Modernizing GHG Accounting Rules and Climate Leadership Programs

When Should Companies be Able to Claim They Consume Carbon-Free Electricity?

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Abstract

Electricity buyers have become a growing force in clean energy deployment. Thousands of companies have set voluntary renewable energy and/or emissions reduction goals. Almost universally, companies use established rules for reporting emissions arising indirectly from electricity use, as detailed in the GHG Protocol's *Corporate Standard* and *Scope 2 Guidance*. For over two decades, the Protocol has been used to set targets, track progress, and inform stakeholders. In many ways, the Protocol has succeeded.

However, these accounting rules are out of sync with the actions required to achieve net-zero emissions. The current Scope 2 Market-Based method has three major limitations:

- It does not accurately measure the emissions associated with electricity use,
- It fails to recognize the value of firm carbon-free electricity (CFE) and balancing (e.g., storage) resources, and
- It was not designed to estimate and prioritize actions that actually reduce emissions.

The GHG Protocol update process now underway is the best opportunity to improve the Market-Based method in time to meet science-based climate goals and strengthen GHG inventory accounting. The following improvements are needed:

- Market-based inventories (MBIs) should reflect supply that is deliverable to the location of customer consumption.
- MBIs should reflect supply that matches the timing of customer consumption.
- Customers should be able to count equally all energy attribute certificates (EACs) purchased and retired either directly or on their behalf by their load-serving entity.
- EACs should be used to substantiate claims of CFE use and their ownership rights should be fairly allocated to customers who purchase them without double counting, double paying, or cost shifting.
- Required CFE purchases by customers, even if not claimed, should not be permitted to reduce the MBIs of other customers who have not purchased EACs. Without EAC purchases, fossil emission factors should be applied using the best available information.

These improvements would enable companies to report accurate and credible claims about the emissions from supply serving their electricity use, while creating demand to accelerate the growth of all CFE resources necessary to fully decarbonize electricity grids reliably and affordably. System analyses across various markets and recent contracting experience support the relationship between reductions in an improved MBI and the development of the array of clean energy technologies needed for electric sector decarbonization.

About the Authors

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Neil Fisher is a Partner at *The NorthBridge Group*, where he has over thirty years of experience providing economic and strategic consulting services to both regulated distribution and vertically-integrated electric utilities, competitive generators and energy suppliers, and other companies and policy organizations active in the energy space. Before and throughout the restructuring process of the U.S. electricity industry, Mr. Fisher has assisted clients with wholesale market design, competitive market analysis and strategy, regulated power supply procurement, and state regulatory initiatives and strategy. Using a combination of market insights, policy and regulatory expertise, perspectives on the energy transition, and rigorous analytic and economic skills, he has worked with clients to develop recommendations to modernize GHG accounting and reporting policies, assess risks for existing generation and new investments, evaluate emerging clean energy technologies, and achieve carbon-free procurement goals.

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The views expressed within this paper are solely the responsibility of the authors, although informed by extensive discussions with stakeholders involved with GHG accounting.

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SECTION I

Introduction

A. Across the globe, efforts are failing to develop the array of clean energy technologies and supporting policies to achieve net zero emissions by mid-century or earlier.

According to the October 2022 report by the United Nations (UN) Environment Programme, there exists today no credible pathway to the Paris Agreement goal of limiting global warming to 1.5 degrees Celsius.[i] Across the globe, efforts are failing to develop the array of clean energy technologies and supporting policies to achieve decarbonization at the rate needed. In the absence of effective, systemic government policies to incentivize power sector decarbonization, electricity buyers have become a growing force in clean energy deployment.[ii] But the GHG accounting and reporting system, and the leadership and standard-setting programs that depend on them, have not kept pace with changes in electricity procurement nor with increasing urgency of goals to achieve net-zero emissions by mid-century or earlier.[1] While government and private pledges to cut emissions to nearly zero now cover more than 90% of the world's economy, emissions levels are still rising.[iii] Society cannot afford actions and expenditures to support claims of progress while not actually reducing real-world emissions.

B. The GHG Protocol is the world's most established and widely used GHG accounting standards for how companies, cities, and countries measure, manage, and report GHG emissions.

Companies and third-party leadership programs almost universally use established rules for calculating and reporting emissions arising indirectly from electricity use ("Scope 2" emissions) based on the GHG Protocol Corporate Accounting and Reporting Standard (*Corporate Standard*)[2] and amendment, known as the *Scope 2 Guidance*.[3]

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1 Since the Protocol's inception, climate goals, the Protocol's use, and technologies have changed dramatically.

2 The first version of the *Corporate Standard* was published in 2001.

3 The *Scope 2 Guidance* was published in 2015.

The GHG Protocol Initiative is a multi-stakeholder partnership of businesses, non-governmental organizations (NGOs), governments, and others convened by the World Resources Institute (WRI), a U.S.-based environmental NGO, and the World Business Council on Sustainable Development (WBCSD), a Geneva-based coalition of 170 international companies. Launched in 1998, the Initiative's mission was to develop internationally accepted GHG accounting and reporting standards for business and to promote their broad adoption.

For over two decades, the Protocol has played an important role in informing company actions and investments in climate mitigation. In many ways it has been a success, encouraging the development of wind and solar in the most economically viable locations. The Protocol has become the rulebook for carbon and clean energy disclosures, e.g., CDP, formerly known as the Carbon Disclosure Project, and leadership programs, e.g., Science Based Targets Initiative[4] or SBTi[iv].[5] Nearly 19,000 companies, worth over half the global market capital, report to CDP using Protocol standards.[v] The Protocol "also forms the basis for mandatory corporate reporting programs in effect in the UK and those coming into effect in the EU; it is also likely to be the recommended format for mandatory reporting requirements expected from the US Securities and Exchange Commission."[vi] For companies that aim to reduce their GHG footprints, the Protocol is an important consideration in procurement decisions and how to demonstrate reductions in attributional emissions inventories.

The *Corporate Standard* outlines the accounting and reporting rules for creating corporate inventories. It requires companies to quantify emissions from the generation of acquired and consumed electricity, steam, heat, or cooling (collectively referred to as "electricity").[vii] To calculate Scope 2 emissions, the Corporate Standard recommends multiplying electricity consumption (in MWh) with certain emission factors to arrive at the total GHG emissions impact of electricity use.[viii] Companies rely on these reported totals to set targets, track progress, and inform their stakeholders.[ix] Two methods are used to calculate Scope 2 emissions:

- **Location-Based Method** – The Location-Based inventory (LBI) reflects the average emissions intensity of grids on which energy consumption occurs based on grid average emission factor data, assuming a customer "consumes" the shared mix of generation on the local grid irrespective of their procurement actions.[x]
- **Market-Based Method** – The Market-Based inventory (MBI) "reflects emissions from electricity that organizations have purposefully chosen" or receive through "their lack of choice."[xi] It evaluates an organization's procurement actions by netting out purchases of energy attribute certificates (EACs)[6] within a defined market boundary. When EACs are not available, emission factors are applied to the remaining consumption in accordance with a hierarchy described in Table 6.3 of the *Scope 2 Guidance*.

While *Scope 2 Guidance* requires dual reporting using both methods, companies have more control over their MBI and many companies opt to use the Market-Based method as the basis for target setting, measuring performance, and supporting claims associated with electricity use.[xii] In theory, and as described below, the MBI was designed to reflect the *location* and *timing* of purchased electricity supply and/or EACs from *all sources* of generation in relation to a company's consumption. Key features of the current Scope 2 Market-Based method include:

1. **Location Matching.** The *Scope 2 Guidance* quality criteria states that all contractual instruments used in the Market-Based method for Scope 2 accounting shall be sourced from the same market in which the reporting entity's electricity-consuming operations are located and to which the instruments are applied, and utility-specific emission factors shall be calculated based on delivered electricity.[xiii]
2. **Time Matching.** The *Scope 2 Guidance* quality criteria states that all contractual instruments used in the Market-Based method for Scope 2 accounting shall be issued and redeemed as close as possible to the period of energy consumption to which the instrument is applied.[xiv]

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4 By the end of 2022, the cumulative total number of companies with validated science-based targets was 2,079 with another 2,151 companies with commitments to set targets, representing over a third of the global economy by market capitalization.

5 Third party leadership and target-setting programs include CDP, RE100, SBTi, and the U.S. Environmental Protection Agency's Green Power Partnership

6 To simplify discussion, this paper refers to EACs associated with carbon-free electricity (CFE) as defined in the glossary.

3. **Allocation of All Grid Generation Emissions.** The Market-Based method for Scope 2 accounting applies to all energy generation in a defined grid, not just "low-carbon" or renewable energy from projects benefitting from a specific company's financial support. It concerns the larger allocation process of all energy emissions across all end users. All energy has a direct emission factor associated with generation, and the use of that emission factor does not depend on whether the generation facility is existing or new, or why the generation has occurred. The guidance lays out the policy-neutral mechanics of a Market-Based method for Scope 2 accounting, so that regardless of what causes a project to be built, the EAC still serves as the instrument conveying claims about the attributes of the underlying energy generation for consumers purchasing that generation.[xv]

The Market-Based method is meant to serve the goal of *allocating* emissions to electricity users. The *Scope 2 Guidance* states, "As with financial accounting and reporting, generally accepted GHG accounting and reporting principles[7] are intended to underpin and guide GHG accounting and reporting **to ensure that the reported information represents a faithful, true, and fair account of a company's GHG emissions."**[xvi] But the current method of calculating MBIs is based on a loose application of location-matching, time-matching, and attribute allocation, which is disconnected from the realities of supply procurement to serve electricity use and the changes required to decarbonize electricity grids. This creates a challenge for purposes of companies being able to claim they consume carbon-free electricity.

C. The current GHG accounting rules and rewards ecosystem is out of sync with the actions required to actually achieve net-zero emissions.[8]

Current GHG accounting and reporting can result in a greatly reduced or even zero MBI on paper without reducing the actual GHG emissions associated with supply serving a company's electricity use; without developing the mix of resources needed to balance deliverable CFE supply with demand on the grid; and without reducing GHG emissions to the atmosphere. Recognition of the inaccuracy and misleading nature of such environmental claims has caused significant damage to the credibility of the GHG reporting system, and the actions of companies using them as justification, as evidenced in numerous public analysis and reports.[xvii] Various problems with the Protocol are discussed at length elsewhere and are not repeated here.[xviii] In summary, three fundamental problems with the current Scope 2 Market-Based method are worth highlighting (Fig. 1).[9]

The rationale for retaining and improving the Market-Based method and the importance of enhanced reporting to estimate and prioritize real-world emission consequences that flow from company actions are discussed in a companion paper, *Modernizing GHG Accounting Rules and Climate Leadership Programs: How Attributional*[10] *and Consequential Measures*[11] *Differ and Why Both are Essential to Measure and Incentivize Progress Towards GHG Reduction Goals.*[xix]

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7 The *Scope 2 Guidance* (at 21-23) describes five principles – relevance, completeness, consistency, transparency, and accuracy – to develop fair and true inventories.

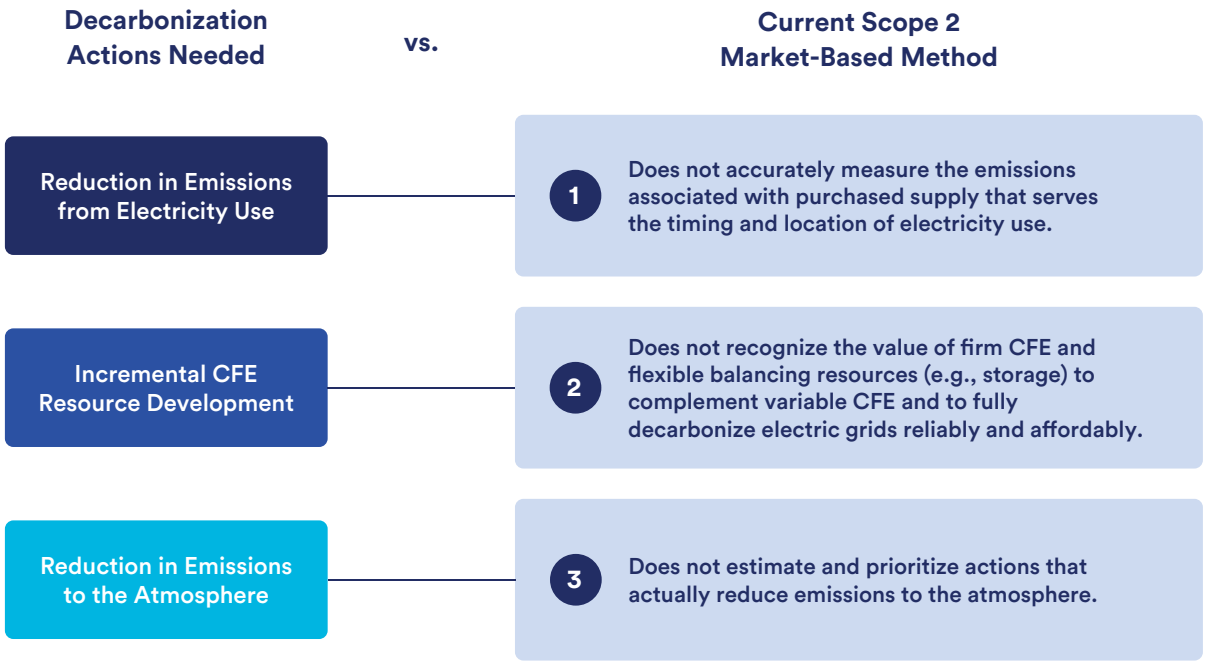
8 The rules and rewards ecosystem is discussed in greater detail in *Modernizing How Electricity Buyers Account and are Recognized for Decarbonization Impact and Climate Leadership*, Green Strategies and The NorthBridge Group, August 2022.

9 To be fair, when the Protocol and MBI were developed, it intentionally relied on the purchase of EACs that were disconnected from supply procurement to serve electricity use and the *Scope 2 Guidance* acknowledges that it was not designed or intended to support calculations of emissions avoided because of a buyer's energy transactions. As climate goals have evolved, it is fair and necessary to question whether these standards and accounting methods should be updated.

10 Attributional accounting was designed to allocate responsibility for emissions within specific boundaries, tied to a company's value chain.

11 Consequential accounting was designed to assess whether actions taken and/or investments made by a company either reduce or increase system-wide emissions to the atmosphere, including impacts outside a company's defined boundaries.

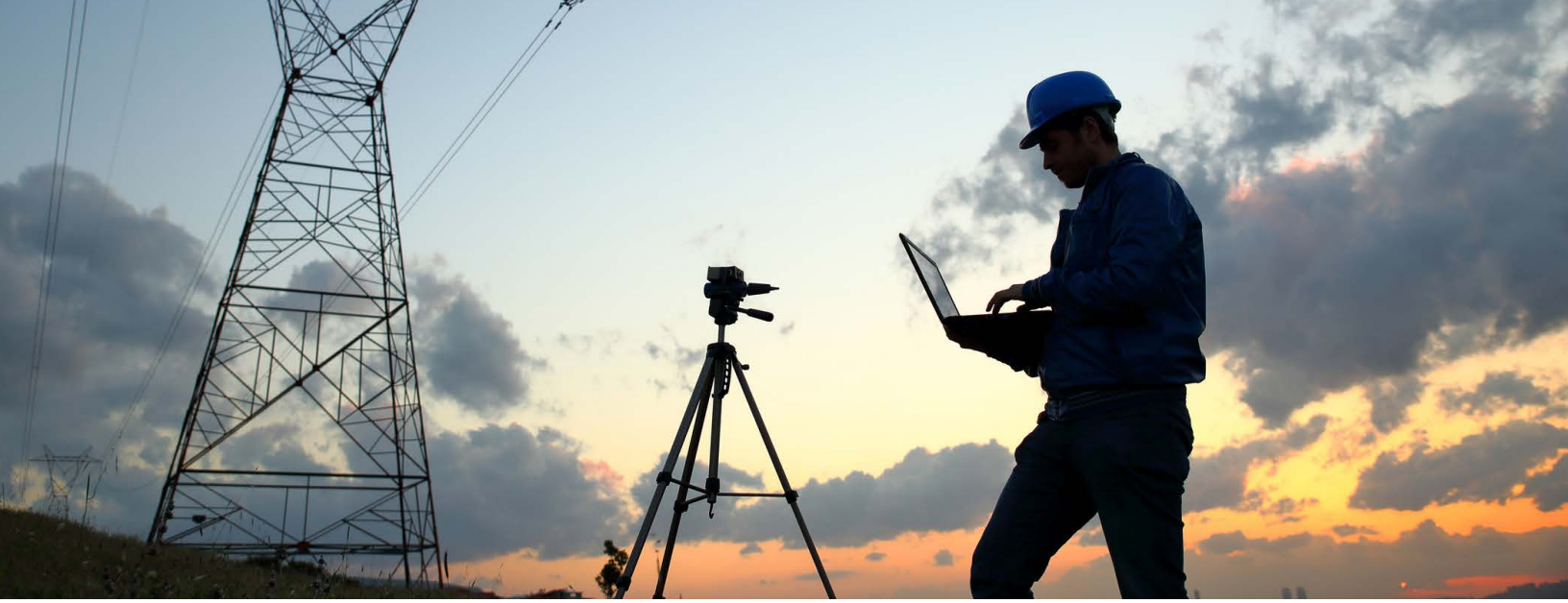
Figure 1: Existing GHG Disclosures and Climate Leadership Programs are Not Aligned with the Actions Needed to Achieve Net Zero Emissions



D. The GHG Protocol update process currently underway is the best opportunity to improve the Market-Based method to maximize the contributions that electricity buyers could make to achieving a fully decarbonized grid on a climate science-based timeline.

