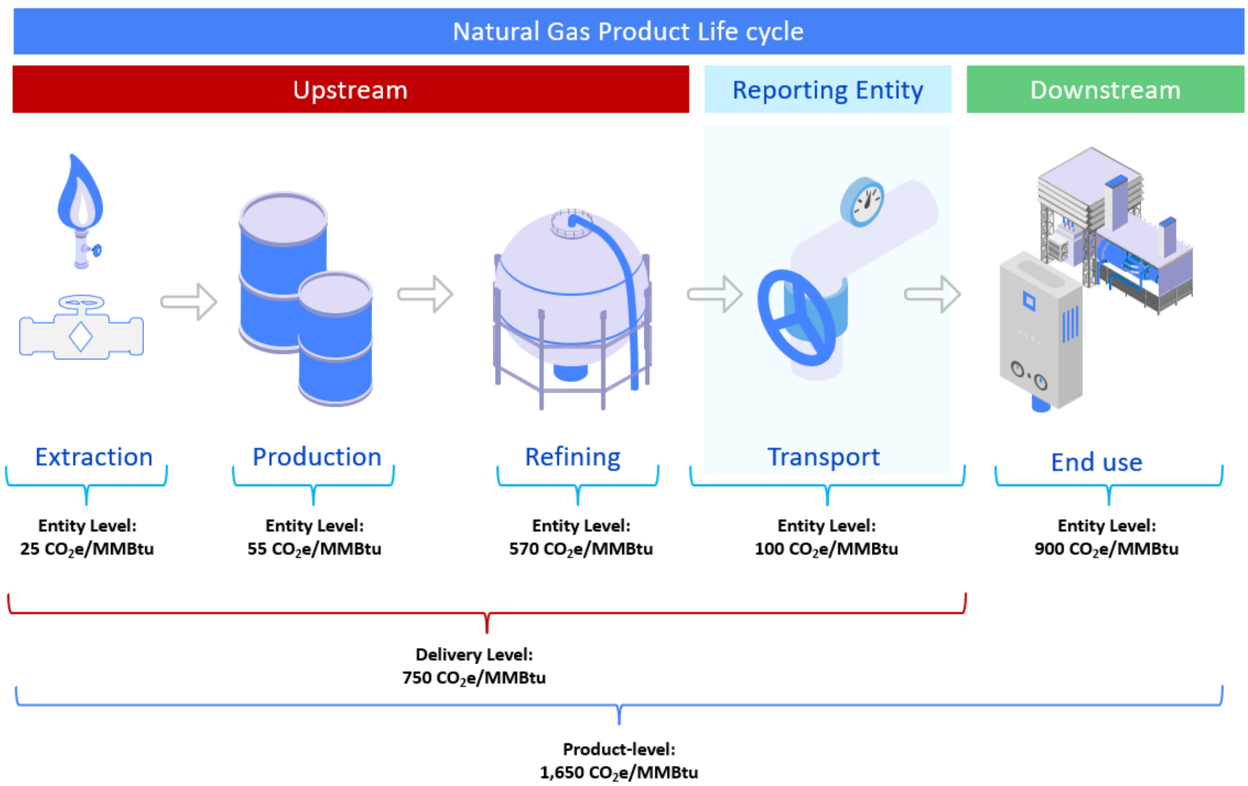

Figure 4. Performance metrics relationship across a value chain

Section 6 of this report highlights other existing GHG accounting and reporting guidance applicable to electricity T&D system and natural gas pipeline common carriers including where guidance on sector-specific performance metrics is available.

Option 3: Justify and Disclose Any Exclusions

Lastly, common carriers can choose to exclude accounting and reporting of emissions associated with any *ambiguous* boundary due to a lack of guidance from the Scope 3 Standard that fits their context. This exclusion should be accompanied by a justification for the exclusion in their GHG emissions inventory report. This option can be supplemented by optional GHG-related data reporting identified in Option 2.

