Modernizing How Electricity Buyers Account and are Recognized for Decarbonization Impact and Climate Leadership

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Abstract

For more than a decade, large electricity buyers have been a growing force for driving the deployment of clean energy and decarbonizing the electricity sector. A myriad of companies has set voluntary renewable energy and/or emissions reduction goals and many participate in third-party programs that encourage and recognize leadership in clean electricity procurement, such as CDP, the Science Based Targets initiative, and the Environmental Protection Agency's Green Power Partnership. Almost universally, companies and third-party leadership programs use an established set of rules for calculating and reporting emissions arising indirectly from electricity use ("Scope 2" emissions): *the Greenhouse Gas (GHG) Protocol's Corporate Standard* and subsequent *Scope 2 Guidance*. The *Protocol's* framework has guided buyer strategies and transaction options to reduce Scope 2 emissions. Aligning their strategies with the *Protocol* and the requirements of third-party programs, buyers have enabled the deployment of many gigawatts of new wind and solar generation capacity, helping to significantly drive down the costs of these technologies.

Nevertheless, the pace at which the electric sector is decarbonizing is well behind the pace needed to both drive emissions out of the sector and to drive emissions out of other sectors through electrification. Given the need to accelerate grid decarbonization, this paper explores whether the current "rules and rewards ecosystem" of GHG accounting and third-party leadership/recognition programs continues to adequately incentivize and support electricity buyers in driving grid decarbonization with their market power. It takes a critical look at the *Protocol's* current approach to Scope 2 accounting – and how it is used by third-party programs – and offers recommendations for modernizing accounting and disclosure and recognition practices to better incentivize and reward buyer procurement strategies that can do even more to accelerate the decarbonization of the grid.

Modernizing the "rules and rewards ecosystem" includes identifying new metrics and information for disclosure. The paper recommends how this more relevant and robust information could be assembled and disclosed in more comparable and consistent formats. It proposes a new standardized "Carbon Facts" reporting system that can be understood and used by stakeholders and recognition programs. Some of the Carbon Facts "Label" information could best be calculated via updated *Protocol* Scope 2 accounting. Other new and important disclosures might best be calculated outside of the *Protocol* but nevertheless be part of new standardized carbon reporting best practices (and both *Protocol*-based and non-*Protocol*-based information could be presented as part of the Carbon Facts disclosure format).

The revised and additional carbon disclosures outlined in the paper are designed to improve accuracy and relevance, while incentivizing and rewarding electricity use and procurement decisions that better optimize decarbonization impact. Accuracy and relevance would be enhanced by changes to Scope 2 location and market-based reporting that yield inventories that better reflect the emissions resulting from a company's actual electricity consumption. Incentivizing and rewarding transactions that contribute to grid decarbonization could be achieved by the reporting of avoided emissions impact arising from transactions and disclosing the extent to which carbon-free electricity (CFE) supply matches the timing and location of a buyer's consumption.

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Executive Summary

To avoid the worst effects of climate change, the world needs to dramatically reduce greenhouse gas emissions and reach a state of net-zero emissions by mid-century. All sectors of the economy must follow this pathway, including the electricity sector. But the decarbonization of the electricity sector must accelerate, not only to mitigate a major source of emissions, but to also accommodate the electrification of other sectors, including transportation and heating. A fully decarbonized grid must be in place well before 2050. The pace of grid decarbonization is currently off-track to meet these timelines, and impactful policy interventions remain elusive.

In the absence of adequate climate policy, many companies and other large buyers of electricity have voluntarily adopted sustainability goals to purchase and use clean electricity in their operations. To date, buyers seeking to meet their commitments have catalyzed the deployment of gigawatts of new renewable (primarily wind and solar) electricity generation capacity. In pursuing such goals, buyers are guided by a clear set of standards and accounting methods and by the rules and methodologies of third-party leadership and recognition programs. However, given the critical need to get as much decarbonization impact from the actions of marketplace buyers as possible, it is fair and necessary to question whether these standards, accounting methods, and ecosystem of leadership and recognition programs are in fact fully aligned with maximizing the contributions buyers can make to address the climate crisis. This is the subject of this paper.

This paper takes a particularly focused look at *The Greenhouse Protocol ("the Protocol")*, whose *Scope 2 Guidance* has provided methodologies and guidance for buyers and is an entrenched part of how external recognition and leadership programs judge buyer actions. The *Protocol*, along with recognition programs that rely on it, has influenced buyer electricity procurement strategies and efforts to reduce estimated Scope 2 emissions (indirect emissions from purchased electricity). A common approach for buyers has been to adopt renewable procurement goals – either as standalone goals or as part of internal or third-party structured greenhouse gas reduction commitments. By procuring renewable energy and/or energy attribute certificates (EACs) (such as Renewable Energy Certificates or (RECs)[a]), buyers have sought to match on an annual basis the megawatt hours (MWh) of wind and

[a] 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. Such attributes have different names in markets outside of North America. For simplicity the terms "REC" or "EAC" are used to mean all similar attribute instruments regardless of their in-market name.

solar generation underlying the RECs that they procure against the MWh of their electricity consumption. The *Protocol* reinforces this approach, recognizing REC acquisition and retirement as a mechanism to reduce reported Scope 2 inventories. Several companies have set – and achieved – a 100% annual matching of renewable electricity/RECs and their electric load. Having met or in the process of meeting initial goals, many buyers are evaluating how to further leverage their electricity procurement to have greater carbon impact under a "next generation" of approaches.

While this *Protocol's* approach and buyer targets to purchase 100% renewable electricity have worked synergistically, the paper highlights an overarching set of issues.

Problem Statement

- The *Protocol's* methods for measuring Scope 2 emissions in their current forms are not adequately aligned with the pathways and actions that are urgently needed in the electric grid to achieve net-zero GHG emission goals in an affordable and reliable manner.
- The incumbent Scope 2 accounting methods do not accurately measure the emissions and carbon-related risks associated with a buyer's purchase and use of electricity or convey the emissions reduction impact (if any) resulting from a buyer's procurement of clean electricity and/or attributes.
- Today's Scope 2 methods do not consider: 1) the timing of carbon-free electricity supply procurements relative to a buyer's consumption of electricity, 2) the location of carbon-free electricity supply procurements relative to a buyer's consumption, or 3) the extent to which a buyer's procurement of clean electricity reduces carbon emissions.
- Since fully decarbonizing the electricity sector will require carbon-free electricity to be always available at all locations on the electric grid, with firm generating and storage resources to complement variable wind and solar, current Scope 2 accounting and disclosure practices are not sufficient to drive the deployment of the full suite of carbon-free electric resources necessary to support net-zero emission goals.
- The current rules and rewards ecosystem is not sufficiently optimized to address evolving stakeholder needs toward disclosing, incentivizing, and rewarding emerging best practices in electricity procurement.

Recommendations

- Scope 2 accounting and reporting practices should be modernized to provide more accurate information about the emissions arising from a buyer's consumption of electricity and a buyer's carbon impact when procuring clean electricity and/or attributes.
- This information should be incorporated and disclosed in a standardized "Carbon Facts" reporting system that can evolve over time but will ultimately include the following:
  - On a locational basis for buyer facilities (regional grid or similar area), the sources and mix of electricity consumed by the buyer, the degree to which the timing of carbon-free electricity supplies match the timing of electricity consumption, and the emissions associated with electricity supplies calculated based on a modified Scope 2 protocol.
  - On a total buyer basis (nationally or globally), the incremental carbon-free electricity procured by technology (distinguishing between variable and firm resources), and the climate impact of procurements and other buyer actions.
- While the full range of data and information – granular customer load, electric supply, and emissions – may not be currently available or is only just becoming available (tracking systems are still being developed in many regions of the United States and customers are working with suppliers to increase data availability), buyers should be encouraged to report as broad a range of information as is available, including that tailored to their procurement goals and other metrics as suggested by a "Carbon Facts" reporting system.

Benefits

- These recommended disclosures would provide a strong foundation for large electricity buyers to continue to improve their procurement practices and support the electricity sector investments needed to achieve net-zero emission goals, including a broadened focus beyond just wind and solar resources by encouraging the deployment of a full suite of existing and emerging firm carbon-free generation, energy storage, load management, and other technologies needed to achieve a carbon-free electricity sector.
- Reporting information that more accurately reflects emissions from electricity procurement and use and decarbonization impacts will allow buyers to better evaluate alternative electricity procurement actions and provide better and more relevant information that can then be used by third-party leadership and recognition programs, investors, and environmental, social and governance (ESG) ratings entities.
- This will result in a modernized "rules and rewards" ecosystem better aligned with the changes needed to decarbonize the grid and fully support companies looking to make a bigger impact.

A "Carbon Facts 1.0" label might look something like this:

Information to Better Reflect Emissions from Electricity Use

(tied to timing and location of buyer consumption)

Information to Measure Decarbonization Impact from Buyer Actions

(not necessarily tied to timing and location of buyer consumption)

Carbon Facts 1.0 (Illustrative) **Reported for Prior Calendar Year**	
Annual Consumption (By Regional Grid / Balancing Authority)	_MWh
Time Interval Used for Scope 2 Reporting / Consumption Matching	[Annual][1]
Scope 2 Emissions (Track emissions from use and climate risk exposure) ● Location-Based (annual load * average grid EF; absent contracts) ● "Modified" Market-Based (tied to same regional grid as load)[2]	 _ tCO_2 _ tCO_2
Optional: Annual Average CFE % Matched to Hourly Consumption[3] (Track consumption matching goals)	_%
Annual CFE Purchases (Not by Regional Grid / Balancing Authority)	
Total Annual CFE (Track purchasing goals -- RE100/CFE100)[4]	_% of consumption
Decarbonization Impact and Avoided Emissions (Track carbon reduction goals)	
Incremental Total CFE (by resource type)[5] Describe Other Buyer Actions[6]	_ MW / _ MWh
Avoided Emissions ● Carbon Baseline [CB] (annual load @ fossil EF; absent buyer contracts)[7] ● Avoided Emissions [AE] (annual incremental supply @ EPA AVERT EF)[8] Net Emissions [CB]-[AE] **Avoided Emissions Impact** [(CB-AE)/CB-1]	 _ tCO_2 _ tCO_2 _tCO_2/MWh _ tCO_2 _%

1 Buyer can select on an optional basis more granular time interval to measure and report emissions and consumption calculations (e.g., season, month, hour) with hourly matching recognized as the most stringent/accurate. CFE in excess of buyer load in any time period would not be included.

2 Key differences include only CFE/EACs located in the same grid as load counts, CFE cannot exceed load in any time interval, hourly calculations (optional), fossil or non-baseload emissions factors (EF) applied as last resort (proxy for residual mix; not grid average EF), and EACs in grid count if buyer pays for them in utility or LSE rates (i.e., customer load share of state procured RPS, state supported nuclear, ratepayer funded CFE, RPS, etc.). Given the broad use of and familiarity with existing Scope 2 methods, continued incumbent reporting may be desirable initially and may serve as a benchmark as new metrics and evaluation tools are socialized and better understood.

3 Total CFE divided by total load across all hours in the year would result in the Annual Average CFE % Matched to Hourly Consumption, tracked by facility and aggregated by regional grid.

4 This metric should be reported in accordance with RE100 market boundary requirements for a company's global operations. A company could continue to use in-market/out-of-market/bundled/unbundled attributes for purposes of reporting this metric.

5 Incremental CFE could include new capacity, life extensions, repowering, uprates, etc. Any incremental firm and/or new technologies could be identified.

6 Other buyer actions could include investments in energy storage, load management, transmission, etc. that could impact grid emissions.

7 If hourly customer load and marginal emissions factors are not available, annual load and average eGrid fossil (or non-baseload) emissions factors could be used as a proxy for marginal emissions associated with consumption absent any buyer contracts.

8 If hourly incremental supply and marginal emissions factors are not available, the annual incremental carbon-free MWh generation and EPA's most recent AVERT annual avoided CO_2 emissions factor could be used as a proxy for avoided emissions.

Section 7 of this paper includes a more comprehensive "Carbon Facts 2.0" that might eventually be used as data availability improves and calculation methodologies mature.

In considering the current rules and rewards ecosystem and proposing potential changes to modernize the status quo, the paper discusses a number of complexities and consequences of such change, including:

- **Supporting Differing Approaches to more Impactful "Next Generation" Procurement.** Already, buyers are taking different approaches to next generation procurement (and innovative approaches are likely to emerge). For example, a company may prioritize deploying new carbon-free generation in high carbon intensity grid regions, even if it is not where its load is located and its electricity consumption is unchanged, because such a transaction yields near-term and high avoided emissions impact. Another company may prioritize matching 100% carbon-free electricity supply with its consumption at all times and locations, knowing that the ultimate goal is an electricity sector that is net carbon-free at all times and in all places. And another company may seek to use their market power to support the deployment of new carbon-free generation technologies. The paper then posits that new and modified disclosures should be used by third-party leadership and ratings programs to better recognize and support different types of next generation transactions.
- **Change Will Need to be Phased in.** Not all the data needed for some aspects of the comprehensive disclosures are universally available and there are evolving approaches to calculating metrics like avoided emissions impact. Data is becoming more available and best practices are improving and being tested and demonstrated. It will take time for all companies to have the access and expertise to fulfill the ambitions of next generation procurement and disclosure.
- **Next Generation Procurement Options are More Limited for some Companies Depending on their Location.** Companies in many locations continue to face policy and regulatory barriers to procuring carbon-free electricity. Options for such companies may improve in the future, but it must be recognized that not all companies are operating on the same playing field.[b]
- **A Continued Role for Energy Attribute Instruments.** This paper's recommendations envision and support a continued role for EACs/RECs in transactions for clean electricity. To date, RECs have served several purposes, including helping to track generation and allowing owners to make claims to renewable electricity. Several stakeholders are currently working on the development of RECs and other clean energy certificates that capture additional attributes such as the time interval of generation or identify the carbon intensity of the grid's marginal resource at the time the REC was generated. While historical REC use and REC-based accounting approaches have shortcomings from a next generation perspective, attribute certificates will continue to facilitate transactions for clean electricity and can be adapted to advanced procurement and disclosure approaches.
- **New Approaches to Calculating Inventories May Yield Unwelcome Changes.** This paper recommends changes to the incumbent methods of Scope 2 inventory calculation and use of additional methods to calculate inventories. As a result of the recommended accounting changes, it is anticipated that certain corporate Scope 2 inventories may show increased emissions relative to currently reported levels. However, the more comprehensive set of metrics and disclosure proposed will provide more accurate information about the emissions and associated carbon risks arising from a buyer's consumption of electricity and a buyer's carbon impact when procuring clean electricity and/or attributes, and should provide the marketplace with additional metrics by which to recognize corporate progress and leadership towards meeting a net-zero electric grid.

The authors do not purport to have all the answers to what an improved rules and reward ecosystem designed to better drive grid decarbonization ultimately will look like. They do, however, hope to contribute to the ambition and substance of the debate.

[b] The economics and feasibility of certain carbon-free resources also may differ by location.

SECTION 1

The Electricity Sector is Not Decarbonizing Fast Enough

The rapid decarbonization of the electricity sector is an essential component in achieving net-zero emissions by mid-century, both to mitigate a major source of global emissions and because of the anticipated reliance of the transportation, heating, and industrial sectors on electrification to decarbonize. The Intergovernmental Panel on Climate Change's Special Report *Global Warming of 1.5° C* explains, "1.5°C pathways with no or limited overshoot include a rapid decline in the carbon intensity of electricity and an increase in electrification of energy end use (high confidence) … Pathways with higher chances of holding warming to below 1.5°C generally show a faster decline in the carbon intensity of electricity by 2030 than pathways that temporarily overshoot 1.5°C." [1]

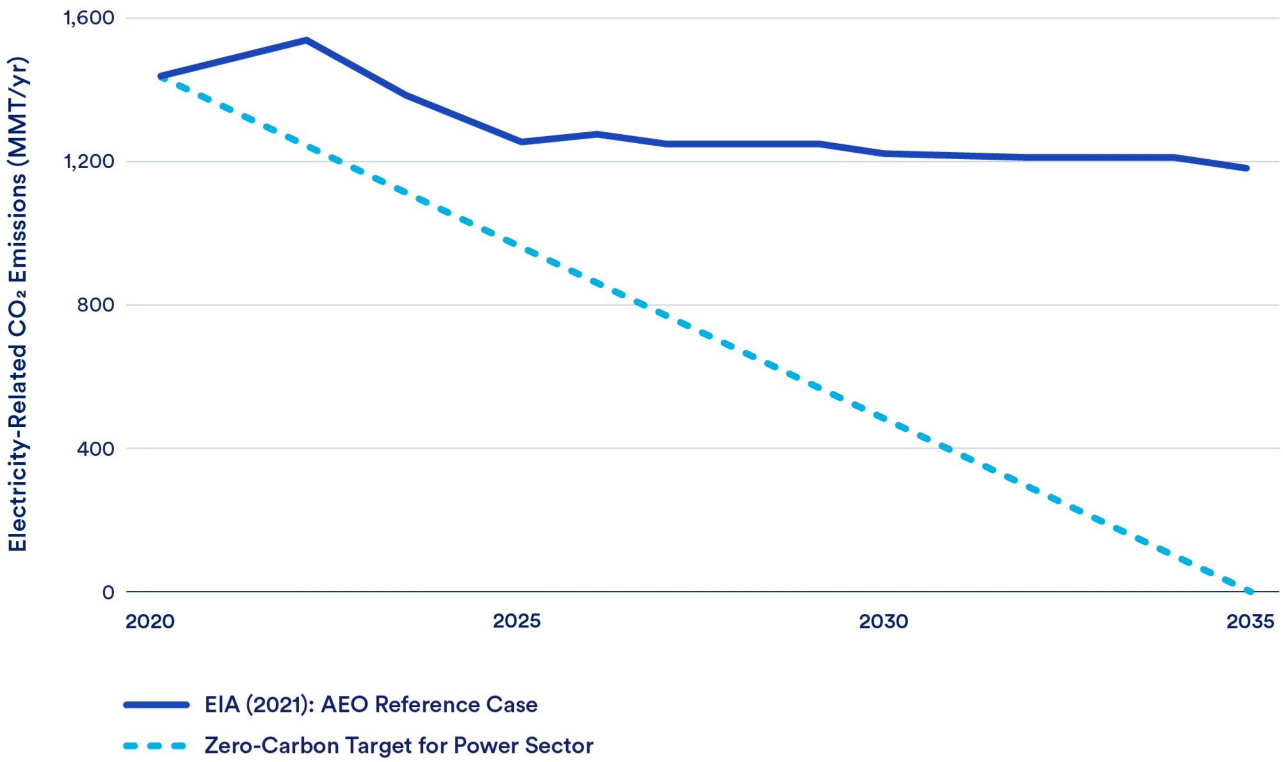
In the United States alone, economy-wide decarbonization and electrification may involve a doubling of electric generation and significant investment in new transmission capacity and grid upgrades.[2] The scale and pace of needed investment in the electric sector to meet such a need is unprecedented and differs from recent trends in the U.S. electric sector. Over the last decade, U.S. power sector carbon emissions have fallen from record highs of around 2.5 billion metric tons to nearly 1.5 billion metric tons, owing primarily to increasing reliance on natural gas and decreasing reliance on coal. The deployment of new wind and solar generation capacity has also contributed to this trend, and while wind and solar generation account for an increasing share of the U.S. mix, in 2021, each contributed around 9% and 4% respectively of the total generation.[3, c] Since 2010, the share of carbon-free generation of total U.S. generation has increased from approximately 30% to 40%.[4]

As a result, the U.S. electric sector currently is not on track to meet mid-century and interim targets. The figure below demonstrates the difference in the trajectory to meet a 2035 carbon-free target and business-as-usual electric sector emissions.

[c] These percentages consider solar generation from utility-scale and small-scale projects. https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

Figure 1: Projected Power-Sector CO_2 Emissions vs. a Zero-Carbon Target

Source: Lawrence Berkeley National Laboratory, *Halfway to Zero Report*, 2021. The figure below compares EIA's 2021 Annual Energy Outlook reference case with a 2035 carbon-free electricity goal. The AEO reference case indicates projected emissions trajectory assuming no changes in current U.S. policy and the continuation of historic industry and technology trends. The 2035 carbon-free electricity target is in line with the Biden administration's 2035 carbon-pollution free electricity pledge. https://eta-publications.lbl.gov/sites/default/files/halfway_to_zero_report.pdf



The decarbonization of the electric sector could follow several potential pathways. Deploying significant variable renewable generation capacity and maximizing energy efficiency and demand management are common features to most pathways, but researchers have explored pathways that diverge in terms of how much they rely on variable renewable generation (with and without batteries) versus a broader portfolio of carbon-free technologies to achieve deep decarbonization. Recent research and analysis assess the potential costs and uncertainties associated with each pathway:

- A 2018 study by Sepulveda, et al. provides a *"comprehensive techno-economic evaluation of two pathways: one reliant on wind, solar, and batteries, and another also including firm low-carbon options (nuclear, bioenergy, and natural gas with carbon capture and sequestration)."* The study finds that *"[a]cross all cases, the least-cost strategy to decarbonize electricity includes one or more firm low-carbon resources. Without these resources, electricity costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not substitute for firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals."* [5]
- A 2018 literature review by Jenkins, et al. reviews 40 studies of pathways to achieve 80-100% reduction in power sector emissions. Certain studies assess meeting decarbonization targets while relying primarily or entirely on variable renewable energy in combination with energy storage and demand management, while other studies rely on those resources plus a range of firm carbon-free resources. Among the literature review's conclusions, the authors find:

"Whichever path is taken, we find strong agreement in the literature that reaching near-zero emissions is much more challenging – and requires a different set of low-carbon resources – than comparatively modest emissions reductions (e.g., CO_2 reductions of 50%–70%). This is chiefly because more modest goals can readily employ natural gas-fired power plants as firm resources. Pushing to near-zero emissions requires replacing the vast majority of fossil fueled power plants or equipping them with CCS.

Given the long-lived nature of power sector capital equipment and long gestation period for R&D efforts, it is critical to examine the distinct challenges inherent to deep decarbonization today; a policy of "muddling through" is unlikely to produce optimal outcomes. The literature outlines potentially feasible decarbonization solutions, but also clarifies several challenges that must be overcome along each path to a carbon-free electricity system. In light of these challenges, and the considerable technological uncertainty facing us today, we conclude that a strategy that seeks to improve and expand the portfolio of available low-carbon resources, rather than restrict it, offers a greater likelihood of affordably achieving deep decarbonization." [6]

- In 2021, The NorthBridge Group published a review and assessment of over 40 studies from a diverse group of analysts at consulting firms, universities and research organizations examining the technological and economic feasibility of deep decarbonization. Among its conclusions, The NorthBridge Group finds *"a diverse portfolio of clean energy technologies, including variable renewables (primarily wind and solar) and firm electric generating technologies, is needed to maintain reliable low-cost electric service, provide flexibility to overcome important economic and deployment uncertainties, achieve decarbonization goals in regions of the country where variable renewable technologies are less competitive and decarbonize non-electric sectors of the economy."* [7]

As highlighted by these analyses, 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 more cost-effective pathway to deep decarbonization.[d] Today, most U.S. grids rely on a diverse set of generation resources – baseload, intermediate/cycling, peaking, etc. – to match supply with customer consumption on a 24/7 basis, and unabated fossil resources are relied on to supply much of the firm and dispatchable power when renewable generation is not available. These unabated fossil resources currently represent about 60% of total U.S. generation. The key question is how to transition from an electric system today that primarily relies on unabated fossil generation to balance supply and demand to one that replaces such resources with carbon-free alternatives to meet the 100% carbon-free electricity objective.[e] Increased deployments of wind, solar, energy storage, and regional transmission are a large part of the answer, but a fully decarbonized grid will also require much more firm and dispatchable carbon-free generation.[f]

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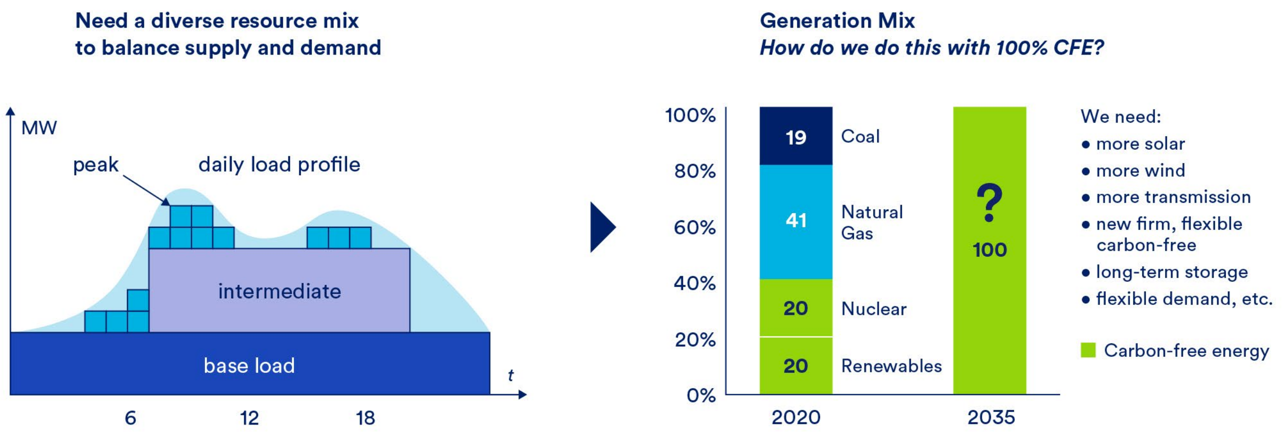
[d] President Joe Biden's Executive Order on Tackling the Climate Crisis at Home and Abroad calls for leveraging federal procurement to help achieve a carbon-pollution free electricity sector by 2035 (https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/). Biden's subsequent Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability and supporting guidance directs federal agencies to secure carbon-free electricity which it defines to include marine energy, solar, wind, hydrokinetic (including tidal, wave, current, and thermal), geothermal, hydroelectric, nuclear, renewably-sourced hydrogen, and fossil generation with carbon capture and storage (https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/).