The problems identified above need to be addressed in the current GHG Protocol update process. WRI and WBCSD initiated a formal process in 2022 to update the Protocol involving over a thousand stakeholders. Experts widely recognize the current Market-Based method has major problems. At the same time, significant stakeholder disagreements over solutions have emerged related to accounting metrics, methodologies, and best procurement strategies. Numerous stakeholders are engaged in the protocol update process where they are presently hashing out those disagreements. The current plan is to finalize and publish updated standards and guidance by the end of 2026. Now may be the last and best chance to improve the GHG accounting standards, and the leadership and target-setting programs that depend on them, to maximize the contributions that electricity buyers could make to achieving a fully decarbonized grid on a climate science-based timeline. More accurate and relevant GHG reporting is essential to accurately evaluate and recognize the climate impact of electricity procurement actions.

As we explain in the next section, we support improvement of MBIs to make them more accurate and relevant to achieving GHG goals. The remainder of this paper focuses on recommendations to improve the MBI and why these changes are necessary.



SECTION II

Improving the Market-Based Method

The Market-Based method should be retained and improved to enable companies to report accurate and credible claims about the emissions from supply serving their electricity use, while creating demand to accelerate the growth of all carbon-free electricity (CFE) resources necessary to fully decarbonize electricity grids reliably and affordably.

An attributional GHG accounting system that seeks to establish an emissions inventory associated with supply serving electricity use requires that electricity supply is attributed properly to end-use customers and the appropriate emission factors are applied.[12] It is especially important that existing CFE, which represents roughly 40 percent of U.S. electricity generation,[xx] and any new CFE be properly attributed to those who pay for this CFE (and not to those who do not pay for this CFE) to support credible environmental claims of using CFE.

The current method of establishing an MBI, however, often lacks a physical deliverability or financial basis for companies claiming specific emission rates. EACs, which are considered the most precise Scope 2 emission factors,[xxi] can be used to eliminate the emissions associated with any MWh of consumption. The EACs, however, are not required to be linked with how, where, and when that consumption is supplied. For instance, a company could purchase 100% of their supply from a nearby coal plant and entirely erase those emissions using unbundled renewable energy certificates (RECs)[13]

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12 The *Scope 2 Guidance* states (at 49) that, "Each unit of electricity consumption should be matched with an emission factor appropriate for that consuming facility's location or market. For the market-based method, this means choosing a contractual instrument or information source for each unit of electricity."

13 A "REC" is a commodity instrument representing the environmental attributes associated with a megawatt-hour (MWh) of qualified renewable energy generation, such as from wind or solar. It is similar to a European Guarantee of Origin or GO and International I-REC.

from a faraway wind farm that is disconnected from delivered electricity supply, but still claim to have achieved Scope 2 reductions. The associated production from that wind farm is not required to reflect supply that is deliverable to the location or timing of the buyer's consumption. Matching RECs purchased anywhere in the United States[14] with consumption on an annual basis enables companies to report a zero MBI with just solar or wind RECs with no firm[15] or dispatchable CFE or batteries required to always achieve reliable CFE supply. Furthermore, a zero MBI suggests that the company's environmental goals are met despite their continued reliance on fossil resources from their local electric grid. Therefore, because of these shortcomings, the current accounting system is not sufficient to drive the deployment of the full suite of CFE resources on all grids necessary to support net-zero emission goals.

Based on research assessing the potential costs and uncertainties associated with different energy transition pathways, there is broad agreement that a technology-inclusive carbon-free energy approach, including firm and dispatchable carbon-free resources to complement variable renewable generation, is likely to be a less risky and cost-effective pathway to deep decarbonization.[xxii]

> The predominant body of analysis on decarbonization of the electricity sector indicates that the fastest, most cost-effective, and reliable pathway to grid decarbonization is through a diverse portfolio of carbon-free technologies, including wind and solar, along with firm CFE and advanced storage technologies.

A diverse portfolio of clean energy technologies is needed to maintain reliable low-cost electric service, provide flexibility to overcome economic and deployment uncertainties, decarbonize regions where variable renewable energy technologies are less competitive, and decarbonize non-electric sectors of the economy.[xxiii]

While EACs are treated the same irrespective of deliverability within the United States, not all CFE receives the same accounting treatment. CFE, especially firm CFE such as nuclear and hydroelectric generation, often is embedded in a mix of both non-CFE and CFE supply (e.g., in supplier/utility emission rates, residual mix,[16] or other grid average emission factors shown in Table 6.3 of the hierarchy of Market-Based emission factors). Due to the order of operations in Scope 2 accounting, it is difficult to use this CFE (bundled with non-CFE resources) to achieve a zero MBI target.[17]

Finally, as described later, company claims of specific emission rates often lack a clear financial justification (e.g., companies can claim to consume CFE they do not purchase that are financially supported by other customers.) In other cases, companies cannot always claim attributes purchased on their behalf (e.g., CFE is not tracked, claimed, or allocated to those who purchase it). As a result, the current system often misallocates energy supply and emissions to customers.

To establish an accurate MBI, five improvements are needed, as shown in Table 1.[xxiv]

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[14] Much of this paper is focused on the United States, but similar time matching and deliverability issues apply to inventory accounting globally. Also, the issues regarding EAC allocation are relevant to markets abroad where there is standard delivery supply service (e.g., without supplier choice) or CFE generation financially supported or subsidized by certain customers.

[15] Firm CFE technologies can supply electricity on demand such as hydropower, geothermal, energy storage, nuclear, hydrogen, and fossil fuels with carbon capture and storage.

[16] The "residual mix" refers to untracked or unclaimed energy and emissions if a company does not have other contractual information that meets the Scope 2 Quality Criteria (e.g., the emissions rate left after the other contractual information – energy attribute certificates, direct contracts, supplier-specific emission rates – are removed from the system). It is used when calculating the emissions from unspecified purchased or acquired electricity where more-accurate information about the resources and emissions associated with electricity use is not available from the user's state, region, or electricity supplier. (*Scope 2 Guidance*, at 27).

[17] Typically, the MBI is calculated by taking a company's annual consumption less any EACs. The remaining consumption is then multiplied by the applicable emission factors. In effect, subtraction of EACs wherever and whenever generated, takes precedence over CFE included in the mix of resources that may actually supply a customer's consumption. Unlike elementary mathematics, the subtraction of EACs is done before the multiplication of emission factors associated with a mix of resources, which may also include CFE. This can be especially problematic for companies seeking to achieve an MBI of zero and are already purchasing significant amounts of CFE in their standard utility service but are not allocated the associated EACs.

Table 1: Market-Based Inventories Should Reflect Supply that is Deliverable to the Location and Timing of Consumption and Should Be Based on Ownership and Allocation of Purchased and Retired EACs

Improvement	Description
1. Location-Matching	Market-Based inventories should reflect supply that is deliverable to the location of customer consumption.
2. Time-Matching	Market-Based inventories should reflect supply that matches the timing of customer consumption.
3. CFE Equality	Customers should be able to count equally all EACs purchased and retired either directly or on their behalf by their load-serving entity (LSE) regardless of why EACs were purchased and when the resource was built.
4. EAC Ownership and Allocation	EACs should be used to substantiate claims of CFE use and their ownership rights should be fairly allocated to customers who purchase them without double counting, double paying, or cost shifting.
5. EAC Integrity	Required CFE purchases by customers, even if not claimed, should not be permitted to reduce the emissions attributed to other customers who have not purchased EACs. Without EAC purchases, fossil emission factors should be applied using the best available information.

The first two recommendations have received significant attention in recent years among stakeholders interested in improving the Market-Based method,[18] while the last three recommendations are discussed less often.

Stakeholders increasingly have recognized the need to rely on more granular location- and time-matching data (recommendations 1 and 2) in GHG accounting. But ironically, less attention is focused on the ownership and proper allocation of ***all*** forms of CFE and/or the associated EACs in an attributional accounting framework (recommendations 3 thru 5).

To be clear, the purpose of these recommended improvements (related to attributional MBI accounting) is to assess the emissions and percentage of CFE associated with *purchased* supply that is *deliverable* to the location and time of company consumption. An improved MBI would focus attention on matching EACs (expressed in MWh) and the associated deliverable CFE with consumption (i.e., re-connecting attributes with generation that could serve electricity use).[19] An improved MBI would encourage companies and their suppliers to assemble the mix of resources needed to deliver CFE supply to the location and timing of consumption reliably and affordably, considering market conditions and the resources available.[20] As described later, the MBI provides a snapshot of emissions allocated to an end-user for a prior period. It does not reveal where the company started, what the company was required to do, what the company did voluntarily, or whether actions taken by the company had a direct consequential impact on overall system emissions (as described in the GHG Protocol for Project Accounting).[21] A prior year's MBI

[18] Over 140 organizations have signed the United Nations *24/7 Carbon-Free Energy Compact*.

[19] EACs could still be unbundled from electricity supply, but now would be associated with generation that is deliverable to a company's electricity use.

[20] As discussed later, service ideally would be provided by utilities and suppliers on an aggregated customer basis and would consider generation and transmission resources available to deliver supply for electricity use.

[21] Consequential impact associated with company investments and supply procurement may or may not be directly linked to the location and timing of a company's consumption. Such estimates are discussed further in the companion paper, N. Fisher et al., *Modernizing GHG Accounting Rules and Climate Leadership Programs: How Attributional and Consequential Measures Differ and Why Both are Essential to Measure and Incentivize Progress Towards GHG Reduction Goals*.

measures where a company ended up, without revealing the level of difficulty to achieve that inventory and without estimating the system impact directly caused by an individual company's actions. More information is necessary to answer those questions.

All these MBI recommendations are consistent with criteria already embedded within the *Scope 2 Guidance* and are discussed further below.

A. Location-Matching: Market-Based inventories should reflect supply that is deliverable to the location of customer consumption.

The geographic market boundary defines the area from which certificates can be purchased and claimed for a company's MBI. RECs were created in the late 1990s and by design separated the environmental attributes from the underlying electricity flows, disconnecting RECs from the physical deliverability of power. This framework promoted the development of renewable energy resources in the most economically viable locations – effectively encouraging companies to minimize the dollars spent per renewable MWh generated, regardless of location.[xxv] Despite differences in state law, local regulatory policy, and variation in physical interconnection within these regions, the entire United States is considered a single market for EAC use when calculating an MBI.[xxvi] (Currently, RE100 goes even further, allowing companies operating in the United States to claim certificates anywhere in the United States or Canada.[xxvii]) Therefore, the current Market-Based method allows companies to rely on fossil generation from their regional grid while purchasing RECs far from their location of consumption. This has led to valid criticisms that the Market-Based method does not accurately measure the emissions associated with a company's electricity use. For instance, SBTi stated,

> The lack of specificity surrounding guidelines for using these instruments effectively, and ambiguity in the definition of market boundaries within GHGP's scope 2 quality guidance may leave room for loose interpretations that result in corporate offsetting of energy emissions (i.e. companies purchasing energy certificates from one grid to claim zero emissions from electricity consumed in an entirely different grid).[xxviii]

Many of the certificates purchased in the United States and in Europe are not associated with electricity supply that could be delivered to customers.[xxix] This practice undermines the credibility of claims related to electricity use made by voluntary market participants and fails to accelerate the development of CFE resources on all electric grids. As more companies seek to understand their carbon footprint and the growth of a mix of CFE resources is likely required to ensure reliable CFE supply on all grids to achieve full decarbonization, "re-connecting" clean energy attributes to deliverable supply becomes necessary.[22]

For purposes of attributional accounting, more granular geographic market boundaries than the entire United States are needed to better measure the emissions from supply serving electricity use.[23] A key question is what market boundary should be used. Stakeholder views in the GHG Protocol update process vary, ranging from global market boundaries[24] to a strict demonstration of deliverability using power flow models or congestion pricing analysis.[xxx] More granular market boundaries, while recognizing the effects and benefits of trade within and across regions, encourage companies to buy CFE supply that is deliverable to the location of customer consumption. But as geographic market boundaries become narrower, resource options available to match CFE supply with consumption become more limited, making it harder and more expensive.[25]

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22 Due to the lack of connection between EACs and deliverability, SBTi proposed that the Protocol no longer accept unbundled certificates under the *Scope 2 Guidance*. (SBTi, Alberto Carrillo Pineda, *Scope 2 Proposal submitted to WRI*, March 14, 2023, at 4.) While the rationale for this proposal is sound, this solution would exclude unbundled EACs that in some circumstances could be associated with time- and location-matched deliverable CFE.

23 Applying more granular geographic market boundaries is consistent with the *Scope 2 Guidance* quality criteria (Table 7.1, 5 and 6).

24 Emissions First Partnership members support evaluating the consequential emissions impact of company actions using a global market boundary not necessarily tied to the location of a company's operations.

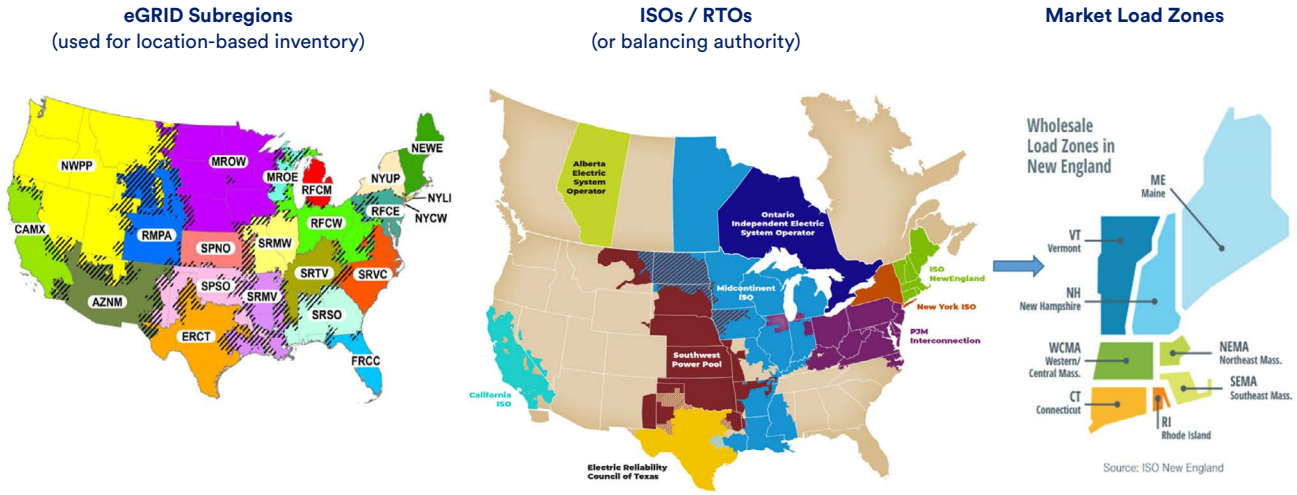
25 Sending market price signals where and when it is hard to balance CFE supply with consumption (sometimes referred to as "scarcity pricing") is valuable but issues can arise over the liquidity of EAC markets within narrower geographic market boundaries.

