Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases

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ABSTRACT

This report examines the greenhouse gas (GHG) accounting methods in use by various GHG reporting programs and jurisdictions in the United States and internationally to account for electric company GHG emissions, with a focus on the accounting for indirect CO_2 emissions associated with wholesale power transactions for delivery to retail end-use customers. It describes different GHG accounting options available to account for the GHG emissions associated with electric power sold to end-use consumers.

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PRIMARY AUDIENCE: Electric company resource planners, staff engaged in corporate strategy, EH&S staff engaged in greenhouse gas (GHG) emissions accounting and reporting

SECONDARY AUDIENCE: State regulatory staff and external stakeholders interested in electric company GHG emissions reporting

KEY RESEARCH QUESTION

This report was prepared to answer a simple question: "*How should an electric company account properly for the GHG emissions associated with the electricity it generates and purchases in wholesale electricity markets and resells to end-use consumers*?"

This report examines the rules and methods being used in different jurisdictions, and different GHG reporting programs, to account for electric company GHG emissions, including those associated with wholesale power transactions. The different rules and methods used to estimate GHG emissions have evolved because of the different intended uses of the data, different policies, and the different motivations companies have for reporting their GHG emissions.

RESEARCH OVERVIEW

EPRI explored and described different GHG accounting methods and approaches being used in the United States and internationally to account for the GHG emissions associated with "undifferentiated" electric power purchased through regional wholesale power markets.

EPRI compared different GHG accounting approaches, and highlighted their similarities and differences related to accounting for GHG emissions embedded in wholesale power purchases. EPRI described in a qualitative manner the potential implications to an electric company associated with using each of the alternate accounting method described. EPRI highlighted the use of GHG emissions accounting information and the implications for electric company resource planning, sustainability and GHG emissions accounting.

Evaluation of the relevant methods to account for GHG emissions of the electric power sector required examining emerging policy and regulatory developments in the United States and internationally, and an array of mandatory and voluntary programs with different rules and modalities for accounting, with many applying entirely distinct GHG accounting frameworks.

KEY FINDINGS

The appropriateness of a given GHG accounting method depends on the goals for using it, the presiding policy motivations, data quality needs and availability, and analytical resource constraints.

While formal GHG accounting methods have evolved considerably in recent years, accounting for the GHG associated with purchased power for resale to end-use consumers is complex and continues to be an uncertain area of GHG accounting

Accounting for GHG emissions from a specific facility or, in the case of an electric company, a generating unit, is the most resolved accounting framework. Facility-based accounting is the commonly used accounting framework for government regulatory programs that entail legal compliance obligations, such as mandated performance standards or cap-and-trade program systems. Using a facility-based approach, an electric company would account only for the GHG emissions of its generating assets and would not account for or report GHG emissions associated with purchased power for resale to end-use customers.

EPRI identified and described five approaches that can be used by electric companies to address the GHG emissions embedded in wholesale power purchased for resale to end-use customers. These options include:

1. A **narrow facility-based approach** that accounts for GHG emissions of facilities owned and operated by an electric company, but excludes emissions associated with power purchases
2. A **simplified portfolio approach** that accounts for GHG emissions of resources owned and operated by an electric company as well as emissions associated with *net* wholesale electricity purchased using a system average emission rate based on all resources on the grid.
3. A **specified portfolio approach** that accounts for GHG emissions of resources owned and operated by an electric company, and any specified wholesale electricity procurement, plus emissions associated with net wholesale purchases using the system average emission rate.
4. An **annual net-short approach** that accounts for the GHG emissions associated with non-dispatchable resources owned and contracted by an electric company, and emissions associated with net system power purchases attributed using a residual system emission rate.
5. An **hourly net-short approach** that utilizes hourly residual emission rates.

WHY THIS MATTERS

The need to account for GHG emissions associated with power resold to consumers arises in several important contexts for electric companies, including measuring progress towards achieving voluntary corporate GHG emissions reduction goals, conducting integrated resource planning activities, and for corporate sustainability reporting.

HOW TO APPLY RESULTS

This report describes methods that can be used by electric companies to account for GHG emissions associated with power purchased in wholesale markets for resale to end-use customers. EPRI identified and described five approaches that can be used by electric companies to account for these GHG emissions in their IRPs, corporate sustainability reports and other corporate communications.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- *Grounding Decisions: A Scientific Foundation for Companies Considering Global Climate Scenarios and Greenhouse Gas Goals*, EPRI #3002014510. Available online at: https://www.epri.com/#/pages/product/3002014510/
- *A Technical Foundation for Company Climate Scenarios and Emissions Goals*, EPRI #3002014515. Available online at: https://www.epri.com/#/pages/product/3002014515/

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PROGRAM: Integrated Energy Planning, Market Analysis and Technology Assessment (Program 178).

GLOSSARY OF TERMS

CAA	Clean Air Act
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregators
CEC	California Energy Commission
CEMS	Continuous emission monitoring systems
CNS	Clean Net Short
CPUC	California Public Utilities Commission
EEI	Edison Electric Institute
EGU	Electricity generating unit
EPA	United States Environmental Protection Agency
EU ETS	European Union Emissions Trading System
GHG	Greenhouse gas
GHGMI	Greenhouse Gas Management Institute
GHGRP	U.S. Greenhouse Gas Reporting Program (40 CFR Part 98)
IPCC	Intergovernmental Panel on Climate Change (IPCC)
IOU	Investor-owned utility
IRP	Integrated resources planning
ISO	Independent System Operator
KWh	Kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LSE	Load-serving entity
MIRECS	Michigan Renewable Energy Certification System
MW	Megawatt
MWh	Megawatt-hour
NERC	National Electricity Reliability Coordinating Council
NGCC	Natural Gas Combined Cycle
NREL	National Renewable Energy Laboratory
PV	Photovoltaic
REC	Renewable Energy Credit (or Certificate)
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
RTO	Regional Transmission Organization

TCR	The Climate Registry
T&D	Transmission and distribution systems
UNFCCC	United Nations Framework Convention on Climate Change
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Information System

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INTRODUCTION

In recent years, a number of electric utilities in the United States have adopted ambitious voluntary goals to reduce their greenhouse gas[1] (GHG) emissions. To assess their progress towards achieving these emissions reduction goals requires electric companies to account for their GHG emissions. Formal GHG accounting methods have evolved considerably in recent years, but some aspects of corporate GHG accounting remain less well specified.

One specific aspect of GHG accounting is particularly challenging for large "load serving entities[2]" (LSEs) that generate electric power and buy and sell electric power in wholesale power markets. These companies are challenged by the need to properly account for the GHG emissions embedded in the electric power they buy to meet their customers' electricity needs.

The need to account for GHG emissions associated with purchased power used for resale to end use consumers arises in several important contexts for LSEs, including measuring progress towards achieving voluntary corporate GHG emissions reduction goals, conducting integrated resources planning (IRP) activities, and corporate sustainability reporting.

1.1 Project Background

In 2018, DTE Electric Company (DTE[3]) engaged EPRI and the Greenhouse Gas Management Institute (GHGMI[4]) to help the company better understand how other LSEs and jurisdictions have addressed this issue, and how different GHG accounting methods may be potentially implemented by DTE and other LSEs in the future.

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[1] The term "greenhouse gas" refers to six gases recognized by the Intergovernmental Panel on Climate Change (IPCC). These six GHGs are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), Perfluorocarbons (PFCs), hydrofluorocarbon (HFCs), and sulfur hexafluoride (SF_6). Carbon dioxide is the most prevalent and important GHG, and accounting for CO_2 emissions in the focus of this report

[2] The term "load-serving entity" generally refers to a broad range of entities engaged in the sale of electric power to retail customers including investor-owned utilities, electric cooperatives, municipal utilities, public power agencies, community choice aggregators and energy service providers. The term electric "utility" often refers specifically to a vertically-integrated LSE that also owns and operates generating resources, transmission and distribution lines. Investor-owned utilities (IOUs) and other LSEs, such as community choice aggregators (CCA) and energy service providers (ESP) are regulated by state public utilities commission (PUC). In this report, we usually use the term "utility" because this report was prepared for DTE Energy, but the methods discussed here are also relevant to other LSEs who are interested in estimating GHG emissions associated with serving end-use load. We have specifically used the term LSE in some places in the report because using the term "utility" in these specific cases would be incorrect or confusing.

[3] We use the acronym DTE to refer to DTE Electric in this report. DTE Electric is a wholly-owned subsidiary of DTE Energy.

[4] The Greenhouse Gas Management Institute is a 501(c)(3) non-profit organization dedicated to training tomorrow's experts on the principles, concepts and techniques to manage and credibly account for GHG emissions. See https://ghginstitute.org for more information.

The objectives of this project are: (i) to improve understanding of the different approaches and methods used by companies and jurisdictions to account for the GHG emissions embedded in wholesale electric power purchased to be resold to end-use customers; and, (ii) to gain deeper understanding of how these different accounting approaches may impact company activities such as IRP, sustainability, and GHG emissions reporting.

This report was prepared to answer what seems to be a simple question: "*How should a utility properly account for the GHG emissions associated with the electricity it purchases in wholesale electricity markets and resells to end-use consumers?*" The short answer is, it depends; the long answer follows. To properly explore this GHG accounting question, it is necessary to understand the commonly used practices embodied in various mandatory and voluntary GHG emissions reduction standards and programs.

This report examines the rules and methods used in select jurisdictions and major GHG reporting programs to account for electric utility GHG emissions, including those associated with wholesale power transactions. The different rules and methods used to estimate GHG emissions have evolved as a result of the different intended uses of the data, different policies, and different motivations companies and other entities have for reporting their GHG emissions.

1.2 Report Organization

Section 1 of this report describes DTE Electric company (DTE), the company's voluntary GHG emissions reduction target, and its interest in learning more about accounting for the GHG emissions associated with serving its customers.

Section 2 delves into the evolving carbon and clean energy policy context associated with GHG emissions accounting.

Section 3 provides an overview of different kinds of wholesale electric power transactions.

Section 4 describes general GHG accounting frameworks, and how they apply to GHG emissions accounting by electric companies.

Section 5 summarizes specific accounting methods being used in the United States and internationally to account for GHG emissions as part of existing mandatory regulatory and voluntary programs.

Section 6 considers DTE's current approach to GHG accounting and describes several alternative approaches that could be used by DTE and other electric companies to account for the GHG emissions associated with power purchased for resale to end-use customers.

Section 7 provides a brief summary of this research project and its overall findings.

1.3 DTE Electric Company

DTE Electric Company (DTE), a subsidiary of DTE Energy, is an electric utility based in Detroit, Michigan. DTE serves more than 2 million retail customers in south-eastern Michigan, with a total system load of 46,525 GWh in 2017. Peak load in the same year was 11,272 MWh.

DTE owns and operates 7,044 MW (summer capacity) of fossil-fired generating resources, 88% of which are coal-fired units. DTE plans to retire three of its existing coal plants (2,159 MW of combined capacity) by 2023, and replace these with combined cycle natural gas turbines.

DTE also owns and operates a 1,161 MW nuclear facility, a fleet of wind power generators with a total capacity of 451MW, and several solar parks totaling 14.4 MW of capacity. DTE holds 19 power purchase agreements (PPAs), including several that contain Public Utility Regulatory Policy Act (PURPA) qualifying facilities. Electricity under these contracts is provided by hydroelectric, waste, landfill gas, wind and biomass generation. Finally, DTE owns 1,089 MW of pumped hydroelectric capacity.

DTE's service territory lies completely within the area controlled by the Midcontinent Independent System Operator (MISO), and DTE participates in the MISO markets as both a generation operator and LSE.

1.4 DTE's Voluntary GHG Emissions Reduction Goal

According to DTE's existing GHG emissions reporting, as shown in Table 1-1, DTE emitted 39,177,354 metric tons of carbon dioxide ($MtCO_2$) in 2005 from its owned generation resources. In addition, the total amount of power purchased by DTE in 2005 reportedly accounted for an additional 806,515 $MtCO_2$ in 2005. In 2016, DTE's emissions from its owned generation declined to 28,948,987 $MtCO_2$, while the CO_2 emissions associated with total purchased power increased to 5,982,810. As shown, DTE's CO_2 emissions from owned and purchased resources fell from 39,983,869 in 2005 to 34,931,798 $MtCO_2$.