[e] From a grid perspective, achieving full decarbonization of the electric grid requires balancing carbon-free electricity supply (including storage discharge) with system demand in all hours and in all electric grids, taking into account transmission constraints within each electric grid and across electric grids.

[f] Achieving the decarbonization of the electric grid will also require maximizing the use of energy efficiency and strategies to manage and shift demand to take advantage of time periods with relatively abundant clean electricity generation.

Figure 2: Transitioning from Unabated Fossil Generation Balancing to 100% Carbon-Free Electric Grids

Source: The NorthBridge Group



Decarbonizing the electricity sector at the pace needed to maximize chances of economy-wide, mid-century climate stabilization targets will require public policy interventions. Nevertheless, market actors – energy buyers, utilities, competitive energy suppliers – have a proven and impactful role to play and it is imperative that their potential to drive grid decarbonization be optimized.

SECTION 2

The Growing Climate Imperative and Increasing Stakeholder Expectations are Driving New Climate Goals and the Need for New Approaches to Disclosure and Recognition

The environment in which large energy buyers operate today is drastically different than that of fifteen, ten, or even five years ago. In the face of the growing climate imperative and in response to new pressures and expectations from a range of stakeholders (including consumers, NGOs, shareholders, and employees), an increasing number of companies across economic sectors are adopting goals to reduce the carbon emissions arising from their operations and value chains. As of 2021, 60% of Fortune 500 companies have adopted a climate-related goal in comparison to 6% in 2016. *RE100*, an NGO-sponsored initiative through which companies pledge to match 100% of their electricity use with renewable energy by 2050 or sooner, boasts 355 member companies.[g] The *Science-Based Targets Initiative* (SBTi)[h] has grown from 1,000 companies committed in 2020 to 2,000 at the beginning of 2022. Companies with approved or pending-approval SBTi commitments represent 20% of the global economy.

At the same time, capital markets are amidst an historic shift as more and more equity investors, debt providers, and asset managers apply varying degrees of ESG considerations to their practices. In 2021, a record $649 billion flowed into ESG-focused funds worldwide, up from $542 billion in 2020. ESG-focused funds accounted for

g RE100 membership grew from 50 companies in 2015 to 355 in 2022. https://www.bloomberg.com/news/articles/2022-02-03/the-growing-corporate-presence-in-global-power-markets

h *SBTi* is a partnership between CDP, the UN Global Compact, the World Resources Institute (WRI), and World Wildlife Fund (WWF). SBTi encourages companies to set GHG reduction targets at a pace and scale consistent with what climate science indicates is necessary to meet the Paris Agreement goals of limiting global warming to well-below 2° above pre-industrial levels and while pursuing efforts to limit warming to 1.5°C. https://sciencebasedtargets.org/how-it-works

10% of worldwide fund assets at the end of 2021.[8] While ESG covers a range of issues, most agree that climate, at the very least, is the long pole in the "E" tent. As the world's largest asset manager, Larry Fink of BlackRock, has stated, "[c]limate change has become a defining factor in companies' long-term prospects."[9] Different capital market players come at the climate issue in different ways – some seeking to drive positive climate impact with their investments, while others are more focused on identifying and minimizing climate risk in their portfolios.

A majority of large companies in the United States and Europe voluntarily disclose data on their carbon footprints (including Scope 2) on a voluntary basis. Many, if not most, large energy buyers calculate their carbon footprints pursuant to the guidance of the *Protocol* and publicly share that information through organizations like *CDP*, a non-profit that runs a global disclosure system of climate related information for investors (formerly known as the *Carbon Disclosure Project*). In 2020, 65% of S&P 500 companies reported their greenhouse emissions footprints, calculated via the *Protocol*, to the market through *CDP*.[10] Nearly 1,000 European companies representing 80% of Europe's market value reported data to *CDP* in 2020.[11] Over 13,000 companies across industries now report through *CDP*, representing a 141% increase since 2015.[12, 13] Additional voluntary mechanisms for corporate disclosure are emerging and evolving. For example, the number of companies assessing and disclosing information regarding their climate-related financial risk consistent with the recommendations of the *Task Force on Climate-Related Financial Disclosures* (TCFD)[14] is growing.[i, 15] Similar to other frameworks, *TCFD* recommends that organizations calculate GHG emissions using the *Protocol* to allow for consistency across organizations.[j]

Building on the growing voluntary disclosure practices and frameworks, financial regulators are increasingly looking at climate change as a financially relevant consideration for investors. In the United Kingdom, as of April 2022, publicly traded companies, banks and insurers, and private companies with over 500 employees are required to disclose their climate-related risks and opportunities in accordance with TFCD recommendations. The United Kingdom is the first G20 country to adopt *TCFD*-aligned reporting requirements.[16] The EU *Non-Financial Reporting Directive* (NFRD) currently requires large, public-interest companies to disclose information on social and environmental challenges.[17] The EU has proposed a separate *Corporate Sustainability Reporting Directive* (CSRD) which would expand the scope of the *NFRD* and incorporate *TCFD* recommendations, beginning in fall 2022.[18] In the United States, the Securities Exchange Commission (SEC) on March 21, 2022 released a proposed rule to require public companies to disclose Scope 1 and 2 emissions, company goals and targets to reduce emissions, and information on climate-related financial risks.[19]

These two major trends – rising buyer participation in climate leadership and recognition programs and the increasing demand for disclosures relating to climate risk and climate leadership – are reshaping the marketplace. This paper assesses whether and how this current "rules and rewards ecosystem" should evolve to align with changing requirements and expectations to develop a modernized disclosure approach that can be used to better recognize and support different types of next generation transactions by providing a set of disclosure rules and incentives that best serve companies seeking to drive greater grid decarbonization impact.

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i TCFD was created by the Financial Stability Board "to develop recommendations for more effective climate-related disclosures that could promote more informed investment, credit, and insurance underwriting decisions and, in turn, enable stakeholders to understand better the concentrations of carbon-related assets in the financial sector and the financial system's exposures to climate-related risks." https://www.fsb-tcfd.org/about/

j As of 2021, TCFD indicates that more than 2,600 organizations support their recommendations, up from 2020 by over a third. TCFD reviewed 1,650 company disclosures in 2021 and found that 50% of these companies had made disclosures in accordance with TCFD recommendations. https://www.fsb.org/2021/10/2021-status-report-task-force-on-climate-related-financial-disclosures/

SECTION 3

Large Buyer Electricity Procurement Has Evolved Over Time with More Ambitious, Complex, and Diverse Objectives

3.1 The First Generation of Procurement

Over a decade ago, leading corporations began to transact directly in renewable energy markets, including by entering into power purchase agreements (PPAs) with wind and solar projects through which the buyer agreed to purchase the electricity output of these facilities and/or the RECs[k] associated with that generation. By entering into PPAs and guaranteeing long-term offtake from new renewable energy projects, buyers often provided the necessary revenue certainty for renewable energy developers to receive financing and begin construction.[l]

Over the years these wind and solar-based transactions became larger, more innovative, and more complex (*e.g.,* "virtual power purchase agreements" ("VPPAs") which often center on contracts for differences whereby the seller and buyer agree to hedge financial risks associated with wholesale market price volatility and the buyer receives RECs but does not physically receive or consume the electric output of the project). In jurisdictions without centralized wholesale markets, where third-party physical electricity supply transactions are not allowed, some local utilities have offered "green tariffs" to buyers to provide them with bundled renewable electricity and/or unbundled RECs. Along with important government policies like renewable portfolio standards (RPS) and tax credits, first generation procurement practices have led to significant additions of renewable energy capacity. Corporate procurement has enabled the deployment of about 47 GW of new utility scale renewable capacity in the United States from 2008 thru 2021.[20]

k In the United States, RECs originally emerged as an instrument for covered entities (such as utilities) to demonstrate their compliance with state renewable portfolio standards (RPS). Buyers would take advantage of the emergence of RECs to demonstrate their purchase of renewable electricity separate from covered entities, and the *Scope 2 Guidance* recognizes RECs as conveying a zero-emission attribute.

l PPAs can be structured in many ways. For purposes of this paper, PPAs are assumed to be structured with a long-term fixed price that supports a revenue stream for energy and RECs sufficient to allow a developer to obtain bank financing.

Buyers often executed these transactions as part of meeting their own voluntary renewable energy and climate goals and/or as part of their participation in third-party programs such as *RE100, SBTi,* or the U.S. Environmental Protection Agency's Green Power Partnership. And typically, the accounting for progress against those goals and programs was done based on the rules and guidance of the *Greenhouse Gas Protocol*.[m] Under the *Protocol's* market-based method to preparing Scope 2 inventories, reporting entities may apply a REC (assigned a zero emissions rate in Scope 2 market-based accounting), either purchased or retired on an entity's behalf, toward a MWh of their actual electricity use (which typically would otherwise have a positive emissions rate based on the carbon intensity of the grid in which they had load). Procurements that yield RECs reduce a company's Scope 2 inventory, which was the key to meeting both internal goals and the terms of most third-party leadership programs. As the World Resources Institute (WRI) highlights, while the *Protocol* requires two distinct methods of calculating Scope 2 inventories (the location-based and market-based methods), "most companies set goals only for their market-based method totals."[21]

Despite the success of first generation procurement in deploying new wind and solar capacity, incumbent procurement approaches can lead to some sub-optimal climate outcomes:

- First generation goals are *purchasing goals* (as opposed to *consumption goals*) and therefore often lead buyers to execute transactions in locations where renewable energy and/or RECs are the most economic (*e.g.*, areas with particularly strong wind and solar resources). Buyers often contract with generation projects on different grids than the location of their load.[n] Such buyers, therefore, continue to rely on local grid supply for the power they consume, including unabated fossil generation.
- Even if a buyer meets a *100%* renewable energy purchasing goal (*i.e., RE100*) with supply located in the *same* regional grid (which is not typical), that buyer still relies on grid-supplied electricity, including unabated fossil generation, to meet a substantial portion of its consumption, given mismatches in timing between renewable energy generation and the buyer's load.
- First generation procurement can be misaligned with reducing electricity sector GHG emissions. RECs have the same "value" (a zero-emissions rate for a MWh of generation) regardless of the actual climate impact of that MWh. For example, a REC from an additional MWh of wind generation in wind-saturated West Texas has the same "value" as a MWh of new solar in fossil-intensive Alabama, even though the amount of carbon emissions avoided by each are radically different.

3.2 Next Generation Procurement

Even with the successes in stimulating the deployment and lowering the costs of wind and solar resources, and even as several large companies announce meeting 100% purchasing goals,[22, 23] leading buyers and other stakeholders in recent years have begun to explore ways to go beyond first-generation procurement. In contrast to first generation procurement, next generation approaches may involve more explicit consideration of the relative carbon emission reduction impact of transactions or how a transaction otherwise contributes to grid system decarbonization. By whatever name,[o] next generation procurement may include one or more of the following objectives:

- **Targeting carbon intensive grids.** In contrast to first generation procurement, next generation approaches may involve more explicit consideration for likely carbon emission reduction impact of transactions. A buyer may invest in and/or secure EAC offtake from new clean generation projects located in grid regions with relatively high carbon intensity (regardless of whether they have load in that grid region) to achieve greater emissions reduction impact.

m The relevant portions of the *Protocol* are discussed in detail in Section 5.

n Market structures and regulatory barriers also impact the location of new renewable energy deployment and the ability of buyers to execute transactions.

o WRI refers to "transformative procurement", which it defines as: "[P]ractices that accelerate the transition to carbon-free energy resources and result in substantial transformation of the grid, beyond those widely used today … Transformative procurement is about purchasing and using clean energy to reduce system-wide emissions and accelerate the transition to carbon-free grids by optimizing how, when, and where resources are deployed. For example, large buyers can undertake advanced forms of procurement and practices to maximize emissions reductions, match their clean energy purchases more closely to their loads, increase the flexibility of the grid, deploy technologies that enable decarbonization, and ensure a just transition to zero-carbon resources." (WRI, page 3). https://files.wri.org/d8/s3fs-public/2021-08/actions-large-energy-buyers-transform-decarbonize-grid.pdf?VersionId=Tw6cz0CZHOH4l8zphdehWBWuULMInm6K

- **Focusing on a broad portfolio of carbon-free generation and other balancing resources.** First generation procurement has focused primarily on wind and solar transactions, and while wind and solar will remain essential tools in decarbonizing the grid, next generation procurement may focus on the full range of carbon-free generation and other technology options, such as hydropower, geothermal, biomass, energy storage, nuclear, fossil energy with carbon capture and storage (CCS), demand-side load management, and transmission expansion.

- **Including a focus on firm and dispatchable carbon-free generation.** Broadening the aperture of targeted carbon-free generation sources also allows a greater focus on firm and dispatchable resources. Ironically perhaps, the rapid increase in deployment of variable renewable energy capacity has increased the importance of firm and dispatchable generation to balance generation and load, and today that function is predominantly served by unabated fossil generation. Whether in pursuit of time-matched procurement or otherwise, decarbonizing firm and dispatchable generation is a challenge that next generation procurement can seek to address.[p]

- **Rethinking capacity additions as *per se* the objective of procurement.** Deploying new clean energy capacity will remain an imperative for grid decarbonization, including wind and solar. But particularly for variable renewable energy, capacity additions can have varying climate benefit and capacity additions alone should not be the metric by which progress and leadership are measured. With a focus on climate impact as the touchstone for procurement, the value of capacity additions will depend on location (the carbon intensity of the grid and potential resources to be displaced) and the timing and type of that carbon-free generation (wind vs. solar and variable vs. firm, for example). And in some cases, procurement may lead to significant climate impact when it helps to extend the life of existing carbon-free generation.

- **Focusing on the timing and location of consumption, rather than the annual purchase of clean energy.** Full grid decarbonization means all grids will rely on carbon-free electricity at all times. While, again, some next generation transactions can seek impact by investing in projects in carbon intense areas irrespective of time and location of load, other next generation buyers may seek transactions that accelerate the deployment of grid resources that can meet their demand on each grid. This approach sends important demand signals that the firm, flexible, and dispatchable resources that a grid relies on to meet demand at all times must shift to lower-carbon resources.[q]

These various potential elements of next generation procurement are not in competition nor mutually exclusive, but each reflects ways that buyers might seek to increase emission reduction impact and/or more directly drive market and system-level changes to achieve full decarbonization of electric generation.

Examples of current next generation procurement efforts include (listed in alphabetical order):[r]

- **Boston University –** As part of Boston University's (BU) commitment to reach carbon neutrality by 2040, BU executed a virtual power purchase agreement in September 2018 with a new wind project in South Dakota. After reviewing 127 proposals that involved wind and solar sited in locations across the country, BU chose a project with the greatest estimated impact on global emissions. BU estimated that its chosen wind project in South Dakota offered avoided emissions two to three times greater than a renewable project with similar output located in New England.[24]

- **Des Moines, Iowa –** In January 2021, the city of Des Moines, Iowa passed a new resolution that aims to achieve 100 percent, 24/7 carbon-free electricity by the year 2035 and net-zero greenhouse gas emissions by 2050.[25]

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p For obvious reasons, first generation procurement approaches aimed at the accumulation of wind and solar attribute instruments are not well-suited to a focus on firm and dispatchable zero-carbon generation. WRI also points to how "transformative energy procurement" includes a focus on firm and dispatchable carbon free generation, along with energy storage and load shifting to better match the timing of load and zero-carbon generation. *WRI*, page 11.

q Some clean energy procurement goals incorporate equity and environmental justice alongside emissions reduction. The Clean Energy Buyers Institute (CEBI) runs the Beyond the Megawatt initiative, supported by Salesforce and members of the Clean Energy Buyers Alliance (CEBA), to inform buyers on incorporating impacts beyond climate in procurement goals. The Federal Government, as well, is committed to ensuring procurement and operations efforts are in line with advancing environmental justice and equity. While this is crucial for a just transition, the scope of this paper focuses primarily on carbon impact. WRI includes an "equitable and just transition" as an objective of "transformative" procurement.

r In 2021, a group of energy buyers, energy suppliers, governments, system operators, solutions providers, investors, and other organizations launched the United Nations 24/7 Carbon-free Energy Compact to work together to achieve 24/7 carbon-free electricity consumption for all consumers. https://www.un.org/en/energy-compacts/page/compact-247-carbon-free-energy

- **Facebook –** In 2020, Facebook reached their goal of purchasing renewable energy for 100% of the volume of its consumption. Facebook requires that the renewable energy it procures comes from projects on the same grid where the data center is located.[26] To reach their goal, they purchased energy from 63 new projects located on the same grids as the data centers that use the energy. Facebook says that the renewable energy projects represent all new generation coming online as a result of its commitment.[27]

- **The Federal Government –** In 2021, President Biden issued the *Executive Order on Catalyzing Clean Energy Industries and Jobs through Federal Sustainability,* which directs the Federal Government to achieve "100 percent carbon pollution-free electricity on a net annual basis by 2030, including 50 percent 24/7 carbon pollution-free electricity" on an hourly basis with electricity that is generated in the same grid region where consumption occurs.[28, 29] The Biden Administration intends for federal electric procurement to catalyze the development of 10 gigawatts of new carbon pollution-free generation capacity.[30] In 2022, the Biden Administration intends to issue instructions to federal agencies on how to align their electricity procurement with the Executive Order goals and how to measure and track their performance in meeting the goals.

- **Google –** Since 2017, Google has matched its global, annual electricity use with purchases of renewable energy.[31] But despite purchasing as much renewable electricity as it consumes in a given year, Google explains "despite our large-scale procurement of renewables, [its electricity consumption] still involves carbon-based power. Each Google facility is connected to its regional power grid just like any other electricity consumer; the power mix in each region usually includes some carbon-free resources (*e.g.*, wind, solar, hydro, nuclear), but also carbon-based resources like coal, natural gas, and oil."[32]

  To address this continued reliance on unabated fossil generation and to further maximize the decarbonization impact of its procurement, in September 2020, Google announced the adoption of a new goal to "decarbonize [its] electricity supply completely and operate on 24/7 carbon-free energy, everywhere, by 2030."[33] In adopting its goal, Google explains:[34]

  "Reaching our 100% renewable energy purchasing goal was an important milestone, and we will continue to increase our purchases of renewable energy as our operations grow. However, it is also just the beginning. It represents a head start toward achieving a much greater, longer-term challenge: sourcing carbon-free energy for our operations on a 24×7 basis. Meeting this challenge requires sourcing enough carbon-free energy to match our electricity consumption in all places, at all times. Such an approach looks markedly different from the status quo, which despite our large-scale procurement of renewables, still involves carbon-based power."[35]

  In May 2021, Google and AES announced an agreement to power Google's Virginia data centers with 90% carbon-free electricity on an hourly basis through a portfolio of wind, solar, hydro, and energy storage resources.[36]

- **Iron Mountain –** Iron Mountain has adopted a goal to use 100% clean energy, 100% of the time in its data centers and achieve net-zero emissions company-wide by 2040.[37] In adopting these goals, Iron Mountain explains:

  "To accelerate decarbonization of the grid, the company is going beyond its RE100 commitment of 100 percent renewable electricity, using the Google methodology for matching site by site electricity use with local clean power generation every hour, every day to achieve 24/7 clean power."[38]

  In 2021, Iron Mountain announced an agreement with RPD Energy and Direct Energy to track the hourly load of its data centers and to match hourly usage of its Pennsylvania and New Jersey data centers with renewable energy on an hourly basis.[39]

- **Microsoft –** In 2021, Microsoft adopted a "100/100/0" commitment, pledging to have 100% of its electric consumption, 100% of the time, matched by carbon-free electricity purchases by 2030, and by 2050, Microsoft seeks to remove all its historical carbon emissions that it emitted directly or through consumption.[40] These commitments follow Microsoft's earlier commitment to execute power purchase agreements equivalent to 100% of its energy needs with renewable projects by 2025. Microsoft indicates it will use more granular data, including Locational Marginal Emissions (LME), which captures the emissions rate associated with the marginal resources serving the grid at specific times and locations, in its decisions to procure clean electricity.[s]

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[s] One of the critical arguments in support of time-matching Next Generation zero-carbon energy procurement approaches is that they will drive and accelerate the decarbonization of firm and dispatchable grid generation resources. It is true that a single or even a few time-matching buyers in a given grid may initially have limited impact on changing such generation resources as supply can be just "re-routed" to other customers without time-matched preferences. But over time, such aggregated demand will drive market change. This concept is noted in the Scope 2 Guidance (albeit in the context of adding new renewable capacity): *"Over time the collective consumer demand for particular energy types . . . can send a market signal to support building more of those types of generation facilities, just as purchasing any product send the market signals to produce more of that product." Scope 2 Guidance*, page 7.

- **Peninsula Clean Energy –** In 2017, Peninsula Clean Energy, a Community Choice Aggregator (CCA) for San Mateo County located just south of San Francisco, adopted a goal to deliver 100% renewable energy on a 24/7 basis by 2025, matching its clean energy supply with its load every hour of every day to reduce its demand signal for unabated fossil fuels from the grid.[41]
- **Salesforce –** In 2021, Salesforce announced meeting its target to purchase 100% renewable electricity to meet match its annual consumption.[42] In taking further steps to maximize the impact of its procurement, Salesforce has begun incorporating avoided emissions impact among other factors[t] in a procurement matrix approach when evaluating different procurement options.

  "In the beginning of our journey, our renewable energy purchases focused mainly on transactional elements like the quantity and cost of what we're purchasing to reach our 100% Renewable Energy target. However, we quickly learned that (unsurprisingly) not all renewable energy is created equal. Two projects with identical transactional details can have enormously different impacts. Some renewable energy projects displace more fossil fuels than others, some are built at the cost of critical habitat for plants and animals, and others provide invaluable support for their local community. For us, purchasing renewable energy is about much more than adding new megawatts of renewable energy to the grid. It's about improving the state of the world, which includes reducing emissions, and so much more." [43]

  Salesforce is focused on reducing carbon emissions in locations and times not necessarily tied to the location of the company's consumption. Salesforce and its partner, WattTime, explain that "emissionality" may involve "deliberately siting [renewable generation projects] in locations where building new renewables displaces particularly polluting power plants" and "works by analyzing what will happen on the grid in response to different potential renewable energy projects being built." [44]
- **Walmart –** Walmart's Gigaton PPA Challenge aims to bring together suppliers to aggregate buying power and educate Walmart suppliers while accelerating clean energy adoption. Advancements under the Gigaton PPA initiative will support actualization of Walmart's Project Gigaton, which aims to avoid one gigaton (one billion metric tons) of CO_2 from Walmart's global value chain by 2030.[45] Through these programs, Walmart is broadening the impact of its electricity procurement strategy. Walmart has also pursued community solar, signing on as an "anchor tenant" to support at least 129 MW of community solar projects. Walmart has subscribed to a share of both U.S. Solar and Nexamp community solar farms and will receive either bill credit or energy attributes for their participation.[46, 47]

As demonstrated by these examples, an increasing number of buyers are already moving beyond first-generation procurement. These next generation procurement approaches represent emerging best practices in procurement that can accelerate the decarbonization of electric grids. With this expansion of buyers' procurement objectives, goals have become more ambitious, complex and diverse. As discussed below, reporting criteria, third-party leadership and recognition programs, and ESG ratings agencies have not yet fully caught up to these changes in procurement ambition and impact.