A report on defining market boundaries highlights these trade-offs, suggesting that voluntary energy markets and Market-Based accounting should align with wholesale electricity markets and reflect some level of physical deliverability while remaining practical enough to encourage broad participation.[xxxi] To evaluate market boundary definitions, three major criteria are recommended: structural relevance,[26] physical deliverability,[27] and practicality.[xxxii]

Given important regional and market structure differences, a single type of market boundary definition is unlikely to work well everywhere in the world. In the United States, several options (Fig. 2 and Fig. 3) are being considered to narrow the current nation-wide market boundary, including ISO/RTO or balancing authorities, eGRID subregions, utility service areas, or bidding/market load zones[28] with the same or similar locational marginal prices (LMPs).

Figure 2: More Granular Market Boundaries Are Necessary for Accurate Market-Based Inventory Accounting

Sources: EPA eGRID maps, ISO/RTO Council, ISO New England



26 The boundaries should align voluntary actions with the needs of the grid and complement existing market and regulatory structures, which are increasingly organized around grid decarbonization in addition to their traditional roles of ensuring the safe, reliable, and affordable delivery of electricity.

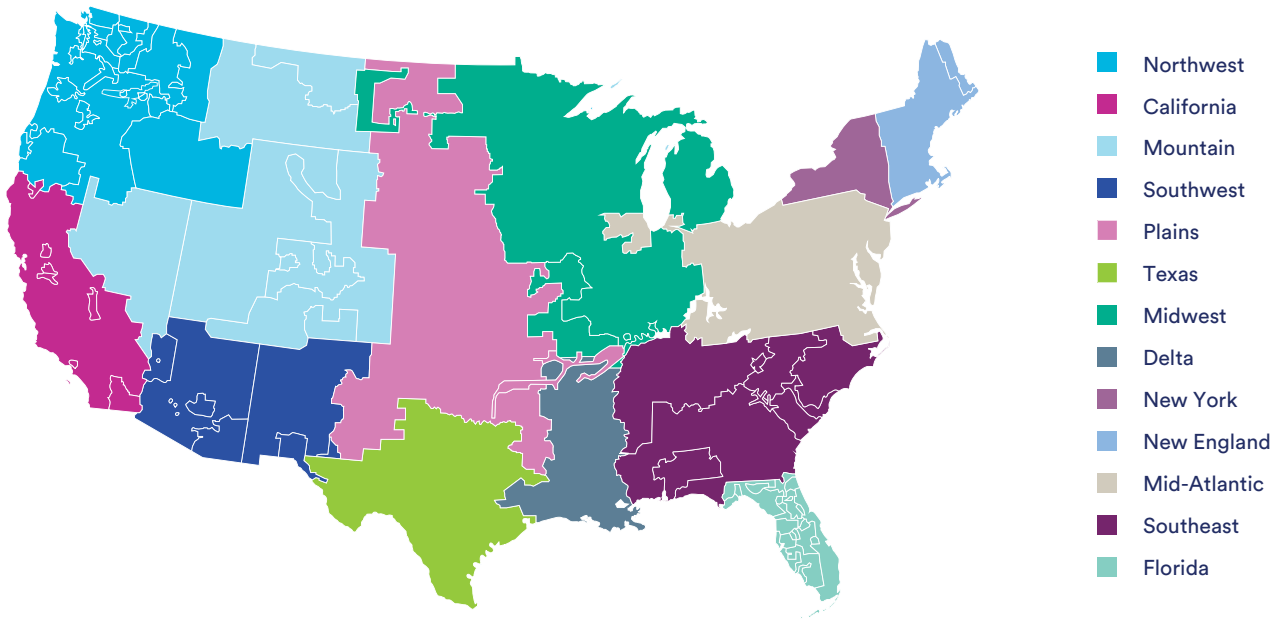
27 Physical deliverability within the same boundary is needed to improve credibility of matching claims and avoid greenwashing.

28 A bidding zone in Europe is the largest geographical area in which bids and offers from market participants can be matched in which a single wholesale electricity market price applies without the need to attribute cross-zonal capacity. Currently, bidding zones in Europe are mostly defined by national borders. In the United States, market load zones are used for wholesale energy market settlement (e.g., New England is divided into eight electric load zones.)

In December 2023, the U.S. Treasury proposed clean hydrogen regulations that would require qualifying EACs to represent electricity that was produced by an electricity generating facility that is in the same region as the relevant hydrogen production facility as defined by the Department of Energy's 2023 National Transmission Needs Study (Fig. 3).[xxxiii]

Figure 3: Market Boundaries for U.S. Clean Hydrogen Proposed Regulations

Source: U.S. Department of Energy, Guidelines to Determine Well-to-Gate Greenhouse Gas (GHG) Emissions of Hydrogen Production Pathways using 45VH2-GREET 2023, December 2023, at 23



As a starting point for purposes of calculating an MBI in the United States, the *Scope 2 Guidance* could count only purchased EACs that are located within or "deliverable"[29] to a) the defined regions specified in the clean hydrogen rules, or b) the same regional grid or balancing authority as load.[30] When possible, a company could be encouraged to select more granular market boundaries if there is pervasive transmission congestion within defined regions.[31]

29 For instance, a company or LSE could qualify EACs out-of-market if bundled with supply that is deliverable to the same market boundary as load (e.g., bundled supply and EACs that are scheduled to the same market boundary as consumption with firm transmission rights).

30 The Long Duration Energy Storage (LDES) Council and McKinsey & Company *study* (at 14) similarly recommended that load, flexibility, and supply should at least be connected to the same bidding or balancing zone, whichever is broader, to accelerate the decarbonization of the grids where the loads are connected.

31 The National Transmission Needs Study indicates that regions with historically high levels of within-region congestion include the Northwest, Mountain, Texas, and New York regions, as well as regions (e.g., California, Northwest, Mountain, and Southwest region) with unscheduled flows that pose reliability risks, which need additional, strategically placed transmission deployment to reduce congestion.

On the one hand, transmission constraints within and between market boundaries should be considered. On the other hand, if an accounting system encourages autarky[32] by requiring that small loads match their profiles with renewable, storage, and firm clean resources in narrowly defined market boundaries, the cost of the energy transition will likely be greatly inflated. Encouraging individual customers to assemble the CFE resources necessary to match their individual loads on a stand-alone basis is likely to be difficult, expensive, and inefficient.[xxxiv] The goal of 24/7 matching should not require every customer to be their own balancing authority, but to recognize the need to contribute to decarbonization of the broader grids where electricity is delivered.

EAC procurement and the accounting systems that support them need to accommodate contracting and EAC trading systems that take advantage of load and resource diversity over large regions, recognizing that such exchanges can drastically lower the capacity and operating costs of meeting load with predominantly CFE supply. In wholesale electricity markets resources and loads are aggregated over tens of thousands, if not millions, of customers. System operators and suppliers balance supply resources with aggregated loads on a 24/7 basis; mainly, to ensure physical reliability and/or financial price affordability and stability. System operators and suppliers must continue to balance supply and demand reliably and affordably but learn to do so with CFE resources. Customers do not need to and should not act alone.[33] Utilities and competitive suppliers that are familiar with matching supply and consumption on an hourly basis can play a crucial role in assembling CFE resource portfolios to serve large groups of customers and help expand market access to all customers. Highlighting the value of location and hourly energy matching in GHG accounting and reporting could increase the customer demand for CFE matching services. Therefore, a challenge is to develop location- and time-matching accounting systems that can enable companies to substantiate credible CFE "use" claims, while also preserving incentives to take advantage of economies of scale and diversity across large regions.

Defining what qualifies as "deliverable" in MBI accounting and choosing a fixed market boundary that respects both transmission constraints and trading within and across market boundaries can be challenging given changes in network conditions. Generation at a particular location may be deliverable to load in some hours but not others. Where centralized markets exist, differences in electricity prices (LMPs) within and across market boundaries could be used to identify when and how pervasive transmission constraints are on electric grids. Again, there is a trade-off in accurately characterizing deliverability and practicality. Market boundaries that better reflect how electricity is sold in today's markets will further encourage de-bottlenecking the transmission system.[34] Indeed, mechanisms have been implemented for many years to enable the trading of physical power between grid regions by booking transmission capacity rights over interconnections, thus respecting physical deliverability. Similar principles and methodologies also could be applied to EAC transactions. Location-matching accelerates the need to address decarbonization on all electric grids.

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32 Autarky refers to a nation or entity that is self-sufficient, or an economic system of self-sufficiency and limited trade.

33 The importance of trading EACs and aggregating loads is also discussed in a companion paper, N. Fisher et al., *Modernizing GHG Accounting Rules and Climate Leadership Programs: How Attributional and Consequential Measures Differ and Why Both are Essential to Measure and Incentivize Progress Towards GHG Reduction Goals*.

34 For example, decarbonizing the grid within New York City (NYC) will likely require expanding transmission access to CFE resources in upstate New York, increasing CFE generation/storage within NYC, and demand-side measures. Defining the Scope 2 Market-Based boundary broadly as all New York State (NYISO) will not encourage these actions. Recognizing the transmission constraints to deliver electricity to NYC within GHG accounting, coupled with market price signals, would further support the need to find solutions to this difficult decarbonization problem.

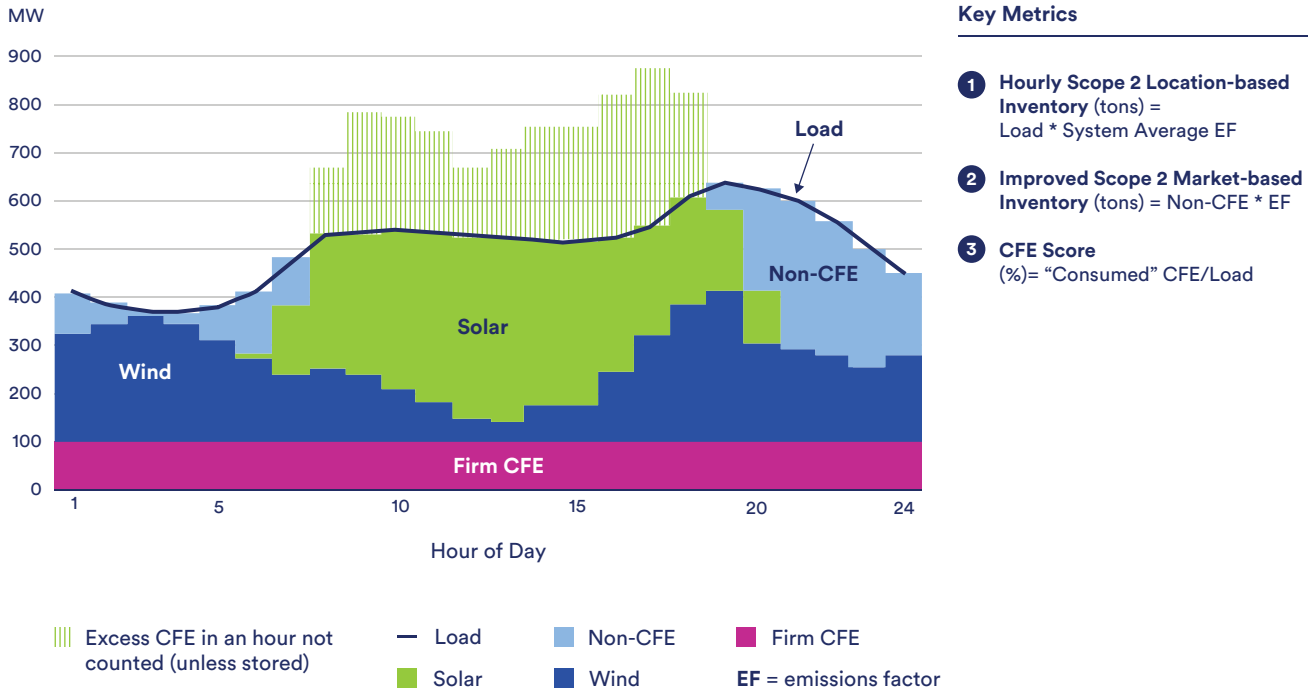
B. Time-Matching: Market-Based inventories should reflect supply that matches the timing of customer consumption.

Most companies calculate MBIs using annual emission factors and annual consumption data. Meanwhile, emission factors vary significantly depending on when electricity is consumed. Using more granular emission factors, supply, and load data would provide a more accurate MBI.[35,36] Hourly or sub-hourly data (preferably metered) is a prerequisite for hourly energy matching of carbon-free supply with consumption. Hourly accounting requires: 1) hourly consumption data,[37] 2) hourly supply purchases,[38] and 3) hourly emission factors (if EACs do not fully cover a company's hourly consumption).[xxxv]

In attributional accounting, there are three important hourly energy matching metrics (shown in Fig. 4). The first two are measured in tons. The third is a percentage.

Figure 4: Granular Time Matching Should Be Used for Accurate Market-Based Inventory Accounting

Source: Figure based on data from Peninsula Clean Energy, Our Path to 24/7 Renewable Energy by 2025, p.12



[35] More granular temporal matching is consistent with the Scope 2 Guidance quality criteria (Table 7.1, 4).

[36] Currently, EACs used in annual calculations typically can be generated within six months prior to or three months after the calculation year.

[37] Ideally, hourly metered data from advanced meters should be used for 24/7 accounting. In retail energy markets, supplier obligations are settled on an hourly or sub-hourly basis. For many customers, consumption is measured monthly based on meter reading schedules. Load profiles are used to convert the monthly consumption data into estimates of hourly or sub-hourly consumption to determine supplier obligations. For each hour, these estimates are aggregated for all customers of an energy supplier, and the aggregate amount is used in market settlement calculations as the total demand that must be covered by the supplier. Absent actual buyer hourly metered load or estimated hourly load based on utility load profiles applied to actual buyer monthly meter reads, estimated hourly load data could be based on standard load profiles by customer type and location. (NREL, 2021, *End-Use Load Profiles for the U.S. Building Stock*); Also, see DOE *Load Profiles* data).

[38] Supply purchases could include contracted resources, utility standard tariff service, green tariff, competitive supply and so forth.

- The first metric is an improved Scope 2 location-based inventory using more granular time and location data. This is calculated by multiplying the hourly consumption (i.e., the load line) by the hourly system average emission factors of the shared mix of generation on the local grid irrespective of a company's procurement actions.[39]
- The second metric, the improved Scope 2 MBI (discussed throughout this paper), considers customer procurement decisions. In hours where the customer does not fully cover their consumption with EACs, the purchased non-CFE supply is multiplied by the applicable emission factors (discussed later).
- The third metric, the CFE Score, measures the percentage of electricity consumption matched with CFE. Visually, it is the sum of the solar, wind, and firm CFE (excluding excess CFE above load in any hour) divided by load.

To lower the improved Scope 2 MBI and increase the CFE Score percentage, suppliers and customers are encouraged to consider all available resources to balance deliverable CFE supply with load, including more wind and solar, storage, firm CFE, load management, and transmission. Detailed system analyses across various markets support the link between pursuing 24/7 procurement goals and the development of a diverse mix of CFE generation and balancing resources[40] needed for reliable, affordable, and clean energy supply.[xxxvi] Recent market contracting experience also supports the need to include firm CFE resources to achieve high levels of hourly energy matching.[xxxvii] Time-matching accelerates the need for a diverse portfolio of CFE generation and other resources.

C. CFE Equality: Customers should be able to count equally all energy attribute certificates (EACs) purchased and retired either directly or on their behalf by their load-serving entity (LSE) regardless of why the EACs were purchased and when the resources were built.