6 OTHER EXISTING GHG REPORTING GUIDANCE FOR COMMON CARRIERS

While the GHG Protocol's existing guidance generally does not aim to address unique activities within sector-specific operations, there is a myriad of guidance available from other GHG reporting programs that contain additional interpretations that may be used to categorize indirect emission sources. **Nine separate reporting programs or overarching guidance materials address common carrier scenarios and GHG emissions accounting.** Table 9 summarizes this guidance and identifies where performance metrics are prescribed for electricity T&D systems. Table 10 summarizes guidance and prescribed performance metrics for natural gas pipelines.

Table 9. Summary of existing guidance for electricity T&D system common carriers.

Electricity T&D Systems and Infrastructure			
Guidance	**Applicability**	**Indirect Emissions**	**Does the guidance include performance metrics?**
The Climate Registry **Electric Power Sector (EPS) Protocol**[39]	1. Electric power-generating facilities 2. Transmission systems that convey electricity from generation to distribution system 3. Distribution systems that convey electricity received from generation or transmission system to final consumers 4. T&D System Operators, including utilities, distribution cooperatives, and other Local Distribution Companies (LDCs) 5. Bulk power transmission operators[40] 6. Power marketers, energy service companies, or retail electricity providers that do not own or operate power generation, transmission, or distribution facilities	Upstream emissions (generation only) of electric power generated and/**or delivered**. Type of GHG accounting: **Entity-level accounting.**	Yes. The EPS provides guidance for calculating *generation* and *delivery* metrics. Delivery metrics only include sales to wholesale retail markets and/or special power products.

[39] 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. TCR's Electric Power Sector Protocol (2009) is a supplement to the 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.

[40] Including utilities, transmission companies, balancing authorities, ISOs, RTOs, and transmission cooperatives

Table 9 (continued). Summary of existing guidance for electricity T&D system common carriers.

Electricity T&D Systems and Infrastructure			
Guidance	**Applicability**	**Indirect Emissions**	**Does the guidance include performance metrics?**
Assessing Low-Carbon Transition – Electricity by ACT[41]	1. Generation only companies 2. Retail only companies 3. Mixed profile companies	Only from upstream retail activities. Does not apply to wires only companies (i.e., companies that do not own or control generating sources). Type of GHG accounting: **Performance-based**[42] **accounting based on entity-level GHG accounting (only select categories of scope 3 are included).**	Yes.

[41] Assessing low-Carbon Transition Initiative's published resources are available at: https://actinitiative.org/act-methodologies.

[42] See https://ghginstitute.org/2023/03/01/what-is-greenhouse-gas-accounting-furnishing-definitions/.

Table 10. Summary of existing guidance for natural gas pipeline common carriers

Natural Gas Common Carrier Pipelines			
Guidance	**Applicability**	**Indirect Emissions**	**Does the guidance include performance metrics?**
Technical Note: Guidance methodology for estimation of Scope 3 category 11 emissions for oil and gas companies (2022) by CDP[43]	1. Companies involved in the extraction and production of oil and gas 2. Companies involved in the transport,[44] handling, and storage of oil and gas and derived products 3. Companies involved in the refining/processing of oil- and gas-derived products (downstream) 4. Integrated companies involved in multiple areas of the oil and gas value chain	Accounting for the remaining use of product life-cycle emissions occurring downstream of reporting companies. Type of GHG accounting: **Value chain accounting - supplemental guidance to Scope 3 Standard.**	No.
Estimating petroleum industry value chain (Scope 3) greenhouse gas emissions by IPIECA[45]	1. Integrated oil and gas companies 2. Exploration and production companies 3. Refining companies 4. Natural gas processor companies 5. Petrochemical companies	Upstream and downstream emission of reporting companies. Does not apply to pipeline-only companies (i.e., companies that transport but do not own or control natural gas). Type of GHG accounting: **Value chain accounting supplemental to Scope 3 Standard (i.e., sector-specific).**	No.

[43] CDP's guidance and technical notes are available at: https://www.cdp.net/en/guidance/guidance-for-companies.

[44] Applies to entities who do not control and/or own goods that are being transported.

[45] Estimating petroleum industry value chain (Scope 3) greenhouse gas emissions. Overview of methodologies (2016). Available at: https://www.ipieca.org/resources/estimating-petroleum-industry-value-chain-scope-3-greenhouse-gas-emissions-overview-of-methodologies.