Figure 3: Evolution of Buyer Climate Procurement Objectives

First Generation Procurement	Next Generation Procurement
■ Support demand for renewable energy generation (RECs, unbundled and bundled from new and existing resources) (e.g., RE100) ■ Add new renewable generation (PPAs with "additionality")	■ Add incremental carbon-free generation in locations and times to maximize CO_2 reductions ■ Seek same-grid carbon-free supply to match load on an hourly basis ■ Support deployment of new carbon-free generation and balancing technologies (e.g., firm/dispatchable CFE or long duration energy storage)

[t] Other criteria include land use, wildlife, solar materials management, job quality/local hire and compliance, community engagement, air quality, etc.

SECTION 4

Climate Leadership and Recognition Programs are Not Adequately Incentivizing Buyers to Align Procurement with Long-Term Grid Decarbonization or to Maximize Avoided Emissions Impact

Third party leadership and recognition programs such as *CDP, RE100, SBTi*, and the U.S. Environmental Protection Agency's *Green Power Partnership* (and various sustainability and ESG ratings agencies and investors) largely align their programs with first generation procurement.[u]

- **CDP:** *CDP* has been immensely successful in promoting transparent climate-related disclosures. It also "grades" companies on their efforts to manage and mitigate their carbon footprints. For example, CDP awards additional points ("Management" and "Leadership" points which contribute to a company's assigned grade) for companies that purchase increasing amounts of renewable energy and/or RECs.[v] And while *CDP* allows reporting entities to follow different methodologies to calculate carbon footprints, for reporting Scope 2 emissions associated with electricity procurement, it aligns very closely to the Scope 2 methodologies of the *Protocol* (discussed below).[48] *CDP* grades are considered highly influential.
- **RE100:** *RE100*, referred to as the "gold standard for ambition" by *CDP*,[49] requires participating companies to adopt goals to source renewable electricity to match an increasing share of their electricity consumption over time (at minimum 60% by 2030, 90% by 2040, 100% by 2050). The *RE100's* Technical Criteria explains that companies

[u] For example, S&P Global's Corporate Sustainability Assessment allows companies to use either location-based or market-based approaches to report Scope 2 emissions (consistent with guidance from the *Protocol*). It also requests that companies disclose their purchases of renewable energy, but without requiring additional information on the underlying transaction mechanisms (e.g., PPA vs. unbundled RECs), or making any assessment as to the actual emissions impact of such transactions.

can meet *RE100* commitments through the production and procurement of renewable electricity through purchase options that include direct power purchase agreements, green tariffs, retail agreements and utility standard supply backed by RECs, and unbundled REC purchases. While *RE100* refers to its required pledges as commitments to "use" 100% renewable energy, *RE100* neither requires nor asks for any information on the relation between such procurements and actual emissions reductions, nor does it require any relationship between procured renewable supply or RECs and the actual timing of the buyer's consumption from the grid. A company can procure from projects located across vast geographies and far from its locations of actual electricity use.[w] Its member buyers are not allowed to count procured non-renewable carbon-free supply toward meeting its goals.

- **SBTi:** *SBTi* asks entities to set "science-based" GHG reduction targets (targets in line with the goals of the Paris Agreement to limit global warming to well-below 2°C and to pursue efforts to limit warming to 1.5°C). *SBTi* directs companies to ensure that their GHG inventories align with *the Greenhouse Gas Protocol Corporate Standard (the "Corporate Standard")*, including Scope 2, and to use its *Net-Zero Corporate Manual* to track progress toward their science-based targets. *SBTi's* Corporate Manual (for companies) and *Corporate Net-Zero Standard Criteria* (for companies setting one or more targets to reach a state of net-zero emissions) provide direction for companies in setting Scope 2 GHG reduction goals. Both sets of criteria direct companies to select either the location-based or market-based method to calculate base year emissions and track performance against the science-based target.[x] Companies can meet Scope 2 reduction targets through one of two options:
    - Reducing base-year location-based or market-based Scope 2 inventories over a defined time period by the appropriate science-based percentage; or
    - Procuring renewable electricity, achieving 80% renewable procurement by 2025 and 100% by 2030.

  SBTi is firmly aligned with *RE100*. Last year *SBTi* released *The SBTi Net-Zero Manual & Criteria, Version 1.0, September 2021* as a proposed framework for companies to develop targets for achieving net-zero emissions by mid-century with requirements for near-term action to reduce emissions.[50] Section 4.5 of the *Manual* encourages its pledging members to "set targets for a certain percentage of electricity procurement to be renewable, in accordance with *RE100* recommendation[s]."

- **EPA Green Power Partnership (GPP).** The *GPP* is a voluntary program that seeks participation from companies and other large electricity buyers "supporting the increased use of green power to reduce the environmental impacts associated with conventional electricity use." The *GPP* limits eligible "green power" sources to renewable resources.[y] Participating companies must purchase renewable electricity equal to a designated percentage of their annual total consumption, allowing companies to meet this requirement with REC purchases.

These programs have done a good job incentivizing first generation procurement and contributed to increasing amounts of wind and solar capacity on the grid. And while they should continue to do that, they should also adapt and expand their frameworks to better incentivize and reward the innovations and increased decarbonization focus and impact of next generation procurement. The modernization of climate leadership and recognition programs could be informed by the new set of metrics proposed in Section 7 of this paper. Without modernization, the role of these programs in driving the needed pace of grid decarbonization will likely be diminished.

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v *CDP Climate Change 2021 Scoring Methodology*, section C8.2 – Scoring criteria: *"Full Management points have been awarded to be eligible for points at Leadership level. If:*
- 50% or more of your 'Total energy consumption' is from renewable sources – 1 point
- 75% or more of your 'Total energy consumption' is from renewable sources – 1.5 points
- 99% or more of your 'Total energy consumption' is from renewable sources – 2 points"
https://guidance.cdp.net/en/guidance?cid=18&ctype=theme&idtype=ThemeID&incchild=1&microsite=0&otype=ScoringMethodology&tags=TAG-605%2CTAG-646

w *RE100* refers to the "market boundary" as an area in which the laws and regulatory framework governing the electricity sector are sufficiently consistent between the areas of production and consumption and there is a physical grid interconnection indicating a level of system-wide coordination. But for North America, *RE100* considers the United States and Canada to be a single market for renewable electricity sourcing and reporting.

x The *Protocol's* Scope 2 rules and guidance are discussed in detail below.

y GPP eligible sources of green power include solar photovoltaic, wind, geothermal, "eligible" hydropower, "eligible" biomass, co-firing of eligible biomass with non-renewables (subject to certain conditions), biodiesel-fueled generations, and fuel cells powered by an eligible resource. https://www.epa.gov/sites/default/files/2016-01/documents/gpp_partnership_reqs.pdf

SECTION 5

An Overview of *the Greenhouse Gas Protocol* and Current *Scope 2 Guidance*

In very fundamental ways, the rules and rewards ecosystem around corporate electricity procurement stands upon the foundation of the *Protocol* and its *Scope 2 Guidance*. Over 20 years ago, a multi-stakeholder partnership of NGOs, companies, governments, and other experts developed the *Protocol* to serve as an internationally accepted standard for global GHG accounting and reporting. Managed by WRI and the World Business Council for Sustainable Development (WBCSD), the *Protocol* identifies relevance, completeness, consistency, transparency, and accuracy as its accounting and reporting principles. The *Protocol* has become the global standard in GHG accounting, and its rules and guidance have been largely incorporated into other disclosure and leadership recognition programs.

The *Protocol* includes guidance across a broad array of applications.[z] The *Protocol's A Corporate Accounting and Reporting Standard ("the Corporate Standard")*,[51] provides guidance to companies for GHG accounting and reporting.[aa] *The Corporate Standard* explains that the *"standard and guidance were designed with the following objectives in mind:*

- *To help companies prepare a GHG inventory that represents a true and fair account of their emissions, through the use of standardized approaches and principles;*
- *To simplify and reduce the costs of compiling a GHG inventory;*
- *To provide business with information that can be used to build an effective strategy to manage and reduce GHG emissions;*
- *To provide information that facilitates participation in voluntary and mandatory GHG programs;*
- *To increase consistency and transparency in GHG accounting and reporting among various companies and GHG programs."*

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z The *Protocol* also offers other guidelines, such as the U.S. Public Sector Protocol, the Land Sector and Removals Guidance, and other sector-specific guidelines.

aa According to the *Protocol, the Corporate Standard* is "written primarily from the perspective of a business developing a GHG inventory. However, it applies equally to other types of organizations with operations that give rise to carbon emissions, e.g., NGOs, government agencies, and universities." *Protocol,* page 3.

The Corporate Standard and subsequent *GHG Protocol Scope 2 Guidance* (released in 2015)[52] establish how companies are to calculate and report the indirect emissions arising from use of purchased electricity (and heat and steam), referred to as Scope 2 emissions.[bb] *The Corporate Standard* explains that the preparation of corporate GHG inventories can serve business objectives, including "[m]anaging GHG risks and identifying reduction opportunities" and "[r]ecognition for early voluntary action." *The Scope 2 Guidance* echoes this point, explaining that businesses preparing Scope 2 inventories can:

- *"Identify and understand the risks and opportunities associated with emissions from purchased and consumed electricity;*
- *Identify internal GHG reduction opportunities, set reduction targets, and track performance;*
- *Engage energy suppliers and partners in GHG management;*
- *Enhance stakeholder information and corporate reputation through transparent public reporting."*[53]

Companies and other buyers around the world now use *the Corporate Standard* and *Scope 2 Guidance* in calculating and reporting their carbon footprints.[cc]

The Scope 2 Guidance codified two distinct methods for Scope 2 accounting and calls for most companies to determine their Scope 2 inventories using both methods.[dd] Each method is similar in that a company will calculate an inventory by determining its electricity consumption and applying the emission factor(s) as called for by the method. *The Scope 2 Guidance* explains that "[b]oth methods are useful for different purposes; together, they provide a fuller document and assessment of risks, opportunities, and changes to emissions from electricity supply over time." *The Scope 2 Guidance* requires most reporting entities to use both methods given that "both calculation methods can help describe the different dimensions of the grid more clearly."

- **Location-based method:** this method "reflects the average emissions intensity of grids on which energy consumption occurs (using mostly grid-average emission factor data)." This method does not consider a company's electricity procurement decisions, nor does it consider the specific generation resource mix contracted by the company's electric utility (though the ultimate location-based inventory is influenced by where a company decides to locate). Location-based estimates rely on using average annual emissions factors from broad geographic, if not national, regions. Such emissions factors are usually available from public entities, allowing companies to use common inputs in their calculations. In the United States, companies use the EPA's eGrid[54] average annual emissions factors.

  The Scope 2 Guidance maintains that the location-based method provides several unique insights into the carbon emissions arising from a company's electric consumption. By not considering a company's specific procurement decisions, a location-based Scope 2 inventory highlights the extent to which the mix of generation resources that are located in a given grid remain carbon-intensive. *The Scope 2 Guidance* explains that the portfolio of resources serving a grid do not necessarily change based on the individual actions of one or more companies and that shifts are only likely to result from the aggregated actions and collective decision making of companies, their suppliers, policymakers, and others.

- **Market-based method:** this method "reflects emissions from electricity that companies have purposefully chosen (or their lack of choice). It derives emission factors from contractual instruments,[ee] which include any type of contact between two parties for the sale and purchase of energy bundled with attributes about the energy generation, or for unbundled claims." In contrast to the location-based method, the market-based method accounts for a company's decision making in procuring electricity and enables a company to calculate a reduced Scope 2 inventory by securing contractual instruments that convey lower carbon emission factors. The market-based method also allows for the use of utility or supplier specific emission factors that reflect the contracted

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[bb] Scope 2 emissions do not include the emissions associated with generating sources owned and controlled by an organization, which are considered Scope 1 emissions.

[cc] In 2016, at least 92% of Fortune 500 companies responding to CDP used the *Protocol* directly or indirectly through a program based on the *Protocol*. https://ghgprotocol.org/companies-and-organizations

[dd] "Companies with any operations in markets providing product or supplier-specific data in the form of contractual instruments shall report scope 2 emissions in two ways and label each result according to the method: one based on the location-based method, and one based on the market-based method. This is also termed "dual reporting."" *Scope 2 Guidance*, page 8.

[ee] *The Scope 2 Guidance* defines "contractual instruments" as: "Any type of contract between two parties for the sale and purchase of energy bundled with attributes about the energy generation, or for unbundled attribute claims. Markets differ as to what contractual instruments are commonly available or used by companies to purchase energy or claim specific attributes about it, but they can include energy attribute certificates (RECs, GOs, etc.), direct contracts (for both low-carbon, renewable, or fossil fuel generation), supplier-specific emission rates, and other default emission factors representing the untracked or unclaimed energy and emissions (termed the residual mix) if a company does not have other contractual information that meets the Scope 2 Quality Criteria."

energy sources that a utility controls within a larger grid region. Using the market-based method, companies have demonstrated reductions in their Scope 2 inventories after executing transactions, such as the purchase of RECs alone, executing power purchase agreements, switching electricity suppliers, or choosing lower-emission products and tariffs.

The Corporate Standard and *Scope 2 Guidance* emphasize that the market-based approach is meant to produce globally consistent and accurate results and ensure credibility, and transparency. Owing to the difficulty of tracking electricity on the grid and the nature of the grid's reliance on a portfolio of resources to meet demand, companies seeking to make claims on which type of electricity they source have historically relied on EACs (in North America, EACs usually take the form of RECs) to make claims on sourcing individual MWh of generation and to convey the attributes of that generation. Such attributes may include the specific source of generation and the emissions factor associated with that source. The acquisition, control, and retirement of RECs ensure that only one party can make claims to a particular MWh. *The Scope 2 Guidance* embraces the use of attribute certificates to demonstrate that a company has sourced a particular MWh of electricity with specific attributes under market-based reporting.

To tabulate market-based inventories, *the Scope 2 Guidance* introduces a "hierarchy" for applying the emission factors of contractual instruments against consumption as well as a set of quality criteria to ensure contractual instruments meet given standards. *The Scope 2 Guidance* directs reporting entities to first apply energy attribute certificates, which it considers the contractual instruments with the highest level of precision in making claims.[ff] In the absence of certificates, the market-based approach directs reporting entities to use the next contractual emission data option (e.g. contracts/PPAs, then supplier or utility-specific emission factors, and then the "residual mix"[gg] on the grid) in the hierarchy, and in the absence of contractual instruments and residual mix information, a company would apply a location-based average emissions factor. The market-based method does not limit the extent to which companies may rely on unbundled energy attribute certificates to reduce their reported market-based Scope 2 inventory.

The Corporate Standard and the *Scope 2 Guidance* acknowledge that the preparation of Scope 2 inventories using the location-based and market-based methods provide distinct perspectives of the emissions arising from a company's purchased electricity. *The Corporate Standard* and the *Scope 2 Guidance* describe what types of information these methods do not necessarily capture and how the disclosure of additional information can provide greater perspective on company emissions and electricity procurement decisions. *The Scope 2 Guidance* provides additional clarification and guidance on certain topics:

- *The Corporate Standard* and *Scope 2 Guidance* are based on "attributional" accounting. In a blog post, the *Protocol* explains that attributional accounting means "allocating electricity emissions to end-users – but not the 'impact' of a given action or activity outside the inventory boundary."[55] *The Scope 2 Guidance* welcomes, but does not require, companies adopting additional priorities for their procurement, such as focusing on offtake from new-build generation or focusing on supporting generation in locations where carbon reduction or community health benefits may be relatively higher.
- *The Corporate Standard* and *the Scope 2 Guidance* do not attempt to define what constitutes "green" energy, nor do they claim to promote specific energy generation technologies or specific electricity labels or programs.
- *The Scope 2 Guidance* recognizes that changes in corporate Scope 2 inventories may not accurately reflect actual emissions reductions caused by transactions.[56] *The Scope 2 Guidance* explains how the *"Corporate Standard* notes that reductions in indirect emissions (changes in scope 2 or 3 emissions over time) may not always capture the actual emissions reduction accurately. . . [g]enerally, as long as the accounting of indirect emissions over time recognizes activities that in aggregate change global emissions, any such concerns over accuracy should not inhibit companies from reporting their indirect emissions."
- The *Scope 2 Guidance* emphasizes that it "does not support an 'avoided emissions' approach to Scope 2." It does state that "[c]ompanies can report estimated grid emissions avoided by low-carbon energy generation and use" but that such calculations are above and beyond the task of using the *Guidance* to create an attributional Scope 2 inventory."[hh, 57]

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ff *The Scope 2 Guidance* includes a hierarchy (though not preference) that lists the options to convey emissions factor based on anticipated precision: energy attribute certificates (higher precision), contracts including power purchase agreements, supplier/utility emission rates, residual mix, and other grid-average emission factors (lower precision).

gg To prevent double counting of GHG emission rate claims tracked through contractual instruments, the market-based method requires an emission factor that characterizes the emission rate of untracked or unclaimed energy. 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). *Scope 2 Guidance*, pages 8 and 11.

hh *The Scope 2 Guidance* notes that calculating avoided emissions would provide "strategic benefits" including "[i]dentifying where low-carbon energy generation can have the biggest impact." *Scope 2 Guidance*, page 52.

- *The Scope 2 Guidance* recognizes that additional disclosure of information about corporate electricity consumption and procurement practices increases transparency and comparability among companies. *The Scope 2 Guidance* says that companies "should" disclose annual consumption and "should disclose key features associated with the contractual instruments claimed, including any instrument certification labels that entail their own set of eligibility criteria, as well as characteristics of the energy generation facility itself and the policy context of the instrument."[58] *The Scope 2 Guidance* also identifies other information that companies "may" disclose on an optional basis including avoided emissions and "advanced grid study estimations" that capture more granular data about the time and location of emissions and how such estimations informed procurement or operational decision making, but such disclosures are not required.[59]
- *The Scope 2 Guidance* directs companies to use Scope 2 inventories to set reduction targets and track progress against those goals.[ii]

Two decades on, it is easy to take for granted what a truly remarkable innovation the *Protocol* was. Without any authority to make companies do anything, the designers of the *Protocol* bet on the idea that leaders would voluntarily choose to adopt it and that others would follow. They bet on the proposition that "what gets measured gets managed." And they understood before many others that the marketplace would use this new information to drive changes in behavior. The *Protocol's* growth and its success are undeniable. Without diminishing these achievements, this paper addresses how the *Protocol* could now be modernized to meet the challenges and opportunities of a changing marketplace.

[ii] The *Scope 2 Guidance* explains "[c]omprehensive scope 2 accounting and reporting should serve as a consistent basis to set reduction targets and measure and track progress toward them over time. Companies should use the boundaries and definitions in Scope 2 as a basis for setting carbon reduction targets as well as energy-use targets and renewable energy procurement targets (for example, a 100 percent renewable energy procurement goal). Each method's scope 2 total can provide an important indicator of performance and show the context in which emission totals are changing." *Scope 2 Guidance*, Section 2.3, page 19.

SECTION 6

Taking a Harder Look at Incumbent Scope 2 Accounting and Disclosure Rules and Practices

Perhaps it is because of its success and reach that it is necessary and appropriate to ask questions about how the *Protocol* might need to evolve to retain its innovative and impactful role in the marketplace. The increasing urgency of grid decarbonization, the emergence of next generation electricity procurement practices, and the onset of greater expectations and requirements for disclosure present such an opportunity. At least three aspects of incumbent reporting rules and practices may merit consideration for change.

6.1 Market-Based Inventories do not Adequately Reflect the Emissions Resulting from Buyer Electricity Consumption

Although the *Protocol's Corporate Standard* and *Scope 2 Guidance* were designed to help companies prepare a GHG inventory that represents "a true and fair account of their emissions" and help companies "identify and understand the risks and opportunities associated with emissions from purchased and consumed electricity," it may be that inventories prepared under current rules do not effectively accomplish either goal.[jj]

Inventories constructed under current rules do not accurately reflect either the actual emissions or the risks associated with the supply that serves a buyer's

[jj] Particularly in light of the SEC's proposed rule – an important basis of which is to disclose climate-related risks to investors – and despite the fact that the *Protocol* intends Scope 2 inventories to "enhance stakeholder information . . . through transparent public reporting," disclosures should seek to communicate information about risks associated with reliance on fossil generation.

electricity demand.[kk] Following the *Scope 2 Guidance*, buyers match their actual annual electricity consumption to their contractual instruments on a MWh-by-MWh basis. Yet ownership of a REC/EAC does not necessarily reflect any change in the buyer's electricity use (including the consumption of carbon-intensive generation sources that are part of the grid mix at its place of load) and may not reflect any change to a buyer's climate risk exposure associated with energy use.[ll] A buyer can calculate a reduced Scope 2 inventory even when nothing about the nature of the electricity it consumes has changed.

Consider a buyer that wishes to procure clean energy and/or other zero-emission EACs in an amount equal to its annual consumption, but is choosing among three different procurement strategies:[mm]

- **VPPA in different grid than buyer load (Strategy A).** Buyer obtains solar RECs from a different regional grid by entering into a VPPA with a new solar plant.[nn]
- **PPA in same grid as buyer load (Strategy B).** Buyer signs a long-term PPA with a new solar plant located within its same electric grid.
- **Contracting for carbon-free retail supply (Strategy C).** Buyer signs a contract with a competitive retail supplier or utility (e.g., green tariff) to match its hourly consumption (on a 24/7 basis) using a diverse portfolio of carbon-free resources within the same electric grid.

[kk] As noted above, the *Protocol* acknowledges that it was not designed or intended to represent the emissions caused by the purchaser's consumption of electricity.

[ll] The *Scope 2 Guidance* explains that market-based inventories were not meant to necessarily reflect the emissions from consumption, since energy attribute certificates "[do] not necessarily represent the emissions caused by the purchaser's consumption of electricity." It adds that "[t]he market-based method reflects the GHG emissions associated with the choices a consumer makes regarding its electricity supplier or product" – meaning that each such instrument reflects the emissions from the underlying generation wherever it occurred. *Scope 2 Guidance*, pg. 26.

[mm] This example could also apply to three identical buyers in terms of size and location with different electricity procurement strategies.

[nn] For both Strategy A and Strategy B, it is assumed that the buyer enters into a long-term contract that supports a revenue stream for energy and RECs sufficient to allow a developer to obtain bank financing.