Not all generation is tracked in the United States. And even where generation is tracked, often generation (or EACs) are not allocated to customers who purchase these resources or attributes. For purposes of attributional accounting, companies should be able to count equally all EACs purchased and retired either directly or on their behalf by their LSE. At a minimum, EACs should be tracked and allocated to customers making voluntary claims about CFE use.[41]

Companies should continue to maintain their freedom to choose their supply sources, where permitted, and their procurement goals. Companies can choose EACs associated with renewable or non-renewable generation, new or existing resources, and bundled or unbundled from supply. EACs also can be purchased for a variety of reasons (e.g., to satisfy state compliance or voluntary procurement goals). Similarly, the integrity of state compliance programs should be maintained, where states can choose to rely on specific types of supply resources. However, Scope 2 accounting rules should be applied consistently in a technology-inclusive and policy neutral manner as originally intended. For purposes of inventory accounting and allocation, CFE is CFE, regardless of why the EACs were purchased. Some stakeholders, including the U.S. government, have increasingly recognized the importance of retaining and increasing all forms of CFE resources (not just renewables) to achieve net zero emissions.[42]

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39 An hourly location-based metric can be used to encourage load shifting and energy efficiency but is less valuable in assessing a company's procurement actions.

40 Balancing resources in this paper refer to non-generation resources that can help balance CFE supply with demand, such as energy storage, load-management, and transmission.

41 Ideally, all generation would be tracked and EACs allocated to customers who purchase them. Certain regions of the country already are served by all-generation certificate tracking systems, such as New England Power Pool Generation Information System (NEPOOL-GIS), PJM Generation Attribute Tracking System (PJM-GATS), and New York Generation Attribute Tracking System (NYGATS). While they issue certificates for all electricity generation and resource types within their regions, the associated attributes are not always allocated and claimed by the customers who pay for these resources and/or EACs.

42 For example, the Renewable Energy Buyers Alliance (REBA) changed its name in November 2021 to the Clean Energy Buyers Alliance (CEBA) and both President Biden's Executive Order 14057 and UN 24/7 Carbon-Free Energy Compact focus on CFE, not just renewable resources.

1) Compliance CFE, utility non-bypassable CFE, and voluntary CFE procurement should count equally.

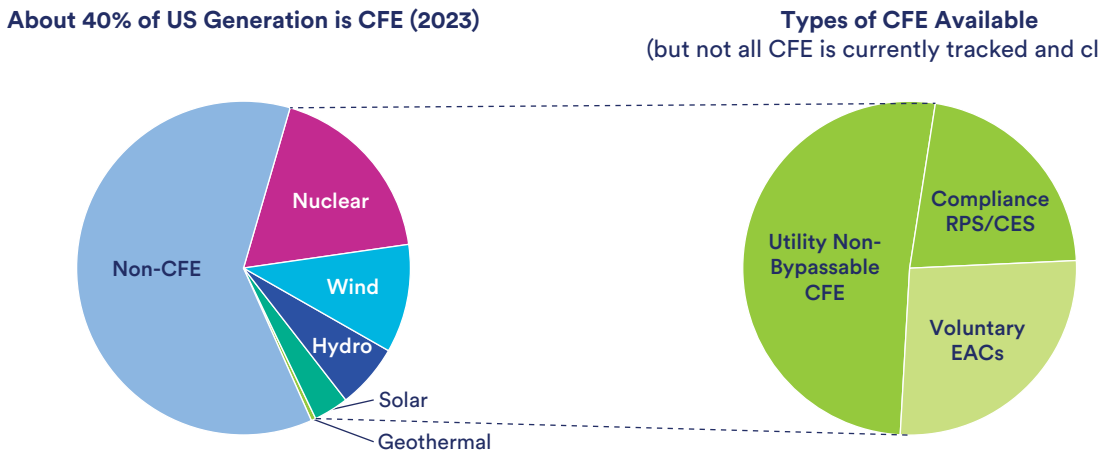
When calculating an MBI, there are three types of CFE purchases that should count equally.

- **"Compliance CFE"** attributes are used to satisfy renewable portfolio standards (RPS) or clean energy standards (CES). Compliance or mandatory markets typically require utilities or electric suppliers to obtain a certain percentage of their electricity generation or sales from renewable or clean energy sources. RECs used to satisfy compliance markets are tracked, verified, retired, and claimed.[43] RPS/CES programs vary by state.[44]
- **"Utility Non-Bypassable CFE"** includes other CFE and/or EACs (bundled or unbundled) that do not meet state RPS requirements that a customer must purchase regardless. For example, many customers are required to purchase their share of nuclear and hydroelectric ratebase generation recovered in utility standard tariff charges in states without retail supplier choice. Or in restructured states, many customers are required to pay their share of the costs to extend the economic lives of nuclear generation assets, backstopped by state legislation and utility non-bypassable distribution charges (e.g., in New York, New Jersey, Illinois, and Connecticut). The EACs associated with this carbon-free generation are not typically allocated to load, claimed, and retired on behalf of customers who pay to keep these assets operating. Nuclear and hydroelectric power represent over 60% of the CFE generation in the United States.[xxxviii] Much of this existing nuclear and hydroelectric generation currently is utility non-bypassable CFE financially supported by customers in specific utility service areas.[xxxix]
- **"Voluntary CFE"** and the associated EACs may be purchased from a utility provider (e.g., a green tariff), competitive retail service provider, included in a power purchase agreement, or unbundled EACs purchased independently from physical power. As the name implies, voluntary EACs are optional. Voluntary procurement accounts for about one-third of U.S. wind and solar capacity additions to date and in recent years about 40 percent of all non-hydroelectric renewable generation.[xl]

Almost three-fourths of existing CFE in the United States is required to be purchased through utility non-bypassable or state compliance programs (Fig. 5).[xli]

Figure 5: Almost Three-Fourths of Existing CFE in the United States is Required through Utility Non-Bypassable or Compliance Programs

Source: EIA, NREL, and The NorthBridge Group



[43] Tracking systems are used to monitor the acquisition and retirement of RECs for RPS compliance.

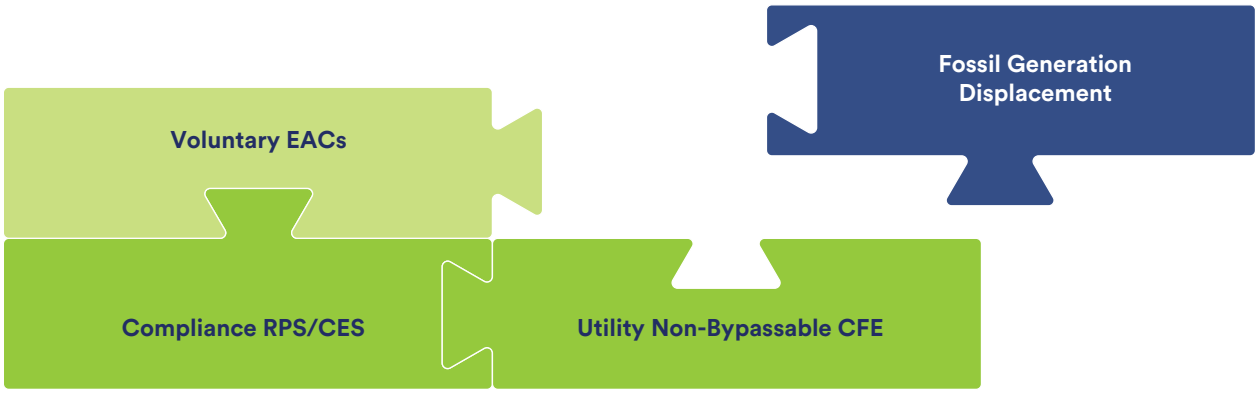
[44] RPS and CES programs can vary significantly in terms of their requirements and compliance timeframes. In some cases, alternative compliance payments can be made in lieu of REC purchases. Some RPS states have multipliers to incentivize specific technologies. In some states, the LSE must procure EACs for the load they serve. In other states, a central procurement agency or the utility obtains EACs on behalf of all customers in the region.

Current accounting rules, however, permit companies to include in their MBI another type of CFE often mixed with other non-CFE resources. This type of CFE is sometimes referred to as "grid CFE" or "grid-supplied CFE,"[xlii] and often is associated with unspecified grid supply, residual mix, or system average generation. Typically, companies cannot point to EACs associated with grid CFE.[45] Utility non-bypassable CFE that is not allocated to load, tracked, and claimed by customers often is included in grid CFE as part of the residual mix and grid average emission factors.

All forms of compliance, utility non-bypassable, and voluntary CFE should count equally and be attributed to those who purchase the associated EACs. When procured and retired EACs associated with compliance programs or ratebase generation satisfy Scope 2 MBI time- and location-matching criteria, they should be allocated on a "load-ratio-share basis"[46] to the customers on whose behalf they are purchased.[47] This is necessary to harmonize U.S. compliance and voluntary markets and align the interests of customers and policymakers to support grid decarbonization in a policy neutral manner – i.e., regardless of whether it occurs via compliance, utility non-bypassable, or voluntary EAC purchases (Fig. 6).[48] Harmonization becomes increasingly important as U.S. RPS/CES programs expand. Among the twenty-nine states plus D.C. with an RPS, sixteen states have RPS targets of at least 50% of retail sales, and seventeen states have a 100% CES or RPS target.[xliii] The ability to include and count all forms of CFE procurement will avoid the need for companies to over procure CFE and better align company interests with public policies.

Figure 6: Voluntary and Compliance Programs Should Complement Rather than Compete in GHG Accounting and Public Policy

Source: The NorthBridge Group



45 Grid-supplied CFE should not be included in a customer's MBI unless it can be demonstrated the customer, or their LSE, procured and retired EACs on the customer's behalf. As discussed later, the White House Council of Environmental Quality (CEQ) subsequently clarified its definition of grid-supplied CFE for purposes of implementing Federal agency procurement of CFE pursuant to Executive Order 14057. CEQ's clarification appears to be consistent with the first two forms of purchased CFE described above – i.e., a pro rata share of compliance CFE and utility non-bypassable CFE.

46 The load ratio share represents a customer's percentage of total utility or supplier demand in that hour (or some other time period).

47 The integrity of existing compliance programs should be maintained while ensuring there is no "double counting" of EACs. Although states may allow more lenient time matching (e.g., using EACs from one year in another year) which would not qualify as time-matched EACs in an improved MBI calculation.

48 An International Energy Agency study (at 34) similarly states that, "policy planning should seek to better define and assess the ways in which renewable electricity targets set by the government interact with clean electricity procurement by corporates." (*Advancing Decarbonisation Through Clean Electricity Procurement*).

The *Corporate Standard and Scope 2 Guidance* were designed to facilitate participation in voluntary and compliance GHG programs.[xliv] Likewise, a key goal of the *Scope 2 Guidance* update is to harmonize and align with accounting rules developed by major regulatory and voluntary disclosure and target-setting programs.[xlv]

> If customers are required to purchase compliance and utility non-bypassable CFE but are not able to fully count these purchases in their inventories, it is reasonable to expect customers to oppose the expansion of clean energy policies, especially when policies impose additional costs without customer benefit in their MBI.

Given that almost three-fourths of existing CFE in the United States is required to be purchased through utility non-bypassable or state compliance programs, it is especially important that the rights to this CFE be properly allocated to customers who purchase this CFE and/or associated EACs regardless of whether customers choose to claim these EACs or not. Customers should be able to count equally their fair share[49] of qualifying location- and time-matched EACs purchased in compliance programs and utility non-bypassable CFE. This type of LSE allocation appears to be consistent with the example in Section 6.6 of the *Scope 2 Guidance* (at 49).

> Companies may also use certificates conveyed to them by their supplier, separately from the other supplier mix information. This ensures equivalent treatment of certificates regardless of how they are sourced. For example, a utility delivers 1,000 MWh in total to customers and 200 MWh of that (20 percent) comes from zero-emitting renewables for which the energy attribute certificates have been retired. Any customer of that utility would be able to claim that 20 percent of their electricity is renewable and substantiated with certificates. If Customer A of this utility consumes 2.5 MWh (of the total 1,000 MWh), they can claim 0.5 MWh [20% of 2.5 MWh] of renewable energy (of the 200 MWh total) without double counting, but cannot claim any more than this. To cover all of their electricity consumption with zero-emission certificates, Customer A would only need to purchase 2 MWh [2.5 – 0.5] of renewables on their own.

But often EACs from state compliance programs in the United States are not allocated to end-use customers and EACs associated with utility non-bypassable CFE are not registered, claimed, or retired.

2) New and Existing CFE should count equally.

The use of an emission factor does not depend on whether the generation facility is existing or new in attributional Scope 2 accounting.[xlvi] But improvements are needed in how existing CFE is treated and allocated. Existing CFE represents about 40% of total U.S. generation.[xlvii] It should not be double counted.[50] Nor should it be ignored in an inventory when matching deliverable CFE supply with consumption. Nor should it be "socialized" and given away for "free" without regard to who financially supports the underlying CFE resources. RMI found that including existing CFE in an hourly match metric lowers the cost of achieving a given match level and may alter the resources procured to meet a given match level but does not significantly change the cost structure of achieving higher levels of hourly matching.[xlviii]

Maintaining and extending the operating lives of existing CFE resources, even if as a transition to new technology development, is a vital component of meeting grid decarbonization goals.[xlix] Resource planning and EAC price signaling should reflect the availability of all CFE resources at a given time and grid location. Several studies have shown that, once a small but significant minority of market participants engage in Market-Based hourly-matching procurement of CFE, an important price signal is established which supports the development of technologies capable of delivering CFE when it is most needed, even though a single purchase of an EAC clearly does not have a one-to-one relationship with construction of a new CFE asset.[l]

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[49] A "fair share" means that a customer should have the "right" to claim EACs that they purchase or their LSE purchases on their behalf, and similarly, not be able to claim EACs that they do not purchase.

[50] No double counting means that no certificate should be double issued, duplicated during transfer, double registered, double canceled, or used more than once.

Some organizations[li] have recommend that "additionality" should be considered in an updated Scope 2 MBI.[51] By design, MBIs currently include all generation. According to the current *Scope 2 Guidance*, sourcing EACs from new generation resources is not required[52] and additionality is "not fundamental to, or largely compatible with, the underlying rules" for Market-Based accounting and allocation.[lii] In contrast, the concept of additionality is often raised as a vital consideration for quantifying project-based GHG reductions.[53]

Certainly, companies should be able to favor using only new CFE resources in their procurement strategies. Presumably, companies that have voluntarily chosen to include additionality criteria in their procurement strategies do so to more directly link their actions to actual emissions reductions.[liii] We fully support the development of new CFE resources and recognize the importance of making decisions that will drive real-world emission reductions. But neither reductions in Scope 2 MBIs[54] nor adding new CFE (in MWh) should be confused with estimating actual carbon reductions (in tons).

A growing body of research and analyses indicates that reductions in MBIs (attributional accounting) should not be confused with estimating system-level GHG reductions (consequential accounting).[liv] For example, a company could acquire RECs from projects where renewable energy production is already relatively abundant and the displacement of fossil energy is minimal or could acquire RECs from an existing resource whose emissions reduction potential has already mostly been achieved.

And not all EACs, even if generated from new resources,have the same climate benefit. Analyses have demonstrated that an additional MWh of CFE can have widely different emission impacts depending on the timing and location of that CFE production.[lv] While not a requirement in Scope 2 accounting, many rely on the concept of "additionality" – whether a company's purchase led to installing more renewables – as a proxy for impact. However, even installing new renewables does not always reduce grid emissions.[lvi] This is especially relevant in areas where increased renewable penetration displaces other CFE, is curtailed due to grid constraints, or requires fossil-fueled reserves to manage ramp-ups, ramp-downs, and volatility. So, additionality measured in terms of new CFE (in MWh) can be a poor proxy for estimating the emissions avoided (in tons).

Attributional accounting is not well-suited nor designed to directly estimate actual changes in emissions on the electric grid resulting from a company's actions.[55] Therefore, as described in another paper, enhanced reporting is needed to directly estimate and prioritize real-world emission consequences that flow from company actions.[lvii] For purposes of calculating an MBI to support claims related to emissions associated with purchased supply to serve electricity use, customers should be able to count equally all EACs purchased and retired either directly or on their behalf by their LSE that satisfy the time and location Scope 2 criteria regardless of why EACs were purchased and when the resources were built.

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51 For instance, a considerable body of modeling research shows that local and hourly matching with new resources actually does drive system-level emissions reductions more deeply than annual matching (*Princeton University*, *Technical University of Berlin*, and the *International Energy Agency*). However, how "additionality" might be considered within Scope 2 inventory accounting principles often is not well-defined.