Table 10 (continued). Summary of existing guidance for natural gas pipeline common carriers

Natural Gas Common Carrier Pipelines			
Guidance	**Applicability**	**Indirect Emissions**	**Does the guidance include performance metrics?**
ISO 14083:2023: Greenhouse gases – Quantification and reporting of greenhouse gas emissions arising from operations of transport chains by International Organization for Standardization (ISO)[46]	1. Transport (includes pipeline transport) or hub operator 2. Transport service organizer 3. Transport service user	Only indirect emissions related to fuel combustion and consumption by transport type. Type of GHG accounting: **Value chain accounting. Inclusive only of organizational transport operations.**	Yes. Operations-based only.
Global Logistics Emissions Council Framework v3.0[47] Note: This guidance is derived from (and endorsed by) ISO 14083:2023	1. Transport (includes pipeline transport) or hub operator 2. Transport service organizer 3. Transport service user	Only indirect emissions related to fuel combustion and consumption by transport type. Type of GHG accounting: Transport chain (i.e., value chain) accounting. Inclusive only of organizational transport operations.	Yes. Generic metric for transport activity.
Oil & Gas Protocol by The Climate Registry[48]	Not applicable to natural gas pipeline-only companies.	Optional reporting of scope 3 emissions. Guidance does not provide calculation methodologies on scope 3 emissions. Type of GHG accounting: **Entity-level accounting.**	No.

[46] Available at: https://www.iso.org/standard/78864.html.

[47] Guidance available at: https://www.smartfreightcentre.org/en/our-programs/global-logistics-emissions-council/calculate-report-glec-framework. This guidance has received the *'Built on GHG Protocol'* recognition mark. For additional details: https://ghgprotocol.org/guidance-built-ghg-protocol.

[48] TCR Oil & Gas Protocol (2010) available at: https://theclimateregistry.org/registries-resources/protocols/.

Table 10 (continued). Summary of existing guidance for natural gas pipeline common carriers

Natural Gas Common Carrier Pipelines			
Guidance	**Applicability**	**Indirect Emissions**	**Does the guidance include performance metrics?**
Assessing Low-Carbon Transition – Oil & Gas (2021) by ACT[49]	1. Integrated O&G companies 2. Integrated gas utilities 3. Entities that exclusively conduct exploration and production 4. Entities that exclusively refine & market oil 5. Entities that exclusively run service stations 6. Entities that exclusively market oil products 7. Entities that exclusively sell retail gas	Only indirect emissions from midstream or downstream transportation, processing of sold products, and use of sold products. **Does not apply to entities that exclusively store and transport oil & gas (i.e., do not know own/produce oil and gas products).** Type of GHG accounting: **Performance-based accounting based on entity-level GHG accounting (scope 1, 2, and select categories of scope 3).**	Yes.
API Compendium (Updated, 2021) and API Guidance Document for GHG Reporting (March 2022) by American Petroleum Institute[50]	1. Oil and gas exploration 2. Oil and gas production 3. Oil and gas gathering and boosting 4. Natural gas processing 5. Natural gas transmission and storage 6. Liquefied Natural Gas (LNG) operations 7. Natural gas distribution 8. Enhanced Oil Recovery (EOR) 9. Crude oil transportation 10. Refining 11. Retail and marketing of petroleum liquids	Indirect emissions for natural gas transmission and storage only include purchased/acquired electricity/heat/steam/cooling. **API Guidance Document for GHG Reporting (Page 26, March 2022),** *"Scope 3 (Category 11) reporting is not applicable to oil and gas pipeline companies that transport but do not produce, refine, or sell the product they transport. Therefore, these assets do not fall under any of the methodologies in IPIECA/API Estimating petroleum industry value chain (Scope 3) greenhouse gas emissions."* Type of GHG accounting: **Entity-level accounting.**	Yes. GHG emissions intensity indicators are provided in the guidance document (2022).

[49] Assessing low-Carbon Transition Initiative published resources available at: https://actinitiative.org/act-methodologies.