In **Strategy A** (Figure 4), the buyer obtains solar RECs from a different grid to match its annual load, but continues to rely on the local electric grid for 100% of its supply. Whether the buyer chooses to purchase all carbon-free supply from the local grid, a mix of unabated fossil or non-fossil resources, or all fossil generation, the buyer can report a Scope 2 inventory equal to zero under the market-based method since the buyer can apply all the RECs purchased from the contracted solar resources in a different grid against its total load, "erasing" away the emissions from the grid-supplied unabated fossil generation.[oo, pp]

Figure 4: Supply Relied Upon vs. GHG Protocol Market-Based Reporting (Strategy A – Representative Day)

The figures (on the left) illustrate the supply mix that the buyer actually purchases in a representative day based on its procurement contracts, while the figures on the right illustrate what it can report for Scope 2 market-based inventories.[qq]

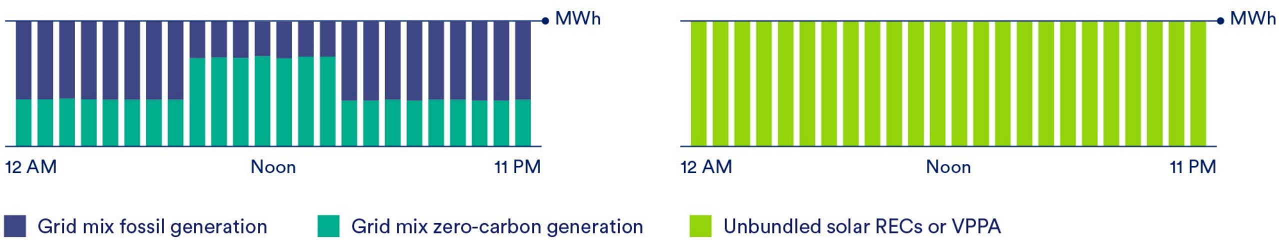
Supply for Hourly Load

Buyer does not "use" any of the solar underlying its VPPA since the project is located in a different grid and thus its actual retail supply can derive from a mix of fossil and non-fossil resources or even 100% fossil

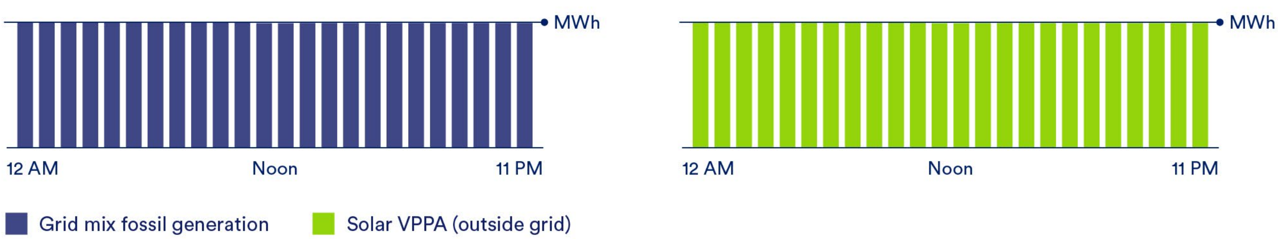
Scope 2 Market-Based Reporting

But the Buyer can apply all contracted RECs from the VPPA against its total consumption and claim zero emissions and 100% renewable energy "use".

Scenario 1: a buyer's retail supply derives from a mix of unabated fossil and non-fossil resources



Scenario 2: a buyer's retail supply derives from 100% unabated fossil resources



[oo] In this example, it is assumed that the buyer purchases RECs out-of-market equal to its annual consumption (enabling the buyer to report zero Scope 2 inventories under the current accounting system), while the supply relied upon on the local grid to serve the buyer's consumption is met by fossil generation.

[pp] Given that the buyer could report zero Scope 2 market-based inventories regardless of the types of supply purchased from the local grid, all else equal, the buyer also would have an economic incentive to purchase the least-cost supply possible. Also note that the buyer could obtain solar RECs in a different grid by either purchasing RECs from existing facilities or by entering a long-term VPPA with a new solar plant. The Scope 2 market-based reporting would be identical, but the associated costs and carbon impacts of these actions would likely be quite different.

[qq] For simplicity and clarity, the figures show customer load constant across all hours in the day. The same concepts apply assuming different consumption patterns or load profiles.

In **Strategy B** (Figure 5), the buyer signs a PPA with an off-site solar project on the same grid as its load. The contracted solar project generally supplies surplus generation to the grid relative to the buyer's load when the sun is shining during the middle of the day (conversely, the buyer takes supply from the grid at night).[rr] Over the course of the year, the solar project generates a volume of RECs that meets or exceeds the buyer's annual consumption. Like Strategy A, the buyer receives a sufficient number of RECs to match against its consumption and zero-out its market-based inventory. However, the buyer still relies on local

Figure 5: Supply Relied Upon vs. GHG Protocol Market-Based Reporting (Strategy B – Representative Day)

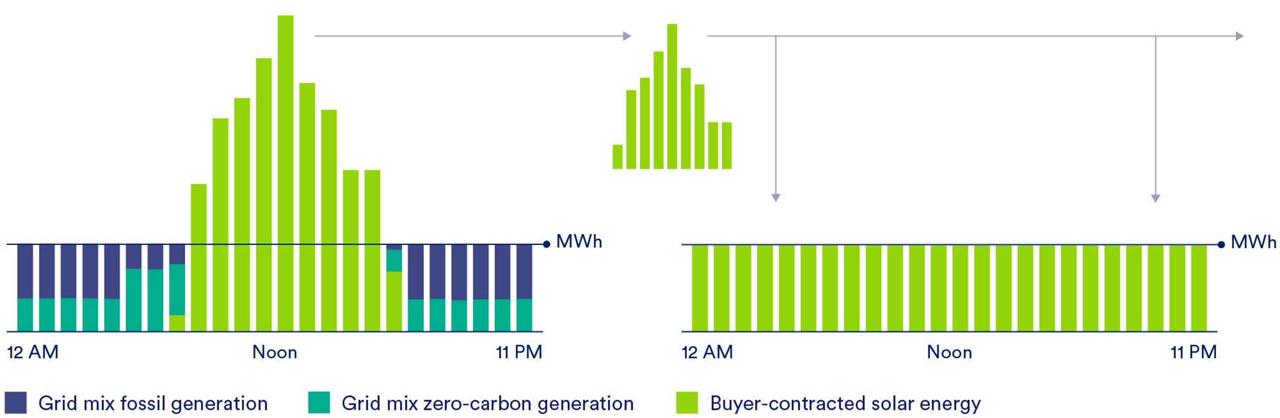
Supply for Hourly Load

Buyer does not "use" all of its contracted intermittent RE on the same grid when it is generated and still relies upon significant amounts of fossil generation from the local grid.

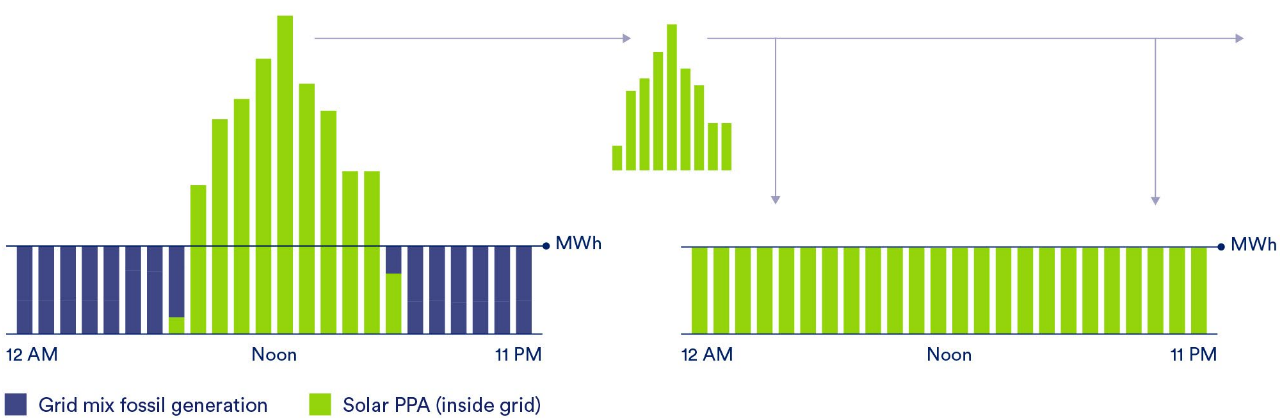
Scope 2 Market-Based Reporting

But buyer can apply "excess" contracted solar energy against the grid-supplied fossil generation and claim 100% RE "use."

Scenario 1: a buyer's retail supply derives from a mix of unabated fossil and non-fossil resources



Scenario 2: a buyer's retail supply derives from significant unabated fossil resources



rr Not surprisingly, in about half of the hours in the year, solar generation supplies zero percent of the load.

grid-supplied electricity when the solar project is not generating,[ss, tt] and none of this grid supply has to come from clean energy sources to claim zero Scope 2 market-based inventories.

In **Strategy C** (Figure 6), the buyer switches its electric supplier or current retail supply contract to match a diverse mix of carbon-free electricity resources within the same electric grid with its hourly consumption (in this case on a 24/7 basis).

Despite matching carbon-free supply with its consumption in every hour, the buyer's Scope 2 emissions would be the same as in Strategy A and Strategy B which still involve reliance on unabated fossil generation from the local grid.

In these examples, neither the Scope 2 location-based method[uu] nor the market-based method recognizes any differences among the three different customer procurement strategies, meaning that a buyer could calculate and report the same Scope 2 inventories in all three scenarios.

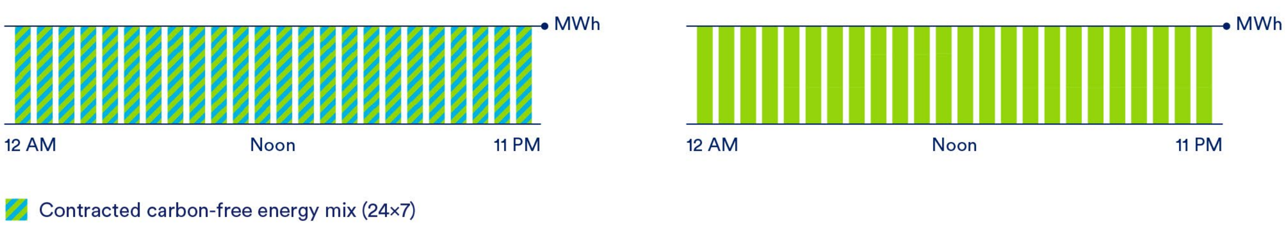
Figure 6: Contracted CFE Supply Matching Hourly Load vs. GHG Protocol Market-Based Reporting (Strategy C – Representative Day)

Supply for Hourly Load

Buyer matches contracted carbon-free supply on the same grid with load on a 24/7 basis.

Scope 2 Market-Based Reporting

But despite matching 24/7 consumption, buyer's Scope 2 emissions would be the same as with Strategy A and Strategy B, which still involve reliance on fossil generation from the local grid.



ss Market experience and modeling indicate that approximately 30% to 50% of the buyer's consumption is likely to come from the local electric grid. Columbia University and The NorthBridge Group published a study of different customer types and supply portfolios in ISO-NE, ERCOT, and CAISO indicating that a supply portfolio consisting of 100% wind or 100% solar, even if located in the same grid as the customer, could result in a buyer relying on the local electric grid for a significant portion of its actual hourly consumption, ranging from 31% to 50%. Melissa Lott & Bruce Phillips, *Advancing Corporate Procurement of Zero Carbon Electricity in the United States: Moving From RE100 to ZC100,* Columbia University and The NorthBridge Group (Dec. 2021), https://www.energypolicy.columbia.edu/research/report/advancing-corporate-procurement-zero-carbon-electricity-united-states-moving-re100-zc100.

tt In 2019, Google, one of the early adopters of a 100 percent renewable electricity target, matched 100% of its annual electricity consumption with renewable energy (i.e., achieving a 100% renewable electricity purchasing goal), but reported on an hourly basis, 39% of its consumption came from fossil generation on the local grid. *Google 2020,* page 6.

uu Even when buyers zero-out market-based inventories, their location-based inventories will continue to reflect the average annual carbon intensity of the regional grid.

vv As also noted above, the *Protocol* acknowledges that it was not designed or intended to support calculations of emissions avoided because of a buyer's energy transactions.

ww Though the *Protocol* offers (currently underutilized) options for estimating avoided emissions on a voluntary basis, measuring real world impact of buyer transactions is not a feature of Scope 2 location-based and market-based reporting and (perhaps consequently) leading climate recognition programs currently do not seek or prioritize that information.

6.2 Reductions in Scope 2 Market-Based Inventories do not Necessarily Reflect the Carbon Reduction Impact Associated with a Buyer's Actions

The reliance on market-based reporting, *Scope 2 Guidance* – and third-party leadership and recognition programs – are not necessarily incentivizing buyers to focus on the actual reduction of GHG emissions.[vv] Instead, buyers are steered to reduce *market-based Scope 2 inventories*. The *Protocol* is not currently able in many instances to distinguish between next generation transactions with high carbon reduction impact and buyer actions with lower carbon reduction impact.[ww] As such, the *Protocol* is not currently positioned to incentivize and encourage buyers to take the actions to maximize carbon reduction in individual procurement decisions or take other actions to help achieve full decarbonization

Consider the following examples:

- A buyer purchases RECs from an existing renewable generation project. Since the generation project already existed, the buyer's action did not achieve any incremental reduction in carbon emissions (yet it can match those RECs against its MWh of electricity consumption to reduce its Scope 2 inventory to zero). In this case, if the buyer were asked to report incremental carbon reduction impact from its transaction, it would report limited or no impact (the purchase of RECs could theoretically provide a revenue stream that keeps an otherwise economically challenged project operational).
- A buyer has the option of executing a VPPA with different projects of similar capacity and output but on different grids – one with lower carbon intensity and one with higher carbon intensity. If two different transactions are identical in every respect (generated electricity and RECs) except the carbon intensity of the grids where they are located, the market-based method does not offer a buyer an incentive to select the project that is likely to have a higher carbon reduction impact. A buyer is likely to let other factors, especially cost, guide its decision making.
- A buyer has the option of executing a PPA with different projects of similar capacity and output in the same electric grid but using different carbon-free technologies (e.g., wind or solar). If the two different projects are identical in every respect (annual generated electricity and RECs) except the timing of the zero-carbon generation, the market-based method does not offer a buyer an incentive to select the type of project that is likely to have a higher carbon reduction impact. Again, a buyer is likely to let other factors, especially cost, guide its decision making.
- A buyer is weighing the option of investing in an on-site solar project for its load located in a relatively high carbon-intensive grid or purchasing RECs from a solar project in a relatively less carbon-intensive grid.

While the climate mitigating impacts of these various alternatives vary greatly, current Scope 2 accounting does little to incentivize a buyer from choosing higher impact options or to reflect the climate benefits of higher impact choices.

6.3 The *Protocol* Provides Insufficient Incentives or Support for other Next Generation Transactions that can Yield Short and Longer-Term Climate Benefit

With the reliance on market-based reporting, neither *Scope 2 Guidance* nor third-party leadership and recognition programs are necessarily incentivizing buyers to focus on the development of a diverse portfolio of zero-carbon generation and balancing (flexible demand and storage) resources needed to decarbonize the electric grid. Similar to how the current rules and rewards ecosystem does little to encourage buyers to site projects in dirtier grids for greater near-term climate benefits, it also does not incentivize or reward buyers that align procurements with other systemic decarbonization benefits.

Here are two examples:

- **Focusing on time and location matching of carbon-free generation and load on a granular basis.** As referenced above, some companies, cities, and the Federal Government have adopted aggressive "24/7" consumption matching goals. Under such goals, buyers are attempting to account for when they consume electricity and what resources are being used to meet their demand. Progress against such goals can be achieved through shifting the timing of load, the use of energy storage and/or contracts for electricity (and bundled attributes) with carbon-free and firm energy resources. As more buyers use this

[vv] As also noted above, the *Protocol* acknowledges that it was not designed or intended to support calculations of emissions avoided because of a buyer's energy transactions.

[ww] Though the *Protocol* offers (currently underutilized) options for estimating avoided emissions on a voluntary basis, measuring real world impact of buyer transactions is not a feature of Scope 2 location-based and market-based reporting and (perhaps consequently) leading climate recognition programs currently do not seek or prioritize that information.

strategy, it can help drive the displacement and retirement of unabated fossil generation resources and demonstrate demand for firm and dispatchable generation and technologies that can manage and shift load to take advantage of time periods with relatively higher clean electricity generation.

- **Pursuing non-traditional investments in new carbon-free technologies that may deliver relatively high system-level decarbonization benefits.** A buyer may choose a contract for offtake from (or otherwise help finance) an innovative and difficult-to-finance firm and dispatchable zero-carbon resource (e.g., a zero-emission Allam Cycle gas plant or a modular nuclear plant) that can displace unabated fossil resources, particularly those currently needed for grid balancing. Current rules and rewards offer insufficient benefit to companies considering such transactions, both because of the lack of EACs for such technologies in some jurisdictions and because the full systemic benefits of new dispatchable carbon-free generation are not currently reported or rewarded.

Location and Timing Matter in Driving Grid Decarbonization

When rethinking Scope 2 inventory calculations to better reflect emissions associated with electricity use, time *and* location matter. A central reason for the discrepancies between what is reported in Scope 2 inventories in the examples above and the reality of a buyer's emissions from electricity consumption is that current accounting and disclosure fail to provide information about how the timing and location of transacted supply (and any associated clean energy attributes) relates to a buyer's actual electricity consumption.[xx]

In the electricity industry, granular timing and location data is essential for reliability (keeping the lights on), for profitability (hedging price risks), and as it turns out, also for measuring emissions, climate risks related to unabated fossil energy consumption, and actual carbon emissions reductions. By considering the location and timing of a buyer's contracted supply, it is possible to gain a better picture of the actual emissions associated with electricity use. Section 7 below gives examples of what can be the significant differences in emissions inventories when more granular time and location factors are used.

Under next generation approaches, whether matching zero-carbon supply with customer consumption or adding incremental zero-carbon supply to displace carbon-emitting generation, more granular timing and location data (consumption, generation, emissions) is beneficial.[yy, zz] The use of more granular data would enable a more precise picture of the emissions (and risks) associated with the supply used to serve a buyer's electricity consumption and can help buyers make more informed decisions to prioritize transactions with greater carbon reduction impact.[aaa]

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xx The current Scope 2 market-based method does not ask for temporal information about procurement other than providing for alignment on an annual basis and does not require matching zero-carbon supply/attributes with the customer location. *The Scope 2 Guidance* explains that inventories prepared with more granular time and location data may be prepared and disclosed on an optional basis (7.3 – Optional information).

yy In March 2022, EnergyTag launched a new *Standard and Guidelines* for the development of granular certificates (GCs) to better trace energy. Consumers will be able to verify the source of their electricity on an hourly basis using standardized GCs.

zz In addition to improving granular data availability, other enabling actions are needed to support next generation procurement, including transmission investment, distribution grid modernization, and federal policy support to reduce the cost of firm carbon free technologies, among others.

aaa The current Scope 2 market-based method does not ask for temporal information about procurement other than providing for alignment on an annual basis and does not require matching zero-carbon supply/attributes with the customer location. *The Scope 2 Guidance* explains that inventories prepared with more granular time and location data may be prepared and disclosed on an optional basis (7.3 – Optional information): *"Where advanced studies (or real-time information) are available, buyers may report scope 2 estimations separately as a comparison to location-based grid average estimations, and buyers can document where this data specifically informed efficiency decision making or time-of-day operations. Because these studies or analyses may be more difficult to use widely across facilities or to standardize/aggregate consistently without double counting, buyers should ensure that any data used for this purpose has addressed data sourcing and boundaries consistent with the location-based method." Scope 2 Guidance,* page 2.

SECTION 7

Modernizing the "Rules and Rewards" Ecosystem Related to Corporate Electricity Use and Procurement

While the *Protocol*, first generation procurement, and a host of leadership and recognition programs have worked synergistically to leverage the power of energy buyers to drive the deployment of renewable energy, the need to decarbonize the electricity sector more rapidly requires that the existing "rules and rewards" ecosystem be modernized.

7.1 Issues that Need to be Addressed When Modernizing GHG Accounting and Reporting Practices

The overarching problem is that the GHG accounting practices and Scope 2 *Protocol*, in their current forms, are not adequately aligned with the changes that are urgently needed in the electric grid to achieve net-zero GHG emission goals in an affordable and reliable manner. More specifically, the Scope 2 market-based accounting method does not accurately measure the emissions impact and carbon-related environmental risks associated with a buyer's electricity use or the emissions impact (if any) resulting from its power supply procurements. This paper has identified several shortcomings that need to be addressed with modernized GHG accounting and reporting practices:

A. Scope 2 Inventories do not Provide a Sufficiently Accurate Representation of the Emissions and Climate Risks Associated with a Buyer's Electricity Use

The *Corporate Standard* intends to *"help companies prepare a GHG inventory that represents a true and fair account of their emissions, through the use of standardized approaches and principles."*[60] Unquestionably, Scope 2 accounting is "standardized," but it is debatable whether it results in a "true and fair" account of Scope 2 "emissions." The location-based method is used to calculate inventories tied to consumption absent any buyer contracts. The market-based approach is used to calculate inventories taking into account buyer contracts, while allowing the use of emission factors from contractual instruments sourced from anywhere across vast geographies near or far from actual electricity consumption.

The *Protocol* does not, however, calculate emissions inventories tied to *actual electricity reliance* after buyer contracts. The *Scope 2 Guidance* explains that businesses preparing Scope 2 inventories have the opportunity to identify and understand the risks and opportunities associated with emissions from purchased and consumed electricity.[61] However, because buyers using the market-based method under the *Protocol* can "erase" emissions from their inventory through various REC/EAC-based transactions without any actual change to the emissions that are a result of the organization's electricity use, the *Protocol* does not provide a fair representation of those actual emissions and may not be adequate to meet the increasing interest of investors seeking to understand a buyer's exposure to climate transition risk.

This disconnect between emissions and electricity use is exacerbated by two problems with incumbent reporting.

i. The *Protocol* does not provide adequate incentive for buyers to account for the timing of consumption and supply

The current Scope 2 market-based method does not ask for temporal information about procurement other than directing the preparation of location-based and market-based inventories on an annual basis using annual emissions factors. In 2015, the *Scope 2 Guidance* recognized that buyers were beginning to use analyses to better understand the carbon intensity of the grid at specific time intervals of their consumption. Since then, data and analytics have only improved. Buyers can now better understand when carbon-free electricity is abundant or when unbated fossil generation is abundant and use that information to manage their load or seek retail products that reduce reliance on unabated fossil generation at given times. As such, calculating more time-granular inventories adds a level of precision in estimating emissions associated with a buyer's electricity use and may encourage greater consideration of time in optimizing carbon reduction impact.

ii. The *Protocol* does not provide adequate incentive for a buyer to account for the location of its consumption and supply

Similarly, because the *Protocol* does not require matching carbon-free supply and/or attributes with the location of a buyer's load, it does not incentivize buyers to seek decarbonization on each grid where it consumes electricity. Further, because market-based reporting allows a buyer to match consumption from one region with RECs/EACs sourced from a different region, it is difficult to assess the extent to which a buyer's electricity purchases remain carbon intensive.[bbb]

B. The *Protocol* – and leadership/recognition programs – do not measure or require the disclosure of the carbon reduction impact resulting from a buyer's decisions

The *Scope 2 Guidance* reiterates that changes in reported Scope 2 inventories may not "capture the actual emissions reduction accurately."[62] The *Guidance* offers only a voluntary and rarely accepted invitation for buyers to estimate avoided emissions from interventions. The *Guidance* focuses on calculating and reporting inventories without attempting to evaluate real-world decarbonization impact. Similarly, third-party leadership, recognition, and ESG evaluation approaches tend to focus on inventories and not impact. Given the urgency of grid decarbonization and the desire of electricity buyers to track and report their contributions toward that end, the ability to quantify and report the actual carbon impacts resulting from carbon-free electricity procurement and investments offers a way for buyers to highlight the emissions impacts of their choices. While stakeholders may disagree whether carbon reduction impact should be included in Scope 2 accounting and reporting, carbon impact accounting needs to become part of a buyer's climate disclosures.

C. Neither Scope 2 accounting nor most leadership and recognition programs capture the system value of firm and dispatchable carbon-free generation

Firm and dispatchable resources are currently dominated by unabated fossil generation and the hardest part of the grid to decarbonize. Since fully decarbonizing the electricity sector will require carbon-free electricity to be always available at all locations on the electric grid, current accounting practices and the *Scope 2 Protocol* are not sufficient to drive the deployment of firm and dispatchable carbon-free electric resources necessary to support net-zero emission goals. Procurements that yield new or maintain existing carbon-free firm and

[bbb] It is true that some buyers may have limited supply options in some service areas and may need to pursue their environmental goals in other markets. However, the *Protocol* does not incentivize buyers to seek locations where incremental carbon-free resources can displace the dirtiest fossil generation.

dispatchable resources have distinct climate value above and beyond their quantity of MWh. The *Protocol* was not designed to capture this value and few (if any) leadership and recognition programs attempt to do so.