52 The U.S. Treasury recently published *proposed regulations* regarding what is required for grid-connected electricity used to power electrolyzers to produce hydrogen to receive the 45V clean hydrogen production tax credit in the Inflation Reduction Act. The legal requirements for determining lifecycle greenhouse gas emissions rates resulting from incremental hydrogen production to receive the tax credit differ from Scope 2 MBI accounting requirements related to all consumption.

53 While the Project Protocol does not require a demonstration of additionality, it is incorporated as an implicit part of the procedures used to estimate baseline emissions, where its interpretation and stringency are subject to user discretion (*GHG Protocol for Project Accounting*, at 8).

54 In the Market-Based method, the same EAC (MWh) is likely to result in a different level of MBI reduction (in tons) depending on who buys that EAC, since the MBI depends on the historical average emission factors applicable to a *company's* procurement activities or grid location and how that company elects to apply that EAC to eliminate the emissions (on paper) associated with a MWh of consumption anywhere in the United States. The MBI reduction is disconnected with the timing and location of CFE production, does not reflect either short-run or long-run marginal system impacts, and may occur without any direct change in overall grid emissions.

55 The *Scope 2 Guidance* (at 90) states that the use of an emission factor does not depend on whether the generation facility is existing or new or why the generation has occurred. The *Corporate Standard* and *Scope 2 Guidance* (at 28) acknowledges that changes in Scope 2 inventories "may not always capture the actual emissions reduction accurately." Instead, the Guidance offers (at 52) an option for companies to estimate avoided emissions separately from interventions using another form of analysis, referred to as project level or intervention accounting.

D. EAC Ownership and Allocation: EACs should be used to substantiate claims of CFE use and their ownership rights should be allocated to customers who purchase them without double counting, double paying, or cost shifting.

When attributing clean attributes to customers, the underlying EACs (whether bundled with supply, unbundled, or currently not tracked) should be treated like property rights.[56] Some owners and/or buyers of these rights may be required or voluntarily choose to claim these rights, while others may not.[57] For purposes of attribution, clear and better rules are required related to:

- Who should be permitted to claim EACs associated with CFE generation,
- How should EACs be allocated to customer load,
- Whether and under what circumstances should EACs be transferred either by sale or attribution without purchase to companies, and
- If CFE is not claimed by customers who are required to pay for the underlying generation (e.g., utility non-bypassable CFE), should this CFE be used in the residual mix or grid average emission factors by other customers to reduce their Scope 2 MBIs?

1) EACs should be used to substantiate claims of CFE use.

EACs should be used to substantiate annual and hourly claims of CFE use, and EACs should be tracked, claimed, and retired.[58] This will enhance credibility of energy matching claims and prevent others from claiming CFE that they did not purchase. Companies should have the "right" to claim the CFE that they or their LSE purchase on their behalf. Allowing companies to count qualifying EACs that they purchase in compliance, utility non-bypassable, or voluntary markets will prevent companies from having to double-pay for CFE. If they choose not to claim their CFE, EACs should not be allocated to others.[59] If companies claim their fair share of utility non-bypassable or compliance EACs, they should not make others on the grid appear worse off (i.e., diminish the CFE share of other electricity buyers). In other words, there should be a relationship between the reporting company's purchases (whether required or voluntary) and the EACs claimed by that company.

2) LSEs should allocate EACs that are used to serve customers.

LSEs that acquire or receive EACs on behalf of their customers should be encouraged to adopt a procedure to allocate those EACs to their customers (Table 2).[60] Because requirements for compliance RPS/CES programs are denominated typically as a percentage of total retail sales, LSEs should distribute any EACs associated with RPS/CES compliance to their customers in proportion to their total megawatt-hour consumption (i.e., on a "load ratio share").[61] A potential method for LSEs to allocate EACs to customers is discussed further in the Appendix.

The use of EACs in inventory accounting should prevent a) double counting, b) double paying (i.e., companies unable to claim CFE they already purchase), and c) cost shifting (i.e., companies claiming CFE they do not purchase and/or are supported by other customers).

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56 Multiple governmental entities and organizations recognize that RECs represent and convey the renewable, environmental and/or social attributes of renewable electricity generation to the owner, along with the legal right to claim usage of that renewable electricity. (CRS, *The Legal Basis for Renewable Energy Certificates*, April 2023).

57 There are administrative costs associated with registering, tracking, and retiring EACs.

58 LSEs and companies should follow the established certificate registration, tracking and retirement standards for EACs to ensure credible and verifiable claims.

59 Today, grid CFE can be claimed by customers who did not buy EACs or do not have a credible claim to the purchase and delivery of the underlying carbon-free supply.

60 In some cases, state disclosure requirements may require suppliers to report their supply sources. Absent that, buyers of electricity, like Federal agencies, should request their suppliers to identify the EACs that are being purchased on their behalf.

61 EAC rights should be allocated pro-rata to the load such that: a) there is location and temporal matching where and when the company is consuming power, b) a causal relationship between the reporting company and the EACs, c) the company has unique use of the attributes, and d) the EACs used cannot exceed the company's consumption in that hour. To the extent LSEs have differentiated EAC supply products or contracts with certain customers, those EACs should be dealt with separately.

Table 2: Required CFE Purchases Should Be Allocated to Customers Who Purchase that CFE to Ensure Accuracy of Market-Based Inventory Accounting

Required CFE Purchases	Cost Recovery Mechanism	Who Should Allocate CFE
Ratebase CFE generation	• Retail tariff	• Vertically integrated utility
State-mandated nuclear support programs	• Non-bypassable utility charge	• Distribution utility
CFE in RPS/CES	• Non-bypassable utility distribution charges • Default service supply rates • Competitive supply charges	• Distribution utility (if RPS/CES purchased on behalf of all customers) • Distribution utility (multiple default service suppliers) • Competitive suppliers

3) The White House Council of Environmental Quality's clarification of their electricity procurement implementing instructions is a good model for how required CFE purchases should be allocated to customers who pay for these resources.

Consistent with these principles, the White House Council on Environmental Quality (CEQ) issued a *memo* in August 2023 that clarified the preferred method for calculating grid-supplied CFE for purposes of implementing Federal agency procurement of CFE pursuant to Executive Order 14057.[lviii] This memo considers CFE that is delivered to a Federal customer as part of default electricity service or the grid mix from a utility or service provider. This CFE creates a baseline, or starting point, that can be layered or stacked together with incremental CFE purchases when pursuing CFE procurement goals. Federal agencies can use a new "supplier-attested" methodology to capture CFE in the supplier's existing grid mix that is delivered to Federal customers pursuant to state and local laws or regulations. Agencies may use the CFE percentage attested to by the electricity supplier so long as the electricity supplier tracks each MWh of delivered CFE in the supplier's grid mix using EACs and delivers or retires those EACs on behalf of the Federal customer. EACs to track supplier attested CFE may be sourced from the agency's pro rata share of:

- In vertically integrated utility markets, CFE delivered from the utility's rate-based and contracted generation; or
- In retail electric choice markets, the sum of: (i) CFE delivered from the competitive supplier's requirement to meet a RPS or CES, and (ii) any electric utility distribution provider's non-bypassable charges for CFE (e.g., a state program supporting existing nuclear power).[62]

Alternative compliance payments, regulatory multiplier credits, and unspecified sources of generation (e.g., null power) are not included in this calculation of CFE. There is no "additionality" or requirement that this type of CFE be in service by a specific date to be counted in the CFE baseline inventory. Importantly, the clarification also makes clear that in vertically integrated utility markets, this CFE calculation should not exceed on a percentage basis what the Federal customer would have otherwise received as part of the standard offer service. In other words, Federal agencies are not permitted to acquire unused, unclaimed EACs associated with CFE included in ratebase generation that effectively other customers within the utility service area are paying for to claim progress toward meeting the government agency's clean energy procurement goals. Federal agencies can count their fair share of what they are required to purchase under state and local laws or regulations, but they cannot acquire (or simply reshuffle) attributes associated with existing CFE that are essentially paid for by other customers, even if those attributes are not tracked or claimed by those customers.[63]

[62] The White House CEQ's new definition of grid-supplied CFE is consistent with the first two forms of purchased CFE described earlier – compliance CFE and utility non-bypassable CFE.

[63] The principles described in the White House memo are being applied in the *Entergy Arkansas Go Zero Tariff*.

The White House CEQ's clarification of their electricity procurement implementing instructions is a good model for how required CFE purchases should be allocated to customers who pay for these resources. It provides a valuable roadmap for moving toward an accurate attributional accounting system (annual and hourly) that properly aligns U.S. compliance and voluntary procurement markets.

E. EAC Integrity: Required CFE purchases by customers, even if not claimed, should not be permitted to reduce the emissions attributed to other customers who have not purchased EACs. Without EAC purchases, fossil emission factors should be applied using the best available information.

1) Grid CFE without EACs should not be included in a customer's MBI.

Grid CFE should not be included in a customer's MBI unless it can be demonstrated that the customer or their LSE procured and retired EACs on the customer's behalf. This is consistent with the existing Scope 2 quality criteria that all contractual instruments used in the Market-Based method for Scope 2 accounting shall be tracked and redeemed, retired, or canceled by or on behalf of the reporting entity and utility-specific emission factors shall incorporate certificates sourced and retired on behalf of their customers.[lix]

2) Required CFE purchases by customers, even if not claimed, should not be permitted to reduce the emissions attributed to other customers who have not purchased EACs.

Customers should not be able to claim utility non-bypassable CFE and/or EACs that are attributed or allocated to other customers. These EACs should not be transferred or "given away for free" in the residual mix to satisfy voluntary procurement goals of customers who did not purchase these EACs. Furthermore, the carbon-free attributes associated with this utility non-bypassable CFE should not be sold to a limited number of customers interested in 24/7 or other voluntary procurement goals. Unlike RPS requirements that are imposed on all LSEs, allowing the transfer of non-bypassable CFE attributes to customers interested in 24/7 would effectively allow customers to "undo" state legislative and regulatory mandates pursued on behalf of all customers. This prohibition on the sale of utility non-bypassable CFE attributes is necessary to ensure that voluntary EAC procurement is in addition to compliance/non-bypassable purchases, not simply a reshuffling of non-bypassable EACs to customers interested in voluntary procurement.[64,65] Customers should be able to claim their fair share of what they purchase, but not claim CFE in the undifferentiated grid mix without the purchase of EACs.

3) Without EAC purchases, fossil emission factors should be applied using the best available information.

To prevent double counting or misallocation of EACs, the *Scope 2 Guidance* should remove from the Table 6.3 data hierarchy "other grid-average emission factors," which includes grid-supplied CFE without EACs.[66] These system average emission factors ignore the EAC ownership rights and claims of customers on the grid and should not be used when calculating MBIs. For both restructured and regulated U.S. markets, Emissions and Generation Resource Integrated Database (eGRID) total output emissions data does not account or adjust for state-level clean energy mandates or other non-bypassable CFE purchases that customers are already purchasing in utility charges. Use of eGRID sub-region data (i.e., total output emission factors) to substantiate CFE claims in an MBI is misleading and can result in double counting or misallocation by failing to recognize the ownership rights of CFE and/or EACs, especially those associated with utility non-bypassable CFE. This cost shifting can result in some customers getting credit for clean energy they did not purchase and others not getting credit for clean energy they did purchase.[67]

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64 This recommendation is limited to utility non-bypassable CFE attributes and does not apply to voluntary EACs, which could potentially be traded by customers and retired against consumption if purchased voluntarily by customers.

65 If all LSEs or customers were required to pursue 24/7 carbon-free procurement (similar to RPS), then the sale of these attributes would be appropriate.

66 This includes eGRID total output system average (US), Defra annual grid average emission factor (UK), and IEA national electricity emission factors.

67 See Appendix for Florida Reliability Coordinating Council example.

Google also recognized the problem of double-counting grid CFE in each hour, stating that:

> In our grid CFE calculations today, we include all carbon-free electricity on the grid, without removing the proportion contracted to other parties that have claims to that electricity through environmental attribute certificates. We recognize that this leads to double counting of the environmental attributes of CFE.[lx]

Today, the data required to properly calculate residual mix (by removing the claims to CFE and other supply by all other customers within a market boundary) is not available on an hourly basis. Calculating the residual mix, even on an annual basis, is challenging given that company claims can be made well after the time of generation and not all types of CFE are currently tracked, allocated, or claimed in the United States.[68]

Instead, EACs should be used to substantiate CFE claims, regardless of whether an MBI (or CFE Score percentage) is calculated on an annual or hourly basis. Any load that is not matched with EACs should apply a fossil emission factor using the best available information (see recommended hierarchy in the Appendix). Compliance markets require LSEs to purchase and retire RECs (or make alternative compliance payments) to satisfy state requirements. Scope 2 Market-Based accounting should require companies, or their LSEs on their behalf, to purchase and retire EACs to substantiate voluntary environmental claims (like 24/7).

4) A bottom-up approach should be used to determine a company's EAC purchases.

A "bottom-up" approach, like described in the CEQ memo and section 6.6 of the *Scope 2 Guidance*, should be used to determine a company's EAC purchases and to calculate an MBI. The approach is bottom-up because it relies on the booking and claiming of attributes from a company's direct purchase of EACs and/or an LSE allocation of EACs tied to the company's purchased supply. Until residual mix can be properly calculated in the United States (i.e., removing all compliance, utility non-bypassable, and voluntary EACs from system average emission factors for a defined market boundary), it should not be used to calculate MBIs. Instead, customers (or their LSE) should have to buy, claim, and retire EACs to substantiate a clean energy use claim. This bottom-up ("show me the EAC") approach will allow customers to count the qualifying EACs they purchase and retire directly and/or are retired on their behalf. Likewise, it will avoid situations where customers might otherwise inadvertently claim what they do not purchase. This approach does not require the use of eGRID system average emission factors or a calculation of residual mix. Given the mix of compliance and voluntary markets and diversity of market structures in the United States, it should be easier to identify a customer's share of EAC purchases on a bottom-up basis than it would be to accurately calculate the hourly residual mix by removing all the clean energy claims and rights (even if not claimed) of all other customers in the region from system average emissions.

This allocate, book and claim, approach avoids double paying for CFE by allowing all forms of CFE to be included in a company's MBI.[69] Purchased EACs will count equally in the MBI (and CFE Score) across compliance, utility non-bypassable, and voluntary programs. Requiring voluntary CFE claims to be substantiated with retired EACs will avoid double counting. Properly allocating the property rights of existing CFE while limiting a company's ability to claim "unclaimed" grid CFE or purchase utility non-bypassable CFE from other customers can help mitigate concerns about reshuffling EACs from existing generation to satisfy the voluntary procurement goals of climate-conscious companies.[70] A company's decision to claim or not claim their fair share of utility non-bypassable or compliance CFE attributes, whether through direct purchases or through an allocation from their LSE, should not impact the inventories of other customers on the grid. This would provide a policy neutral, technology inclusive, CFE standard for customers that will establish the accountability needed to support emission claims related to purchased supply for electricity use.

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68 Many stakeholders in the WRI process also noted that residual mix data is not available in many regions of the world. (WRI, Detailed Summary of Survey Responses on Scope 2 Guidance, November 2023, at 25.) The *Scope 2 Guidance* instructs (at 56) companies not to attempt to calculate their own residual mix. Instead, if a residual mix emission factor is not available, the *Guidance* defaults to use of other unadjusted grid average emission factors even though it can lead to misallocation and/or EAC double-counting.

69 Ideally, all CFE on the grid could be tracked and allocated to the load that pays for it, even if not all customers claim the use of this CFE. Absent an all generation tracking and allocation system, requiring a company or their LSE to purchase EACs will preserve the integrity of certificates and avoid double counting and cost shifting.

70 If existing CFE is allocated properly and its use when making claims is limited to those who purchase the associated EACs, this may also help address some stakeholder concerns about the need to impose new, yet to be defined, additionality requirements in attributional accounting.

SECTION III

Developing a Market-Based Inventory – the Role of a "Baseline"

In the United States, too often customers are unable to claim EACs they are required to purchase in their standard electricity service. When driving to California, it is helpful to know your starting point – whether you are traveling from Maine or Arizona. The same is true in inventory accounting and resource planning when trying to achieve grid decarbonization. An MBI provides a snapshot of emissions allocated to an end-user for a prior period. It does not reveal where the company started, what the company was required to do, what the company did voluntarily, or what route they took to get to that inventory. To better evaluate a company's voluntary actions, more information is required.