Table 1-1
Summary of DTE's CO_2 Emissions 2005-2016

GHG Emissions Source	2005 (metric tons CO_2)	2016 (metric tons CO_2)
Total Owned Generation	39,177,354	28,948,987
Total Purchased Power	806,515	5,982,810
Total Owned plus Purchased	39,983,869	34,931,798
Source: 2018 Environmental, Social, Governance, and Sustainability Report. DTE Energy, Detroit, Michigan: 2018.		

In May 2017, DTE adopted an ambitious voluntary corporate GHG emission reduction goal. DTE aims to reduce its CO_2 emissions by 30% relative to 2005 levels by the early 2020s, and by 80% by 2050. Its interim targets are a 45% reduction of CO_2 emissions by 2030, and a 75% reduction by 2040. DTE plans to achieve these goals by retiring its coal fleet, constructing new renewable generation, and investing in energy efficiency, demand response, and grid modernization [1].

DTE has not specified what specific corporate activities are included in its voluntary GHG emissions reduction target, or the accounting approach it plans to use to monitor its progress toward achieving it. For purposes of this paper, we understand this as a commitment by DTE to reduce the CO_2-equivalent emissions associated with electric generation used to serve the company's retail load over the target timeframes.[5]

[5] This report focuses on CO_2 emissions, which account for the vast majority of global warming potential-weighted emissions from electricity generation. The options and discussion in this report, though, are equally applicable if extended to other GHGs (e.g., methane and nitrous oxide) from generation. Some statistics cited in this report are in carbon dioxide equivalent (CO_2eq), a standard unit used to describe the global warming impacts of several different types of GHG emissions simultaneously.

2
CHANGING POLICY CONTEXT FOR GHG ACCOUNTING

Utilities and utility regulators increasingly are being pressured to consider and account for GHG emissions, and to factor these emissions into their investments and other decision-making processes. For example, investor-owned utilities (IOUs) in California and Oregon must include a carbon price when considering scenarios in their IRPs. Renewable energy mandates affect the types of wholesale electricity an LSE may purchase. Utility "green power" pricing programs require utilities to build new renewable generation resources, or procure renewable energy contracts (e.g., specified PPAs or renewable energy certificates (RECs)) if their own renewable generation is insufficient to serve consumer enrollment in the program.

This section provides an overview of select key policies that drive investment in low carbon and clean energy electricity, with a view to provide context for the discussion of GHG accounting methods that follows.

2.1 Greenhouse Gas Mitigation

Many government jurisdictions around the world have adopted programs to reduce GHG emissions from the electric power sector. Although the United States currently lacks a mandatory federal program to reduce GHG emissions from the electric power sector, some individual states have enacted their own mandatory emissions reduction programs. For example, nine states in the Northeast created the Regional Greenhouse Gas Initiative (RGGI) — the first mandatory GHG cap-and-trade program to be implemented in the United States — which requires electric companies in these states to reduce their CO_2 emissions.

On the west coast, California operates a multi-sector cap-and-trade program that is linked to a similar program in the Canadian province of Quebec. Some observers expect Oregon to adopt a cap-and-trade program intended to link to California's in the 2019 legislative session. Other states are pushing policies to require utilities to divest from coal-fired generation.

In addition to these mandatory state efforts to reduce GHG emissions, many electric utilities have adopted ambitious GHG emissions reduction goals and have been implementing voluntary programs to mitigate their GHG emissions.[6] In addition to DTE, other utilities have adopted ambitious GHG reduction goals, including Alliant, Ameren, American Electric Power, CMS Energy, Dominion, Duke, Entergy, Exelon, Green Mountain Power, Madison Gas & Electric, Montana-Dakota Utilities, National Grid, NextEra Energy, NiSource, Pacific Gas & Electric, Pinnacle West, PNM Resources, Portland General Electric, PPL, PSEG, SCE, Southern Company, Vectren, WEC, and Xcel Energy. Many of these utilities have been engaged with

[6] For example, in 2017 Ameren Missouri announced plans to reduce its CO_2 emissions 35 percent by 2030, 50 percent by 2040 and 80 percent by 2050 (based on 2005 levels). Early in 2018 American Electric Power (AEP) announced a strategy to reduce its CO_2 emissions by 60% from 2000 levels by 2030, and 80% from 2000 levels by 2050. And, more recently, Southern Company announced its long-term goal of transitioning to "low- to no- carbon operations" by 2050.

various investor stakeholder initiatives that have encouraged IOUs to disclose their GHG emissions and commit to emission reduction targets.[7]

2.2 Renewable Mandates and Portfolio Standards

State Renewable Portfolio Standards (RPS) and other renewable procurement mandates aim to drive utility investments in renewable generating resources. Electric companies in many parts of the United States now are required to meet state-based RPS goals that typically mandate a specific percentage of the electricity sold to end users be derived from approved "renewable resources." The requirements for the type and location of eligible renewable resources that qualify under specific RPS programs differ widely across states.

While most states with RPS goals have set targets of 5 to 10 to 20 percent of electricity to be generated by renewable sources, other states have set goals that will fundamentally change their systems. For example, California set a goal of 50 percent renewable electricity by 2030 and Hawaii aims to get 100 percent of its electricity from renewables by 2045.

As of 2018, 29 States and the District of Columbia had in place an RPS or other resource-specific utility procurement mandate. Lawrence Berkeley National Laboratory (LBNL) estimates that mandated increases in RPS targets that already have been enacted will drive increases in aggregate electricity sales from renewable resources from 11% to 15% by 2030 [2]. Several States also are considering increasing their existing RPS targets, although a smaller number are considering lowering or eliminating their RPS mandates [2].[8]

2.3 Voluntary Green Power Purchasing Programs

In addition to mandated RPS, individual and corporate electricity consumers are expressing preferences to purchase renewable electric power. As a result, a large number of different types of "green power" pricing programs have been implemented in recent years by electric companies around the country.[9] There are many different types of these utility programs, but typically they require consumers who want to buy "green" power to pay a small premium on their electric bills to support development of new renewable generation or the purchase of qualifying RECS.

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[7] "Duke Energy, SSE, and PPL, have already issued reports including a 2-degree scenario analysis, and many others have indicated that they plan to do so soon in conjunction with setting new long-range greenhouse gas reduction goals." *Source*: https://www.ceres.org/news-center/press-releases/new-ceres-framework-enables-us-electric-power-industry-assess-climate. In response to shareholder resolutions, Entergy announced in 2018 that they intend to produce a report evaluating the risks to the company of a two-degree scenario in which the world is quickly decarbonizing. *Source*: https://www.asyousow.org/press-releases/2018/5/4/entergy-responds-to-shareholder-distributed-energy-business-model-proposal-company-commits-to-prepare-two-degree-risk-report

[8] LBNL also notes that a few states also have created separate "clean peak" standards or energy storage targets in tandem with an RPS.

[9] *Quantifying Greenhouse Gas Emissions Reductions Associated with Large-Scale End-Use Energy Efficiency Projects*. EPRI, Palo Alto, CA: 2016. 3002005589. Appendix C of this report provides an overview of a number of green power programs that have been implemented by electric companies in recent years.

In recent years, many large consumer-facing corporations and some municipalities have made commitments to "purchasing"[10] some or all their electricity from renewable resources.[11] For example, both Apple and Google announced their worldwide operations now are powered with 100 percent renewable generation resources. [12]

In 2017, the National Renewable Energy Laboratory (NREL) reported that approximately 5.5 million customers made procurement claims to 112 million MWh of renewable electricity, or about 3 percent of U.S. retail electricity sales [3]. A few communities, primarily in California, are also creating community choice aggregation (CCA) mechanisms. These new CCAs make it possible for a community to procure wholesale electric power directly for their citizens. In these cases, the CCA continue to rely on the existing local utilities to own, operate, and plan the transmission and distribution systems [4].

Currently, most voluntary programs (46% in 2017) allow consumers to participate in green programs by purchasing excess RECs (i.e., those not used for utility compliance under a mandatory RPS program [3]). But, a fast-growing trend is the use of renewable power purchase agreements (PPAs) and virtual PPAs, which typically take the form of financial contracts between a large corporate electricity consumer and an independent power producer [5].[13] In North America, 2.78 GW of renewable electricity was claimed through new PPAs in 2017, with most PPAs signed by major companies in the information technology sector [6].[14]

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[10] "Purchasing" here is in quotes because it is economically debatable whether retiring non-compliance RECs, using virtual PPAs, or making other renewable attribute claims entail proper ownership transactions of electricity from specific generators [7].

[11] For example, see the RE100 initiative (http://there100.org/), and the Renewable Energy Buyers Alliance (REBA), (http://rebuyers.org/wp-content/uploads/2017/10/0.-REBA-2017-Complete-deck-2.pdf)

[12] https://www.forbes.com/sites/energyinnovation/2018/04/12/google-and-apple-lead-the-corporate-charge-toward-100-renewable-energy/#714772371b23 .

[13] A virtual PPA is a form of financial hedge. The American Council on Renewable Energy (ACORE) describes a virtual PPA as when "the purchaser agrees to buy an amount of power from its local utility or another entity for a fixed rate. Meanwhile, the power producer agrees to generate and sell the same amount of renewable energy into the grid at the variable market (or merchant) rate. When the market rate exceeds the fixed rate, then the producer will pay the excess amount to the purchaser. When the market rate is less than the fixed rate, then the purchaser will make a payment to the producer equal to the difference between the fixed and market rates." <https://acore.org/wp-content/uploads/2017/12/Renewable-Energy-PPA-Guidebook-for-Corporate-and-Industrial-Customers.pdf>

[14] This trend in consumer choice for renewable electricity claims is not limited to the United States. As of early 2018, PPAs for renewable electricity had been executed in 75 countries. However, most transactions still occur in Europe and North America [8].

3
WHOLESALE POWER TRANSACTIONS

3.1 Market Context

Wholesale electricity markets in the United States have changed dramatically in the past 20 years. While traditional electricity markets dominated by vertically-integrated utilities continue to exist, primarily in the Southeast and Northwest, a significant portion of electric generation and load in the United States is now managed by a Regional Transmission Organizations (RTO) or Independent System Operators (ISO).[15] These organizations operate the electricity transmission system within their footprints, ensure non-discriminatory access to transmission, and ensure system reliability. The ISOs also operate organized wholesale electricity markets.

Organized wholesale electricity markets help lower costs and improve the overall efficiency of the electric power system by fostering competition across generators. A “security-constrained economic dispatch” is used to dispatch electric generation resources across an entire ISO footprint based on generator bid prices, load, and system constraints (e.g., transmission availability and congestion) to minimize total system cost.

In areas of the country not served by an RTO or ISO, utilities manage their own systems and dispatch their own resources. They also transact electricity bilaterally and via exchanges to manage their generation supply and load. The existence of “power pools,” where utilities essentially “pool” their generation, increases efficiency by dispatching resources based on cost (i.e., merit order).

3.2 Utility Participation in Organized Markets

Utilities that operate within an ISO typically are required to bid all the electric power they generate into the ISO, and to purchase power from the ISO to meet customer demand.

Within an organized electricity market, such as the one operated by the MISO, electric companies submit bids or bid curves to make their resources available to the market operator for dispatch, indicating a price and MW quantity for specific intervals. Typically, bids are submitted for hourly time intervals for the following day (i.e., the day-ahead market), and for 15- and 5-minute increments in the real-time markets. Because the market operator dispatches the system economically, an electric company’s ownership or contract for a specific generating resource does not guarantee that a specific generation resource will be dispatched by the system operator at any given point in time. If a specific generation resource’s bid is higher than the market clearing price at a given time, or if there are local transmissions constraints, the resource will not be dispatched. If an electric company wants to increase the likelihood that a specific generation resource will be dispatched, it can submit a low- or zero-price bid. All generators that are dispatched receive the same market clearing price, rather than their bid price, for their generation output.

[15] As of 2017, two-thirds of U.S. load was located in ISO/RTO regions [10].