Many of these issues are becoming increasingly evident to key thought leaders and stakeholders. As stated by WRI:

> *"To date, most corporate clean energy targets have focused on matching electricity consumption with clean energy and renewable energy attributes, including RECs, on an annual basis. As such, the quantity of clean energy* ***procured*** *(in megawatt-hours, MWh) and the emissions rate associated with that amount of energy have long been used as the standard metrics, or criteria, to measure the impact of corporate procurement . . . As transformative clean energy procurement practices become more commonplace, and corporate buyers set increasingly ambitious climate and decarbonization goals,* ***the way we quantify and assess the impact of corporate clean energy actions may need to evolve.*** *To enable transformative clean energy procurement practices, new product offerings from utilities and suppliers will be needed for buyers to undertake transformational procurement.* ***In addition, the metrics, incentives, and programs used to track progress need to shift to accommodate a changing landscape."***[63]

Given that GHG accounting practices and Scope 2 *Protocol*, in their current forms, are not adequately aligned with the changes that are urgently needed in the electric grid to achieve net-zero GHG emission goals, it is important to determine what types of information the marketplace needs to better evaluate a growing range of buyer actions and what new metrics, GHG accounting approaches, and evaluation tools are needed to incentivize and reward next generation procurement actions.

7.2 New Information and Revised Accounting for More Relevant and Modernized Disclosure that Improves Accuracy and Better Incentivizes Buyer Contributions to Grid Decarbonization

The information needed for more relevant and modernized disclosures falls largely into two categories:

- Information to Better Reflect Emissions from Electricity Use; and
- Information on the Decarbonization Impacts of Buyer Actions.

A. Information to Better Reflect Emissions from Electricity Use

Under a modernized approach to accounting and reporting, buyers would calculate and disclose *modified* Scope 2 emissions inventories, as well as additional information not currently part of Scope 2 inventory reporting. Both the modifications to Scope 2 inventory accounting and the additional information about the sources of buyer electricity supply are an attempt to improve the accuracy and relevance of disclosed information related to the emissions arising from electricity use.[ccc] Such modernized disclosure would include:

i. Modified Scope 2 location-based inventories that better reflect emissions related to a buyer's actual electricity use;
ii. Modified Scope 2 market-based inventories that better reflect emissions related to a buyer's actual electricity use;
iii. Supply sources used to serve a buyer's electricity use; and
iv. The percentage of carbon-free electricity used to serve a buyer's electricity use.

[ccc] Given the broad use of and familiarity with existing Scope 2 methods, continued incumbent reporting may be desirable initially and may serve as a benchmark as new metrics and evaluation tools are socialized and better understood.

i. Modified Scope 2 Location-Based Inventories that Better Reflect a Buyer's Actual Electricity Use

The incumbent approach of location-based reporting could be improved with the use of more granular information. Changes to improve location-based calculations and disclosure could include:

- **Amending the Scope 2 Guidance to call for the preparation of location-based inventories with emissions factors that better reflect the timing of a buyer's consumption.**[ddd] By pairing load and grid emissions factors on a more granular basis than annually, buyers will have greater clarity regarding which time periods are relatively more carbon intensive. More granular consideration of the carbon intensity by time may also better incentivize buyers to manage their electricity use to take advantage of time periods with abundant carbon-free electricity and shift away from time periods with higher carbon intensity. Today, calculating the location-based inventories by matching hourly consumption with hourly emissions factors may not be feasible but will be as hourly customer load and average grid emissions factors become available.[eee]

  As WRI explains,

  "To further aid in assessing local grid decarbonization, others have also encouraged pairing location-based accounting methods with hourly average emissions factors, ultimately shifting away from using annual averages (Miller 2020a). Analysis conducted in Spain showed that corporate GHG emissions calculated using hourly average emissions factors were 5 to 9 percent higher than emissions calculated using conventional protocols, highlighting the need to further refine and more accurately track procurement impact (Spork et al., 2015)."[64]

  A more recent study calculated Scope 2 GHG emission inventories for approximately 113,000 simulated residential and commercial buildings in 52 grid balancing areas across the United States using annual-average, hourly and other temporal grid emission factors. The study indicates that the annual average carbon accounting can result in an overestimation up to 33% and underestimation up to 22% when compared to hourly-average accounting, depending on a number of factors.

  "…in regions where the variability in hourly carbon intensity is higher, annual-average accounting results in higher inventory bias… the magnitude and direction of the bias depends on the variability of the building load, and how highly correlated that load is with periods of high or low carbon intensity on the grid, both on a seasonal and daily basis…the results illustrate how the bias in carbon inventories is based on a combination of factors including the variability in hourly building demand, the variability in hourly carbon intensity, and the correlation between building demand and grid carbon intensity…However, the results of this study make clear that in today's electricity system, annual-average emissions accounting yields imprecise emission inventories in most regions and for most end-users."[fff]

  Based on their detailed analysis, these authors recommend that hourly (or sub-hourly) accounting be adopted as the best practice for attributional GHG accounting of grid-consumed electricity and for location-based Scope 2 GHG inventories.[ggg]

- **Encouraging buyers to disclose inventories on a regional grid[hhh] basis.** Buyers currently can report emissions as one aggregate total. Disclosing inventories by regional grid, rather than aggregated to a buyer level, will better demonstrate geographically where exposure to carbon intensive generation is the highest.

[ddd] Improvements may also be possible eventually to better reflect the location of a company's consumption with consideration of transmission constraints within regional grids. For example, despite being located within the same regional grid, emissions rate factors in New York City are likely to be different than those in upstate New York at any given point in time. An inventory could potentially be calculated that matched consumption with average emissions factors based on market or load zones withing a regional grid considering transmission congestion (e.g., similar to locational marginal prices).

[eee] U.S. stakeholders should encourage EPA and/or U.S. regional grid operators to report hourly average emissions factors in each sub-region to improve accuracy and comparability in reporting. For both the calculation of location-based inventories and market-based inventories, establishing a standardized set of hourly emissions factors applicable to each regional grid that could be applied to grid supply (not from dedicated contracts or resources) would improve accuracy and comparability in reporting. Relevant data and accounting issues are discussed more fully in the appendix.

[fff] Gregory J Miller et al 2022 Environ. Res. Lett. 17 044073, pages 5, 9-10, https://iopscience.iop.org/article/10.1088/1748-9326/ac6147/pdf.

[ggg] Further, the study highlights that these annual accounting biases will only get worse, based on current trends in building energy demand and grid carbon intensity. As grids continue to integrate more variable and intermittent renewable energy sources to meet state renewable portfolio standards and other climate goals, the variability in hourly carbon intensity will likely increase. And as more and more large end-use loads are electrified, such as vehicle charging, water heating, and space conditioning, building, and total facility load profiles may become spikier and more variable. Both these trends will increase the bias (or inaccuracies) associated with Scope 2 emissions inventories calculated using annual average emissions factors and annual load.

ii. Modified Scope 2 Market-Based Inventories that Better Reflect a Buyer's Actual Electricity Use

When buyers purchase electricity to serve their load, the timing and location of that supply matters. Ultimately, supply must be "delivered" to buyers based on the times and location of their demand. Contractual electricity supply obligations are typically defined by each hour (or sub-hour) for a particular delivery area, even if a customer (or group of customers) does not have an hourly meter. This raises the question: why should clean energy attributes be treated differently? The marketplace needs to know more about the extent to which buyers are relying on unabated fossil generation, taking steps to minimize that reliance, the emissions that are the result of their actual electricity supply, and the decarbonization impacts of buyer interventions and transactions. While incumbent market-based accounting limits the scope of information a buyer can provide through an attributional accounting framework,[iii] there are potential ways to improve the accuracy and relevance of these inventories.

- **Market-based inventories should be calculated for supply (including clean energy attributes) that better reflect the timing and location of a buyer's electricity use.**[jjj] A modified calculation of Scope 2 market-based emissions would include the following key differences in how carbon-free electricity is reported: 1) only carbon-free supply located in the same regional grid as consumption would be counted,[kkk] and 2) carbon-free electricity surpluses during a time interval would not be used to offset deficits in other time periods unless energy storage is used. This limitation of excess carbon-free supply in a time period coupled with the matching of use and emission factors can result in significant differences from – and greater accuracy than – today's market-based inventories. Peninsula Clean Energy, a Community Choice Aggregator in California, reported that the GHG intensity of its power in 2020 was 12 lb-CO_2e/MWh when measured under the current Protocol using an annual matching standard, but emissions would have been 187 lb-CO_2e/MWh if measured with hourly matching of supply and demand – a 15x difference in GHG intensity.

  Both the modified Scope 2 market-based accounting and the electricity use matching metric (Annual Average CFE % discussed later) should be tied to the timing and location of a buyer's consumption. And while hourly calculations will be the most accurate and could become common practice at some point, limitations on data availability may make it appropriate for buyers to have options as to time-based calculations. This would provide flexibility to allow a buyer to choose the level of difficulty when matching carbon-free supply with its electricity use. For example, a buyer could continue to calculate and report information over an annual period with a key difference being that carbon-free supply/attributes would come from the same regional grid.[lll] Another buyer could report its modified Scope 2 market-based inventories and Annual Average CFE % using an hourly interval. Or a buyer may choose a middle ground and use monthly calculations.

- **As with the location-based method, buyers should use appropriate hourly emissions factors in each region and apply to their supply using a standardized accounting methodology to improve comparability in reporting.** Again, such information may not be yet available in all regions.

- **Encourage buyers to disclose inventories on a regional grid basis.** Buyers currently can report emissions as one aggregate total across regions. Disclosing inventories by regional grid will better demonstrate geographically where exposure to carbon intensive generation is the highest.

The suggested modifications to Scope 2 inventories are summarized below:

[hhh] 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). In areas where no such structure exists, then the electricity balancing authority can be used. A balancing authority ensures, in real time, that power system demand and supply are balanced. 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.

[iii] The differences between attributional and consequential accounting are described later.

[jjj] Ideally, transmission constraints within each regional should be considered. However, for the foreseeable future, these calculations should be performed by regional grid until there is more experience with this methodology and better data becomes available.

[kkk] See Appendix for treatment of exports and imports across regional grids.

[lll] Admittedly, this would be a significant difference for buyers with existing load in unorganized markets with limited supply options. As discussed later, buyers should be able to reduce carbon emissions in markets outside their regional grid and receive recognition for their efforts.

Modified Scope 2 (Market-Based)

- Only count EACs representing carbon-free generation that are owned and/or retired on behalf of customers located in the same regional grid or balancing authority as load
- Do not allow CFE attributes used for inventory calculations to exceed load in any time interval
- Use more granular time-based calculations (hourly if possible)
- Apply fossil or non-baseload average emissions rates as last resort if residual mix or other emissions rates are not available
- Count buyer's share of EACs in same grid that buyer pays for in utility / LSE rates while following three principles: no double counting, no double paying, no cost shifting

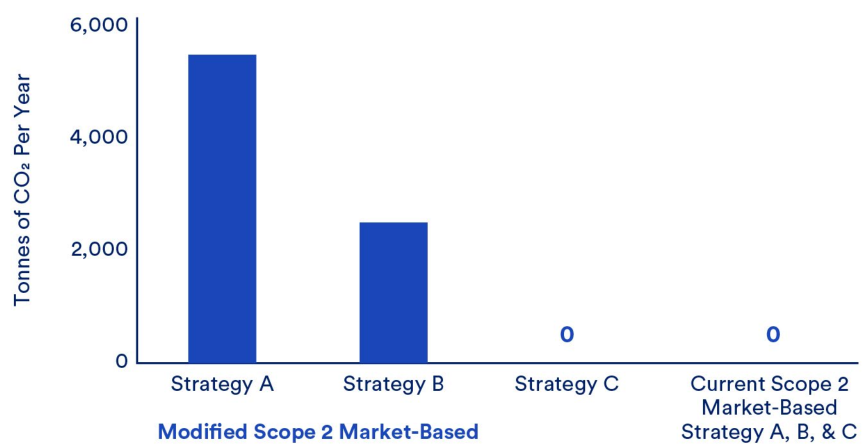
The suggested modified Scope 2 location-based and market-based inventories reported would be more useful to investors and other stakeholders than incumbent practices.[mmm] For example, while the emissions associated with a buyer's electricity use depend on the size of the customer, the load profile, the contracted timing and location of zero-carbon supply, etc., using the three procurement scenarios described in Section 6 for a representative customer located in ERCOT, the differences in modified Scope 2 market-based emissions can be shown for procurement Strategies A, B, and C (as described on pages 26 through 29) and how they compare with existing Scope 2 market-based reporting.[nnn]

This granular lens provides much more information as to the differences in emissions associated with electricity use. And those differences increasingly matter as stakeholders including investors (and financial regulators) might want to better understand the relative climate risks associated with electricity use for different procurement strategies.[ooo] Current disclosures would

Figure 7: Modified vs. Current Market-Based Accounting

(Based on Big Box Store Customer in ERCOT with 1 MW Average Load/Hour)

Source: The NorthBridge Group



[mmm] The percentage change in the market-based versus the location-based inventories could serve as a benchmark to evaluate the effect of buyer procurement decisions (or inactions) on their emissions resulting from their electricity use.

[nnn] The example is based on a representative Big-Box customer in ERCOT, who has an average hourly load of 1 MW and consumes 8,760 MWh of energy annually, in accordance with the hourly load pattern for that type of customer in ERCOT.

[ooo] The *Scope 2 Guidance* explains: *"Electricity is a vital input and resource for most corporate operations, but increasingly poses GHG-related risks. These liabilities arise from climate regulations targeting the energy sector, changing energy technology and fuel costs, tradeoffs between low-carbon sector goals and other environmental objectives…and changing consumer preferences for low-carbon products, as well as scrutiny from investors and shareholders over what energy choices a buyer makes and how it purchases energy. Scope 2 GHG reporting also can introduce reputational risks from GHG claims that are unsubstantiated or unknown. The results of each scope 2 calculation method highlight different risks and opportunities associated with electricity purchasing and use. Furthermore, the actual contractual instruments claimed in the market-based method will shield or expose buyers to different risks associated with the changing cost of energy and related GHG." Scope 2 Guidance*, page 15.

provide little relevant information or distinction for these procurement strategies. Admittedly, this more granular accounting is not perfect. A buyer in Strategy C could still "consume" fossil generation within the local grid, while contracting for clean energy supply or EACs in other parts of the regional grid where such power is not "deliverable" to the customer given constraints with transmission. Also, these modified inventories do not attempt to measure the carbon impact associated with each of these buyer actions. Strategy A and Strategy B may have a higher overall carbon reduction impact from their electricity procurement actions. Therefore, as discussed later, even if improvements are made to encourage granular time and location reporting of Scope 2 inventories, the recommended modifications to the location and market-based methods do not necessarily capture the impacts of buyer strategies seeking to enhance overall emissions reductions. Additional reporting would be needed to capture such impacts.

iii. Disclosure of Supply Sources Used to Serve a Buyer's Electricity Use

Having a better understanding of the supply sources used to serve a buyer's electricity use would allow the emissions and the energy transition risks associated with that supply to be assessed more accurately.[ppp] Buyers should request suppliers to provide a breakout of carbon-free electricity supply by resource type used to meet a buyer's consumption, as well as the percentage of consumption covered by unbundled Energy Attribute Certificates obtained from the regional grid.[qqq] Similarly, suppliers could be asked to identify non-carbon-free supply (if any) by resource type. And suppliers could be asked to identify unspecified (residual mix) supply from the regional grid (if any) used to provide service.[rrr] Buyers, of course, need access to information on the sources of their supply. Today, they could request this information from suppliers, which may or may not yield complete information. Supply sources (and associated emissions factors) may already be or could become available because of existing or future state or federal supplier disclosure requirements.[sss] More granular data by hour or month could be used to support a buyer's consumption matching claims and would further improve the accuracy of emissions calculations and the assessment of energy transition risks associated with that supply.[ttt, uuu]

iv. Disclosure of the Percentage of Carbon-Free Electricity Used to Serve a Buyer's Electricity Use

A buyer can seek to match carbon-free electricity with its consumption by procuring a time-matched product from an electricity supplier, using demand management, and/or utilizing energy storage resources. By calculating the extent to which electric consumption is matched by the generation of carbon-free electricity at specific times, a buyer may highlight its progress toward always using clean electricity.

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ppp The *Protocol's* location-based method includes no information about buyer contracts and the emissions associated with electricity use after those contract purchases. The *Protocol's* market-based method is primarily focused on purchases (of attributes and/or supply contracts), but not necessarily tied to consumption. As a result, the Protocol requires no information to be reported on the electricity supply mix actually used to serve hourly load.

qqq CFE MWh in each hour would be needed to track a 24/7 goal, while the percentage of CFE that matches consumption could be reported and disclosed on an aggregated annual basis. Identifying and reporting whether the resource is a "firm" or "variable/intermittent" zero- carbon resource would also be helpful to better understand how the mix of CFE corresponds with higher levels of CFE consumption matching. Tracking of all forms of clean energy attribute certificates (EACs) could also support hourly and other consumption matching claims for both suppliers and buyers.

rrr Emissions factors for the residual mix are generally not available in the United States. If most carbon-free resources are "claimed" in compliance or voluntary markets and allocated accordingly, to avoid double counting, unspecified supply could be assigned higher than average grid emissions factors (e.g., emissions factors for non-baseload or fossil resources). This topic is discussed in more detail in the Appendix.

sss Some regional grids already track the supply mix for the region, and in some cases, LSEs may be required to report their supply mix on an annual basis. For example, in California an existing Power Content Label law requires every LSE that offers an electricity product for sale to retail consumers to disclose its electricity sources as a percentage of annual sales and the associated intensity of greenhouse gas emissions for the previous calendar year. Also, both NEPOOL GIS and PJM-GATS currently track all-generation on their systems.

ttt Disclosures could only include aggregated information. Hourly load and generation data needed to calculate certain metrics may include data viewed as competitively sensitive by customers and suppliers. Confidentiality issues are addressed briefly in the Appendix.

uuu Because even a 100% annual match of carbon-free supply with annual use likely means that a buyer still relies on fossil generation from the regional grid for a significant portion of its load, suppliers could be asked to disclose the supply mix by resource type used to serve the buyer's hourly load.

All CFE supply (or EAC attributes) that a buyer pays for whether on a voluntary or mandatory basis (in supply contracts, utility tariffs, or direct purchases) could be used to satisfy consumption matching claims.[vvv] There are a few ways a buyer could disclose the extent to which carbon-free supply matches the timing and location of its electricity use. The first measures the average CFE percentage across all hours of the year (Annual Average CFE %), and the second discloses whether a minimum percentage of carbon-free electricity is supplied in each time interval.[www] In all cases, the same methodology could be applied, such that carbon-free supply could not exceed the buyer's consumption during the time interval selected and only carbon-free supply located in the same regional grid could be included. A buyer could select a time interval (annual, seasonal, month, week, hour, etc.) to track and disclose consumption matching goals with varying degrees of difficulty, where hourly matching could be considered by evaluators to be more difficult than longer time matching intervals. This flexibility would allow buyers to report metrics consistent with their procurement strategies (and data availability), and at the same time, would allow buyers pursuing more stringent next generation standards to distinguish and get credit for their actions in their accounting and reporting disclosures.

B. Information to Better Assess the Decarbonization Impacts of Buyer Actions

At the heart of modernizing GHG accounting and reporting – and of changing the focus of third-party leadership and recognition programs – is incentivizing and rewarding buyer decisions and interventions that make real-world decarbonization impact. The type of changes to attributional accounting practices discussed above would improve the relevance (and accuracy) of disclosures but do not squarely address the disclosure of impacts. Additional disclosures that might help incentivize and reward impactful buyer actions may include focusing on impacts beyond what might be "attributed" to a given buyer's footprint.[xxx]

> While the impressive growth in clean energy development is an encouraging signal that we can tackle the harms of greenhouse gases and climate change, we should remember that clean energy deployment itself is not the ultimate goal. Tracking environmental goals in traditional units of MWh of clean energy is an outdated and imprecise approach that does not measure the carbon emissions reductions actually achieved…[yyy, 66]
>
> – ReSurety and the Brattle Group

[vvv] Allowing customers to consider all forms of carbon-free supply, including supply embedded in utility/LSE rates that customers already pay for, would better align stakeholder incentives to advocate for increases in carbon-free supply on their local grid. In other words, customers may be reluctant to pay for resources that they cannot count toward their reduction in emissions inventories or load matching claims.

[www] These two approaches are discussed further in the Appendix.

[xxx] Thus, the impact related type of disclosures discussed here could – or could not – become part of the *Protocol*.

[yyy] ReSurety and the Brattle Group suggest that the focus of buyers and stakeholders should shift toward "location marginal emissions". Estimating locational marginal emissions involves determining the emissions displaced by injecting a MWh of clean electricity at a specific time and location on the grid, thus enabling buyers to incorporate new variables in their procurement decisions and to understand the relative carbon impact of different transaction options. This concept is further explored in Locational Marginal Emissions – A Force Multiplier for the Carbon Impact of Clean Energy Program, available at: https://www.brattle.com/wp-content/uploads/2021/08/Locational-Marginal-Emissions-A-Force-Multiplier-for-the-Carbon-Impact-of-Clean-Energy-Programs.pdf

As one commentator notes:

> *"The fact is, my avoided emissions help you and yours help me. And optimizing sustainability strategies to measure and maximize the emissions consequences of our actions for everyone, doesn't just affect our own individual inventories."*[65]

Emerging next generation procurement approaches seek to make more positive climate impact, and buyers should have pathways to disclose the results of those interventions more clearly. Attempting to measure decarbonization impact, even if not perfectly, is a prerequisite.

Several analyses have highlighted the importance of changing the focus from counting MWh of generation to measuring carbon impact. For example, WattTime found that a Kansas wind project had 2.3 times the emissions impact as a California solar project.[67] Similarly, Salesforce concluded that a West Virginia solar project had almost three times the emissions impact as a California solar project,[68] and a Boston University study found that a South Dakota wind project would have two to three times the emissions impact as a similar project in New England.[69]

> *"The net change in system-wide emissions depends on the marginal generating units and will be different depending on where clean electricity is added and the hours in which it is generated. What we have demonstrated in this paper is that the net reduction in carbon emissions can vary by several hundred percent from one location to another within a given electric power region and from one hour to another within the same day. Optimizing clean energy investments can often more than double their impact on reducing carbon emissions."*[zzz]

These types of analyses make intuitive sense – it matters when and where incremental carbon-free supply is added and what type of generation it displaces. And even if the measurement of carbon impact is not reflected in updated market-based Scope 2 inventories, new impact disclosures are likely to become the priority focus of stakeholders and recognition programs.

i. Disclosure of Buyer Actions that have Grid Impact

A buyer's procurement actions can impact overall grid emissions by supporting new carbon-free resources that displace unabated fossil generation either on the grid where its load is located or on another grid irrespective of the location of a buyer's consumption. A key objective of measuring and disclosing decarbonization impact is to prioritize incremental carbon-free development (including new-carbon free resources, life extensions of existing carbon-free projects, repowering of hydro, uprates, etc.) in locations and times that yield the greatest carbon impact. Some argue that consumption matching (tying procurement to the same regional grid) may significantly limit the geography of investment in carbon-free generation projects. Since climate change is a global phenomenon, the location of carbon reductions does not matter. Therefore, some argue buyers should focus their efforts on maximizing carbon reductions by identifying the specific locations and times when the dirtiest unabated fossil generation can be displaced.

A new approach would be to provide an opportunity for a buyer to disclose and describe the actions it has taken to reduce grid emissions both in terms of the incremental change in resources (e.g., the development of incremental carbon-free generation or storage capacity) and in terms of avoided emissions. To begin, a buyer could identify and disclose the quantity of incremental carbon-free resources (MW) it currently supports via contract and/or finances, inclusive of all forms of incremental carbon-free supply (e.g., wind, solar, and other). As part of this disclosure, buyers could also identify the incremental firm carbon-free supply and storage capacity added. These and perhaps other categories, such as investments in new emerging technologies or transmission expansion, may also be important to consider when assessing the carbon impact of buyer actions and measuring progress toward full decarbonization. A buyer could also identify other potential actions or interventions (e.g., load shifting, energy efficiency, etc.) that it believes could impact grid emissions overall.