[50] API GHG Reporting Resources available at: https://www.api.org/news-policy-and-issues/sustainability/ghg-reporting.

Table 10 (continued). Summary of existing guidance for natural gas pipeline common carriers

Natural Gas Common Carrier Pipelines			
Guidance	**Applicability**	**Indirect Emissions**	**Does the guidance include performance metrics?**
NGSI Methane Emissions Intensity Protocol (2021) by Natural Gas Sustainability Initiative[51]	Five segments of the natural gas supply chain: 1. Onshore production 2. Gathering & boosting 3. Processing 4. Transmission & storage 5. Distribution (only applicable to LDCs)[52]	Does not account for indirect emissions. Metrics are calculated based on total direct CH_4 emissions and total gas throughput. For distribution companies, throughput as reported to EIA (Form 176). Type of GHG Accounting: **Performance-based accounting based on facility-level accounting (scope 1 emissions only).**	Yes.

[51] Available at: https://www.aga.org/research-policy/natural-gas-esg-sustainability/natural-gas-sustainability-initiative-ngsi/.

[52] This aligns with EPA's definition under Subpart W and Subpart NN boundary which excludes interstate and intrastate pipelines delivering gas directly to major industrial users.

7 KEY INSIGHTS

Electric companies and combined electric and natural gas utilities emit GHGs from a wide range of activities. Many voluntary and mandatory GHG accounting frameworks exist in the U.S. and internationally that a company may use to account and report their GHG emissions. These frameworks utilize different GHG accounting approaches, estimation methods, and reporting guidelines and often involve some ambiguity in their instructions. The major existing GHG accounting frameworks and guidance are intentionally generic and non-sector-specific, resulting in technical gaps for specific economic sectors. **One of the areas lacking technical guidance in the energy sector relates to common carriers and the proper accounting of GHG emissions associated with natural gas pipelines and electric system transmission and distribution infrastructure.**

This EPRI technical update report summarizes existing GHG accounting guidance from the perspective of entities that own common carrier energy infrastructure, both for voluntary and mandatory GHG accounting and reporting purposes.

Regulatory Requirements

In addition to regulatory requirements in the U.S. for electric companies to report GHG emissions through the EPA's GHGRP for facilities that emit more than 25,000 mt CO_2e per year, the GHGRP also includes subparts (DD and NN) that identify reporting requirements related to common carrier infrastructure.

Subpart DD identifies requirements for reporting the emissions of SF_6 and perfluorocarbons (PFCs) related to electric T&D equipment across electric power systems.

Subpart NN identifies requirements for suppliers of natural gas transported through common carrier infrastructure (but may not be purchased or owned by the pipeline owner).

Similar to EPA's GHGRP, natural gas transported via pipelines must be reported regardless of its ownership by the owner or operator of the pipelines, companies, plants, or facilities as required by EIA Form-176.

Scope 2 Emissions Associated with Electricity T&D Systems

There are two predominant categories of scope 2 emissions for electric companies and combined utilities: (i) indirect emissions from electric power purchased or acquired and consumed; and (ii) indirect emissions associated with electricity "consumption" associated with transmitting electricity across T&D systems (i.e., T&D line losses).

The second type of scope 2 emissions is unique to electric companies that own and operate T&D systems. Within a GHG inventory, 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 as well as the electricity being transmitted through them.

The structure of an electric company's operations influences the correct categorization of T&D line losses. In section 2 of this report (Table 3), we highlight guidance for accounting for T&D line losses for four common forms of electric company corporate entities:

1. Vertically integrated companies (e.g., investor-owned utilities, and some large public power agencies;
2. Generation and transmission co-ops (G&Ts);
3. Transmission and/or distribution companies (i.e., wires-only companies); and
4. Independent power producers (IPPs).

For power companies that both generate power and are responsible for providing energy to meet end-use load (i.e., vertically integrated companies), scope 2 emissions do not include T&D line losses because these indirect emissions typically are accounted for within the company's reported scope 1 direct emissions. For an end-use customer, however, the indirect GHG emissions associated with these line losses are reported as scope 3 emissions, while the indirect emissions associated with generating the power they purchase are considered scope 2.