A standardized "Baseline" could help all customers define their "you are here" starting point. This Baseline can be expressed in terms of a CFE Score (%) and carbon intensity (in pounds or kg per MWh) based on the customer's share of what is *required* for utility standard service in regulated states or utility default/competitive supply service in restructured states.[71] Whether pursuing annual or hourly energy matching goals, the Baseline should measure *required* CFE purchases (and emissions associated with non-CFE supply) absent any voluntary clean energy procurement actions. EEI and U.S. utilities are well-positioned to lead the effort to develop standardized Baselines by service area.[lxi]

The Baseline concept is similar to "standard delivery" service, or "passive procurement", that has been described by other organizations, including the Center for Resource Solutions (CRS), the RE100 Initiative, and Clean Energy Buyers Association (CEBA). In general, these concepts focus on renewable electricity, but should apply to all generation, including all forms of CFE.

[71] The Scope 2 Location-Based inventory ignores the attribute claims and rights to CFE of all customers. LBI emission factors are usually based on the eGRID subregion system average regardless of company supply and EAC purchases. In contrast, the Baseline considers the supply and EACs that the customer is *required* to purchase in a utility service area.

CRS defines Standard Delivery Renewable Energy (SDRE) as delivered energy as a result of an LSE's renewable energy or carbon targets, a state government's renewable or clean energy standard, or circumstances where renewables are a cost-effective resource.[lxii] CRS explains that there is a strong consensus that consumers can claim to be using SDRE when renewable energy attributes and other requirements for credible renewable electricity usage claims are substantiated using credible data. Unfortunately, there is limited data available that transparently documents SDRE.[lxiii] SDRE is provided to all customers often to comply with a government mandate, and in such instances, customers have no documentation that RECs have been retired on their behalf.

> SDRE **may be credibly reported** by a customer as consumed renewable energy and by a provider as delivered renewable energy **when the attributes of the renewable energy are retained or retired on behalf of the customer** (or a group including the customer), and other established requirements for credible renewable electricity usage claims are met.[lxiv]

To support credible claims, CRS recommends that the data describes delivered electricity, that attributes are exclusively owned by or retired on behalf of the consumer (or a group including the customer) and not double counted, that attributes are not double claimed, and that generation occurs in the same market and relative timeframe as consumption.[lxv]

RE100 technical requirements similarly recognize that "passive procurement" may include:

> …renewable electricity in the electricity utility/supplier mix that has not been voluntarily procured by corporate buyers but is delivered by default. Corporate buyers can claim use of default delivered renewable electricity if, and only if, an equivalent amount of EACs is retired by the utility/supplier. Corporate buyers wishing to claim use of this renewable electricity must seek relevant information from their utility/supplier to justify their claims.[lxvi]

Similarly, CEBA refers to electricity that is delivered to a customer by their local supplier without any action by the customer to procure a unique resource mix.[lxvii] CEBA explains that,

> Improving accessibility and quality of data for standard delivery renewable electricity can help all market actors, including government entities, energy suppliers, and energy buyers make more informed renewable electricity policy and procurement decisions.[lxviii]

To improve reporting of standard delivery service, CEBA makes three recommendations:

- Encourage voluntary supplier-specific mix reporting by utilities, building off an initiative from EEI,
- Study and develop a national infrastructure and mandate for consistently reporting emissions and resource mixes for all LSEs, and
- Build consensus around which data sources commonly used to represent standard delivery electricity can support specified electricity consumption claims.[lxix]

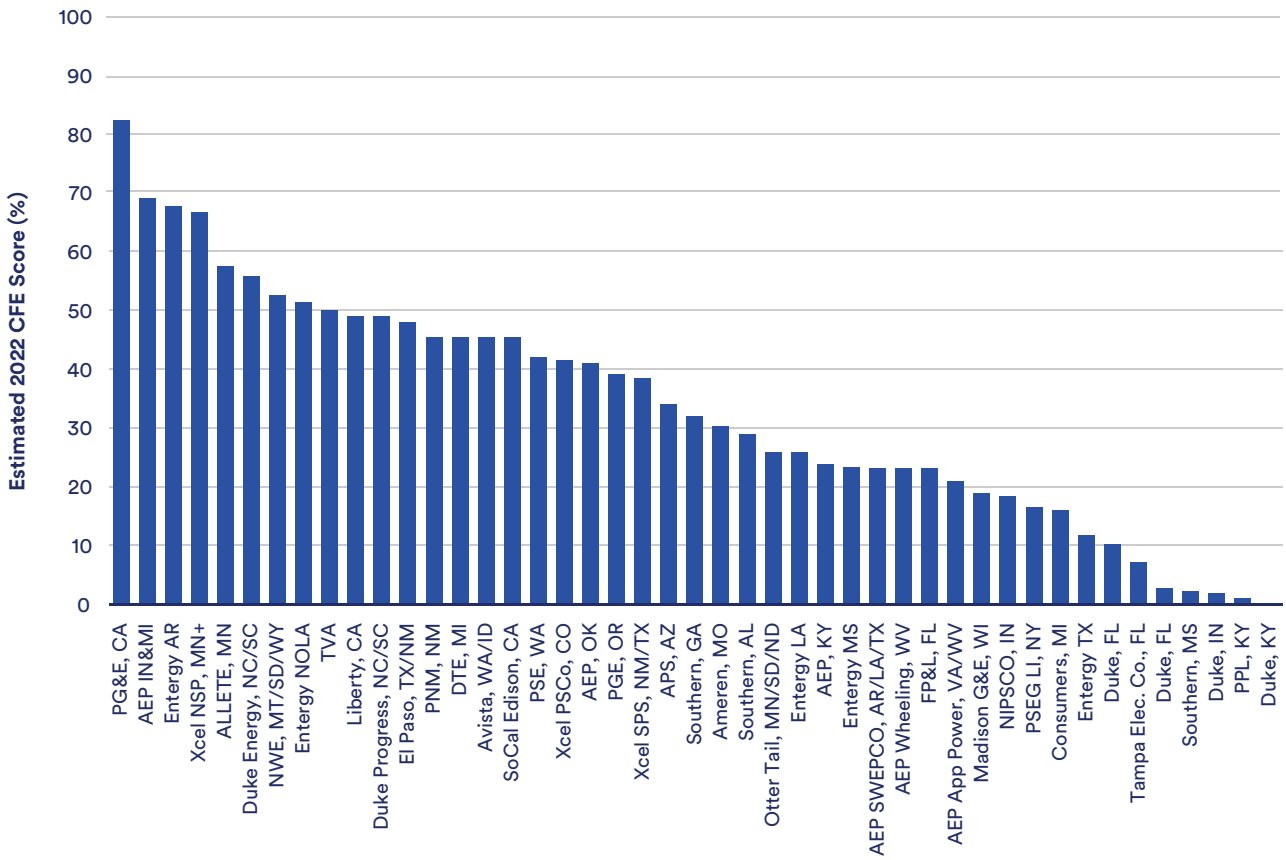
These principles expressed by CRS, RE100, and CEBA should apply to measuring the Baseline. They should apply in establishing the CFE Score and carbon intensity before any voluntary procurement actions are taken by a company.

The NorthBridge Group analysis (Fig. 7) illustrates why calculating the Baseline is important and the likely range in starting points. Due to regional differences in the generation mix, the Baseline CFE Scores vary significantly by utility service area, ranging from 0% to 82%.[72]

[72] Estimated CFE Score calculated using 2022 annual utility data from EEI Electric Company Carbon Emissions and Electricity Mix Reporting Database. Available utility or regional 2022 hourly load and generation data profiles were applied to annual load and CFE generation.

Figure 7: Baseline CFE Scores Vary Significantly by Utility Service Area

Source: The NorthBridge Group



The difficulty in achieving a CFE Score of 100% depends on the CFE resources available. Obviously, moving from a 60% to 100% CFE Score has different costs and impacts than moving from a 0% to 100% CFE Score. To determine what percent of a customer's consumption is supplied by CFE, examine the absolute level of the CFE Score. (Did the customer make it to California or not?) To determine what voluntary effort the customer made, examine the difference in the current CFE Score from the Baseline CFE Score. (Did the customer travel to California from Arizona or Maine?) To determine whether a customer took actions that can be directly linked to emission reductions in the atmosphere, estimate the avoided emissions on the grid (What route did the customer take to California?). The accounting and recognition programs should be modernized to accurately measure and better address each of these relevant questions.

SECTION IV

Conclusion

An improved MBI that reflects supply (and EAC) purchases that are deliverable to the location and timing of customer consumption would enhance the accuracy, relevance, and transparency of information provided to potential users of the GHG Protocol (e.g., recognition programs, ESG rating companies, investors, consumers, etc.) regardless of a company's chosen electricity procurement strategy. Improvements in the Market-Based method will help ensure that the reported information represents a faithful, true, and fair account of a company's GHG emissions. In attributional accounting, when companies (or their LSE) purchase and retire EACs associated with deliverable CFE matching their electricity consumption in each hour, using an improved MBI method, companies should be able to claim they are "using" CFE.[73] This will make it easier to evaluate climate leadership and whether companies are making real strides in reducing the emissions associated with their purchased supply that serves their consumption.[74]

An improved MBI can reduce the risk that consumers are misled by claims about the energy used to produce the goods and services they consume, avoid unwarranted and unjustified conclusions about the real benefit to the climate from company actions and help protect reporting companies from accusations of "greenwashing".

A summary of the recommended Market-Based inventory improvements and their purpose are shown in Table 3.

We recognize that important issues remain regarding *how* and *when* given the available data we can accurately measure emissions associated with supply procurement to serve electricity use.[75] This will require more granular time and location emission factors, generation, and load data. It will also require developing market systems to better track, allocate, verify, and trade granular time-stamped EACs. The use of specific emission rates in an MBI needs to align with a Company's financial support of supply purchases serving their consumption.

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[73] Hourly matching claims should be substantiated with the use of hourly granular certificates.

[74] Company actions that affect real-world emissions, both within and outside a company's area of operations, should also be evaluated separately and recognized.

[75] The need for new impact disclosures is discussed in greater detail in proposals submitted to WRI and in other papers prepared by The NorthBridge Group and Green Strategies, Inc., endorsed by Clean Air Task Force.

Table 3: Summary of Recommended Market-Based Inventory Improvements

Recommendation	Purpose	Current MBI	Improved MBI
Location-Matching: Market-Based inventories should reflect supply that is deliverable to the location of consumption.	Develop CFE resources necessary to serve all grids, while recognizing the benefits of power trading.	Broad market boundaries (e.g., anywhere in U.S.)	• As a starting point in United States, count only the purchased EACs that are located within or deliverable to a) the defined regions specified in the clean hydrogen rules, or b) the same regional grid or balancing authority as load. • Consider transmission congestion within and electricity trading across defined market boundaries whenever possible.
Time-Matching: Market-Based inventories should reflect supply that matches the timing of consumption.	Create demand for mix of resources necessary to always balance CFE supply and load.	Annual	• Use hourly calculations (when data is available); do not allow EACs to exceed load in any hour. • When hourly data is not available, profiles could be used to estimate how annual calculations might compare with hourly matching figures. (e.g., 100% annual matching might translate to 50% hourly matching depending on the load and resources involved.)
CFE Equality: Count equally all EACs purchased and retired either directly or on customer's behalf.	Technology and policy inclusive; prevent double paying for CFE.	CFE when combined with non-CFE resources is difficult to use to zero out MBI.	• Count equally all EACs purchased and retired on behalf of customer regardless of why EACs were purchased and when the resources were built.
EAC Ownership and Allocation: Count only EACs purchased and retired.	Enhance the financial basis for use of specific emission rates.	Customers cannot always count CFE and/or EACs they financially support.	• EACs should be used to substantiate voluntary CFE energy matching claims and should be tracked, claimed, and retired. • A bottom-up "book and claim" direct purchase or LSE allocation approach should be used.
EAC integrity: Do not count grid CFE without purchased EACs.	Prevent double counting and cost shifting.	Customers can sometimes count grid CFE and/or EACs they do not financially support.	• Consumption that is not matched with EACs should apply a fossil emission factor using the best available information (See Appendix). • Customers should not be allowed to acquire or claim EACs associated with existing CFE paid for by other customers, even if those attributes are not tracked or claimed by those customers.

Electricity supply is routinely monitored by location and time to support resource planning, operations, and compliance with financial contract obligations.[76] Using more granular data when calculating an MBI, defining appropriate market boundaries, and adhering to a CFE technology-inclusive, policy neutral approach is critical to create the demand to accelerate the growth of all CFE resources necessary to fully decarbonize electricity grids reliably and affordably.

Certainly, ongoing work will need to address a range of questions and details as to the timing for imposing new requirements, the burden of completing enhanced disclosures, and the availability of necessary data. While resolving these issues will be difficult, building the reform process around improved and new metrics will ensure that the Protocol continues to be a critical agent for reaching climate ambition. It is time to stop playing checkers when the climate requires chess. An improved MBI is an important component of measuring and reporting progress using more relevant, transparent, and accurate information.

[76] Suppliers in restructured states either have access to customer-specific interval data or rely on utility load profiles applied to meter reads (that typically record monthly consumption) to define a supplier's supply obligation of serving their customers in each hour.

SECTION V

Appendix

A. How LSEs can allocate supply resources to customers.

Much of our current GHG accounting system is predicated on companies disclosing the emissions associated with their purchases.[77] But in many instances, utilities or competitive suppliers are in a better position to inform their customers what they are supplying. Routinely, suppliers assemble resource portfolios to provide their customers with full requirements service, where supply must match their customers' load obligations on an aggregated basis in a particular market zone by hour.[78] This section is intended to help LSEs think about how to assign resource entitlements to customers.

In an hourly, Market-Based emissions accounting system, inevitably there will be hours in which an LSE imports or exports power. That is, the supplier's demand will not precisely equal their entitlements to generation from owned or contracted resources in some, if not all, hours. It will be either selling excess electricity to other parties or purchasing undifferentiated energy from the grid, whether through an ISO or bilateral transactions. Which and what types of resources should be deemed to support customer demand in these hours? Hours with exports can be considered separately from hours with imports but in both cases, the underlying principle is that emissions accounting should endeavor to use the best representation available of the resources that support the needs of the suppliers' customers.

In hours of energy exports, when an LSE has resource entitlements that exceed customer demand, some generation must be deemed to meet the supplier's customer demand while the remaining, excess generation will be deemed to fulfill market sales to other suppliers' customers. The supplier could employ one of many hierarchies to assign resource entitlements to match their customers' demand: for example, it could select the lowest cost resources, it could select the resources with the lowest emission rates, or it could select the resources that are in the closest proximity to their customer base. Our recommended approach is to assign resource entitlements from resources with the lowest variable operating costs (fuel plus operations and maintenance), much like RTO/ISOs do, in ascending order until customer demand is matched. This represents the set of resources that would be operational absent the opportunity to provide electricity to other entities. To the extent that some resources are dispatched for non-cost reasons (e.g., to provide ancillary services, to provide local reliability in a congested region, or through self-scheduling to manage fuel supply), these can be placed at the bottom of the supply stack so they are assigned to customers first. All resources assigned to customers rather than wholesale sales are assigned pro-rata to all customers; that is, customers receive a blend of all resources needed to meet LSE demand, unless they take service on a special tariff backed by specific resources, such as a solar tariff. The sample resource "stack" shown in Fig. 8 illustrates this concept.