These disclosures alone, of course, are not sufficient to measure carbon impact. More information on the timing and location of incremental carbon-free generation (and any other buyer actions) and its impact on the grid overall is required to calculate avoided emissions.

zzz Hua He et al, *Using Marginal Emission Rates to Optimize Investment in Carbon Dioxide Displacement Technologies*, Tabors Caramanis Rudkevich, page 7, Electricity Journal 34, 2021.

ii. Disclosure of Avoided Emissions

Avoided emissions calculations measure the real-world reductions in carbon emissions associated with buyer actions. Avoided emissions depend on a) whether overall grid emissions change (e.g., whether an incremental carbon-free resource supported by a buyer would displace fossil generation or displace other carbon-free generation depending on the timing, location, and type of carbon-free generation); and b) whether a buyer's actions caused the change.[aaaa] A consequential framework[bbbb] provides a decision tool that can be used to understand the consequence of an intervention on grid emissions relative to a baseline where the intervention did not occur.[cccc] This type of analysis is focused on measuring emissions impact and can be used to answer important questions, including: *Where to build a new wind or solar farm for maximum impact? What type of carbon-free technology will have the most impact? Where would locating a new facility cause the least amount of carbon emissions? When is the best time to consume electricity to lower carbon emissions? What is the effect of new energy storage on the grid's carbon emissions?* To answer these questions, granular location and timing data are needed.

"If the goal of energy purchasers or public policy is to reduce emissions, the most effective strategy is to purchase and use electricity in locations and at times when marginal emission rates are low and to invest in new renewable or clean generation that will deliver power into the power grid in locations where and at times when marginal emission rates are high."[dddd]

To support efforts to measure real-world carbon impact on the electric grid, new disclosures might include the following avoided emissions metrics.

a) Carbon Baseline (absent buyer actions) (measured in tonnes of CO_2)[eeee] **–** This metric is like the modified location-based method described above. However, it could be based on a buyer's hourly consumption and marginal emission factors (instead of average emission factors).[ffff] This metric could be used to compare against the carbon impact of incremental changes in load and serve as a baseline to "normalize" avoided emissions for customers of varying size. Note that the emissions factors used to calculate the Carbon Baseline would be linked to the timing and location of customer consumption; whereas the emissions factors used to calculate the avoided emissions should be based on the location of the intervention, which may or may not be the same as the location of the customer.[gggg]

b) Avoided Emissions *(measured in tCO_2 and tCO_2 / MWh of generation)* – Carbon impact can be measured over different timeframes depending on the type of buyer intervention. In the short run, changes are considered based on emissions assuming no change in the existing fleet of generators. In the long run (such as 5 years or more), forward looking projections consider changes that can induce both operational and structural changes to the grid (e.g., the building of new carbon-free resources and the retirement of unabated fossil generation). While detailing the methodologies used to calculate avoided emissions is beyond the scope of this paper, many industry experts have been studying this important topic in recent years and have developed methods and models to calculate avoided emissions.[70,71,72,73] Approaches vary and can range from relatively simple to extremely complex. Avoided emissions can potentially be calculated with existing public data and use different geographic boundaries or time periods. More granular data can provide a more accurate climate impact assessment (e.g., avoided

[aaaa] There is not always a direct cause-effect relationship between the single activity of the reporting company (purchasing and consuming energy) and the resulting GHG emissions on the grid, so not all transactions will have an avoided emissions impact. For most smaller consumers of electricity, their energy procurement choices help to increase aggregate demand to drive the development of new CFE generation.

[bbbb] The attributional framework is intended to measure the emissions related to a buyer's electricity use, which is useful in assessing a buyer's exposure to climate risks (more so with the changes suggested in this paper). The consequential framework is designed to measure the carbon impact on the grid overall resulting from a buyer's actions / interventions. Both approaches provide useful information but answer different questions and why we include both types of metrics in our Carbon Facts label.

[cccc] This calculation is not necessarily tied to the timing or location of customer consumption but could be. For example, avoided emissions calculations can measure the impact of changes in customer consumption levels (energy efficiency) or patterns (load shifting).

[dddd] Hua He et al, *Using Marginal Emission Rates to Optimize Investment in Carbon Dioxide Displacement Technologies*, Tabors Caramanis Rudkevich, page 7, Electricity Journal 34, 2021.

[eeee] A tonne, also known as a metric ton, is equal to 1,000 kg, (or 2,204.6 pounds).

[ffff] If hourly customer load and marginal emissions factors are not available, annual load and average eGrid fossil (or non-baseload) emissions factors could be used as a proxy for marginal emissions associated with consumption absent any buyer contracts.

[gggg] For example, if a buyer located in California chooses to build/finance a new solar farm in Australia, the carbon footprint would be based on emissions factors in California, while the avoided emissions estimate would be based on emissions factors in Australia.

emissions could be calculated using annual figures or an hour-by-hour basis). Some of the calculation issues, such as the implications of selecting one type of emissions factor over another in these calculations, are discussed further in the Appendix.[hhhh] In addition to reporting avoided emissions (in metric tons) associated with incremental carbon-free generation, a buyer could also report avoided emissions per MWh in aggregate across all projects to provide a better sense of its avoided emissions impact on a per unit of generation basis.

c) **Avoided Emissions Impact –** This would be calculated as the percentage change in net emissions[iiii] relative to the carbon baseline to normalize the avoided emissions quantification for customers of varying size. This percentage could exceed 100% if a buyer's actions avoid more emissions than its carbon footprint associated with its electricity use. Third party recognition programs could encourage companies to achieve relatively higher percentages.

The calculation of avoided emissions does not depend on the claims of others, but is dependent on input assumptions, and stakeholders have not yet agreed on a consensus set of best practices for calculating avoided emissions or in using such calculations to evaluate the ambition of buyer efforts or to recognize leadership.[jjjj] Avoided emissions can be used for different purposes.[kkkk] While long-term forecasts of avoided emissions may be used for internal company decision-making, reporting disclosures of avoided emissions may more appropriately be based on actual empirical evidence about what happened during a prior year. A buyer could begin to quantitatively measure avoided emissions beginning with relatively less complex calculations with readily available data (e.g., using EPA's most recent AVERT annual avoided CO_2 emissions factor). Nevertheless, the imperative of focusing on decarbonization impact suggests that we begin to require such disclosures as soon as possible and with the best available data and methodologies.

C. Putting it all Together with New Market-Facing Disclosures: a "Carbon Facts" Label

Evaluating buyers, their emissions from using electricity, and their efforts to achieve carbon reduction impact through procurement requires collecting and disclosing a range of information, certainly more than what is captured in current location-based and market-based inventories. The ultimate and ideal result of modernizing accounting and disclosure should be the ability to capture the full range of relevant information in a single summary format. For example, analogous to nutrition facts labels customers commonly see on packages at the local grocery store, a "Carbon Facts" label might summarize carbon-related information in a standard and comparable format. It would seek to summarize the carbon emissions resulting from a buyer's electricity use and help reveal how a buyer's procurement strategy and decision making furthered real-world decarbonization progress.[llll] Like a food label, some metrics reported may appear favorable, while others at the same time may appear unfavorable.

[hhhh] Typically, locational marginal emissions rate factors are used in avoided emissions estimates. But these can be calculated based on short-run or long-run marginal rates. Avoided emission estimates also can be calculated based on historical figures or based on modeled projections. And some stakeholders base their calculations on hourly average emissions rate factors.

[iiii] Net emissions are equal to the carbon baseline less the avoided emissions.

[jjjj] As highlighted by the Corporate Standard, "[g]enerally, as long as the accounting of indirect emissions over time recognizes activities that in aggregate change global emissions, any such concerns over accuracy should not inhibit companies from reporting their indirect emissions." Similar logic also can be applied to calculating avoided emissions. Exact precision is not required to measure carbon impact. In many instances, it may be obvious that the avoided emissions impact is zero. In others, we may be able to identify that there is a clear impact and that it could be significant. Transparent accounting and reporting should provide information about the estimated carbon impact and the methodologies used to calculate that impact. Recognition programs and ESG rating companies can then better evaluate the weight of the evidence provided to support those claims.

[kkkk] For example, if one were seeking to create carbon offsets from procurement transactions, that raises a different set of questions that include concerns about double-counting. In contrast, it may not be necessary for buyers to "own" avoided emissions if solely disclosing estimates of avoided emissions in order to provide insight into the relative decarbonizing impact of transactions.

[llll] If certain metrics cannot be calculated and disclosed by a supplier/buyer in some or all locations (e.g., insufficient data is available), then a supplier/buyer might be required to disclose that they were unable to report such information for the following reasons. The primary goal being to increase transparency and highlight data gaps and other market barriers to reporting (as opposed to "penalize" buyers for not reporting such information).

The granularity and extent of the disclosures that might make up a Carbon Facts Label could increase over time. A nearer-term "Carbon Facts 1.0" label might look like this:

Information to Better Reflect Emissions from Electricity Use

(tied to timing and location of buyer consumption)

Information to Measure Decarbonization Impact from Buyer Actions

(not necessarily tied to timing and location of buyer consumption)

Carbon Facts 1.0 (Illustrative) **Reported for Prior Calendar Year**	
Annual Consumption (By Regional Grid / Balancing Authority)	_MWh
Time Interval Used for Scope 2 Reporting / Consumption Matching	[Annual][1]
Scope 2 Emissions (Track emissions from electricity use and climate risk exposure) ● Location-Based (annual load * average grid EF; absent contracts) ● "Modified" Market-Based (tied to same regional grid as load)[2]	_ tCO_2 _ tCO_2
Optional: Annual Average CFE % Matched to Hourly Consumption[3] (Track consumption matching goals)	_%
Annual CFE Purchases (Not by Regional Grid / Balancing Authority)	
Total Annual CFE (Track purchasing goals -- RE100/CFE100)[4]	_% of consumption
Decarbonization Impact and Avoided Emissions (Track carbon reduction goals)	
Incremental Total CFE (by resource type)[5] Describe Other Buyer Actions[6]	_ MW / _ MWh
Avoided Emissions ● Carbon Baseline [CB] (annual load @ fossil EF; absent buyer contracts)[7] ● Avoided Emissions [AE] (annual incremental supply @ EPA AVERT EF)[8] Net Emissions [CB]-[AE]	_ tCO_2 _ tCO_2 _tCO_2/MWh _ tCO_2
Avoided Emissions Impact [(CB-AE)/CB-1]	_%

[1] Buyer can select on an optional basis more granular time interval to measure and report emissions and consumption calculations (e.g., season, month, hour) with hourly matching recognized as the most stringent/accurate. CFE in excess of buyer load in any time period would not be included.

[2] Key differences include only CFE/EACs located in the same grid as load counts, CFE cannot exceed load in any time interval, hourly calculations (optional), fossil or non-baseload emissions factors (EF) applied as last resort (proxy for residual mix; not grid average EF), and EACs in grid count if buyer pays for them in utility or LSE rates (i.e., customer load share of state procured RPS, state supported nuclear, ratepayer funded CFE, RPS, etc.). Given the broad use of and familiarity with existing Scope 2 methods, continued incumbent reporting may be desirable initially and may serve as a benchmark as new metrics and evaluation tools are socialized and better understood.

[3] Total CFE divided by total load across all hours in the year would result in the Annual Average CFE % Matched to Hourly Consumption, tracked by facility and aggregated by regional grid.

[4] This metric should be reported in accordance with RE100 market boundary requirements for a company's global operations. A company could continue to use in-market/out-of-market/bundled/unbundled attributes for purposes of reporting this metric.

[5] Incremental CFE could include new capacity, life extensions, repowering, uprates, etc. Any incremental firm and/or new technologies could be identified.

[6] Other buyer actions could include investments in energy storage, load management, transmission, etc. that could impact grid emissions.

[7] If hourly customer load and marginal emissions factors are not available, annual load and average eGrid fossil (or non-baseload) emissions factors could be used as a proxy for marginal emissions associated with consumption absent any buyer contracts.

[8] If hourly incremental supply and marginal emissions factors are not available, the annual incremental carbon-free MWh generation and EPA's most recent AVERT annual avoided CO_2 emissions factor could be used as a proxy for avoided emissions.

The types of information included in the Carbon Facts Label are broadly grouped into information to better reflect emissions from electricity use (on the top part of the label) and information to measure decarbonization impacts from buyer actions (on the bottom half of the label). Stakeholders' views about the inherent "value" of different first and next generation procurement strategies may vary. The Carbon Facts label is designed to inform an accurate assessment across a broad range of electricity procurement strategies, including both first generation and next generation approaches. The Carbon Facts label could be used to track more accurately emissions from electricity use and a buyer's climate risk exposure. It could also allow a buyer to disclose, on an optional basis, its progress on matching CFE supply with its hourly consumption.[mmmm] The Carbon Facts label could also provide an opportunity for a buyer to disclose its progress in meeting RE100 or CFE100 purchasing goals on an annual basis, not necessarily tied to the timing and location of its consumption. Finally, the Carbon Facts label could include information to report the decarbonization impacts (if any) from buyer actions both on a qualitative and quantitative basis. It is possible that a buyer could score very high on the attributional metrics (on the top part of the label) but very low on the decarbonization metrics (on the bottom half of the label). The converse is also possible – a buyer could score very low on the attributional metrics but very high on the decarbonization metrics. It is also possible that a buyer could score very high on both the attributional and the decarbonization metrics.

Buyers can begin to take actions and measure these metrics now to better align with next generation electricity procurement approaches while market reforms and reporting standards continue to evolve. As was the case with first generation procurement, leading buyers are likely to share their methodologies used to measure and track progress over time, socialize successes, and encourage others to follow.

In the future, a more extensive "Carbon Facts 2.0" label may be appropriate, including more information about the supply sources used to serve a buyer's electricity use and more precise calculations of emissions, consumption matching, and avoided emissions using more granular time and location data.

Illustrative Carbon Facts 2.0 labels are shown in the Appendix for each of the buyer procurement strategies A, B and C presented in Section 6.

While a more comprehensive approach to accounting and disclosure (like a Carbon Facts label) would better support and incentivize next generation procurement, few buyers are likely ready to do it all. More granular customer load, electric supply, and emissions tracking systems are still being developed in many regions of the United States. Some market players have already begun to establish the tools necessary to facilitate this kind of reporting, such as the development of supplier disclosure requirements, the creation of granular energy attribute certificates, the release of more granular data (load, supply, emissions), and the development of sophisticated models to calculate avoided emissions. But just as mechanisms like PPAs and VPPAs – and even carbon accounting itself – were at first implemented by only a few buyers, these new accounting and disclosure practices will become more accessible and common over time.

Nevertheless, new and modified disclosures such as those suggested here, even if phased-in over time, would support electricity buyers in continuing to enhance their procurement practices and make even greater contributions to decarbonizing the electricity sector. Reporting information that more accurately reflects emissions from electricity use and that reflects the decarbonization impact of interventions will also provide the type of information needed to improve public recognition programs and ESG ratings systems so that leading buyers are appropriately recognized and rewarded for their efforts.

[mmmm] Short of hourly time matching every day all year, a buyer today might progress from annual to seasonal, to monthly, to weekly and then hourly matching – relying on the best available temporal generation and load data.

Illustrative Carbon Facts 2.0 label

Information to Better Reflect Emissions from Electricity Use

(tied to timing and location of buyer consumption)

Information to Measure Decarbonization Impact from Buyer Actions

(not necessarily tied to timing and location of buyer consumption)

Carbon Facts 2.0 (Illustrative) **Reported for Prior Calendar Year**	
Annual Consumption (By Regional Grid / Balancing Authority)	_MWh
Supply Sources (% of Annual Consumption) (by resource type) • Supply Contract / Utility Tariff CFE[1] • Supply Contract / Utility Tariff Non-CFE • Allocated Carbon-Free Electricity (CFE)[2] • Unspecified Grid Supply (residual mix, if any)	 _ % _ % _ % _ %
Unbundled Energy Attribute Certificates	_%
CFE Supply % Matching Consumption (Track consumption matching goals) • Time Interval Used for Matching (and Scope 2 Reporting) • Annual Average CFE % (average across all hours) • [Hourly] Minimum CFE % (0-100%)	 [Hourly][3] _% _%
Modified Scope 2 Emissions (Track emissions from use and climate risk exposure)[4] • Location-Based (load * grid average EF; absent contracts) • Market-Based (with RECs/EACs, LSE contracts & grid supply) • MB vs. LB [MB/LB-1]	 _ tCO_2 _ tCO_2 _%
Annual CFE Purchases (Not by Regional Grid / Balancing Authority)	
Total Annual CFE (Track purchasing goals -- RE100/CFE100)[5]	_% of consumption
Decarbonization Impact and Avoided Emissions (Track carbon reduction goals)	
Incremental Total CFE (by resource type)[6] • Incremental Firm CFE • Incremental New Technology Describe Other Buyer Actions (energy storage, load management, etc.)	_ MW / _ MWh _ MW / _ MWh _ MW / _ MWh
Avoided Emissions • Carbon Baseline [CB] (load @ marginal EF; absent buyer contracts)[7] • Avoided Emissions [AE] (from buyer interventions)[8] Net Emissions [CB]-[AE] **Avoided Emissions Impact** [(CB-AE)/CB-1]	 _ tCO_2 _ tCO_2 _tCO_2/MWh _ tCO_2 _%

1 Each resource should be identified as "firm" or "intermittent." Supply should be based on actual figures.

2 Allocated CFE (if any) refers to CFE that a buyer pays for in its utility rates absent any buyer action (e.g., RPS procured by the state or state-supported clean energy generation (nuclear), etc.) that is not supplied by a load-serving entity (LSE). RPS provided by an LSE should be included in the LSE's supply mix.

3 Buyer can select time interval to measure and report matching and emissions calculations (e.g., annual, season, month, hour) with hourly matching recognized as the most stringent/accurate. CFE in excess of buyer load in any time period would not be included. Total CFE divided by total load across all time periods in the year would result in the Annual Average CFE %, tracked by facility and aggregated by regional grid.

4 Given the broad use of and familiarity with existing Scope 2 methods, continued incumbent reporting may be desirable initially and may serve as a benchmark as new metrics and evaluation tools are socialized and better understood.

5 This metric should be reported in accordance with RE100 market boundary requirements for a company's global operations.

6 Incremental CFE could include new capacity, life extensions, repowering, uprates, etc.

7 This metric could be based on emissions factors (e.g., marginal) different than those used in the modified location-based method above and could be used to measure the carbon impact of incremental changes in load. If hourly customer load and marginal emissions factors are not available, annual load and average eGrid fossil (or non-baseload) emissions factors could be used as a proxy for marginal emissions associated with consumption absent any buyer contracts.

8 If hourly incremental supply and marginal emissions factors are not available, the annual incremental carbon-free MWh generation and EPA's most recent AVERT annual avoided CO_2 emissions factor could be used as a proxy for avoided emissions.

SECTION 8

Modernized "Rules" for Disclosure will Enable Modernized "Rewards"

Modernized accounting and disclosure should lead to more accurate and impactful ways for investors, third-party leadership programs, and other stakeholders to incentivize and/or evaluate a buyer's leadership, risk management, and contributions to decarbonization. This paper identifies new metrics and disclosures that should be incorporated into third-party leadership, reward, and evaluation programs and approaches, but it does not describe exactly how such third parties should incorporate such disclosures or amend decision-making or program design. It does, however, seek to make the case that these stakeholders should move beyond their decidedly first-generation approaches to better incentivize and reward buyer actions that more meaningfully contribute to meeting the challenge of climate change.

8.1 Adding a Greater Focus on Decarbonization Impact

Recognizing and incentivizing climate leadership should become better based on the actual climate benefits of buyer decision-making and interventions. As WRI notes:

> *"Looking forward, recognition programs, awards, and other incentives that encourage large energy buyers to undertake clean energy action should also recognize the impact that buyers have on accelerating grid decarbonization and reducing overall GHG emissions."* [74]

A focus on impact necessarily means going beyond examination and measurement of Scope 2 attributional inventories (which were not specifically intended as a reflection of impact). Even using an improved Scope 2 inventory calculation system as described above would not be enough. If emissions reductions and accelerating the decarbonization of the grid are key objectives of third-party leadership and recognition programs, then corporate electricity procurement interventions that contribute to those ends should be considered and "credited" even if grid decarbonization impacts are not reflected in an improved Scope 2 market-based corporate inventory.

"Impact", however, can take many forms and the range of metrics and disclosures in the Carbon Facts label approach are intended to help assess a wide range of decarbonization impacts from buyer actions. Some buyer actions may have more carbon impact on mitigating climate change in the near term, while other buyer actions (such as investments in emerging firm and dispatchable carbon-free technologies) could enable greater carbon reductions in the long term. This means that the value of some next-generation interventions may not be adequately captured either through an improved inventory or through an avoided emissions calculation alone (such as time and location matching on a local grid). Enhanced disclosures and modernized leadership and recognition approaches are needed to reflect this full range of positive impacts.

For example, depending on where a buyer is located, it may be more or less feasible to seek carbon-free supply within its regional grid or achieve a high 24/7 matching percentage. In such cases, an out-of-market "virtual" transaction may be the best emissions impacting alternative, and an avoided emission estimate may then be the key metric to consider.[nnnn] Some stakeholders suggest that measuring avoided emissions is too subjective and too complex to disclose to the public. The data and methodologies to do so, however, are becoming more available, and it should be possible for stakeholders to align on important concepts in measuring and disclosing avoided emissions estimates.

Alternatively, a buyer may seek to help commercialize a new carbon-free technology or otherwise use its market power to help drive the increased use of firm and dispatchable carbon-free generation to displace the unabated fossil assets that currently largely serve that role. The Carbon Facts label approach posited in this paper is an effort to show how a broad range of such metrics and disclosures might be standardized and compared, even if imperfectly, just as the *Protocol* does today for attributional accounting. Measuring carbon impact, when combined with other metrics described in this paper, can help drive the changes that are urgently needed in the electric grid to achieve net-zero GHG emission goals in an affordable and reliable manner.

8.2 Better Inventories and Better Information on the Carbon Impact of Buyer Actions Enable Better Ways to Evaluate and Reward

The types of information included in the Carbon Facts label are broadly grouped into two categories: information to better reflect emissions from electricity use and information to measure the decarbonization impact of buyer actions. The modified approach to Scope 2 inventory accounting is meant to better convey information about the former, and the additional disclosures around avoided emissions represent the latter. Both types of information matter and could – or should – be part of evaluation and reward. But today's inventory methodologies do not accurately or adequately convey information about emissions from electricity use, and they do not include information on impact at all.

Figure 8: Recognition and Reward on Both Sides of the Scale

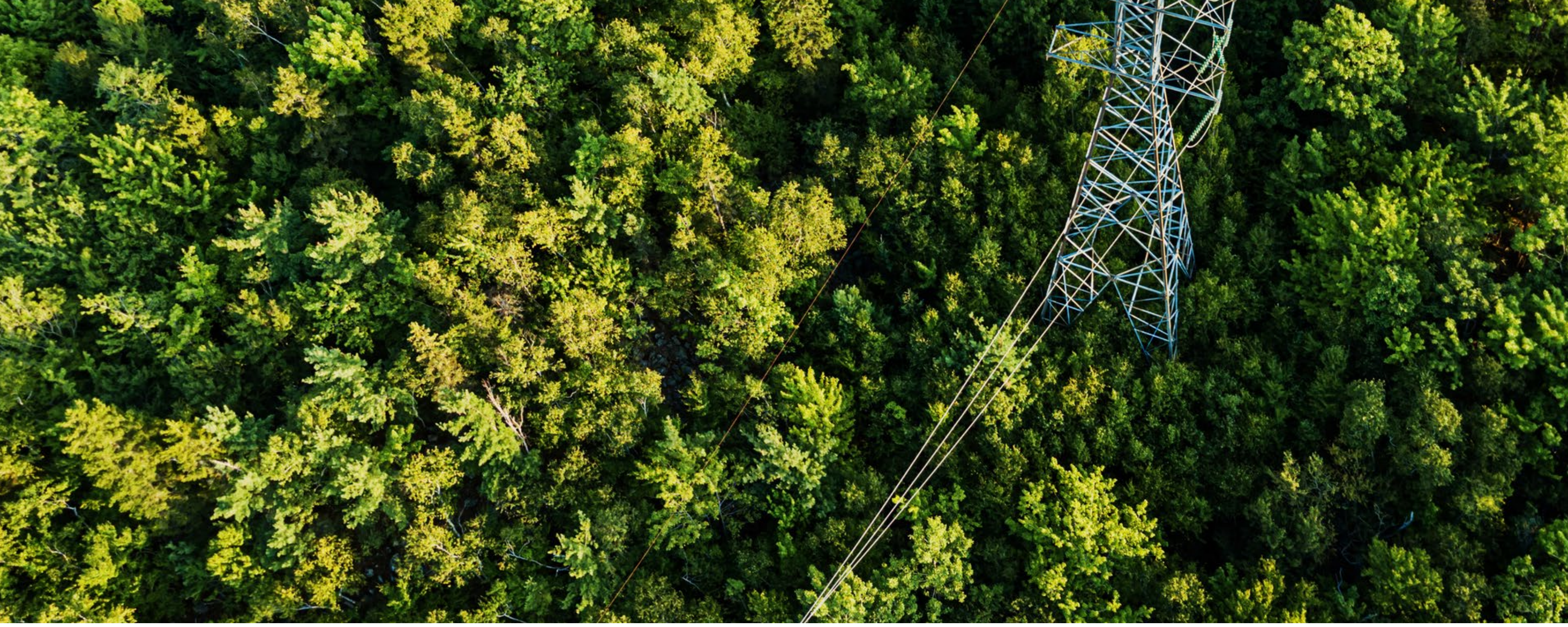
[nnnn] Again, there are critical roles that companies can play in driving the decarbonization of the electricity sector beyond their procurement decisions, such as interventions in regulatory proceedings and support for various electricity sector decarbonization policy proposals at the state and federal level. While beyond the scope of this paper, we think that such actions should be part of how companies are evaluated for leadership by analysts, investors, stakeholders, and recognition programs.