In the case of a power generator that purchases electricity from an external third party to power its own operations (i.e., the power generator acting as an end-use customer), the total amount of scope 2 emissions is equal to the emissions that result from the 3rd party generating the energy purchased and consumed by the company. The emissions associated with any *upstream* T&D line losses would be considered scope 3 emissions for the electric 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 operations, they would report scope 2 emissions associated with T&D line losses.

Transmission and/or distribution companies who only own and operate T&D equipment (i.e., wires-only companies) generally account for the indirect GHG emissions associated with T&D line losses as scope 2 emissions. **In the case of wires only company that purchases power for resale, the reporting of emissions associated with line losses occurring within their organizational boundary could be an area of inadvertent double counting of emissions between scope 2 and scope 3.**

To avoid double counting between scope 2 and scope 3, the reporting company may report the indirect GHG emissions associated with the purchased power for resale under scope 3, category 3, activity D (purchased power for resale to end-use customers) based on the total amount of power delivered to end-users. The indirect emissions from T&D line losses that occur within the company's boundaries, after receiving the purchased power through to delivery to the end-user, would be reported as scope 2 emissions. In the event the reporting company opts to report scope 3, category 3, activity D based on the total amount of power purchased and also reports scope 2 emissions associated with line losses, this would lead to double counting across scope 2 and scope 3. Electric companies may account for T&D line losses associated with wholesale power purchases within scope 2 or scope 3, depending on the specifics of the transactions, with the goal of not double counting the emissions.

Scope 3 Emissions Associated with Electricity T&D Systems

The GHG Protocol also provides guidance and information for the accounting of emission sources occurring in the value chain of T&D line owners in cases where the owner or operator of a T&D system does not generate electricity. However, **the GHGP guidance remains ambiguous regarding accounting for and reporting indirect GHG emissions associated with electricity flowing through a common carrier electricity T&D system in which the common carrier does not own the electricity flowing through its lines.**

This ambiguity results in different emission profiles for an electricity T&D company that *does not* generate or purchase electricity, compared to a power company with a T&D system that *does* generate or purchase electricity. The ambiguous nature of the existing guidance on how to account for T&D-related emissions is a contentious topic and is being considered further in the ongoing GHGP review and revisions process.

GHG Emissions from Common Carrier Natural Gas Transmission

In addition, the GHG Protocol does not provide specific guidance and information for the treatment of indirect emission sources occurring in the value chain of natural gas pipeline owners when the pipeline owner does not own or control the natural gas flowing through their systems.

In the absence of specific guidance, the existing guidance for electric T&D systems can be interpreted as being analogous to natural gas pipelines as both types of infrastructure operate as common carriers for the distribution of undifferentiated energy commodities. The main value chain difference is that the largest emission sources in the natural gas value chain occur *downstream* from pipelines whereas for an electric T&D system, the largest value chain emissions source is *upstream*. Reporting similarities derive from the nature of operating as a common carrier and being responsible for the handling and delivery of goods and any losses occurring within their systems.

Although the Scope 3 Standard delineates that downstream emissions also include indirect emissions from products that are distributed but not sold, the standard is not clear whether *distributed products* apply to products not owned or produced by the reporting company.

For upstream indirect emissions, however, the language is inflexible and restricts reporting of indirect emissions to *purchased* or *acquired* goods and services and does not clarify whether it should include emissions from distributed products that are not *purchased* or *acquired* (i.e., owned), or consumed by the reporting company.

For common carriers who do not purchase, acquire, or control the goods flowing through their systems and are financially structured based on a flow rate fee (e.g., $/MWh, $/mcf), the reporting company's GHG inventory compilers currently often resort either to (i) subjective interpretation of the GHG Protocol or (ii) seeking additional sector-specific GHG reporting guidance. These two approaches commonly cause reporting across companies to be inconsistent in their accounting decisions and therefore not comparable in their reporting. This is an issue that extends beyond the power sector.