Electric utilities also submit load forecasts to the market operator in the day-ahead market and adjust these in the real-time market. To the extent a utility has flexible load that is willing to curtail in real-time (e.g., demand response), the utility also submits minimum offer bids to indicate the MW quantity that can be curtailed, and at what price.

For the purposes of this report, it is critically important for readers to understand that electric power purchased from a wholesale power market like MISO in real time is *undifferentiated*, as it is essentially a mix of electric power generated by all of the resources generating across the entire ISO system at the time the electricity is used. Because of this, utilities that buy power through an ISO have no way to know the specific sources of the electricity they purchased, or the GHG emissions associated with it.

Although utilities like DTE may own or have PPAs with specific power generation resources, such as wind resources, the actual electric power received at any given moment is determined by the generation resources operating at that moment, and do not relate to the specific generation sources owned or included in a company's PPA.

3.2.1 Variable Renewable Energy in Centralized Markets

Renewable energy resources typically have no fuel costs, and as a result their marginal cost of generation is zero. Because these resources do not have to cover marginal costs, owners and operators of these resources typically bid renewable generation into wholesale markets at a zero price. This approach ensures their renewable resources will be dispatched in the power market and will receive the market-clearing price, even during hours when the price is low.

Because renewable resources like wind and solar photovoltaic (solar PV) exhibit uncertain and variable output, it is challenging for market operators to manage electric systems to handle the swings in renewable output in regions where renewable penetration is high like in California. While operators generally prefer to decrease output of higher-cost, fossil-fired resources when renewable output is high, oversupply of generation in a market also can require curtailment of renewable resources if the excess generation cannot be exported into neighboring regions.

Utilities that procure renewable resources to meet RPS requirements, or for other reasons, typically contract for the full generation output from these resources and the corresponding RECs of the facility, regardless of when that electricity is generated.

3.3 Bilateral Transactions

Electric companies also purchase electric generation and capacity on a bilateral basis, or via electronic trading platforms, to ensure that energy and capacity are available when needed. In ISO regions, contracts for physical delivery (as opposed to financial-only contracts) require the electricity to be bid and delivered into the organized market. In areas without an ISO, delivery is made through the utility's own transmission and distribution system.

When a utility buys electricity in the wholesale power market, the contracts typically only specify a price (for energy and transmission), delivery point, megawatt (MW) quantity, and duration. Because energy has been transacted traditionally as an undifferentiated commodity, there was no need to specify the resource. (This contractual structure is not true of ancillary services, such as flexible or fast-start capacity.) Thus, most wholesale electricity contracts between a generator and an LSE (and any intermediaries) are "unspecified" or undifferentiated.

That is, the electricity delivered under the contract may be sourced from <u>any</u> available generating resource. In contrast, if electricity purchased in response to a renewable mandate or from Qualified Facilities under PURPA, the specific generating resource is identified.

Finally, utilities may also sell electricity bilaterally when they have excess supply or wish to take advantage of favorable prices. Typically, this energy also is sold as undifferentiated power.

4

GHG EMISSIONS ACCOUNTING FRAMEWORKS FOR THE ELECTRIC POWER SECTOR

Multiple methods and standards exist to account for GHG emissions related to electric power sector emissions. Available methods differ significantly depending on their context and purpose. In this section, we provide an overview of the different conceptual frameworks for GHG emissions accounting. The following section describes specific GHG accounting standards and programs, some of which are hybrids that combine elements of at least two frameworks.

GHG accounting frameworks principally are defined by clearly drawing the system boundaries within which emissions (and removals) of GHGs are counted. **Emissions occurring outside these boundaries are excluded from the accounting**. The specific GHG emissions sources to be included or excluded depends on the purposes for which the accounting is undertaken. In general, system boundaries for GHG accounting purposes can be defined along two dimensions.

First, the system boundaries can be defined based on the set of emissions-generating *activities* that are considered relevant for a particular accounting exercise. For example, relevant activities may be those that occur within a company's organizational boundaries, within a particular economic sector, or within the boundaries of a jurisdiction or territory. The *types* of activities considered relevant may also vary for different accounting exercises (e.g., electricity generation only, or all emissions-generating activities within the boundaries of an organization).

Second, the system boundaries can be defined based on the *scope* of relevant emissions generated or caused by covered activities. Different activities may give rise to emissions *directly* (e.g., combustion of fossil fuels) and *indirectly* (e.g., through extraction, production, and transportation of fossil fuels). Whether indirect emissions are considered relevant depends on the accounting exercise being conducted and its purpose. The specific types of GHG emissions considered relevant (e.g., CO_2 and/or other GHGs) also can vary from context to context.

GHG accounting frameworks also can be distinguished based on whether they are *attributional* in nature (i.e., focused on attributing GHG emissions — direct or indirect — to particular activities) or *causational* (i.e., focused on determining *changes* in emissions caused by a particular action, intervention, or activity, also referred to as consequential).

Attributional and causational methods are methodologically distinct and generally should not be combined into a single accounting framework. For example, accounting frameworks focused on *attributing* emissions to electricity generation should not be combined with methods that estimate emissions *displaced or avoided* by the same generation. In an attributional framework, the goal is to ensure that emissions attributed to individual generation resources will sum to an overall total (measured or estimated) emissions from all resources or entities. Subtracting emissions that *would have occurred in the absence* of a particular action is contrary to an attributional accounting framework because then emissions across entities would no longer sum to the correct system-wide total.

Major GHG accounting frameworks relevant to the electricity sector are listed in Table 4-1 and described further below.

Table 4-1
Major GHG Accounting Frameworks Relevant to the Electricity Sector

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

Finally, GHG accounting frameworks are often combined with – but are distinct from – GHG *reporting* standards. Various corporate environmental sustainability reporting standards have been developed, for example, to provide a common template for companies to report on progress towards achieving sustainability goals in ways that are consistent and comparable. These standards often prescribe the use of particular GHG accounting frameworks (e.g., corporate entity-level accounting, following the *Corporate Accounting and Reporting Standard* described in section 4.2), and may also prescribe specific *methods* to calculate emissions from specific sources or activities in conjunction with these standards (see Box 4-1).

Box 4-1. Corporate Environmental Sustainability Reporting in the Power Sector

In recent years, electric power companies have faced increasing pressure from shareholders, consumers and other stakeholders to improve their corporate sustainability activities and reporting. **As part of this effort, a number of organizations have developed corporate sustainability reporting frameworks to be used to track key sustainability metrics over time and to report on progress towards achieving key corporate sustainability goals.**

For example, the Edison Electric Institute (EEI), a non-profit trade association comprised of investor-owned electric utilities and other power generators, recently unveiled a new environmental, social, governance (ESG), and sustainability-related reporting template. The purpose of this reporting tool is to help EEI's member electric companies provide the financial sector with more uniform and consistent ESG/sustainability data and information.[16]

Based on the EEI ESG/Sustainability reporting template, an electric company is encouraged to report the CO_2 emissions associated with its owned generation and total purchased electric power. The CO_2 emissions associated with its owned generation may be adjusted for equity ownership share to reflect the percentage of output owned by reporting entity.

In addition, the EEI reporting approach suggests that purchased power emissions should be calculated using the most relevant and accurate of the two following methods:

1. For direct purchases, such as PPAs, use the direct emissions data as reported to EPA;
2. For market purchases where emissions are unknown, use applicable regional or national emissions rate, including: ISO/RTO-level emission factors; The Climate Registry emission factors; or, eGrid emission factors.

4.1 Facility-Based Accounting

Accounting for emissions from a specific facility or, in the case of an electric company, a generating unit, is the most resolved accounting framework. The boundaries are defined by the physical footprint of the power plant or factory, or building, or another geographic site. Typically, only direct emissions occurring on this site counted, versus emissions that might be affected by the facility's operations, but which physically occur outside of the site's boundaries.

Facility-based **accounting is the most commonly used accounting framework for government regulatory programs that entail legal compliance obligations such as mandated performance standards or cap-and-trade systems.** Under a facility-based approach, an electric company would account only for emissions of its generating assets. Facility-based GHG accounting, in the context of regulatory-based emissions trading systems, is also referred to as "source-based" accounting, because it focuses on the physical facilities that are direct sources of emissions. Source-based emissions accounting often is used to assure compliance with government-mandated regulatory programs. For example, source-based accounting is used by the

[16] See http://www.eei.org/issuesandpolicy/finance/Pages/ESG-Sustainability.aspx, for more information about the EEI ESG/Sustainability reporting initiative.

federal government to ensure electric company compliance with the Clean Air Act, Title IV Acid Rain Program that regulates SO_2 and NO_X emissions, as well as, for reporting to the EPA under the GHG Reporting Rule.

4.2 Entity-Level Accounting

An entity can be a corporation, other type of organization, or even a person or group of people. Typically, it is represented by a legally incorporated entity. The widely accepted standard for attributing GHG emissions to an entity is the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) *Greenhouse Gas Protocol Corporate Accounting and Reporting Standard* ("Corporate Standard")[17] [11].

4.2.1 GHG Accounting Scopes

The Corporate Standard introduced the concept of accounting "*scopes*," which were defined to clearly delineate potential overlaps in the emissions footprints of different entities based on whether the emissions are *direct* or *indirect*. So-called Scope 1emissions are those arising from sources directly owned or controlled by an entity. Scope 2 emissions are indirect emissions associated with purchased electricity or heat that is consumed by an entity. Scope 3 emissions are all other indirect emissions attributable to an entity's activities, which may occur either "upstream" (e.g., associated with inputs to activities), coincident with activities (e.g., employee travel emissions), or "downstream" (e.g., associated with the use of products generated by an entity's activities). Under the Corporate Standard, the goal is to avoid any double counting of emissions within the same scope).

Under the Corporate Standard, reporting of Scope 1 and 2 emissions is required, while Scope 3 reporting is optional. This presumes that, for most organizations, Scope 1 and 2 sources will be the primary targets of efforts to manage GHG emissions. For some entities, however, Scope 3 emissions may offer a significant opportunity to achieve emissions reductions, both because of the quantity of emissions involved and the ability of an entity to influence those emissions through its own actions.

4.2.2 Purchased Power for Resale

The Corporate Standard specifically assigns to Scope 3 any GHG emissions associated with purchased electricity that is resold to end users (i.e., electricity purchased by an electric utility to meet customer load). This makes sense because the electric generators who sold the power would claim these emissions as Scope 1, while end users would report the emissions as Scope 2.

The only emissions an electric utility itself would count under Scope 2 are those emissions associated with electricity that is "consumed" during transmission and distribution to customers (e.g., transmission and distribution line losses). **Technically, this means that accounting for the GHG emissions embedded in power sold to customers is an "optional" accounting component of an electric company's total GHG emissions footprint.** However, since utilities often have some flexibility to choose the specific attributes of the electric power they purchase

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[17] See https://ghgprotocol.org/about-us for more information about *Greenhouse Gas Protocol Corporate Accounting and Reporting Standard.*

on behalf of their customers, it may make sense for an electric company to account for these emissions and include them in their GHG reduction goals.

Although the Corporate Standard—and the GHG Protocol Initiative's accompanying *Corporate Value Chain (Scope 3) Accounting and Reporting Standard* [12]—prescribe how GHG emissions associated with electricity purchases resold to end users should be *reported*, they do not prescribe specific methods for calculating and quantifying these emissions.

4.3 Sectoral Accounting

GHG accounting at the sectoral level addresses emissions from an entire industry, such as from the cement production or auto manufacturing sectors. This framework can draw on elements of facility, entity, and value chain accounting, and may involve both direct and indirect emissions. We will not discuss this GHG accounting framework any further in this report, but it is included here for completeness.

4.4 Jurisdictional or Territorial Accounting

Activity boundaries relevant for GHG accounting also can be set by the geographic boundaries of a political jurisdiction's territory. An example is at the country level, which is the basis of international treaties and agreements, such as the United Nations Framework Convention on Climate Change (UNFCCC) Kyoto Protocol and the 2015 Paris Agreement.

Generally, the emissions counted under jurisdictional accounting frameworks are those emissions released to the atmosphere by activities physically occurring within the jurisdiction's territory (i.e., direct emissions). However, there are also some jurisdictional approaches that incorporate indirect upstream and/or downstream emissions associated with goods that are imported or exported, which may be estimated using methods analogous to "value chain" accounting at a larger scale (discussed below). An example application for this kind of jurisdictional accounting framework is the United States Inventory of GHG Emissions and Sinks [13].