With better information on emissions from use and with new information on impact, both can be incorporated in leadership and evaluation methodologies.

For example, a customer that enacts energy efficiency measures or that matches purchased CFE supply with the timing and location of its load can reduce the left side of the scale. Alternatively, a buyer could take actions that reduce emissions in grid regions independent of the location of its consumption and increase avoided emissions on the right side of the scale. And it is certainly possible that a buyer could take actions that simultaneously reduce emissions from electricity use and have significant decarbonization impact, or a buyer might independently take actions to improve each side.[oooo]

It is likely true that the modified and additional disclosures proposed in this paper would make evaluation (and leadership/reward programs) more complicated than, say, an RE100 approach. But while perhaps more complicated, modernized evaluation and reward systems will also become more aligned with the grid decarbonization timelines called for by climate science.

oooo Emissions that a company caused to be avoided could equal a portion of the emissions from their electricity use, be equal to it, or be greater.



SECTION 9

Conclusion

The authors do not purport to have proposed a complete and adequate approach to modernizing rules and reward ecosystem of large buyer electricity use and procurement. The intent is to challenge the status quo and to promote engagement and contributions that can lead to a changed system that is commensurate to both the growing ambitions of buyers and the increasingly urgent need to decarbonize the electricity sector.

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Appendix – Data, Accounting and Reporting Issues

Fully implementing the accounting and reporting recommendations outlined in this paper will take time to accomplish. Many suppliers and buyers do not currently have access to all the data needed to complete the Carbon Facts label. Suppliers and buyers will require better access to granular load, generation, and emissions factor data and with a more standardized format to enable such reporting. Further, many of the accounting methodologies needed to fully implement this reporting, particularly regarding the calculation of Scope 2 inventories using more granular data, the disclosure of electric supplier content, and the calculation of avoided emissions, are still under development, and stakeholders need to align on acceptable best practices.

At the same time, considerable supply, load, and emissions data is already available in some form. More is quickly becoming available and numerous efforts are under way to develop and refine accounting methodologies.[a] At least some, if not most, of more granular Scope 2 accounting can be done today, even with current data and methodological limitations, particularly considering that improvement not perfection should be the immediate goal of Next Generation procurement efforts. The underlying methodologies, data and rigor of calculations that may be used today can be improved and perfected over time.

This Appendix reviews some of the most important accounting and data issues that need to be addressed, including the current availability of data, need for new types of data, accounting methodologies, and approaches to improve current accounting and reporting practices. It is organized in the following manner:

[a] Ideally, many of the calculations required to implement a Carbon Facts label could be automated in a spreadsheet template to ease reporting and support comparability across organizations. Buyers could select the geographic market boundary and time interval to be used in reporting. Buyers could enter customer-specific information, such as load data, EACs purchased, supply sources, and emissions factors for dedicated resources or supply mix. Emissions factors by regional grid (or sub-region) could be pre-populated in the template to calculate location-based inventories or to calculate emissions associated with unspecified supply sources (if any) to be used as a “residual mix” or as proxies if residual mix emissions factors are not available.

Appendix Contents

APPENDIX SECTION 1

Availability of Granular Data

1.1 Customer Load

Hourly (or sub-hourly) consumption data (preferably metered or else estimated) is a prerequisite for hourly matching of carbon-free supply with consumption. Hourly consumption data can also be used to more accurately measure emissions associated with a buyer's electricity use and inform decisions about the carbon impact of a buyer's actions to alter its consumption. As of 2020, U.S. electric utilities had installed 102.9 million advanced metering infrastructure (AMI) systems, often referred to as smart meters.[b] AMI includes meters that measure and record electricity usage at a minimum of hourly intervals, the type of granular data that is needed. AMI installations range from basic hourly interval meters to real-time meters with built-in two-way communication that is capable of recording and transmitting instantaneous data. About 65% of electricity meters across the United States are AMI[c] and AMI metering exists in both regulated and restructured states depending on state and utility policies.[d]

Hourly consumption metering data, however, does not exist or still is difficult for many buyers to access. This can be especially challenging for organizations in multiple locations and service areas with a mix of monthly, hourly, and 15-minute interval data provided by different service providers in different formats. When hourly consumption data does exist, it should be used for consumption matching (and associated emissions calculations).

In the absence of metered hourly consumption data, load profiles could be applied to actual meter reads for a customer or a group of customers (e.g., Community Choice Aggregation or green tariff). A load profile represents the chronological sequence of hourly demands for a specified subset of, or for all customers of, a Load-Serving Entity (LSE). A load profile typically varies according to customer type (residential, commercial, or industrial), temperature, holidays, weekends, etc.[e] Utilities and other suppliers use this information to plan how much electricity they will need to supply at any given time. 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 in each hour. Even if a customer's meter does not measure its hourly consumption, either the default service provider (in most cases the utility) or a competitive supplier has a market obligation to supply a specific amount of electricity in each hour delivered to a particular market area or customer load zone.[f] The local utility should have access to either the hourly metered load data or the methodology used to determine the hourly supply obligation associated with serving retail customers within its service area. To match CFE with hourly consumption and to more accurately report emissions associated with electricity use, both customers and their suppliers need to have reliable access to this metered or "deemed" consumption data. This is necessary to enable more detailed CFE matching and emissions disclosures.

If, for whatever reason, access to hourly load data is not available to a buyer and relying on a load profile is impractical, another option would be for the buyer to match their supply and consumption and calculate emissions inventories on a less granular basis (e.g., monthly).

b These include AMI meters for 11.8 million commercial customers and 468 thousand industrial customers. https://www.eia.gov/tools/faqs/faq.php?id=108&t=3#:~:text=In%202020%2C%20U.S.%20electric%20utilities,installations%20were%20residential%20customer%20installations

c https://www.utilitydive.com/news/us-smart-meter-penetration-hits-65-expanding-utility-demand-response-reso/611690/,December 21, 2021.

d In 2020, the AMI penetration rate was 62% and 58% for commercial and industrial customer classes, respectively. https://www.eia.gov/electricity/annual/html/epa_10_05.html

e Typically, load profiles are applied to the meter reads for groups of customers within the same utility rate schedule.

f Imbalances in a supplier's scheduled supply and its supply obligation in each hour are typically settled at spot market locational marginal prices (LMP), which vary by time and location.

1.2 Supply Sources Associated with Electricity Use

Understanding the supply sources used to meet a buyer's electricity use is another prerequisite to calculate a reliable measure of the emissions and assess the energy transition risks associated with that supply. Buyers need access to granular information on the sources of their supply, either by requesting this information from suppliers or as a result of state or federal disclosure requirements. Utilities and wholesale/retail suppliers are likely to be in the best position to provide this information to buyers.

Supply (or EACs) used to serve a buyer's consumption generally can come from one or more types of sources:

- Carbon-free electricity (CFE) or EACs from buyer supply contracts (including PPAs or competitive supply service) or utility supply service;
- Non-CFE from buyer supply contracts or utility supply service;
- Allocated CFE or EACs (attributable to state-purchased RPS or state-supported clean energy in utility rates);[g] and/or
- Unspecified grid supply or system power (residual mix).[h]

Supply sources (and EACs) for electricity use should be tracked both in terms of MWh and the percent of annual consumption to support both emissions calculations and consumption matching claims.[i] If a buyer elects to match CFE with load on an hourly basis, then the buyer/LSE will need to track CFE supply sources on an hourly basis based on actual CFE supply and load. As buyers increasingly demand products that more closely match CFE with the timing and location of their consumption, new data and market tools are being developed to enable consumption matching and to facilitate more accurate reporting of the emissions resulting from a buyer's electricity use.[j] While disaggregated market data and more granular clean energy tracking and reporting systems are still being developed, buyers could also be given the option to report information over less granular time periods (e.g., matching CFE on a monthly, seasonal, or annual basis) to provide flexibility for buyers, while encouraging and recognizing the importance of more granular tracking. For example, buyers who can demonstrate hourly matching of CFE with their consumption could get recognized at a higher level of environmental leadership than buyers who match CFE on an annual basis.[k]

Buyers also should request suppliers to provide a breakout of CFE supply (and EACs) by resource type. Similarly, suppliers could be asked to identify non-CFE supply (if any) by resource type. And suppliers could be asked to identify unspecified or system power (residual mix) from the regional grid, if any. Having a better understanding of the supply mix (and EACs) associated with electricity use would support a more accurate calculation of the associated carbon emissions.[l]

U.S. regional grid operators and balancing authorities generally know the resources that operate on an hour-by-hour basis throughout the year. Some regional grids already track the supply mix for the region, and in some cases, LSEs may be required to report their supply mix on an annual basis. For example, in California an existing Power Content Label law requires every LSE that offers an electricity product for sale to retail consumers to disclose its electricity sources as a percentage of annual sales and the associated intensity of greenhouse gas emissions for the previous calendar year. Also, both NEPOOL GIS[m] and PJM-GATS currently track all-generation on their systems, whereas other

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[g] Allocated CFE supply or EACs (if any) refers to compliance/mandated CFE that a buyer pays for in its utility rates absent any buyer action (e.g., RPS procured by the state or state-supported clean energy generation (nuclear), etc.) that is not supplied directly to a buyer by a load-serving entity (LSE). The different categories of CFE sources are discussed later in this appendix.

[h] This refers to supply from the grid from unspecified sources when emissions factors are not otherwise available.

[i] Note there may be differences in the information tracked versus disclosed to protect confidential information.

[j] For example, EnergyTag reports that the producer and production metering data requirements for granular certificates will be the same as existing energy attribute certificate mechanisms. The major additional specific requirement will be that data are provided with at least hourly time resolution. *EnergyTag Standard for GC Schemes*, page 23, March 31, 2022.

[k] As more and more companies make commitments regarding their relative use of renewable and other carbon-free clean energy sources, and as more and more investors and companies recognize the significantly different emissions impacts that result from hourly compared to annual matching methodologies, it is important that a buyer disclose the time interval over which the buyer is matching its clean energy purchases to electricity consumption.

[l] Note that there may be a significant difference between the sources of supply and the energy attributes procured even if purchased within the same regional grid. For instance, a buyer could rely on fossil generation from the local grid to serve its load, while at the same time procure unbundled RECs from the local grid.

[m] https://www1.nepoolgis.com/New England Supply Mix and Emissions

systems track renewable energy only. The European Union (EU) has established electricity source disclosure requirements for electricity sold to end-use consumers. Electricity suppliers are required to display on its invoice the contribution of each energy source to the overall fuel mix of the supplier and inform customers of the environmental impact. The EU has established a system to allocate electricity generation "attributes," such as fuel type and CO_2 emissions, to electricity suppliers and their customers.[n] More work is needed in the United States to make granular supply mix data for each grid, each LSE, and residual mix (unclaimed electricity on the grid) available to buyers.

1.3 Types of Emissions Factors

Current Scope 2 accounting attributes grid emissions to each user of electricity on the grid based on the average emission factor of all generators operating on the grid where the electricity is consumed (location-based method) or based on the contractually purchased energy by the buyer (market-based method). This accounting has several objectives, including measuring the emissions related to a buyer's electricity use and to assess a buyer's exposure to climate risks. The *Scope 2 Guidance* directs reporting entities to use "use the most appropriate, accurate, precise, and highest quality emission factors available for each method."[o] But too often emissions factors used in these calculations do not accurately reflect the relevant timing, location or the type of emissions factors related to a buyer's electricity use.[p]

Emissions factors can be measured over different geographic boundaries and time periods and be based on different methodologies, as shown in Appendix Figure 1.

The *Scope 2 Guidance* for market-based accounting includes a hierarchy of options for emissions factor based on anticipated precision: energy attribute certificates (higher precision), contracts including power purchase agreements, supplier/utility emission rates, residual mix, and other grid-average emission factors (lower precision).

Emissions factors also can be used to measure the carbon impact on the grid resulting from a buyer's actions or interventions. Typically, this type of analysis is based on locational marginal emissions rates (sometimes referred to as LMER or LME). Such emissions factors reflect the carbon intensity of the grid's marginal, or last resource dispatched, to meet a given level of demand at a certain time. These factors can be based on historical data or modeled forecasts and calculated over short or long time periods into the future. In some instances, different hourly average emissions factors are used as a proxy for marginal emissions factors.

Both average and marginal emissions factors provide useful information. Average emissions factors can be used to allocate emissions related to electricity use to individual buyers, while marginal emissions factors can help estimate the incremental change in emissions associated with a buyer's actions. These different types of factors are designed to answer different questions, and why both types of emissions factors are incorporated in information reported in the proposed Carbon Facts label. Besides determining the purpose, other considerations for selecting the appropriate emissions factors, include accuracy, accessibility, transparency, simplicity, consistency / standardization, scalability and cost. Some of the more common average emissions factors used for attributional Scope 2 accounting are described briefly below.

i. Total Output Average Emissions Factors

The total output average emissions rate (AER) is the total emissions divided by the total generation associated with all resources within a defined region and time period. Average emissions are calculated based on the electricity generation mix considering the tonnes of CO_2 emitted divided by the MWh generated. The average can be calculated by location (U.S., state, electric grid, sub-region, load zone) and time period (annual, season, month, hour, etc.). In the United States, units are usually expressed in lb/MWh for CO_2.[q]

[n] https://www.aib-net.org/certification/uses-certificates/fuel-mix-disclosure

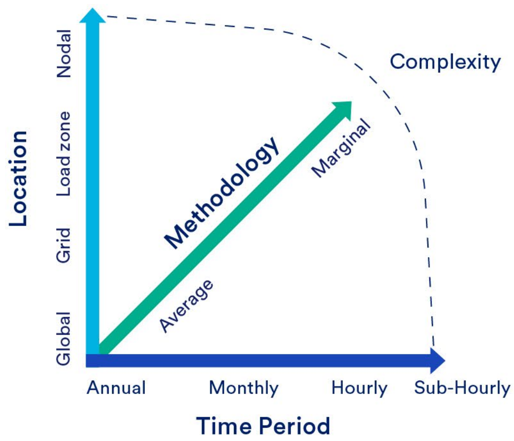
[o] *Scope 2 Guidance*, Section 6.5 Choose emission factors for each method, page 45.

[p] Unlike electricity supply obligations, EACs are not required to be tied to the timing and location of a buyer's electricity consumption. Also, system average grid emissions factors, whenever applied in either the location-based or market-based methods, generally do not recognize the attribute claims of other buyers.

[q] Approximately 2,204.62 pounds is equal to one metric tonne or 1,000 kg.

Appendix Figure 1: More Granular Carbon Accounting

Source: The NorthBridge Group



Types of Emissions Factors Include:

1. Average: Total
2. Average: Residual Mix
3. Average: Fossil or Non-Baseload
4. Marginal: Short-Term (historical / forecast)
5. Marginal: Long-Term (forecast based on econometric or simulation model)

Scope 2 location-based inventories rely on total output average annual emissions factors from broad geographic, if not national, regions and reflect the average annual carbon intensity of the regional grids on which energy consumption occurs (using mostly grid-average emission factor data), where all MWh are assigned the average emission factor of the grid to which the consuming asset is connected. Such average emissions factors are usually available from public entities, allowing companies to use common inputs in their calculations. In the United States, companies often use the average annual emissions factors reported in EPA's Emission & Generation Resource Integrated Database (eGrid).[r] These are subregional emissions factors corresponding to the weighted-average emission factor of all facilities supplying power to the grid in the subregion. These subregions were developed to minimize imports and exports, as shown in Appendix Figure 2. Average emission factors also could be based on all electricity production occurring in a defined grid distribution region that approximates a precise energy distribution and use area (e.g., RTO or balancing area).[s]

By design, the location-based method, which relies on average grid emissions factors, does not account for specific company purchases.[t] Applying a single generic emission factor across a multi-state region ignores the very significant policy differences between neighboring states and the ownership/control of zero-emission attributes. For example, customers in one state may have no claim to non-emitting generation in a nearby state even if the location-based emission rate applicable to

r U.S. Environmental Protection Agency's *Emissions & Generation Resource Integrated Database* (eGRID) is a globally recognized source of emissions data for the electric power generated in the United States (www.epa.gov/egrid). 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. https://www3.epa.gov/ttnchie1/conference/ei20/session3/adiem.pdf

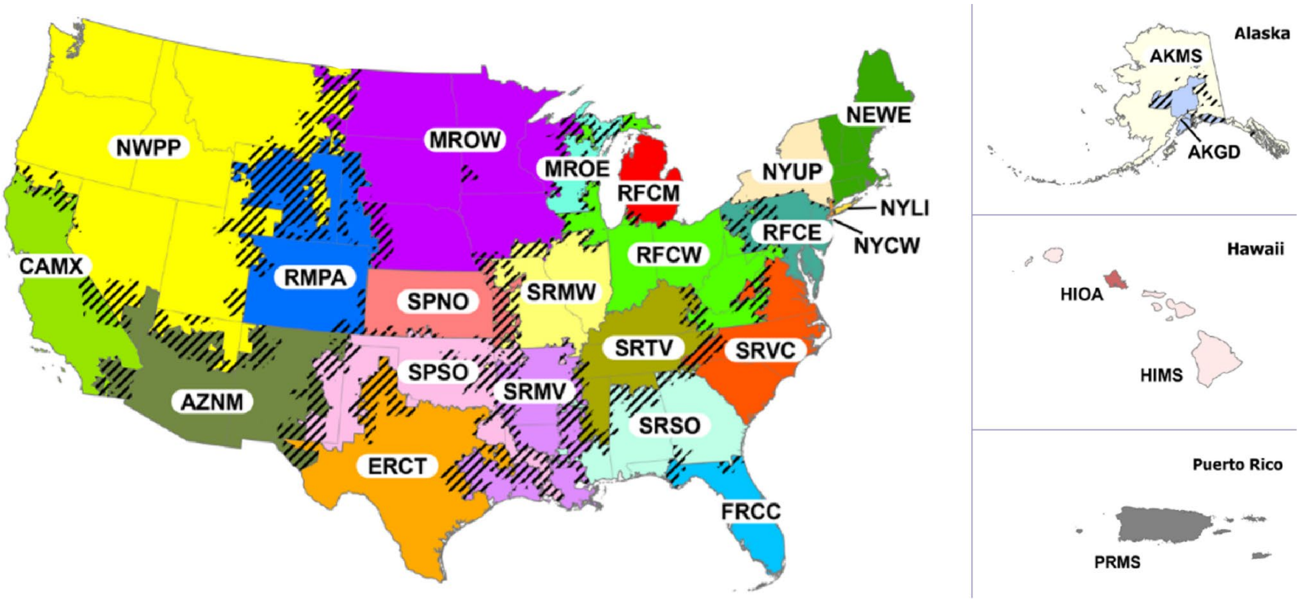
s Emission factors generally should reflect net physical energy imports/exports across the grid boundary, since imported energy may be used to serve consumption with a defined area.

t The location-based method also does not account for the purchases/claims of other buyers. Therefore, even if a buyer chooses not to procure electricity from specific generating resources, its market-based inventories are likely to be higher than the grid average, especially if other buyers within or outside the grid voluntarily purchase and retire clean energy attributes that are included in the grid average emissions factor.

u While coal generation has declined over the last decade in the United States, some states – WV, WY, MT, KY, UT – continue to rely heavily on coal generation. Meanwhile, CFE represents a large share of the energy mix in some states – VT, SD, WA, ME, ID, NH – that have significant hydro or nuclear generation coupled with renewable generation. https://www.nei.org/resources/statistics/state-electricity-generation-fuel-shares

Appendix Figure 2: Map of eGRID Subregions

Crosshatching indicates that an area falls within overlapping eGRID subregions due to the presence of multiple electric service providers.



both reflects that zero-emission power.[u]
Average emissions rates from the U.S. electricity sector generally have been declining over time as natural gas and renewable generation displace coal generation. As renewable and other carbon-free generation becomes a larger share of the U.S. energy mix in the future, average emissions rates can be expected to decrease further potentially widening the gap between grid average emissions rates and the emissions rates associated with fossil generation resources on the margin.[v]

The mix of generating resources varies across U.S. power markets. As a result, both average emissions rates and the opportunities to displace fossil generation on the margin vary dramatically by location – i.e., the carbon impact of adding incremental CFE to the grid will vary dramatically by location. Better granular location and time emissions factor data can inform decisions about where, when, and what type of CFE is most needed to achieve net-zero emissions goals.

ii. Residual Mix Emissions Factors

To prevent double counting of GHG emission rate claims tracked through contractual instruments, the Scope 2 market-based method requires an emission factor that characterizes the emission rate of untracked or unclaimed energy. Residual mix refers to the average emissions factor associated with untracked and unclaimed sources of electricity. 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.

> *The emissions from all untracked and unclaimed energy comprise a residual mix emission factor. Consumers who do not make specified purchases or who do not have access to supplier data should use the residual mix emission factor to calculate their market-based total.*[w]

[v] This trend of declining system average emissions rates is threatened by possible future retirements of nuclear facilities that potentially could get replaced partially by new, carbon-emitting natural gas generation. Today, nuclear energy accounts for nearly half of the carbon-free electricity generated in the United States.

[w] *Scope 2 Guidance*, page 27.

This emission factor creates a complete data set under the market-based method, and represents the regional emissions data that consumers should use if they operate in a market with choice for consumers, differentiated products, and supplier specific data, but did not purchase certificates or a specified product, do not have a contract with a specified source, or do not have supplier-specific information.[x]

Understanding the residual mix is important for several purposes. First, it can be used to more accurately estimate the emissions factors associated with grid supply (or unspecified system power) for Scope 2 market-based reporting. It also could be used to determine whether any unclaimed CFE exists on the local grid when matching CFE supply with customer load. Calculating the residual mix is challenging given that a buyer's "claims" can be made well after the time of generation and not all types of claims are currently tracked or reported in the United States. As a result, the *Scope 2 Guidance* instructs companies not to attempt to calculate their own residual mix and simply notes that depending on the region and percentage of tracked electricity, this residual mix may closely resemble a "grid average" data set or may be significantly different.[y]

In Google's February 2021 white paper, it recognized the double-counting problem when determining the amount of CFE on the grid in each hour.

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.*** *However, as clean electricity procurement by voluntary purchasers continues to scale, we are aiming to remove privately claimed clean electricity and include only unclaimed CFE for purposes of calculating Google's CFE Score (what is also known as the "residual mix").*

Today, the data to do this is not available, but we hope to work with industry partners to create these capabilities. There are challenges measuring the residual mix due to the lack of centralized accounting that properly incorporates hourly energy certificate data flows and inter-grid electricity trading. *While there have been some efforts to calculate residual mix, such as Green-e in the US, these calculations are lagging by several years; they also lack specific data on grid mix and are only presented on an annual basis. The AIB in Europe has recently refined their methodology to properly incorporate import and export flows for reporting the residual mix data for European countries, but similarly, they only present the data on an annual basis. Properly calculating hourly residual mix will be dependent on time-based tracking (highlighted in the previous section) and will require a centralized effort to aggregate the energy certificate flows for each grid.*[z]

As Google notes, some have tried to address the residual mix calculation to some extent, but more work is needed. Green-e adopts the residual mix concept but the data lags are long, does not include all clean energy attributes, and is only available on an annual basis.[aa] In addition, EEI, in collaboration with member companies, corporate customers, and the World Resources Institute, developed a carbon emissions and electricity mix reporting template to collect timely and consistent carbon dioxide intensity rates accounting for RECs for delivered electricity by operating company data and to provide that information to customers in one central location.[bb] The database provides the annual carbon emissions intensity rates (lb CO_2/MWh) for the utility average and utility specific residual mix (accounting for RECs). Customers who purchase the standard utility product from their electric provider can use the provided utility specific residual mix carbon intensity rates to calculate their Scope 2 emissions for market-based reporting. This information is not yet

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[x] *Scope 2 Guidance*, page 52.