Accounting for Products Distributed but not Sold

Accounting and reporting emissions associated with products that are distributed but not sold, such as commodity natural gas and electricity transported via common carrier infrastructure, presents challenges for owners of this type of infrastructure because the available GHG accounting guidance for addressing this situation is not definitive.

There are several alternative approaches electric companies and combined utilities may use to account for and report emissions associated with the transport of products that are distributed but not sold via common carrier infrastructure based on different interpretations of the GHG Protocol. These include: (i) common carriers can establish their GHG emissions reporting boundaries to include *all* electricity and natural gas the company transports; (ii) common carriers can provide GHG-related information about their operations under the Scope 3 Standard's guidance for *optional reporting*; (iii) common carriers can report on optional entity-level, product-level and/or delivery-level performance indicators, such as GHG emissions intensity metrics; or (iv) common carriers can exclude accounting and reporting of emissions associated with any *ambiguous* boundary due to a lack of guidance from the Scope 3 Standard accompanied by a justification for the exclusion in their GHG emissions inventory report.

While the GHG Protocol's existing guidance does not provide specific and complete guidance for conducting GHG emissions accounting and reporting for common carrier energy infrastructure companies, there is a myriad of guidance available from other GHG reporting programs that contain additional interpretations that may be used to categorize these indirect emission sources. Nine separate reporting programs or overarching guidance materials address common carrier scenarios and provide some guidance on associated GHG emissions accounting.

A CRITERIA FOR DETERMINING RELEVANT EMISSION SOURCES

The Scope 3 Standard provides criteria for determining which emission sources to consider including or excluding when developing a scope 3 emissions inventory. The criteria listed below are useful for interpreting an organization's indirect emissions impacts through a value chain assessment framework and provide a good starting point for determining which scope 3 emissions sources may be most relevant to a company's operations.

1. **Size**: the source contributes significantly to the company's total anticipated scope 3 emissions.
2. **Influence**: there are potential emission reductions that could be undertaken or influenced by the company related to the source.
3. **Risk**: the source contributes to the company's GHG risk exposure.
4. **Stakeholders**: the source is deemed critical by key stakeholders.
5. **Outsourcing**: the source is an outsourced activity previously performed in-house, or activities outsourced by the reporting company that are typically performed in-house by other companies in the reporting company's sector.
6. **Sector guidance**: the source is identified as significant by sector-specific guidance.
7. **Other**: the source meets any additional criteria for determining relevance developed by the company or industry sector.

B GHG ACCOUNTING FOR A WIRES-ONLY COMPANY DELIVERING PURCHASED POWER TO END USERS

In the example below, we illustrate the case of a wires only LSE that purchases power for re-sale to end users. The wires-only company purchases 35% of the power generated by the third-party generator. Additionally, the current line loss rate in its distribution system is assumed to be 5%. The total upstream emissions associated with all power entering the LSE's boundary is 7,876,750 mt CO_2e.

Entity	Total MWh
Third-party generator: Total MWh generated	15,000,000
Wires only company: Total MWh purchased for re-sale to end-users (35%)	5,250,000
Wires only company: Total MWh delivered to end-users	4,987,500
Wires only company: Total MWh lost in delivery system (i.e., 5% line losses)	262,500
Metrics	
T&D line losses	5%
Percent of generated power purchased by wires-only company	35%
Percent of generated power delivered by wires-only company to end-users	33.25%
EF1 (mt CO_2e/MWh)$^+$ $^+$EF1 = Generator's Total Scope 1 (mt CO_2e)/Total MWh Generated	1.50
EF2 - Purchased Electricity Upstream Emissions (mt CO_2e/MWh)$^\wedge$ $^\wedge$EF2 = Generator's Scope 3, Activity A (mt CO_2e)/Total MWh Generated	0.000333
EF3 - Electricity Life Cycle EF (mt CO_2e/MWh)$^\#$ $^\#$EF3 = EF1 + EF2	1.5000333

Scenario 1 – Calculating scope 3 with total net MWh delivered to end-users

In this scenario, both the wires-only company and end-users account for all the upstream emissions associated with purchased power and consumed through T&D losses. Additionally, the LSE accounts for the upstream emissions associated with power delivered to end-users. The mass-balance check confirms both entities account for the total 7,876,750 mt CO_2e across their scope 2 and scope 3 totals. No double counting across an inventory occurs.