4.5 Value Chain Accounting

Value chain GHG accounting is focused on attributing indirect emissions to a particular activity or set of activities. It can be applied, for example, to estimate Scope 3 emissions in entity-level accounting. For a company, value chain emissions are those that are associated with the goods and services it purchases (upstream), and the products and services it sells (downstream), such as the energy used by its products, and the emissions from their disposal. However, value chain accounting also can be applied to a single, specific product (e.g., by accounting for all the energy and materials that feed into its production, and emissions associated with its use and disposal (often referred to as "product-based" accounting). Life-cycle assessment techniques and methods can be used to estimate value chain (and product) emissions.

In the context of the electric power sector, **value chain accounting approaches can be used to attribute GHG emissions to electricity consumption by end-users or load – aka "load-based" accounting.** Here, the challenge is to identify the specific mix of resources used to generate consumed electricity. In some cases, a specific generation resource can be identified and assigned to electricity that is consumed. In other cases, the source of electricity may be undifferentiated, in which case a methodology is needed to estimate some kind of an average resource mix. Load-based accounting can involve a combination of methods used to estimate GHG emissions from an electric utility's own resources as well as emissions associated with procured electricity.

One challenge electric companies face when considering load-based accounting is that the electric power purchased may not correspond to power actually consumed by the company's customers (i.e., purchases may not temporally or spatially match load).

Procuring RECs, for example, is considered to be a form of power purchasing by some market observers, but the renewable generation associated with RECs may not coincide in time or location with the purchaser's own load (or the load of its customers, in the case of a utility buyer). Similarly, utilities or companies with PPAs specific to generation resources cannot guarantee those resources will be dispatched coincident with their load, or that the contracted resources always will be used to fulfill power delivery obligations.

An additional issue that must be addressed when determining the GHG emissions attributable to electricity that is *consumed* is whether to calculate emission factors based on *power purchases* (i.e., using approaches referred to as "portfolio-based" methods in Section 5), or based on the resources that were actually *physically dispatched* to meet load. Approaches based on power purchases are referred to in Section 5 as "portfolio-based" methods; the "Clean Net Short" method described in section 5 is an example of an approach that attempts to match dispatch of power generation resources to load.

4.6 Project- and Policy-Based Accounting

The accounting frameworks discussed above are all *attributional*, meaning they attribute emissions to certain activities. For the electric power sector, attributional accounting is focused on quantifying the emissions "footprint" associated with electricity generation, purchasing, and/or consumption.

The other major category of GHG accounting frameworks is *causational.* These accounting frameworks are used to quantify changes in emissions caused by a specified intervention. Typically, such interventions are associated with the implementing a specific project, such as an energy efficiency project [9], construction and operation of a wind farm, or a specific policy (e.g., RPS policies).

In the electricity sector, two important conceptual differences between causational and attributional accounting approaches are the relevant *quantities* of electricity being examined, and the relevant *sources of emissions* involved. In causational accounting, the objective is to quantify an incremental amount of electricity that is generated (or avoided) by a project or policy (e.g., a new renewable energy project), relative to a counterfactual baseline (i.e., what would have happened in the absence of the policy or project being developed). The resulting change in emissions is then calculated by estimating what mix of resources *would have* been dispatched to generate the same amount of electricity in the absence of the intervention associated with the project or policy. Causational approaches focus on what resources are on the *margin* for dispatch during times when a project is active, and/or types of new capacity that would have been built in the baseline if the project had not been implemented. The emissions displaced or avoided by a project activity are calculated using a *marginal emission factor* (usually expressed in metric ton CO_2/MWh), which can be calculated in a variety of different ways for both existing resources (i.e., the "operating margin") and displaced/avoided new resources (i.e., the "build margin") [14].

Usually project- and policy-based accounting is focused on estimating GHG emission *reductions* resulting from projects or policy actions. As such, it is not directly relevant to addressing how to attribute GHG emissions to power purchases resold to end-users which is an attributional exercise. However, we have included the discussion of it here for completeness.

5
GHG ACCOUNTING METHODS

The GHG emissions accounting frameworks introduced in the previous section have been applied in different ways for a variety of regulatory and voluntary policy purposes, including implementing GHG cap-and-trade programs, power content disclosure, corporate sustainability reporting, and IRP. The selection of the appropriate GHG accounting method used is dictated by the goal of the accounting exercise, data availability, policy objective and external circumstances (e.g., stakeholder or stockholder demands, technical limitations). This section describes specific GHG accounting methods currently in use in the United States and internationally, and their applicability to the electricity sector.

5.1 Facility or "Source-Based" Accounting Methods

Facility, or source-based, accounting methods are used under existing regulatory programs such as local air pollutant permitting and compliance programs, hazardous air pollutant programs, and cap-and-trade programs, including the European Union's Emissions Trading System (EU ETS), RGGI, and the California GHG emissions cap-and-trade program.

In the United States, the U.S. EPA administers the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98), and mandates through regulation the reporting of GHG-related data from sources, including electricity generation facilities, that emit above a threshold.[18] The U.S. EPA prescribes detailed methodologies that must be used to quantify and report GHG emissions from each source category. Emissions from utilities burning fossil fuels often are measured by using continuous emission monitoring systems (CEMS) due to their high accuracy, but the rules allow some flexibility in methodological choice, such as measuring fuel composition data (i.e., carbon content) or using approved default emission factors.

The EPA's GHGRP is the basis for both the RGGI and California GHG emissions reporting programs described below.

5.1.1 EU Emissions Trading System (ETS)

The EU ETS is an example of a GHG cap-and-trade program that places an absolute quantity limit (or cap) on CO_2 emissions on approximately 12,000 emitting facilities located in the EU [15]. The EU ETS was phased in between 2005 and 2008, and regulated entities (aka covered entities) are responsible for emitting 40-45 percent of the EU's CO_2 emissions [16]. Facilities were allocated emission allowances or permits to emit GHG emissions and are allowed to trade allowances among themselves and other market participants in an open market. Covered facilities, including electric companies, must measure and report their CO_2 emissions and subsequently surrender an emissions allowance for every metric ton of CO_2 they emit on an annual basis. Power plants and all combustion facilities with a capacity greater than 20 MW are covered by the EU ETS, including commercial and institutional establishments.

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[18] Power generation facilities generally are required to submit annual reports if their annual GHG emissions exceed 25,000 metric tons CO_2eq.

The EU ETS requires covered entities to have an approved monitoring plan for reporting their annual GHG emissions and contains requirements for annual emissions reports, use of standardized estimation methodologies, and periodic verification or accuracy by accredited third-party auditors. The EU ETS uses facility-level, source-based accounting and requires reporting of scope 1 emissions only [17]. The EU ETS does not contain rules for quantifying GHG emissions associated with purchased power.

5.1.2 RGGI Reporting

The Regional Greenhouse Gas Initiative (RGGI) also is a facility-level regulatory program. RGGI entered into force in 2009 and placed a quantitative limit (the "cap") on annual emissions of CO_2 from power plants operating in nine states in the Northeast and Mid-Atlantic region of the United States. RGGI requires each power plant burning fossil fuel with a capacity of 25 megawatts or larger to report its emissions [18]. Like the EU ETS, RGGI is based on facility-level, source-based accounting of scope 1 emissions only.[19] And like the EU ETS, the GHG accounting method used by RGGI also does not address emissions associated with wholesale power purchases for resale to retail customers.

5.1.3 California Mandatory GHG Reporting

The California Air Resources Board (CARB) adopted a GHG reporting rule[20] to support preparation of the State's GHG emissions inventory, and the implementation of its GHG emissions cap-and-trade program. The California cap-and-trade program is unique among emission trading programs as it regulates emissions associated with electricity imported into the state, in addition to direct emissions associated with electricity generated in state. As a result of this design, the GHG mandatory reporting rule addresses the reporting and quantification of electricity imports and associated emissions. Although the California GHG reporting program is an unusual hybrid, it is more closely aligned with a facility, or source-based, accounting method than a load-based method. Imported electricity is essentially treated as another source of emissions. LSEs do not report emissions associated with load, but they are required to report emissions associated with electricity imports when they are the responsible importer.

For in-state emission sources, including electricity generators, California's GHG reporting requirements are based on those established by U.S. EPA under the Clean Air Act (Title 40, Code of Federal Regulations (CFR), Part 98). CO_2 emissions from combustion of biogenic fuels are reported, but do not incur a compliance obligation under the cap-and-trade program.

For electricity imports into the state, California distinguishes between "*specified*" imports and *unspecified* imports. An electricity import is considered to be from a specified resource if the electricity has been directly delivered from the resource to California *and* the resource is owned and/or operated by the importer or the importer has a contract that explicitly identifies that specific resource as the source of electricity. Electricity is considered directly delivered if there was a continuous transmission path from the source to a sink in California, as indicated by

[19] See RGGI Model Rule at https://www.rggi.org/program-overview-and-design/design-archive/mou-model-rule

[20] Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations (CCR), sections 95100-95157.

a single e-tag[21], or if the resource is physically connected to, or controlled by, a California balancing authority, including the California Independent System Operator (CAISO) [19]. Imports from specified resources are assigned the emission rate of the underlying resource, as calculated by the CARB based on EPA data. Importers of electricity from zero-emission resources are required to provide generator meter data to document that the output of the resource matched the scheduled and reported delivery.

Electricity that is sourced from the wholesale market, or which otherwise does not meet the requirements for a specified import, is considered *unspecified* and assigned a default emission rate. The default emission rate is 0.428 metric tons CO_2eq/MWh. This is similar to the CO_2 emissions rate of a natural gas combined cycle (NGCC) generating unit. This emission rate was calculated at the time the cap-and-trade program was adopted based on the average emission rate of resources in the Western Electricity Coordinating Council (WECC) area having a capacity factor of less than 60%.[22]

5.2 Load-Based Accounting

As described in section 4, associating CO_2 emissions with electricity consumption is a value chain accounting approach, often referred to as "load-based" accounting. The challenge with load-based accounting methods is electricity can be generated from different primary energy sources [20]. In some cases, a specific resource can be identified and assigned to electricity that is consumed. In other cases, the source of electricity may be undifferentiated, in which case a methodology is required to estimate an average resource mix. Load-based accounting can therefore involve a combination of methods to estimate GHG emissions from a utility's own resources and emissions associated with procured electricity.

5.2.1 RPS Accounting

Accounting for RPS compliance is not technically a GHG accounting method, but because it is often used as the starting point for power source disclosure, or load-based GHG accounting, it is important to understand.

Under most RPS programs, accounting for renewable electricity procurement is done by tracking the generation, purchase and retirement of RECs by each utility. The output of eligible renewable resources is metered at the resource level when it is injected into the grid and a corresponding REC is electronically issued for each MWh. The issuance, transfer and retirement of RECs typically is administered by a designated tracking system, such as the Michigan Renewable Energy Certification System (MIRECS) or the Western Renewable Energy Information System (WREGIS). Utilities that are subject to an RPS mandate demonstrate compliance with the program by submitting a report generated by the appropriate REC tracking system that shows purchases and retirement of RECs in accordance with program rules.

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[21] After electricity has been transacted, it must be scheduled on a transmission path from the generating source to the point where the electricity will be consumed (the "sink"). Power that flows between grid "balancing areas" is scheduled using electronic tags (e-tags) overseen by the National Electricity Reliability Coordinating Council (NERC).

[22] This capacity factor was selected to be representative of marginal generation resources.

5.2.2 The Climate Registry Electric Power Sector Protocol

The Climate Registry (TCR)[23] provides an Electric Power Sector (EPS) Protocol as a supplement to the General Reporting Protocol for corporate and facility voluntary GHG emissions reporting [21]. TCR is a voluntary corporate GHG reporting program, but it requires its members to use the EPS Protocol if their operations involve electricity generation or delivery (i.e., transmission and / or distribution).[24] Specifically, for the latter electricity delivery group, the EPS Protocol addresses the following types of entities (these are also described in Figure 5-1):

- Transmission and Distribution (T&D) System Operators, including utilities, distribution cooperatives, and other Local Distribution Companies (LDCs);
- Bulk Power Transmission Operators, including utilities, transmission companies, balancing authorities, ISOs, RTOs, and transmission cooperatives; and
- Power marketers, energy service companies, or retail electricity providers that do not own or operate power generation, transmission or distribution facilities.