Typically, CFE resources will have zero or near zero variable costs and will be the first or among the first resources to be assigned to match customer demand, but this need not always be the case.[79]

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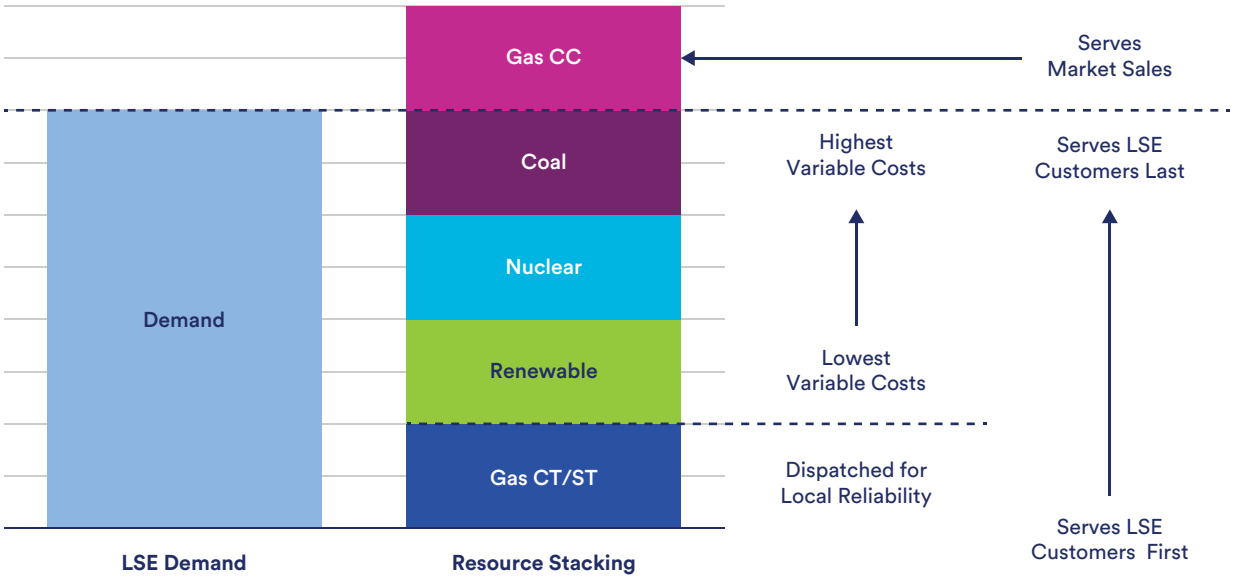
77 This is analogous to customers having to list the ingredients of everything they buy when shopping at a grocery store or when ordering a meal at a restaurant.

78 Retail suppliers often provide supply to their customers on an aggregated basis, not necessarily tying specific resources to an individual customer.

79 As suppliers experience hours with excess EACs and seek to sell them, they will create and provide liquidity to spot markets and in turn make hourly EACs available to suppliers with complementary load shapes, lowering the cost of time-matching and encouraging efficiency among suppliers.

Figure 8: Illustrative Load-Serving Entity Resource Stacking and Assignment



In hours of net energy purchases, when a supplier's entitlements from specified resources are less than customer demand, an emission rate must be assigned to market purchases using the best attempt possible to capture the location, source, or characteristics of these purchases. Under a perfectly coordinated, universally adopted accounting mechanism, all resources deemed to be in excess by exporting suppliers could be allocated to importing suppliers. In the absence of such an exchange, market purchases should use a representative regional, fossil-only rate. To avoid double counting and further substantiate environmental claims, no CFE should be assumed to be included in undifferentiated market purchases. To the extent power flow data is available and provides insight to the regions from which the supplier's purchases may originate, that can be incorporated into the calculation as well.

B. How LSEs can allocate utility non-bypassable CFE and/or EACs to customers.

After the utility or competitive supplier determines the amount of non-bypassable CFE and/or EACs within its supply portfolio, they then need to determine how to allocate these entitlements to customers. To ensure consistency with a Market-Based inventory using hourly granularity, an allocation reflective of customer consumption and generation in that hour is appropriate. This can be achieved by apportioning attributes from CFE generated in each hour pro rata to customers based on each customer's percentage of total utility or supplier demand in that hour (i.e., via the customer's load-ratio share), as shown in Table 4.[80] Using this method, a customer consuming electricity solely in overnight hours would receive no allocation of CFE from an LSE whose EACs were solely sourced by solar generation during the day.

[80] This is not the only allocation methodology that may be considered. For instance, similar principles could be applied for annual energy matching. Or if customers participating in a Green Tariff had a strong desire to know their allocation factor on a forward-looking basis, the LSE could determine the allocation factor using the customer's load-ratio share across a recent interval such as a calendar year.

Table 4: Method for Load-Serving Entity to Allocate CFE/EACs to Customers

Consumption and Generation	Current year data used
Time Period Considered	Hourly
Basis for Customer Allocation (%)	Actual customer load ratio-share of total LSE demand in each hour
Variability of Allocation Factors	Percentages vary depending on load-ratio share in each hour
CFE to be Allocated (MWh)	Based on actual hourly CFE generation

The arrival of new customers or new electricity consumption taking service from an LSE raises the question: how and when should new demand be allocated CFE? Unless a customer is receiving service that is matched or supported with designated resources that differ from the remaining customer pool (e.g., through a solar tariff), all customers who pay the same rates to support the same portfolio of resources should be equally entitled to EACs from that portfolio at that time, regardless of whether the customer has been served by the LSE for one year or multiple years.[81] Assigning preferential entitlements of some resources to customers based on their tenure as a customer would be challenging to track or implement fairly and would run counter to utility ratemaking and resource planning principles. Similarly, to the extent that an LSE accommodates new demand by including new CFE in their supply portfolio dedicated to all customers, the EACs associated with these resources would flow to all (legacy and new) customers. If existing customers stop receiving standard service for any reason, the EACs from legacy CFE resources that would otherwise be allocated to that customer can be reallocated among remaining customers.

C. Consumption that is not matched with EACs should apply a fossil emission factor using the best available information.

Emission factors used for inventory accounting should be based on the "most appropriate, accurate, precise, and highest quality" information available.[lxx] Scope 2 Market-Based accounting should require companies, or their LSEs on their behalf, to purchase and retire EACs to substantiate voluntary environmental claims (like 24/7). Any load that is not matched with EACs should apply a fossil emission factor based on the following hierarchy, and as shown in Fig. 9.

- EACs tied to non-CFE (i.e., fossil) resources,
- Contracts/tariffs tied to specific fossil resources,
- Supplier-specific emission factors (not including any grid CFE unless carbon-free EACs have been allocated to customer load),[82]
- Hourly residual mix for fossil generation (if available)
- Unspecified hourly supply:
  - RTO/ISO hourly average fossil generation emission rates (considering deliverability of imports when possible)
  - eGRID fossil fuel output or eGrid non-baseload emission rates[83]

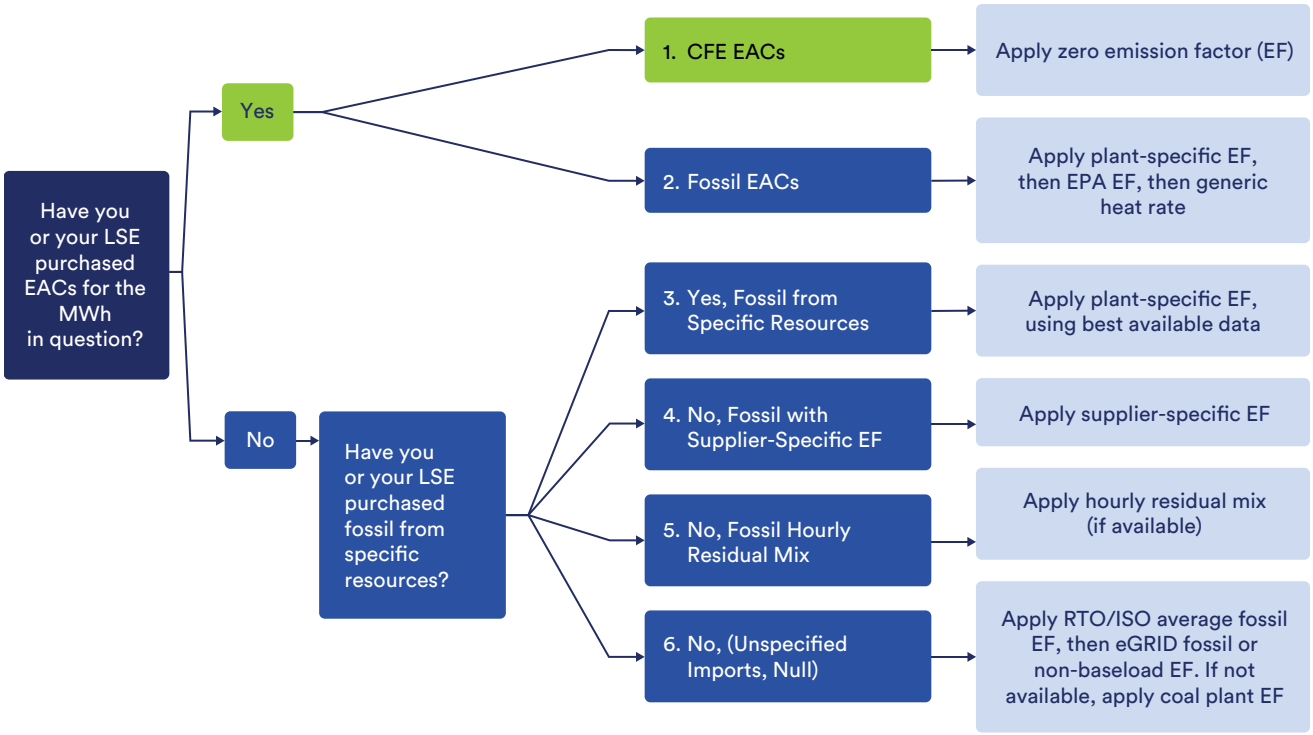
81 If the LSE does not utilize an allocation methodology based on current year data, the new customer or new demand should receive a commensurate EAC allocation as soon as is practicable, recognizing that some time lag may be unavoidable.

82 Emissions representing the portfolio of resources used (owned or procured) for retail customers or sales.

83 Published annual eGRID fossil fuel and non-baseload emission factors are on average about 70% higher than total output emission factors (although this difference varies by eGRID subregion depending on the supply mix). As renewable penetration increases, the gap between fossil/non-baseload and total output emission factors tend to increase. Use of either eGRID fossil fuel or non-baseload emission factors would be a significant improvement over the current application of total output emission factors.

Figure 9: The Best Emission Factors Available Should Be Used for Inventory Accounting

Source: The NorthBridge Group



Using this decision tree, the first question is whether a company or their LSE purchased EACs for the MWh in question. If yes, and it is carbon-free, this is used to calculate a CFE Score % and substantiate hourly MBI inventory using an emission factor of zero. All CFE counts equally.

Everything else on the tree shaded in blue is considered fossil or non-CFE supply. If a company has EACs or granular certificates (GCs) for non-CFE resources, ideally these GCs would have emissions factors tagged on the certificate. But if not, then use the best available emission factor data for that specific plant (e.g., EPA CEMS data on fossil generation 25 MW and larger).

If a company does not have EACs, determine whether the company or their LSE purchased fossil generation from specific resources. If yes, apply plant-specific emission factors using best available emission factor data for that specific plant, and if data for that specific plant is not available, a generic heat rate could be used.

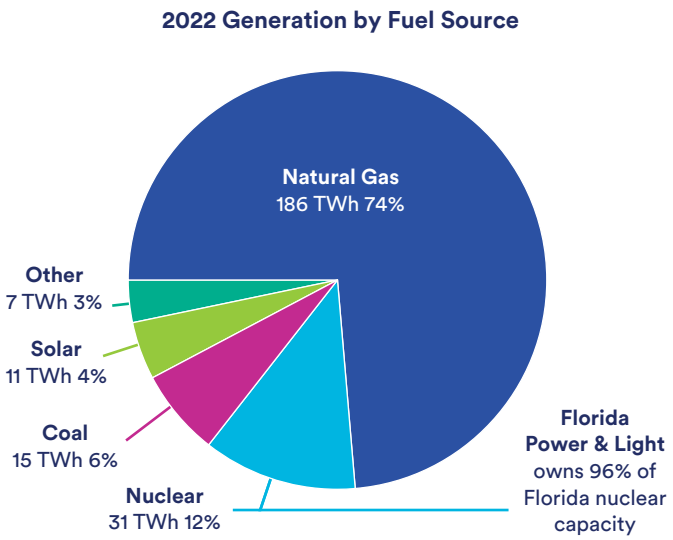
If a company has not purchased fossil supply from specific resources, then in order of preference use a supplier-specific emission factor, an hourly residual mix for fossil generation,[84] or unspecified emission factor based on the RTO/ISO fossil average emission factor or eGRID fossil or non-baseload emission factor (hourly preferred). And as a last resort, the worst applicable fossil emission factor could be applied. This process would ensure the integrity of carbon-free energy "use" claims.

[84] Unlike other emissions factors listed here, this would require tracking of all other claims and rights of other buyers within the defined market area.

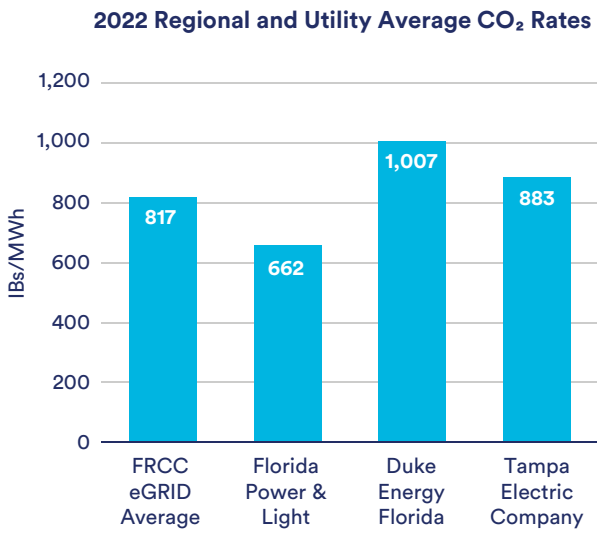
D. Use of eGRID system average emission factors can result in misallocation of CFE to customers with little causal connection to that CFE.

Consider the eGRID subregion: Florida Reliability Coordinating Council (FRCC). While most electricity is generated from natural gas, nuclear energy provides the second-largest share. About 96% of this nuclear generation is owned by Florida Power & Light (FP&L), which FP&L ratepayers pay for through non-bypassable charges. According to the utility average emissions rates reported to the Edison Electric Institute (EEI) for 2022, FP&L's emissions rate was well below the eGRID average for FRCC, while Duke Energy Florida and Tampa Electric Company reported average emission rates above the FRCC average (Fig. 10). MBIs should similarly assign the nuclear CFE to FP&L customers. However, if the attributes of the nuclear CFE were not registered and retired by FP&L or not claimed by FP&L customers, it could be counted as grid-supplied CFE in the residual mix or in system average emission factors to reduce the requirements of other Florida customers.

Figure 10: Market-Based Inventories Should Reflect Purchased Supply: Florida Reliability Coordinating Corporation Example



Source: EPA eGRID2022 Database



Sources: EPA eGRID2022 Database, EEI Electric Company Carbon Emissions and Electricity Mix Reporting Database

In this case, use of the eGrid FRCC average emission factor (as a last resort in the Scope 2 emission factor hierarchy) would produce a lower MBI than either the emission factors associated with ratebase generation supported by Duke Energy or Tampa Electric ratepayers. The ability to use more favorable default emission factors may result in unintended incentives to not seek out more accurate emission factors in the Market-Based Scope 2 data hierarchy (Table 6.3) or to "swap" fossil for unspecified grid purchases to apply a better emission factor in a company's inventory.[85]

[85] For example, a company or their supplier could purchase coal supply and sell it back into the local market and replace it with unspecified grid supply.

SECTION VI

Glossary and Acronyms

Additionality	A criterion often applied to GHG project activities, where additionality denotes that the outcome of an intervention "would not have happened anyway"—i.e., that the project activity (or the same technologies or practices that it employs) would not have been implemented in the absence of that intervention (or Baseline Scenario).
Allocation	The process of assigning responsibility for GHG emissions from a specific generating unit among its various users of electricity.
Attribute	Descriptive or performance characteristics of a particular generation resource. For Scope 2 GHG accounting, the GHG emission rate attribute of the energy generation is required to be included in a contractual instrument in order to make a claim.
Attributional accounting	Attributional accounting is designed to allocate responsibility for emissions within specific boundaries, tied to a company's value chain.
Avoided emissions	An assessment of emissions reduced or avoided compared to a reference case or baseline scenario. Typically, avoided emissions represent the total carbon emissions, estimated in tCO_2e, from grid electricity that are displaced by the addition of a new CFE generation project to the same grid.
Balancing area	Balancing authorities are a functional role defined by the North American Electric Reliability Corporation and are primarily responsible for balancing electricity supply, demand, and interchange on their electric systems in real time. This balance is needed to maintain the safe and reliable operation of the power system and includes managing transfers of electricity with other balancing authorities. There are 66 balancing authorities in the United States.
Balancing resources	In this paper, balancing resources refer to non-generation resources that can help balance CFE supply with demand, such as energy storage, load-management, and transmission.
Baseline scenario	A hypothetical description of what would have most likely occurred in the absence of any considerations about climate change mitigation.