	Emissions (mt CO_2e)				
Entity	**Scope 1**	**Scope 2**	**Scope 3**		**Mass-balance check**
Electricity Generator	**22,500,000**	*	Category 3, Activity A	**5,000.00**	(22,500,000 + 5,000) × 35% = **7,876,750**
Wires only company	*	262,500 MWh × EF1 = 393,750	Category 3, Activity B	262,500 × EF2 = **87.50**	393,750 + 87.5 + 7,482,912.5 = **7,876,750**
			Category 3, Activity D	4,987,500 × EF3 = **7,482,912.5**	
End-users	*	4,987,500.00 MWh × EF1 7,481,250	Category 3, Activity B	4,987,500.00 × EF2 = **1,662.50**	7,481,250 + 1,622.5 + 393,837.5 = **7,876,750**
			Category 3, Activity C	4,987,500.00 × (0.05/1-0.05) × EF3 = **393,837.50**	

* Not displayed/calculated for simplification.

Scenario 2 – Calculating scope 3 with total MWh <u>purchased</u> for re-sale to end-user

In this scenario, both the wires only company and end-users account for all the upstream emissions associated with purchased power and consumed and T&D losses. However, since the LSE accounts for the upstream emissions associated with power purchased, <u>the LSE inadvertently double counts</u> the emissions under scope 2 and scope 3 associated with T&D losses. The mass-balance check confirms the LSE double counts 393,837.5 (393,750 + 87.5) in its scope 3, category 3 (activity D).

	Emissions (mt CO_2e)				
Entity	**Scope 1**	**Scope 2**	**Scope 3**		**Mass-balance check**
Electricity Generator	**22,500,000**	*	Category 3, Activity A	**5,000.00**	(22,500,000 + 5,000) * 35% = **7,876,750**
Wires only company	*	262,500 MWh × EF1 = **393,750**	Category 3, Activity B	262,500 × EF2 = **87.50**	393,750 + 87.5 + 7,876,750 = **8,270,587.5**
			Category 3, Activity D	(5,250,000 × EF3) = **7,876,750**	
End-users	*	4,987,500.00 MWh × EF1 **7,481,250**	Category 3, Activity B	(4,987,500.00 × EF2) = **1,662.50**	7,481,250 + 1,622.5 + 393,837.5 = **7,876,750**
			Category 3, Activity C	4,987,500.00 × (0.05/1-0.05) × EF3 = 393,837.50	

* Not displayed/calculated for simplification.

Scenario 3 – Calculating scope 3 with total MWh purchased for re-sale to end-user (without reporting scope 2).

This scenario is the same as Scenario 2; however, the LSE opts to avoid double counting by not reporting scope 2 emissions. <u>Note: this approach directly contradicts the guidance as determined by the GHG Protocol.</u>

	Emissions (mt CO_2e)				
Entity	**Scope 1**	**Scope 2**	**Scope 3**		**Mass-balance check**
Electricity Generator	**22,500,000**	*	Category 3, Activity A	**5,000.00**	(22,500,000 + 5,000) × 35% = **7,876,750**
Wires only company	*	Not in accordance with scope 2 guidance	Category 3, Activity B	No purchased/acquired electricity reported	**7,876,750**
			Category 3, Activity D	(5,250,000 × EF3) = **7,876,750**	
End-users	*	4,987,500.00 MWh × EF1 **7,481,250**	Category 3, Activity B	(4,987,500.00 × EF2) = **1,662.50**	7,481,250 + 1,622.5 + 393,837.5 = **7,876,750**
			Category 3, Activity C	4,987,500.00 × (0.05/1-0.05) × EF3 = **393,837.50**	

* Not displayed/calculated for simplification.

The mass-balance check in the scenarios above calculated whether all life-cycle emissions associated 5,250,000 MWh power generation (from fuel extraction to generation), 7,876,750 mt CO_2e, are reported as indirect emissions in other organization's scope 2 and scope 3 estimates.

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