The EPS does not focus on providing guidance for how to estimate Scope 3 emissions associated with CO_2 emissions attributable to power purchased by an electric utility to be resold to end-use customers. TCR states that it is optional for its members to report these Scope 3 emissions. But, the EPS Protocol does provide some guidance on this issue as part of two other methods that address:

1. The estimation of a utility's Scope 2 emissions associated with transmission and distribution line losses (Chapter 14), and
2. The estimation of emission metrics (e.g., tons CO_2/MWh) for power deliveries that electric companies may optionally disclose to their customers under the EPS (Chapter 19).

Quantified scope 3 emissions associated with wholesale power purchases for resale are inputs to these other two methods in the EPS Protocol. Section 14.2.3 of the EPS Protocol's describes a method to determine scope 3 GHG emissions (only for CO_2, CH_4, and N_2O) associated with power purchased by an electric company. For specified purchases, the method simply states that an emission factor applicable to the specific source should be "identified through contract and/or financial accounting records (such as invoices and payments)." If a unit-specific emission factor is not available, then a default factor for the known fuel type may be used, with suggested factors provided in the EPS Protocol. **For unspecified or system mix purchases, the method states that the "annual average output emissions rate for the applicable subregion…where the power is obtained" should be used (e.g., eGRID).**

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[23] The Climate Registry (TCR) is a non-profit organization that designs and operates voluntary and compliance GHG reporting programs globally, and assists organizations in measuring, reporting and verifying (MRV) the carbon in their operations to manage and reduce it. TCR also consults with governments nationally and internationally on all aspects of GHG measurement, reporting, and verification. To learn more, please see https://www.theclimateregistry.org .

[24] A number of electric companies participate in TCR, including Exelon, San Diego Gas & Electric, and number of CCAs in California and IPPs that operate both in the US and Mexico. For more information about TCR, see https://www.theclimateregistry.org/ .

EPS Report Entity Type

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

Notes:

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

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

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

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

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

Figure 5-1
Expected Emissions Categories for Various EPS Organizations [18]

Chapter 19 of the EPS Protocol provides optional guidance for reporting "efficiency metrics" (i.e., emission intensities) that can be disclosed to consumers of wholesale or retail power deliveries. However, no quantification method for these scope 3 emissions is provided in this chapter. Rather, the guidance addresses how to disaggregate estimated emissions to develop separate metrics for different customer categories (e.g., general retail consumers, wholesale power sales, and special power products such as green pricing programs). The user is referred to the method in Chapter 14 for estimation.

The EPS Protocol does permit electric companies to adjust their efficiency metrics based on REC retirements as follows:

- REC retirements for RPS compliance can be applied only to adjust the efficiency metric for retail customers (or overall electricity sales if not disaggregated).
- Retirements of voluntary market RECs can be applied to any consumer category metric.

5.2.3 Fuel-Mix and Power Source Disclosure Programs

Many states with RPS mandates have adopted programs to require or allow electric companies to disclose the composition of generating resources used to serve customer load.[25] These programs, which are referred to as "fuel mix," "power source disclosure programs," and "power content labels," account either for the generating resources averaged across a utility's sales, or generating resources used to supply specific clean-energy products available to customers.

The determination of the specific power generating resources used to meet customer demand typically is based on the utility's own resources and procurement contracts, most importantly renewable procurement.

For instance, a Washington State statute requires each utility to report the mix of generating fuels used to serve load to the Washington Department of Commerce [22]. This information then is used to determine an aggregated fuel mix for the State, which is used to prepare the State's GHG emission inventory.

Similarly, California law mandates utilities and other retail electricity providers disclose the sources of power supplied in their service areas. Public Utilities Code Section 398.1(b) requires LSEs to submit a detailed report of their resource mix to the California Energy Commission (CEC), and to disclose to customers the types of resources used to generate electricity by disclosing information using a standardized power content label. This label, however, does not currently provide the public information about GHG emissions associated with their electricity consumption. A new state law passed in 2016 (AB 1110) requires LSEs to disclose to consumers the GHG emissions intensity of their supplier's electric service products. The CEC has begun rule making procedures to update the State's power source disclosure regulations to comply with AB 1110. GHG emissions data is scheduled to be included in the power content label in 2020.

Washington Fuel Mix Disclosure

Under Washington's program, each utility reports total retail load and electricity generated or purchased to serve that load. Generation is reported by specific fuel or other resource type, where known, or as unspecified market purchases. For claimed renewable energy purchases, utilities also report a corresponding quantity of purchased and retired RECs, regardless of whether the RECs were bundled with the electricity.

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[25] The U.S. Department of Energy and the North Carolina Clean Energy Technology Center maintain a Database of State Incentives for Renewable Energy (DSIRE) that summarizes North American energy disclosure policies (https://openei.org/wiki/Generation_Disclosure).

Utilities deduct any wholesale electricity sales to ensure that reported generation and procurement match retail load. Additionally, electric power that is purchased and sold directly to customers pursuant to green power programs are not reported.

Oregon GHG Reporting Program

Oregon's mandatory GHG reporting program requires utilities (and the Bonneville Power Administration) to report sources of electricity and associated emissions used to serve retail load in Oregon. Like the Washington fuel-mix disclosure program, Oregon's rule requires reporting of fuels and emissions from the utility's own generating assets, as well as from power purchases. Where the generation source is known, the utility is required to report the appropriate emission factor or fuel source. For unknown sources, Oregon's program uses the same default system emission factor as California, 0.428 metric tons CO_2eq/MWh.

In keeping with the Oregon RPS program rules, utilities can use "unbundled" RECs (i.e., RECs purchased without delivery of the underlying electricity) to meet up to 20% of their RPS compliance obligation. The GHG reporting program allows these purchases to be reported with zero associated emissions.

California's Power Source Disclosure Program

Two distinct issues arise when GHG emissions are accounted based on a utility's portfolio of owned and procured electricity for delivery to retail customers, as under the Washington Fuel Mix Disclosure or Oregon GHG reporting program.

First, under a *portfolio approach*, the output and associated emissions of contracted resources are attributed to that utility based on contract terms. For variable energy renewable resources (e.g., wind and solar), this can create a mismatch between claimed generation and load in real time. For example, some CCAs in California claim they are meeting their customer's load entirely with solar and/or wind power. However, there are times of the day when the sun doesn't shine (i.e., at night and when clouds block the sunlight), and times and seasons when the wind doesn't blow. During these periods when these variable energy resources do not generate power, other generation sources are providing power into the grid, including fossil-fired generation sources. By allowing LSEs to treat all procured renewable electricity as zero emission, regardless of whether the electricity actually serves the entity's load, generation in excess of an LSE's load during one period can be credited against the output of emitting resources during another period. This effect is further exacerbated in RPS programs that allow utilities to count unbundled RECs for RPS compliance.

Second, portfolio accounting typically estimates GHG emissions intensity (i.e., GHG emissions per MWH) of undifferentiated electricity purchases as an annual generation-weighted average of all resources on the grid. This can blur significant seasonal and/or intra-day (peak/off-peak) differences in the emission intensity of system power. For instance, in the Northwest, reliance on fossil generation decreases dramatically in the spring when snowmelt increases output by hydroelectric resources. Similarly, more generating resources are called upon during peak load periods in the afternoon and early evening, then during off-peak periods, such as the middle of the night. Depending on the relative differences in systems emission intensity and the utility's load needs during these periods, averaging may overstate or understate actual GHG emissions associated with serving load.

The Clean Net Short Approach

In California, the Clean Net Short (CNS) method was developed to address these two problems. It was first proposed by Pacific Gas and Electric (PG&E) in the ongoing CEC proceeding to revise the Power Source Disclosure program [23], as directed by California Assembly Bill 110. As of the time of this writing, the CEC proceeding is ongoing and the final methodology remains undetermined.

However, following the initiation of the CEC proceeding, the California Public Utilities Commission (CPUC) adopted a modified version of the CNS method to be used by LSEs under the CPUC's jurisdiction to forecast GHG emissions in their IRPs [24]. California Senate Bill 350 (SB-350), enacted in 2015, required the CPUC and the CEC to establish individual GHG targets for LSEs[26] under their respective jurisdictions[27], and to factor these targets into IRP. The CPUC sought to align LSE targets with the State's GHG targets, including those under the cap-and-trade program, and to ensure that the method used to account for GHG emissions would be consistent with that used under the State's GHG cap-and-trade program. In April of 2018, the CPUC adopted the CNS approach as the method to be used by each LSE to account for their GHG emissions for the purposes of IRP. The description of the CNS method below is based on the method adopted by the CPUC.

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

Under the CNS approach, only the output of *non-dispatchable resources* in each LSE's portfolio (e.g., variable renewable energy resources, nuclear, hydropower, and some combined heat and power contracts) are considered to serve that LSE's load. Dispatchable resources owned or contracted by the LSE, mainly natural gas-fired generation, are considered to the serve the entire system, rather than the LSE's own load. (Because the California IOUs were

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[26] In CA, IOUs, energy service providers, and CCAs fall under the jurisdiction of the CPUC and are required to file IRP's with the CPUC under SB350. The CEC is responsible for promulgating guidelines for IRP planning toward the SB350 targets for public utilities.

required to divest of their coal-fired resources years ago, coal-fired generation is not directly addressed in the CPUC's CNS approach.)

The distinction between dispatchable and non-dispatchable resources has two implications when it comes to accounting for GHG emissions associated with serving load. First, it enables use of a "residual emissions rate" for system power. The residual system emission rate is calculated based on the generation weighted average of dispatchable resources only (i.e., those resources that are not assigned specifically to LSE portfolios). The CPUC has forecast the CAISO hourly residual system emission intensity for the IRP planning horizon using the RESOLVE model[28] [25]. This model calculates the system residual emission intensity based on dispatchable resources in, and unspecified imports into, the CAISO system.

Second, rather than counting the output of all non-dispatchable resources in an LSE's portfolio toward that LSE's load, the CNS approach only attributes generation of those resources to the LSE to the extent the LSE has sufficient load to use that generation. In other words, the total generation of non-dispatchable resources claimed by a LSE in an hour must be less than or equal to the LSE's load in the same hour.

If the LSE has non-dispatchable generation in excess of its load in an hour, the LSE receives an GHG emission credit. This credit is calculated by multiplying the quantity of non-dispatchable generation by the residual system emission rate for that hour. This approach reflects the fact that renewable generation displaces dispatchable system generation, rather than non-dispatchable generation in the LSE's portfolio.[29]

If the LSE's load exceeds the total generation by its non-dispatchable resources in an hour, the remaining load is considered to be served by system generation. Emissions are assigned based on the residual system emission rate for that hour.

The CNS methodology, as adopted by the CPUC for its IRP planning, uses the following steps:

1. Each LSE forecasts load for the appropriate planning period, using approved load forecast assumptions determined by the CPUC.
2. For each hour, the LSE calculates its CNS load. This value is calculated by taking the hourly load forecast and:
    a. Deducting forecast generation of owned or contracted zero emission resources[30] (e.g. renewable resources within the CAISO system, hydroelectric);

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[28] RESOLVE is an electric sector long-term capacity expansion software tool that is used by the CPUC and other entities to conduct long-term system resource planning studies.

[29] Although the notion of "displacing" other generation may sound like it is mixing causational and attributional accounting, in this case, the net effect is equal to subtracting a quantity of residual system emissions from the LSE with excess renewable generation, while simultaneously adding this quantity to other LSEs, maintaining an accurate total of emissions across all load on the system. (The "displaced" emissions are not calculated using a counterfactual baseline.)