Baseload	A type of power plant that operates continuously (or nearly continuously) to meet base levels of power demand that can be expected regardless of the time of day or year.
Bidding zone or market load zone or market hub	A bidding zone in Europe is the largest geographical area in which bids and offers from market participants can be matched in which a single wholesale electricity market price applies without the need to attribute cross-zonal capacity. Currently, bidding zones in Europe are mostly defined by national borders. In the United States, market load zones are used for wholesale energy market settlement where the locational marginal price is the same (e.g., New England is divided into eight electric load zones.) A market hub is a collection of locations intended to represent an uncongested price for electric energy, facilitate electric energy trading, and enhance transparency and liquidity in the marketplace.
Bundled	An energy attribute certificate or other instrument that is traded with the underlying energy produced.
Carbon-free electricity (CFE)	CFE is electrical energy produced from resources that generate no carbon emissions, including marine energy, solar, wind, hydrokinetic (including tidal, wave, current, and thermal), geothermal, hydroelectric, nuclear, renewably sourced hydrogen, and electrical energy generation from fossil resources to the extent there is active capture and storage of carbon emissions that meets the EPA's requirements.
Carbon intensity	Carbon intensity is a measure of how much carbon dioxide is released to produce a kilowatt hour of electricity.
CFE score	The percentage of load that is matched with CFE within or deliverable to a defined market boundary. It can be measured by hour or annually. If measured hourly, purchased CFE in excess of load in one hour cannot be used in another hour unless stored.
Company	The term company is used in this paper as shorthand to refer to the entity developing a GHG inventory, which may include any organization or institution, either public or private, such as businesses, corporations, government agencies, nonprofit organizations, assurers and verifiers, universities, etc.
Compliance (or mandatory) CFE	Compliance CFE attributes are used to satisfy renewable portfolio standards (RPS) or clean energy standards (CES). Mandatory or compliance markets typically require utilities or electric suppliers to obtain a certain percentage of their electricity generation or sales from renewable or clean energy sources. RECs used to satisfy compliance markets are tracked, verified, retired, and claimed. RPS/CES programs vary by state.
Consequential accounting	Consequential accounting is designed to assess whether actions taken and/or investments made by a company either reduce or increase system-wide emissions to the atmosphere, including impacts outside a company's defined boundaries.

Cost shifting	In this paper, cost shifting refers to companies being able to claim CFE/EACs they do not purchase and/or are supported by other customers.
Double counting	No double counting means that no certificate should be double issued, duplicated during transfer, double registered, double canceled, or used more than once.
Double paying	In this paper, "double paying" refers to companies unable to claim CFE they already purchase and then having to purchase additional CFE or EACs to reduce their Market-Based inventory.
eGRID	U.S. Environmental Protection Agency's *Emissions & Generation Resource Integrated Database* is a globally recognized source of emissions data for the electric power generated in the United States. Data in eGRID are displayed at the plant level and are also aggregated to state, electric generating company, power control area, eGRID subregion, NERC region, and the U.S. total levels.
eGRID fossil fuel output emission rate	eGRID fossil fuel output emission rates are calculated based on plants whose primary fuel is coal, oil, gas, or other fossil fuel.
eGRID non-baseload emission rate	eGRID defines non-baseload emission rates as the output emission rates for plants that combust fuel and have capacity factors less than 0.8, weighted by generation and a percent of generation determined by capacity factor.
eGRID subregion	eGRID subregions are defined by EPA and were developed as a compromise between NERC regions (which EPA felt were too big) and balancing authorities (which EPA felt were generally too small). The subregions were defined to limit the import and export of electricity to establish an aggregated area where the emission rates most accurately matched the generation and emissions from the plants within that subregion.
eGRID total output emission rate (or system average emission rate)	The eGRID annual total output emission rate is the measure of the emissions as it relates to the net generation output. It is calculated as the emissions mass divided by the generation MWh multiplied by a unit conversion factor. Units are in lb/MWh for CO_2. Average emission factors represent all generation occurring within a defined region and should reflect net physical energy imports/exports across the grid boundary.
Emissions	The release of greenhouse gases into the atmosphere.
Emission factor	A factor that converts activity data into GHG emissions data.

Energy attribute certificate (EAC)	A category of contractual instruments used in the energy sector to convey information about energy generation to other entities involved in the sale, distribution, consumption, or regulation of electricity. This category includes instruments that may go by several different names, including certificates, tags, credits, etc. (EACs can apply to all types of generation, but to simplify discussion, this paper refers to EACs associated with carbon-free electricity.)
Fair share allocation	In this paper, a "fair share" allocation means that a customer should have the "right" to claim EACs that they purchase or their LSE purchases on their behalf, and similarly, not be able to claim EACs that they do not purchase.
Firm CFE	Firm CFE technologies can generate electricity on demand such as hydropower, geothermal, energy storage, nuclear, hydrogen, and fossil fuels with carbon capture and storage.
Granular certificate (GC)	Certificate relating to the characteristics of energy produced during a period of one hour or less. GCs are commonly referred to as time-based EACs.
Greenhouse gases (GHG)	GHGs are the seven gases covered by the UNFCCC: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6), and nitrogen triflouride (NF_3).
Grid or regional grid	A system of power transmission and distribution (T&D) lines under the control of a coordinating entity or "grid operator," which transfers electrical energy generated by power plants to energy users—also called a "power grid." The boundaries of a power grid are determined by technical, economic, and regulatory-jurisdictional factors. A regional grid corresponds to the area over which a single entity manages the operation of the electric power system and ensures that demand and supply are balanced. In the United States, this generally refers to one of seven RTOs or ISOs (California ISO, Electric Reliability of Council of Texas, Midcontinent ISO, New England ISO, New York ISO, PJM, Southwest Power Pool). These regional grids cover about half of the states and roughly two-thirds of total U.S. annual electricity demand.
Grid or system operator	The entity responsible for implementing procedures to dispatch a set of power plants in a given area to meet demand for electricity in real time.
Inventory or market boundary	An imaginary line that encompasses the direct and indirect emissions included in the inventory. It results from the chosen organizational and operational boundaries.
Location-based method (Scope 2)	A method that reflects the average emissions intensity of grids on which energy consumption occurs based on grid average emission factor data, assuming a customer consumes the shared mix of generation on the local grid irrespective of their procurement actions. Average energy generation emission factors are for defined locations, including local, subnational, or national boundaries.

Locational marginal price (LMP)	LMP is a way for wholesale electric energy prices to reflect the value of electric energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. LMP is defined as the marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved real-time security constrained economic dispatch program solution. LMP is expressed in $/MWh. LMP is a pricing approach that addresses transmission system congestion and loss costs, as well as energy costs. LMPs can be calculated in both the real-time energy market and day-ahead energy market. The LMP calculation calculates the full marginal cost of serving an increment of load.
Marginal emissions rate or factor	Short-run or operating marginal emission rates (sometimes referred to as SRMER, LMER, LME, or MER) represents the emissions per unit change in electricity consumption or injection of generation, considering changes in power plant production levels from one moment to the next assuming no structural changes in the grid, such as plant retirements or additions. Long-run or build marginal emission rates (sometimes referred to as LRMER) represents the emissions per unit change in electricity consumption or injection of generation, considering both operational (short-run) and long-term structural changes in the grid (e.g., the building and retirement of capital assets, such as generators). A buyer action can affect grid emissions across one or more timeframes and could have multiple marginal impacts.
Marginal generator or unit	Marginal generator(s) or unit(s) are the units "out on the edge of the supply stack" that would increase or decrease output in response to an increase or decrease in demand. In general, there is always one marginal unit representing the system energy price in a competitive market or system lambda (i.e., the cost of the next kWh that can be produced by an electricity supply system's generating units) in a regulated market. When there is congestion on the system, there will be one additional marginal unit for each constrained transmission line on the system.
Market-based method (Scope 2)	A method that reflects emissions from electricity that companies have purposefully chosen (e.g., through contracts) or receive through their lack of choice.
MBI	Market-based inventory of emissions established using the Scope 2 market-based method.
Megawatt (MW)	A unit of electrical power. One megawatt of power output is equivalent to the transfer of one million joules of electrical energy per second to the grid.
Megawatt-hour (MWh)	A unit of electrical energy equal to 3.6 billion joules; the amount of energy produced over one hour by a power plant with an output of 1 MW.
Null power	Energy from which energy attribute certificates or other instruments have been separated and sold off, leaving the underlying power without specific attributes.

Power purchase agreement (PPA)	A type of contract that allows a consumer, typically large industrial or commercial entities, to form an agreement with a specific energy generating unit. The contract itself specifies the commercial terms including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project. In order for the consumer to say they are buying the electricity of the specific generator, attributes shall be contractually transferred to the consumer with the electricity.
Regional Transmission Organization (RTO) / Independent System Operator (ISO)	An RTO is an electric power transmission system operator that coordinates, controls, and monitors a multi-state electric grid. The purpose of the RTO is to promote economic efficiency, reliability, and non-discriminatory practices while reducing government oversight. An independent system operator (ISO) is an organization that coordinates, controls, and monitors the operation of the electrical power system within a single U.S. state, but sometimes encompasses multiple states.
Renewable energy	Energy taken from sources that are inexhaustible, e.g. wind, water, solar, geothermal energy, and biofuels.
Renewable energy certificate (REC)	A type of energy attribute certificate, used in the U.S. and Australia. In the U.S., a REC is defined as representing the property rights to the generation, environmental, social, and other non-power attributes of renewable electricity generation. It is a commodity instrument representing the environmental attributes associated with a megawatt-hour (MWh) of qualified renewable energy generation, such as from wind or solar. A REC is like a European Guarantee of Origin or GO or International I-REC.
Renewable portfolio standards (RPS)	A state- or national-level policy that requires that a minimum amount (usually a percentage) of electricity supply provided by each supply company is to come from renewable energy.
Residual mix	The “residual mix” refers to untracked or unclaimed energy and emissions if a company does not have other contractual information that meets the Scope 2 Quality Criteria (e.g., the emissions rate left after the other contractual information – energy attribute certificates, direct contracts, supplier-specific emission rates – are removed from the system). It is used when calculating the emissions from unspecified purchased or acquired electricity where more-accurate information about the resources and emissions associated with electricity use is not available from the user’s state, region, or electricity supplier.
Scope 2 emissions	Indirect emissions from the generation of purchased or acquired electricity, steam, heat or cooling consumed by the reporting company.
Supplier-specific emission factor	An emission rate provided by an electricity supplier to its customers, reflecting the emissions associated with the energy it provides. Suppliers offering differentiated products (e.g. a renewable energy product) should provide specific emission rates for each product and ensure they are not double counted with standard power offers.

Tracking system	A database or registry that helps execute energy attribute certificate issuance and cancellation/retirement/claims between account holders in the system. It can track information on certificates or generation occurring throughout the defined system. They are typically tied to geopolitical or grid operational boundaries.
Unbundled	An energy attribute certificate or other instrument that is separate, and may be traded separately, from the underlying energy produced.
Utility non-bypassable CFE	Utility non-bypassable CFE includes other CFE and/or EACs (bundled or unbundled) that do not meet state RPS requirements that a customer must purchase regardless. For example, many customers are required to purchase their share of nuclear and hydroelectric ratebase generation recovered in utility standard tariff charges in states without retail supplier choice. Or in restructured states, many customers are required to pay their share of the costs to extend the economic lives of nuclear generation assets, backstopped by state legislation and non-bypassable utility distribution charges (e.g., in New York, New Jersey, Illinois, and Connecticut). The EACs associated with this carbon-free generation are not typically allocated to load, claimed, and retired on behalf of customers who pay to keep these assets operating.
Vintage	The date that electric generation occurs and/or was measured, from which an energy attribute certificate is issued.
Voluntary CFE	Voluntary CFE and the associated EACs may be purchased from a utility provider (e.g., a green tariff), retail service provider, included in a power purchase agreement, or unbundled EACs purchased independently from physical power. As the name implies, voluntary EACs are optional.

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[lii] Scope 2 Guidance, at 90-91.

[liii] For example, Google, *24/7 Carbon-Free Energy: Methodologies and Metrics*, February 2021, at 5.

[liv] Google, *24/7 Carbon-Free Energy: Methodologies and Metrics*, February 2021, at 1, 6, 8, 12, 14, and 20. Matthew Brander, *The Most Important GHG Accounting Concept You May Not Have Heard of: the Attributional Consequential Distinction*, GHG Management Institute, March 2021, at 1-5. Enrique Gutierrez, Julia Guyon, Craig Hart, Zoe Hungerford, and Luis Lopez, *Advancing Decarbonisation Through Clean Electricity Procurement*, International Energy Agency, November 2022, at 12-14, 23-25, 54-65, and 72-73. Roger Ballentine, Patrick Falwell, Liana Biasucci and Neil Fisher, *Modernizing How Electricity Buyers Account and are Recognized for Decarbonization Impact and Climate Leadership*, Green Strategies and The NorthBridge Group, August 2022, at 32-45. EPRI, *24/7 Carbon-Free Energy: Matching Carbon-Free Energy Procurement to Hourly Electric Load*, December 2022, at 22.

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[lvi] *What is Additionality (and Emissionality)*? Electricity Maps blog, March 8, 2023.

[lvii] Neil Fisher, Roger Ballentine, Benjamin F. Hobbs, Armond Cohen, Jeanette Pablo and Iain Kaplan, *Modernizing GHG Accounting Rules and Climate Leadership Programs: How Attributional and Consequential Measures Differ and Why Both are Essential to Measure and Incentivize Progress Towards GHG Reduction Goals*, The NorthBridge Group, Green Strategies, Johns Hopkins University, and Clean Air Task Force, April 2024.

[lviii] *Clarification of Grid-Supplied Carbon Pollution-Free Electricity Calculation Methodology*, White House Council of Environmental Quality, August 4, 2023.

[lix] Scope 2 Guidance, Table 7.1 Scope 2 Quality Criteria, 3 and 6.

[lx] Google, 24/7 Carbon-Free Energy: Methodologies and Metrics, February 2021, page 23.

[lxi] EEI, in collaboration with member companies, corporate customers, and the World Resources Institute, developed a carbon emissions and electricity mix reporting template for delivered electricity by operating company. Further work would be needed to standardize this information across reporting utilities. *EEI Utility CO2 Emission Factor Database*. Similarly, CRS's commented to the EPA that, "The standardization of methodologies for calculating utility-specific emission factors that convey the GHG emissions intensity of contractually delivered electricity to customers…would significantly increase the accuracy of tracking progress towards corporate climate targets. Further working with utilities to centrally publish a comprehensive standardized dataset of utility-specific emission factors by product would streamline reporting and facilitate more accurate tracking of goals over time." CRS Comments, *Docket ID No. EPA-HQ-OAR-2022-0878*, January 18, 2023.

[lxii] CRS, *Accounting for Standard Delivery Renewable Energy*, Clean Energy Accounting Project, March 2021, at 1.

[lxiii] CRS, *Accounting for Standard Delivery Renewable Energy*, Clean Energy Accounting Project, March 2021, at 2.

[lxiv] CRS, *Accounting for Standard Delivery Renewable Energy*, Presentation by Todd Jones, March 16, 2021, at 13, emphasis in original.

[lxv] Ibid., at 27.

[lxvi] *RE100 Technical Criteria*, December 12, 2021, Section 5.1, at 12, emphasis in original.

[lxvii] CEBA, *Principles of Accounting for Renewable Electricity in the U.S.*, Executive Summary.

[lxviii] CEBA, *Principles of Accounting for Renewable Electricity in the U.S.*, Executive Summary.

[lxix] CEBA, *Principles of Accounting for Renewable Electricity in the U.S.*, Executive Summary.

[lxx] Scope 2 Guidance, section 6.5, at 45