[30] Zero-emissions resources include wind, solar, hydro, and nuclear that do not emit GHG when they generate electric power. Renewable resources generally are considered "climate-neutral," although some, such as biogas or landfill gas, do emit GHGs. However, because they do not result in a net increase in GHGs, they are effectively treated as zero emission.

b. Deducting forecast generation of owned or contracted non-dispatchable emitting generation (e.g., CHP);
c. Deducting any forecast discharge of stored electricity; then,
d. Adding any forecast charging to electricity storage.

3. CNS emissions are calculated by multiplying CNS load for the hour by the CAISO system GHG intensity for that specific hour. If the CNS load is negative, the LSE is considered to have oversupplied zero emissions electricity that displaced fossil generation in the CAISO system during the hour. The LSE calculates an emission credit by multiplying the CNS load by the system residual emission rate in that hour.
4. Portfolio emissions associated with dispatch of the LSE's owned/contracted generation is calculated using a generation weighted-average of the facility-specific emission rate of those resources.
5. Any emissions credit from oversupplied renewable generation is subtracted from the LSE's total portfolio emissions within that hour.
6. The LSE sums its CNS emissions and its portfolio emissions across each hour, and across the forecast period.

The CPUC has provided an Excel-based calculator[31] to facilitate use of the CNS approach in IRP planning [26]. In the next section of this report, a sample calculation is shown illustrating the calculational steps in this methodology.

[31]See
http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/GHG%20Calculator%20for%20IRP%20v1.4.5.xlsx

6 OPTIONS FOR GHG EMISSIONS ACCOUNTING FOR PURCHASED POWER FOR RESALE

The previous section surveyed the major GHG accounting standards and programs relevant to the electric power sector. This section synthesizes these examples into a series of options for how an electric utility like DTE, or other LSE, may account for and report the GHG emissions associated with serving electricity to its retail customers:

- A **narrow facility-based approach** that accounts for GHG emissions of facilities owned and operated by the utility, but excludes emissions associated with power purchases;[32]
- A **simplified portfolio approach** that accounts for emissions of resources owned and operated by the utility, as well as emissions associated with *net* wholesale electricity purchases using a system-average emission rate based on all resources on the grid;
- A **specified portfolio approach** that accounts for emissions of resources owned and operated by the utility, and any specified wholesale electricity procurement, plus emissions associated with net wholesale purchases using the system-average emission rate; and
- An **annual net-short approach** that accounts for emissions associated with non-dispatchable resources owned and contracted by the utility, and emissions associated with net system power purchases attributed using a *residual* system emission rate.
- An **hourly net-short approach** that utilizes hourly residual system emission rates.

6.1 Narrow Facility-based Approach

The narrow facility-based approach, as explained above, typically is the approach a utility will use to report its GHG emissions under a regulatory program entailing legal compliance obligations, such as under a cap-and-trade program. Utilities, such as DTE, that operate fossil-fueled generation already estimate and report their CO_2 emissions at the facility-level for one or more regulatory programs (e.g., RGGI, U.S. EPA GHG Reporting Program, California cap-and-trade program, etc.). But, a facility-based approach does not address the pertinent question of how to account for the GHG emissions associated with all electricity, including from wholesale purchases, sold to retail customers.

6.2 Simplified Portfolio Approach

The approach used by DTE to estimate the emissions associated with serving its customers' retail load in both its Sustainability Report and in its CDP reporting (previously the Carbon Disclosure Project) appears to be a simplified portfolio approach, based on the fact that DTE has not used specific emission rates for its renewable PPAs. For each calendar year, DTE has summed the

[32] In cases where a utility is also reporting emissions at a corporate level, then its indirect (Scope 2) emissions associated with transmission and distribution losses may be added to its facility-based Scope 1 emissions in keeping with specified reporting rules of the presiding reporting program.

emissions from its own generation facilities. DTE deducts the total generation of its own resources from its retail load to calculate the delivered retail volume of its wholesale electricity purchases. Emissions associated with purchased electricity are then calculated by multiplying this volume by an annual regional grid average emission factor.

DTE's 2017 IRP indicates that a significant portion of its renewable electricity is purchased, rather than coming from DTE-owned generation assets. For instance, DTE has six wind PPAs with a combined capacity of 458 MW. This purchased wind capacity exceeded the generating capacity of DTE's own wind farms (451 MW) in 2017. **By using the current simplified portfolio approach, DTE likely is underestimating the impact of its clean energy purchases on GHG emissions associated with serving its retail load.**

6.3 Specified Portfolio Approach

By using a specified portfolio approach, DTE would be better able to reflect the low carbon benefit of its renewable and other PPAs, such as CHP, in its emissions calculations. By using this, rather than assigning a system average emission rate to all purchased power, DTE would categorize purchases by resource type and assign the emission rate of the underlying resource, when known. Where purchased power is not associated with a specified resource, the system average emission rate would be used.

The accuracy of the specified portfolio approach to estimating emissions associated with serving a utility's load depends on two factors. First is the extent to which actual generation by the utility's portfolio of owned resources and specified PPAs matches its load throughout the year.

For example, if a utility's load in some hours is less than the generation from its coal fleet, then the excess coal generation actually is serving the load of other utilities in the larger system. Conversely, if there are hours when wind generation output exceeds the utility's load minus output of its non-dispatchable resources (i.e., coal and nuclear), it would be incorrect to consider the renewable generation as serving the utility's load, and the coal serving the market, because the renewable generation in those intervals is likely displacing emissions associated with dispatchable resources (i.e., natural gas) in the overall system, rather than the less dispatchable coal-fired resources.

The second factor that may impact the accuracy of the specified portfolio approach in attributing GHG emissions to load is the accuracy of the emission factors assigned to system purchases. In DTE's Sustainability Report, the emission factor attributed to system purchases was a constant 0.58 metric tons CO_2eq/MWh for all years. In its CDP accounting, DTE used the eGRID emission factor for the Michigan sub-region of MISO at a value of 0.577 metric tons CO_2eq/MWh. In these cases, these emissions factors are quite close and the small differences likely would have no significant impact on total emissions. However, in other cases, the use of different regional emissions factors could lead to significant differences in total emissions.

Further, the eGRID emission factors reflect a generation weighted average for *all* resources. As discussed above and further below, it would be reasonable to consider non-dispatchable resources (i.e., renewables, nuclear and coal) as assigned to particular LSEs, and instead calculate a MISO average residual emission factor. A residual emission factor would better reflect the mix of resources that respond to changes in load.

6.4 Annual Net Short Approach

A significant improvement in accuracy may be achieved by using an approach that distinguishes between dispatchable and non-dispatchable resources, and includes only dispatchable resource in the calculation of a grid residual system emission factor. Such a method would essentially be an annualized version of the CNS approach described above. In recognition of the fact that many utilities outside of California, including DTE, have coal-fired resources in their generation portfolios, this paper refers to this approach as the *Net Short method*.

The Net Short method would use a constant residual emission rate, reflecting the measured or projected generation-weighted emission rate of only dispatchable resources on the grid, averaged across a year. Use of an annual averaged residual emission rate would improve the accuracy of estimated emissions associated with serving load relative to use of an all-resources system average emission rate, because it eliminates the double-counting in the residual system emission factor of non-dispatchable resources in utility portfolios. To accurately identify these residual resources would require knowledge of which non-dispatchable resources are owned or contracted to utilities and other LSEs in the region. However, a reasonable approximation may be achieved simply by calculating the emission factor based on natural gas resources only, since these are the only fully dispatchable resources on the system.

Under the Net Short method, emissions associated with the output of all non-dispatchable resources in the utility's portfolio[33] are first calculated and summed for the year. If generation by these resources over the year exceeds the utility's load for the year, then any surplus generation in excess of the utility's load would result in an emission credit. The emission credit is calculated by multiplying the volume of surplus generation by the residual emission rate. The credit then is added to the utility's total emissions for year, thereby decreasing emissions.

Importantly, this method works regardless of the source of the surplus generation. The reason is that the credit always reflects displacement of dispatchable resource (e.g. NGCCs) attributed the residual emission rate, rather the emission rate of the displacing resource (e.g. the non-dispatchable coal or renewable generators).

6.5 Hourly Net Short Approach

The accuracy of the Net Short method could be improved further by using hourly, rather than annually averaged, residual emission factors. The actual residual emission factor of a grid varies over time due to the need to call on less-efficient peaking units during periods of heavy load. These units typically have a higher heat rate (BTU/KWh)[34], and thus a higher emission rate than other natural gas-fired generating units, which would be reflected in a higher residual system emission rate during the hours they are operating on the system [27].

To use an **Hourly Net Short method,** the utility would make the same calculations as for the Annual Net Short method, but for each hour within the year. The impact of moving to hourly residual emission factors from an annual residual emission factor would depend on the amount of

[33] Any specified sales by the utility, for instance a utility that is long on hydro, and sells a portion of the output to another entity, would not be included in the utility's portfolio.

[34] In 2017, the average heat rate for natural gas-fired power plants in the United States was 7,812 BTU/KWh according to the Energy Information Administration (see reference 27).

variability of the hourly residual emission rate compared to the annual rate, and the extent to which a utility's reliance on system power varies over time. Although working with hourly resolution would be data-intensive, it should be feasible for LSEs, including utilities such as DTE, that participate in an ISO market because both generation and load is metered and settled sub-hourly. However, the ISO itself would need to be involved in implementing this approach.

Table 6-1 summarizes the differences between these five GHG accounting approaches.

Table 6-1
Methodological Options for Utility Accounting

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

6.6 Comparison of Different Accounting Options

To better understand how the different accounting options may impact the calculation of CO_2 emissions associated with serving a utility's load, it is useful to walk through a couple of numerical examples.

Example 1

Table 6-2 shows the portfolio of owned and operating generating resources, as well as PPAs, for a hypothetical utility. In addition, assume the emission factors for the utility's coal and NGCC fleets are 0.90 and 0.43 metric tons CO_2eq/MWh, respectively, as shown in Table 6-2.

Table 6-2
Hypothetical Utility Generation Portfolio, Purchased Power Agreements, and Emission Factors

Generation Resource Type	Owned Assets (MW)	PPAs (MW)	Emission Factor (ton CO_{2e} /MWh)
Coal	5,000	-	0.90
Nuclear	1,000	-	-
NGCC	2,500	-	0.43
Wind	700	700	-
System	-	2,000	-
Total	9,200	2,700	-

Figure 6-1 shows generation by these resources over a 24-hour period, compared to the utility's load in the same period. The utility's nuclear plant generates at maximum capacity throughout the day. Its coal fleet runs at maximum capacity during peak-load hours but backs down during off-peak hours in the middle of the night. Wind resources generate as available. (For purposes of these examples, we assume no curtailment.) For most hours of the day, the combined output of all the utility's own and contracted resources is less than the utility's load in that hour. However, between 2 am and 6 am, the output of these resources exceeds the utility's load.

As shown in Table 6-3, the generation-weighted system average emission rate for all resources is 0.65 metric tons CO_2eq/MWh, and the residual system emission rate is 0.43 metric tons CO_2eq/MWh. (The residual system emission rate effectively reflects the grid average emission rate of natural gas-fired resources.)

Table 6-4 presents the data for our hypothetical utility over a 24-hour period and Table 6.5 shows the calculations and results using the five methods.

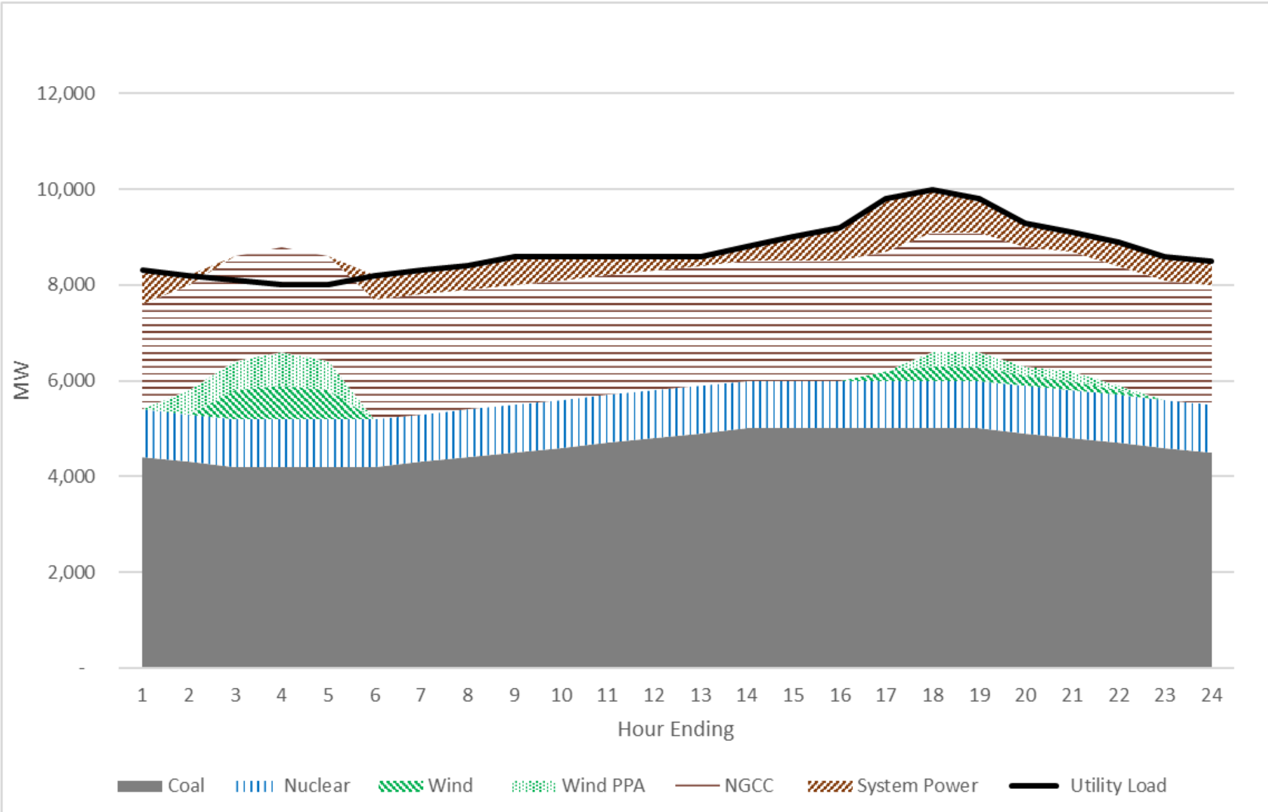

Figure 6-1
Hypothetical Portfolio of Generation and System Purchases

Table 6-3
Generation-weighted System Average Emission Rates

Emission Rate Type	System Average Emission Rates (ton CO_{2e}/MWh)
All Resources	0.65
Residual Resources	0.45

Table 6-4
Hypothetical Utility Sample Calculations Over 24 Hour Period Using Emission Factors and System Average Emission Rates

Hour	Utility Load (MW)	Utility Owned Generation Coal (MW)	Nuclear (MW)	NGCC (MW)	Wind (MW)	Purchased Power Wind PPA (MW)	System Power Drawn (MW)	System Power Displaced (MW)	System Power Displace- (Net Short Methods) Drawn (MW)	Displaced (MW)	Hourly Emissions Factor (tCO2e/MWh)	Hourly Emissions - Variable ER (tCO2e)
1	8,300	4,400	1,000	2,200	-	-	700	-	2,900	-	0.41	5,149
2	8,200	4,300	1,000	2,200	-	500	200	-	2,400	-	0.40	4,830
3	8,100	4,200	1,000	2,200	600	600	-	(500)	1,700	-	0.39	4,443
4	8,000	4,200	1,000	2,200	700	700	-	(800)	1,400	-	0.38	4,312
5	8,000	4,200	1,000	2,200	600	600	-	(600)	1,600	-	0.39	4,404
6	8,200	4,200	1,000	2,500	-	-	500	-	3,000	-	0.40	4,980
7	8,300	4,300	1,000	2,500	-	-	500	-	3,000	-	0.42	5,130
8	8,400	4,400	1,000	2,500	-	-	500	-	3,000	-	0.43	5,250
9	8,600	4,500	1,000	2,500	-	-	600	-	3,100	-	0.44	5,414
10	8,600	4,600	1,000	2,500	-	-	500	-	3,000	-	0.45	5,490
11	8,600	4,700	1,000	2,500	-	-	400	-	2,900	-	0.47	5,593
12	8,600	4,800	1,000	2,500	-	-	300	-	2,800	-	0.48	5,664
13	8,600	4,900	1,000	2,500	-	-	200	-	2,700	-	0.48	5,706
14	8,800	5,000	1,000	2,500	-	-	300	-	2,800	-	0.48	5,844
15	9,000	5,000	1,000	2,500	-	-	500	-	3,000	-	0.49	5,970
16	9,200	5,000	1,000	2,500	-	-	700	-	3,200	-	0.48	6,036
17	9,800	5,000	1,000	2,500	200	-	1,100	-	3,600	-	0.48	6,228
18	10,000	5,000	1,000	2,500	300	300	900	-	3,400	-	0.47	6,098
19	9,800	5,000	1,000	2,500	300	300	700	-	3,200	-	0.46	5,972
20	9,300	4,900	1,000	2,500	200	200	500	-	3,000	-	0.45	5,760
21	9,100	4,800	1,000	2,500	200	200	400	-	2,900	-	0.44	5,596
22	8,900	4,700	1,000	2,500	100	100	500	-	3,000	-	0.43	5,520
23	8,600	4,600	1,000	2,500	-	-	500	-	3,000	-	0.42	5,400
24	8,500	4,500	1,000	2,500	-	-	500	-	3,000	-	0.40	5,250
Total	209,500	111,200	24,000	58,500	3,200	3,500	11,000	(1,900)	67,600	-		130,039

Table 6-5 presents the calculation results for the hypothetical utility for each of the accounting methods described in this section.

Table 6-5
Hypothetical Utility Sample Calculation Results by Accounting Method

Accounting Method	Total Emissions (tons CO_{2e})
Facility	125,235
Simplifed Portfolio	133,425
Specified Portfolio	131,150
Annual Net Short (using Annual EF)	130,500
Hourly Net Short (using Hourly EF)	130,039

Using a **facility-based accounting method**, the utility would count only the emissions associated with the generation of the resources it owns and operates. Total emissions over the 24-hour period under this option would be 125,235 metric tons CO_2eq. This reflects the emissions of the utility's coal and gas fleet. Because nuclear and wind generation emit zero GHG emissions, these resources do not contribute any emissions to the total.

Under **a simplified portfolio approach**, the utility would report emissions associated with generation of its own resources, as under facility-based accounting, and to this quantity it would add emissions associated with net wholesale electricity purchases (load minus total generation by owned resources). Emissions for these wholesale purchases would be attributed at the system average emission rate appropriate for the region. Total emissions in this example using this approach would equal 133,425 metric tons CO_2eq.

For the **specified portfolio approach**, the utility would again start from the emissions associated with generation of its own resources. To this quantity, it would add any emissions associated with contracted, specified power purchases. (In this example, all the specified PPAs are with wind resources, so these purchases do not add any CO_2 emissions. However, if a utility had PPAs with GHG-emitting resources, such as CHP facilities, this specified procurement would result in additional emissions). The utility would again calculate net wholesale purchases, but under the specified option, the net would be calculated by summing the total load over the year and deducting the combined generation of its own resources and resources under specified PPAs. Again, emissions attributed for wholesale purchases would be attributed at the regional grid-averaged emission rate. Because this approach does not attribute emissions to the generation of the utility's wind PPAs, it reduces the utility's total emissions to 131,150 metric tons CO_2eq.

Using an **Annual Net-short method**, the utility would account for emissions of only the non-dispatchable resources and specified PPAs in its portfolio. All its dispatchable resources (i.e., NGCCs) would be considered part of the system mix. The utility then would calculate GHG emissions associated with system power purchases by subtracting the total generation of its non-dispatchable resources and PPAs from its total load and multiplying this quantity by the *residual* system emission rate. Because the residual emission rate is much lower than the all-resources system average emission rate, this method reduces total emissions associated with serving the utility's load to 130,500 metric tons CO_2eq.

In this example, use of the **Hourly Net Short method** decreases the company's total emissions even more to 130,039 metric tons CO_2eq. Under other scenarios, moving to an hourly approach may *increase* emissions compared to an Annual Net Short method.

Example 2

In the previous example, moving from a Specified Portfolio Approach to an Annual Net Short method resulted in the utility relying on system power (which includes generation from its own NGCC resources) during all hours.

This second example presents a hypothetical future, where all utilities have retired coal facilities and built out high levels of both wind and solar generating capacity. In this example, generation by the non-dispatchable resources in the utility's portfolio actually displaces system power during some hours.

Table 6.6 shows the utility's portfolio and figure 6.2 the utility's load, generation and reliance on system power over a 24-hour period.

Table 6-6
Hypothetical Utility Generation Portfolio, Purchased Power Agreements, and Emission Factors

Generation Resource Type	Owned Assets (MW)	PPAs (MW)	Emission Factor (ton CO_{2e} /MWh)
Coal	-		0.90
Nuclear	1,000		-
NGCC	2,500		0.38
Wind	4,000	3,000	-
Solar	2,000	1,000	
System		1,000	-
Total	9,500	5,000	-

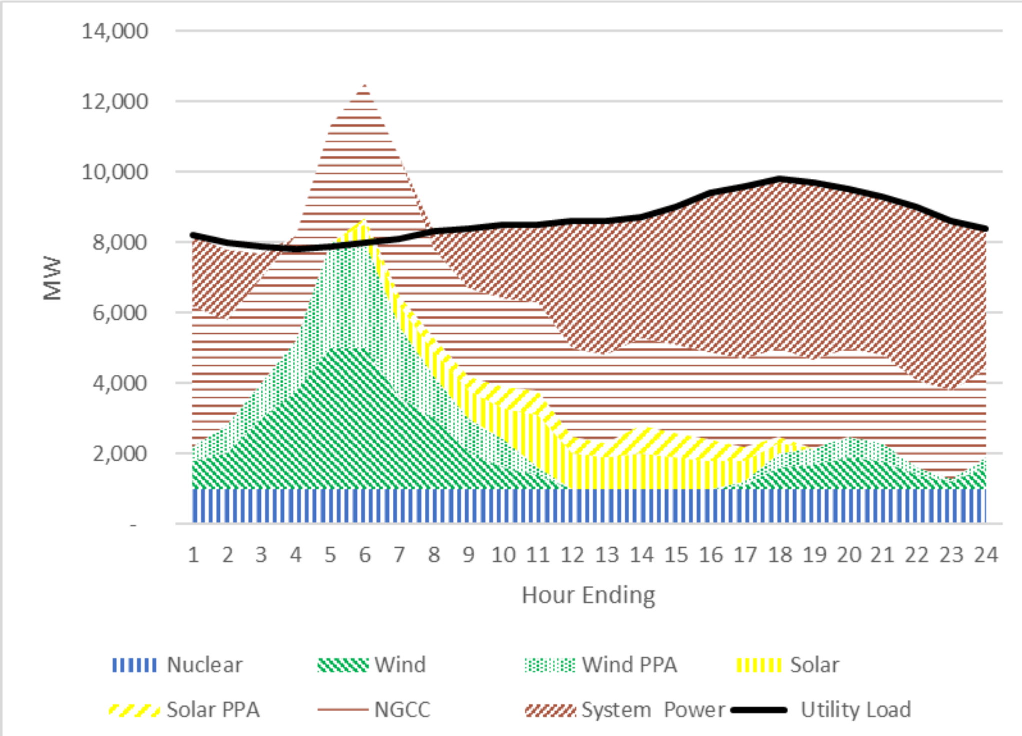

Figure 6-2
Hypothetical Portfolio of Generation and System Purchases

During hours 5 and 6, the combined output of the utility's non-dispatchable nuclear, wind and solar resources, plus wind and solar PPAs *exceeds* its total load. This can also be seen in the displacement of system power (Net Short Methods) highlighted in yellow in Table 6-8.

A comparison of the results using each of the five methods for this example is shown in Table 6-7. Note that under this example, use of the Hourly Net Short method results in higher emissions than the use of the Annual Net Short Method, due to the higher system residual emission rates during hours when the utility must rely heavily on the system (e.g. hour 23).

Table 6-7
Hypothetical Utility Sample Calculation Results by Accounting Method

Accounting Method	Total Emissions (tons CO_{2e})
Facility	25,270
Simplifed Portfolio	62,620
Specified Portfolio	53,895
Annual Net Short (using Annual EF)	49,500
Hourly Net Short (using Hourly EF)	56,697

Table 6-8
Hypothetical Utility Sample Calculations Over 24 Hour Period Using Emission Factors and System Average Emission Rates

Hour	Utility Load (MW)	Utility Owned Generation					Purchased Power		System Power		System Power (Net Short Methods)		Hourly Emissions Factor (tCO2e/MWh)	Hourly Emissions - Variable ER (tCO2e)
		Coal (MW)	Nuclear (MW)	NGCC (MW)	Wind (MW)	Solar (MW)	Wind (MW)	Solar PPA	Drawn (MW)	Displaced (MW)	Drawn (MW)	Displaced (MW)		
1	8,200	-	1,000	4,000	800	-	400	-	2,000	-	6,000	-	0.41	2,460
2	7,800	-	1,000	3,000	1,000		800		2,000	-	5,000	-	0.40	2,000
3	7,700	-	1,000	3,000	2,000		1,000		700	-	3,700	-	0.39	1,443
4	7,800	-	1,000	3,000	2,800		1,400		-	(400)	2,600	-	0.38	988
5	7,900	-	1,000	3,300	4,000		3,000		-	(3,400)	-	(100)	0.38	(38)
6	8,000	-	1,000	3,800	4,000	500	3,000	200	-	(4,500)	-	(700)	0.38	(266)
7	8,100	-	1,000	3,900	2,600	600	2,000	300	-	(2,300)	1,600	-	0.39	624
8	8,300	-	1,000	2,500	2,000	700	1,200	400	500	-	3,000	-	0.44	1,320
9	8,400	-	1,000	2,500	1,000	800	1,000	400	1,700	-	4,200	-	0.45	1,890
10	8,500	-	1,000	2,500	600	900	800	600	2,100	-	4,600	-	0.46	2,116
11	8,500	-	1,000	2,500	400	1,500	200	700	2,200	-	4,700	-	0.47	2,209
12	8,600	-	1,000	2,500		1,000	-	500	3,600	-	6,100	-	0.47	2,867
13	8,600	-	1,000	2,500		900	-	400	3,800	-	6,300	-	0.48	3,024
14	8,700	-	1,000	2,500		1,000	-	800	3,400	-	5,900	-	0.48	2,832
15	9,000	-	1,000	2,500		900	-	700	3,900	-	6,400	-	0.48	3,072
16	9,400	-	1,000	2,500		800	-	600	4,500	-	7,000	-	0.49	3,430
17	9,600	-	1,000	2,500	100	600	100	400	4,900	-	7,400	-	0.48	3,552
18	9,800	-	1,000	2,500	600	300	400	200	4,800	-	7,300	-	0.47	3,431
19	9,700	-	1,000	2,500	700	-	450		5,050	-	7,550	-	0.46	3,473
20	9,500	-	1,000	2,500	900	-	600		4,500	-	7,000	-	0.45	3,150
21	9,300	-	1,000	2,500	800	-	500		4,500	-	7,000	-	0.46	3,220
22	9,000	-	1,000	2,500	400	-	200		4,900	-	7,400	-	0.48	3,552
23	8,600	-	1,000	2,500	200	-	100		4,800	-	7,300	-	0.46	3,358
24	8,400	-	1,000	2,500	600	-	300		4,000	-	6,500	-	0.46	2,990
Total	207,400	-	24,000	66,500	25,500		17,450		67,850	(10,600)	124,550	(800)		56,697

7 CONCLUSIONS AND KEY INSIGHTS

This report has explored the options available to electric utilities, like DTE, to account for the GHG emissions associated with electric power sold to end-use consumers. Specifically, it examined the methods used by various GHG reporting programs and jurisdictions to account for emissions, with an emphasis on accounting for emissions associated with wholesale power transactions for sale to retail end-use customers.

7.1 Project Summary

The evaluation of relevant methods to account for GHG emissions of the electric power sector required an examination of emerging policy and regulatory developments in the United States and internationally, and an array of mandatory and voluntary programs with different rules and modalities for GHG accounting, with several built upon distinct GHG accounting frameworks.

Section 6 of this report considered DTE's current approach to GHG accounting, and how alternative methods might impact its future GHG reporting.

There is no definitive answer to the question of which accounting method DTE or other LSEs should use to account for GHG emissions associated with specified and unspecified power purchases. The appropriate accounting methods depends on several factors, including:

- The willingness and ability of an ISO (e.g., MISO) to provide accurate emission factor data that is resolved temporally on an hourly or more granular basis, and perhaps geographically if possible.
- The demands for accuracy and data quality that may be imposed by regulatory agencies, stakeholders, and resource planning needs.
- How much precision an utility wants or needs in forecasting and charting its progress toward its voluntary CO_2 reduction goal and aligning with emerging climate policies.
- Finally, it depends on timing and resource constraints. The Net Short approach is relatively new, and implementing it likely would require DTE to use additional staff and financial resources to implement.

7.2 Key Insights

The project team has identified the following key insights that may assist DTE and other LSEs in determining how to account for the GHG emissions associated with serving retail load, organized according to the section of the report in which they are discussed.

7.2.1 Section 1: Introduction

- In recent years, a number of utilities in the United States have adopted ambitious voluntary goals to reduce their future GHG emissions. Assessment of progress towards achieving these goals requires utilities to account for their GHG emissions.

- While formal GHG accounting methods have evolved considerably in recent years, accounting for the GHG associated with purchased power for resale to end-use consumers is complex, and continues to be a challenging area of GHG accounting.
- The need to account for GHG emissions associated with purchased power arises in several important contexts for utilities including measuring progress towards achieving a voluntary corporate GHG emissions reduction goals, conducting integrated IRP-related activities, and corporate sustainability reporting.

7.2.2 Section 2: Policy Context

- Utilities and utility regulators are increasingly being pressured to consider and account for GHG emissions, and to factor these emissions into their investments and other decision-making processes.
- Many government jurisdictions around the world, including individual states and regions in the United States, have adopted programs to reduce GHG emissions from the electric power sector.

7.2.3 Section 3: Wholesale Power Markets

- Although electric companies like DTE may have PPAs with specific power generation resources, such as wind, the actual electric power DTE receives from its wholesale purchases at any given moment is determined by the generation resources operating at that moment in the MISO system, and do not relate to the specific generation sources included in a company's PPA.
- Electric power purchased via an organized power market like MISO is *undifferentiated*, as it is a mix of electric power generated by all of the resources generating across the entire system at the time the electricity is used. Most wholesale electricity contracts between a generator and an LSE (and any intermediaries) are for "unspecified" or undifferentiated power resources.

7.2.4 Section 4: GHG Accounting Frameworks

- Multiple methods and standards exist for GHG emissions accounting related to electric power sector emissions. Available methods differ significantly depending on their context and purpose.
- Accounting for emissions from a specific facility or, in the case of the electric sector, a generating unit, is the most resolved accounting framework. Facility-based accounting is also the most commonly used accounting framework for government regulatory programs that entail legal compliance obligations, such as reporting programs and cap-and-trade systems. Under a facility-based approach, an electric company would account only for the direct GHG emissions of its generating assets.
- Corporate GHG emissions are delineated by "scopes." Scope 1 emissions are those arising from sources *directly* owned or controlled by an entity. Scope 2 emissions are *indirect* emissions associated with purchased electricity or heat consumed by an entity. Scope 3 emissions are *all other indirect emissions* attributable to an entity's activities.

- Accounting for the GHG emissions embedded in electric power sold to customers is an "optional" accounting component of an electric company's total GHG emissions footprint under the WRI/WBCSD GHG Protocol Corporate Accounting Standard.
- Because electric companies often have some flexibility to choose the specific attributes of the electric power they purchase on behalf of customers, it may make sense for an electric company to account for emissions from purchased power and include them in their GHG reduction goals.
- Although the GHG Protocol Corporate Standard—and its accompanying Corporate Value Chain (Scope 3) Accounting and Reporting Standard—prescribe *how* GHG emissions associated with electricity purchases resold to end users should be reported, they do not prescribe specific *methods* to calculate and quantify these emissions.
- In the context of the electric power sector, value chain accounting approaches can be used to attribute GHG emissions to electricity consumption or load – aka "load-based" accounting. Here, the challenge is to identify the specific mix of resources used to generate consumed electricity.
- One challenge electric utilities face when considering a load-based accounting method is that the electric power purchased may not correspond to power actually consumed by the company's customers (i.e., purchases may not temporally or spatially match load).
- In recent years, electric companies have faced increasing pressure from shareholders, consumers and other stakeholders to improve their corporate sustainability activities and reporting.

7.2.5 Section 5: GHG Accounting Methods

- Facility-based accounting methods are used under the existing regulatory programs such as local air pollutant permitting and compliance programs, hazardous air pollutant programs, and cap-and-trade programs, including the EU ETS, RGGI, and the California GHG emissions cap-and-trade program.
- In the United States, the U.S. EPA administers the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98), and mandates through regulation the reporting of GHG-related data from sources, including electricity generation facilities, that emit above a threshold. The EPA's GHGRP is the basis for both the RGGI and California GHG emissions reporting programs.
- The California cap-and-trade program is unique among emission trading programs in that it regulates emissions associated with electricity imported into the state, in addition to direct emissions associated with electricity generated in state. As a result of this design, its GHG mandatory reporting rule addresses the reporting and quantification of electricity imports and associated emissions.
- Although the California GHG reporting program is an unusual hybrid, it is more closely aligned with a facility, or source-based, accounting method than a load-based method. Imported electricity is essentially treated as another source of emissions.
- California distinguishes between *specified* imports and *unspecified* imports. An electricity import is considered to be from a specified resource if the electricity has been directly delivered from the resource to California, and the resource is owned and/or operated by the

importer or the importer has a contract that explicitly identifies that specific resource as the source of electricity.

- In California, imports from specified resources are assigned the emission rate of the underlying resource. Importers of electricity from zero-emission resources are required to provide generator meter data to document that the output of the resource matched the scheduled and reported delivery.
- Electricity that is sourced from the wholesale market, or which otherwise does not meet the requirements for a specified import, is considered unspecified and assigned a default emission rate. The default emission rate used in California currently is 0.428 metric tons CO_2eq/MWh.
- Two distinct issues arise when GHG emissions are accounted based on a utility's portfolio of owned and procured electricity for delivery to retail customers. First, the output and associated emissions of contracted resources are attributed to that utility based on contract terms, and second, portfolio accounting typically estimates GHG emissions intensity (i.e., GHG emissions per MWH) of undifferentiated electricity purchases as an annual average. The *Clean Net Short (CNS) method* was developed in California to address these two problems by better matching generating resources to a utility's load.
- The basic concept of the CNS is that each LSE's GHG emissions is based on the LSE's projected hourly electricity demand. The methodology is based on the idea that the portion of an LSE's load that is met by undifferentiated system power is ascribed a GHG emissions rate that reflects the marginal locational GHGs emitted by the generating resources operating during the specific hour the electric power is delivered.

7.2.6 Section 6: GHG Accounting Options

EPRI identified and described five approaches that can be used by electric companies to address GHG emissions embedded in power sold to end-use customers. These options include:

1. A **narrow facility-based approach** that accounts for GHG emissions of facilities owned and operated by a utility, but excludes emissions associated with power purchases.
2. A **simplified portfolio approach** that accounts for GHG emissions of resources owned and operated by an electric utility as well as emissions associated with *net* wholesale electricity purchased using a system average emission rate based on all resources on the grid.
3. A **specified portfolio approach** that accounts for GHG emissions of resources owned and operated by an electric utility, and any specified wholesale electricity procurement, plus emissions associated with net wholesale purchases using the system average emission rate.
4. An **annual net-short approach** that accounts for the GHG emissions associated with non-dispatchable resources owned and contracted by an electric utility, and emissions associated with net system power purchases attributed using a residual system emission rate.
5. An **hourly net-short approach** that utilizes hourly residual emission rates.

8
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