[y] *Scope 2 Guidance*, page 56.

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

[aa] The "Green-e® residual mix emissions rate" is calculated by first subtracting all unique Green-e® Energy certified sales in MWh from the total generation within each eGrid subregion. The total CO_2 emissions for each region are then divided by this new generation number for each subregion, resulting in an adjusted emissions rate (lb CO_2/MWh) for each subregion. Green-e® residual mix emissions rates are published every Spring using Green-e® voluntary renewable energy market sales data collected during the annual Green-e® verification audit from two calendar years prior and the most recent U.S. generation and emissions rate at the time of publication. It does not include any data that is not reported to Green-e and does not include all carbon-free resources. https://www.green-e.org/residual-mix

[bb] EEI Utility CO_2 Emission Factor Database

reported for all utility service areas and only available on an annual basis. And in many cases, where distribution utilities no longer own generation, the grid intensity of supply purchases made on behalf of default service customers is not currently obtained by utility buyers.[cc]

In the European Union, Fuel Mix Disclosure regulations require all suppliers to disclose to customers the fuel mix and emissions associated with the power that they supply to customers. All energy has a direct emissions factor associated with generation. In the United Kingdom, the Department for Energy and Climate Change (DECC) then removes all claimed generation from the overall average, which leads to the creation of a "residual" energy mix with an associated emissions factor. This is issued to all suppliers so that they can complete their calculations for any of their supply without certificates or contracts. This combination of verified supplier claims and allocation of the remaining emissions back to suppliers ensures consistency across suppliers and accounting for all generation emissions. This information is available on an annual basis, but not yet available hourly.[dd]

If a residual mix emissions factor is not available, the current *Scope 2 Guidance* explains that "[o]ther unadjusted grid average emission factors such as those used in the location-based method may be used." [ee] Using unadjusted grid average emissions factors, however, by definition, largely ignores the claims of other buyers of clean energy and/or the associated attributes, both within and outside the market area. More needs to be done to respect the environmental attribute "property rights" of those who own and/or pay for these clean energy attributes to prevent double counting both on an annual, and eventually, hourly basis. Most existing energy attribute certificates, such as RECs, are typically issued monthly, and only track electricity from renewable sources, and do not provide information about when a MWh of electricity was produced. Generation tracking systems should expand to track all forms of generation by time and location and provide information about carbon emissions. Granular time-based certificates can help support and verify claims about clean energy use and can encourage the development of carbon-free technologies in hours when it is most needed. Removing claimed clean energy from the grid supply would result in hourly residual grid mix data that would allow organizations to both avoid double counting and obtain a more accurate accounting of their emissions.[ff]

Absent a calculation of residual mix emissions factors, the *Scope 2 Guidance's* market-based method could be updated to instruct buyers to use emissions factors that better reflect emissions from unclaimed resources. For example, in restructured states, buyers could rely on the EPA's published emissions factors for "fossil" or "non-baseload" generation (described below), excluding from the denominator any output from CFE resources which sell their attributes separately. At the same time, RECs, emission free energy credits (EFECs) and any other clean energy attributes in the regional grid that are retired on the customer's behalf could be used by each customer to reduce their reported Scope 2 inventories. In vertically integrated jurisdictions, the supplying utility could calculate the Scope 2 inventories based on actual generation to serve load, and customers could use those emissions as the starting point for Scope 2 purposes, adjusted for any RECs or other attributes that are retired on their behalf. Under this approach, the "property rights" of all clean energy attributes would be respected, and there would be no double counting or double paying of clean energy attributes.

iii. Fossil Fuel Output Emissions Factors

eGRID fossil fuel output emission rates are calculated based on plants whose primary fuel is coal, oil, gas, or other fossil fuel. EPA's published emissions factors for fossil fuel output include the fossil fuel emissions in the numerator but unlike the system average emissions factor, it excludes from the denominator any output from CFE resources. These fossil fuel emission rates are currently available on an annual basis for all eGrid data years and have been used to estimate avoided emissions from resources that would displace grid supplied electricity, especially before the non-baseload emission rates were developed for eGrid.

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cc Utility supply procurement to serve default service customers is typically evaluated based solely on price for a pre-defined product and does not usually consider the carbon intensity of the supply.

dd https://www.aib-net.org/certification/uses-certificates/fuel-mix-disclosure

ee *Scope 2 Guidance*, page 56.

ff EnergyTag discusses some of the challenges for calculating residual mix on an hourly basis but plans to address this issue in future working group meetings. (EnergyTag, *Granular Certificates Use Case Guidelines*, pages 24-25).

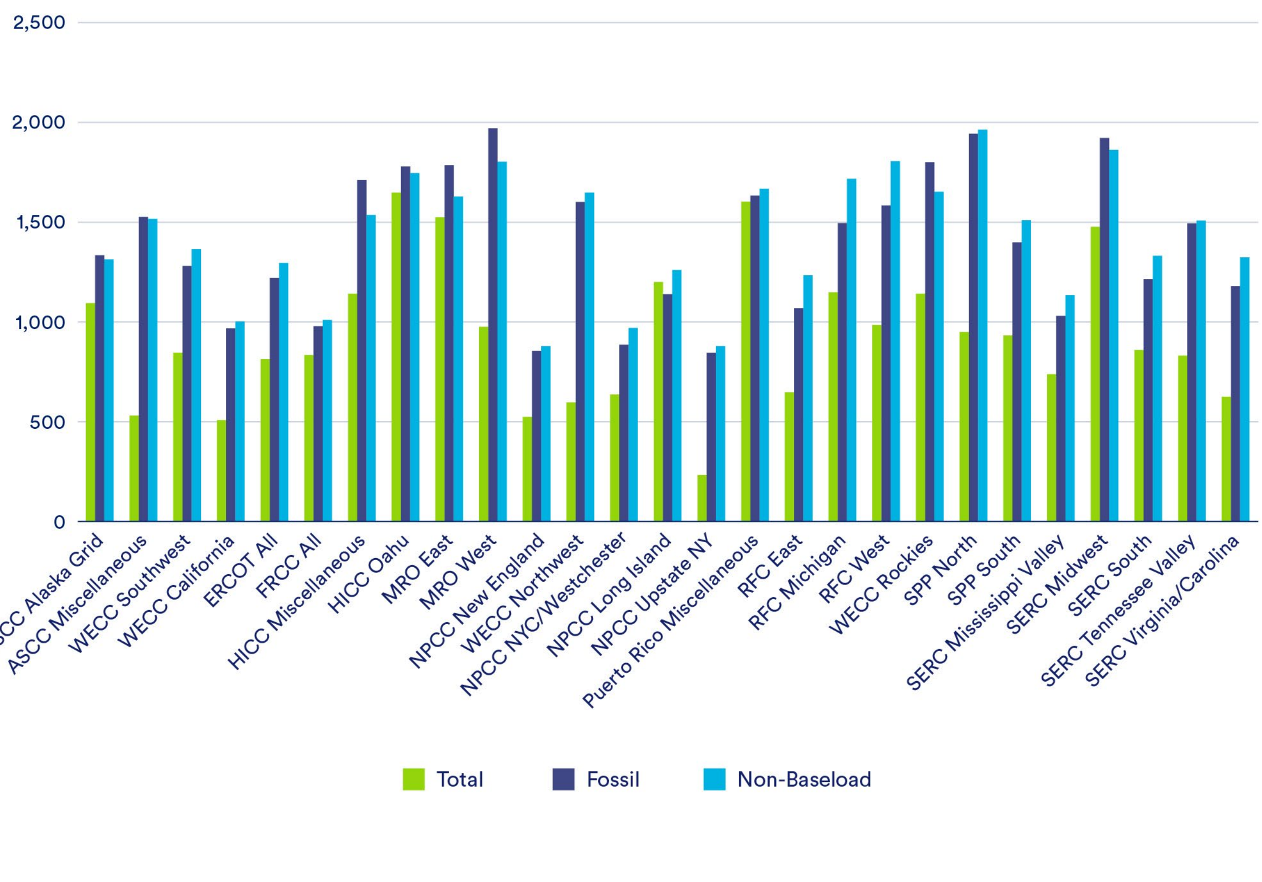
iv. Non-Baseload Emissions Factors

eGRID also reports emissions factors for non-baseload generation. Baseload plants are typically called upon to provide electricity to the grid no matter what the demand for electricity and generally operate except when undergoing routine or unscheduled maintenance. This emissions rate is the sum of the non-baseload emissions divided by the sum of non-baseload net generation. The non-baseload emissions factor removes from the denominator non-dispatchable resources (e.g., wind and solar) and generating resources with high-capacity factors (80% or higher). These emission rates were developed to provide an estimate of emission reduction benefits from energy efficiency and clean energy projects. These values became available in 2004 and represent an annual approximation of the weighted average emission intensity of the generators on the margin by eGrid subregion or state.[gg]

Both the fossil or non-baseload emissions factors are higher than the total output average emissions rate. Either could be selected by the EPA or other guidelines to be used as the default emissions factor to be applied when a buyer (or supplier) cannot specify a carbon-free or other contracted supply source. This would discourage suppliers from relying on unspecified supply sources (which are most likely to include non-CFE generation) or selling the output from known high emission resources into centralized power markets and "replacing" it with supply in real-time markets with

Appendix Figure 3: eGrid Average Emissions Rates (2020)

(lbs / MWh)



gg https://www.epa.gov/sites/default/files/2018-07/documents/mbg_2-4_emissionshealthbenefits.pdf unspecified system power at lower average emissions factors. Appendix Figure 3 shows the eGrid annual average emissions factors by subregion for total, fossil, and non-baseload output.

As expected, the fossil and non-baseload emissions factors tend to be higher and more similar than the total output emissions factors. Relying on existing eGrid fossil or non-baseload emission factors as the default rate for unspecified grid supply (when residual mix or better information is not available) would significantly reduce the likelihood of clean energy attributes being double-counted. It would also provide an incentive for buyers to request and suppliers to provide information about the sources of their supply and the associated emissions factors needed for better market-based accounting disclosures.

Wherever possible, emissions factors that are specific to the generation unit (e.g., a coal plant at a specific location) or a supplier's particular supply mix should be used for market-based reporting. More generic average emissions factors (e.g., fossil, non-baseload or residual mix), whether by year or by hour, should only be applied to unspecified supply sources. And they should be applied using a standardized methodology with widely accepted emissions factors by region (ideally determined by a centralized government body or regional organization) to facilitate comparisons and ease reporting.

v. Marginal Emission Factors (not used for attributional Scope 2 accounting)

Marginal emissions factors are frequently used when quantifying avoided emissions resulting from a buyer's actions. These emissions factors are discussed in more detail later in the avoided emissions section of this appendix.

1.4 Annual versus Hourly Emissions Factors

Average annual emissions factors over broad geographic areas are typically used in GHG reporting, even though emissions factors can vary significantly by season, time of day, and location (and often within a regional grid). Calculating emissions using hourly loads and hourly emissions factors within each regional grid would be an improvement from current practice.[hh] The formula for calculating emissions from each facility's load when hourly load data is available is shown below:

$$\sum_{facility=1}^{i} \sum_{hour\ t=1}^{8760} (MWh\ load_{i,t} * EF_{i,t})$$

There is an important difference, mathematically, between simply multiplying annual load by an annual average emission factor (2 numbers) versus multiplying hourly loads by hourly emissions factors (2 × 8,760 numbers). The latter provides a more accurate picture of overall emissions levels associated with electricity use and provides more information to buyers about when best to consume electricity from a carbon perspective. In the United States, the Energy Information Administration (EIA) has launched an Hourly Electric Grid Monitor that provides generation data at an hourly resolution.[ii] EIA also estimates hourly CO_2 emissions from all electric-generating units in the Lower 48 states that are both metered by balancing authorities and used to serve required demand.[jj] For example, Appendix Figure 4 shows the hourly CO_2 emissions intensity for the period March 27 through April 9, 2022.

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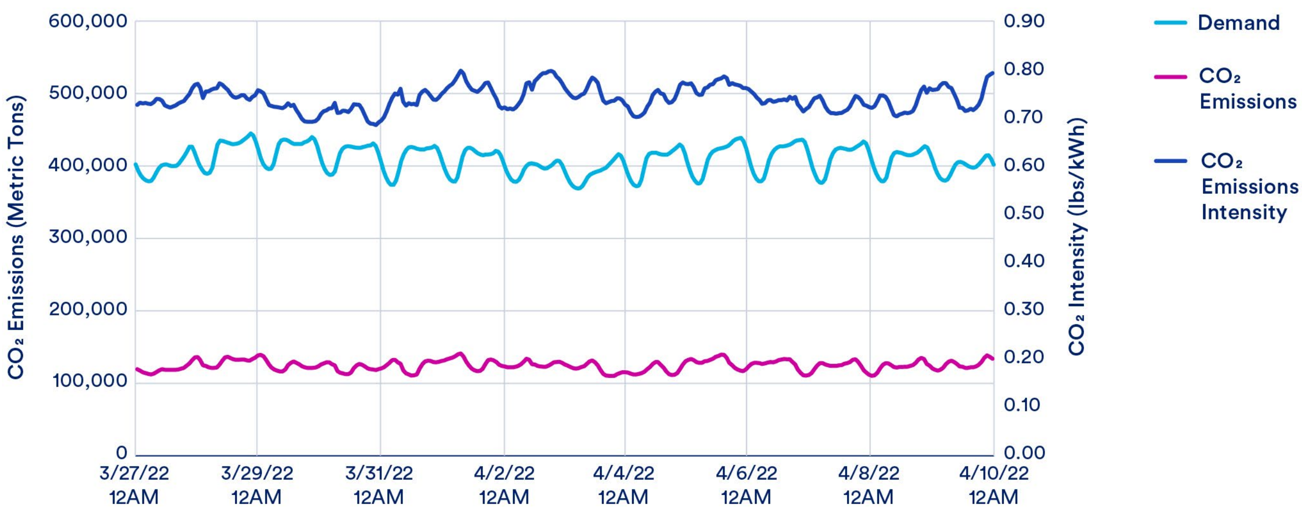
hh More granular time and location emissions factors could improve the accuracy of emissions calculations – whether using average grid emissions factors for location-based accounting, applying the hierarchy of emissions factors for market-based accounting, and marginal emissions factors (or fossil / non-baseload emissions factors) to establish the carbon baseline or calculate avoided emissions.

ii Form EIA-930 data collection provides a centralized and comprehensive source for hourly operating data about the high-voltage bulk electric power grid in the Lower 48 states. EIA collects the data from the electricity balancing authorities that operate the grid. https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48

jj https://www.eia.gov/electricity/gridmonitor/about/

Appendix Figure 4: Hourly CO_2 Emissions Intensity

Source: U.S. Energy Information Administration, Form EIA-930, 'Hourly and Daily Balancing Authority Operations Report'



This data is provided by balancing authorities or transmission operators, which can be prone to gaps and errors. Regional grid operators and/or balancing authorities track generation data on an hourly (and sub-hourly) basis, but better reporting of this hourly generation data and the associated emissions is needed, preferably in a standardized format, that can enable more accurate buyer emissions accounting and reporting.

1.5 Confidentiality of Competitively Sensitive Customer and Supplier Data

Some of the data required to calculate the metrics in the Carbon Facts label requires hourly customer load and supplier generation data that may be viewed as confidential or competitively sensitive. Care is needed to protect this confidential information when developing summary metrics for disclosure. Customer load or supplier information could be tracked by a third party (as needed) on an hourly basis to verify CFE claims, but aggregated annual percentages could be reported for CFE matching and supply sources to protect sensitive customer and supplier information.

More granular load, generation, and emissions factor data are necessary ingredients to enable more accurate supplier and buyer CFE matching and emissions disclosures. Access to granular data in standardized formats would greatly help efforts to better measure progress toward achieving buyer goals related to electricity procurement and evaluating the carbon impact of a buyer's electricity procurement actions.

Matching Carbon-Free Electricity Supply with Buyer Consumption

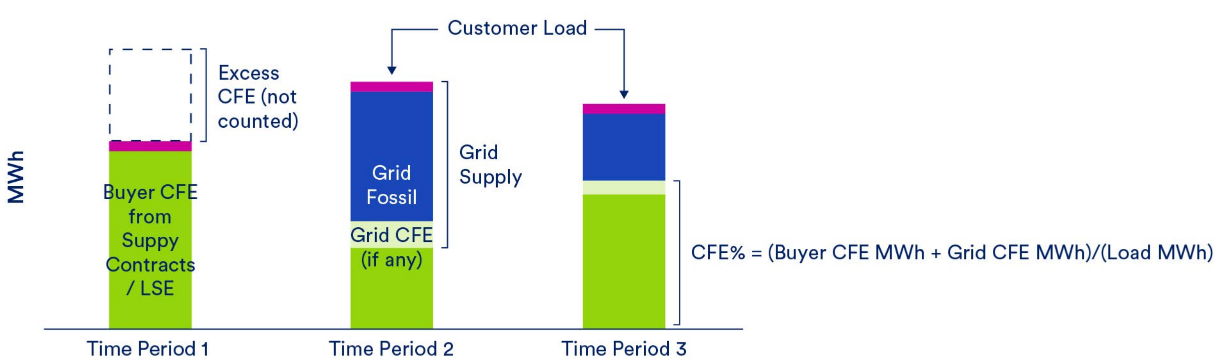
2.1 Overview

Matching CFE supply with buyer consumption can be done over different time intervals, different geographic boundaries, and include different types of carbon-free resources.[kk] Today, RE100 requirements for U.S. facilities are based on annual matching of RECs within the United States and Canada, including only renewable energy resources. The modified Scope 2 market-based approach outlined in this paper would rely on hourly matching (ideally) of all forms of clean energy attributes within the same regional grid (or more granular area considering transmission congestion), such that the CFE in any hour cannot exceed the customer's load in that hour. The CFE percentage in each time period is the percentage of the buyer's load that is served by CFE within that geographic location.

Measurement time periods (e.g., annual, season, month, week, hour) and locations (regional grid, subregion, load zone, etc.) could become more granular as data becomes available and progress is made toward matching CFE supply with buyer load. A higher CFE % can be accomplished by increasing a buyer's CFE in its supply mix, storing excess CFE for use in another hour when needed, managing buyer's load (energy efficiency, load shifting, siting/expansion/contraction decisions, etc.), as well as by non-buyer improvements in reducing CO_2 emissions associated with regional grid supply. Independent of the measurement period, the CFE % can be expressed over a year as the sum of CFE across all time intervals (e.g., hours) divided by the total annual load. As discussed later, "Grid CFE" included in this calculation should include only unclaimed residual mix CFE (if any) and allocated CFE that the buyer has already paid for in its utility rates (and is not already included in LSE supply).

The remainder of this section describes several different approaches to matching supply and load and then several methodological issues that shape the way matching is done.

Appendix Figure 5: CFE % of Total Load



[kk] To be clear, when discussing matching CFE supply (and the associated clean EACs) with buyer consumption, this is being considered in a contractual or financial sense, similar to the way electricity commodity full requirements service is provided, not physically tracing the electrons from a generation resource to a buyer's load.

2.2 Different CFE Matching Approaches

i. Minimum % in Every Hour versus Average Across All Hours

Exec. Order 14057 (E.O. 14057), 86 Fed. Reg. 236, *Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability* (Dec. 8, 2021) establishes the goal to achieve a carbon pollution-free electricity sector by 2035. That is, to match 100% of consumption on the grid with CFE supply (including storage discharge) in every hour of the year in all locations. The accounting / goal-setting issue is how to measure and report matching CFE supply with consumption at levels below 100%. For example, E.O. 14057 establishes a 50% 24/7 carbon pollution-free electricity goal by 2030. The E.O. defines 24/7 matching of CFE supply with actual electricity consumption on an hourly basis (not over an annual period) and requires that CFE be produced within the same regional grid where the energy is consumed. However, when consumption matching goals are set below the 100% level (e.g., the E.O. 50% CFE interim goal by 2030), they can be interpreted and measured differently.[ll]

One interpretation of the matching requirement is that at least 50% of the load must be matched with CFE supply *in every hour* of the year by 2030 (Hourly Minimum CFE Percentage). Another interpretation of the requirement is that at least 50% of the load must be matched with CFE supply *averaged over all the hours* in the year (Annual Average CFE Percentage), where CFE could be 0% in one hour and up to 100% in another hour. The Hourly Minimum CFE Percentage approach is more stringent and more likely to require the use of firm dispatchable carbon-free resources. Establishing a goal that requires matching 50% of the load with CFE supply in every hour of the year by 2030 also is consistent with the end-state objective in E.O. 14057 to achieve 100% matching in every hour by 2035, i.e., full decarbonization of the electric grid. However, because it may be more difficult to achieve, some buyers may choose to target a more flexible matching requirement that allows CFE resources to represent 0% of consumption in some hours.

The Carbon Facts label presented in this paper requests buyers to disclose both metrics – "Hourly Minimum CFE % (0-100%)" and "Annual Average CFE % (average across all hours)." These can be calculated and reported together regardless of which matching strategy a buyer pursues. This would allow evaluators to recognize the more stringent matching approach – providing a minimum carbon-free amount in each hour – as well as determine the extent to which CFE supply matched hourly consumption on average over all hours of the year.[mm]

ii. Time Interval for CFE Matching

Not all buyers may be able to establish a goal to match 100% of their consumption on an hourly basis (24/7). Therefore, accounting and reporting standards could allow buyers to disclose "less stringent" time matching intervals – e.g., annual, seasonal, monthly, etc. Similar accounting and verification methodologies could apply, where CFE supply could not exceed consumption during the specified time interval. Evaluators could recognize tiers of leadership as buyers move from annual matching to more granular time intervals with higher levels of technical difficulty. As more and more companies make commitments regarding their relative use of renewable and other carbon-free clean energy sources, and as more and more investors and companies recognize the significantly different emissions impacts that result from hourly compared to annual matching methodologies, it is important that a buyer disclose the time interval over which the buyer is matching its clean energy purchases to electricity consumption.

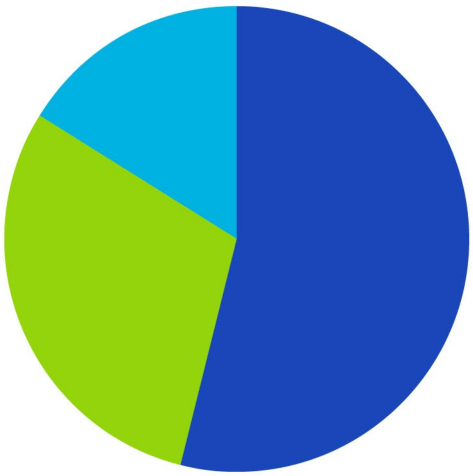
2.3 Integration with RPS, State-Supported CFE, and Other Ratepayer Funded CFE

State RPS policies vary by state with different targets, different resources eligible to meet requirements, and other features. In some states, the LSE (e.g., competitive suppliers and utilities) must procure clean energy certificates (usually specific types of renewable energy) for the load it serves. In other states, a central agency or the utility may obtain RECs or other clean EACs on behalf of all customers in the utility service area(s). In regulated states with vertically integrated utilities, ratepayers may fund the capital and ongoing costs of CFE generation assets.

ll The White House Council on Environmental Quality has not yet adopted implementing instructions clarifying how the 50% hourly consumption matching requirement should be met at the time of this publication.

mm Also, when comparing and evaluating these metrics across buyers, it is important to note that in either approach, what is considered a "good" matching percentage may vary by region, considering the existing CFE resources available in that region.

Appendix Figure 6: CFE / EAC Procurement Methods (Illustrative)



As both mandatory[nn] and voluntary clean energy procurement purchases/programs grow, attributes are expanded to include other carbon-free resources beyond renewable resources, and buyer CFE matching claims become more ambitious, it becomes increasingly important to track and verify all forms of clean energy. CFE supply and/or associated EACs can be procured in either voluntary or mandatory /compliance markets.

Mandatory CFE (if any) can be included in LSE charges or could be included in non-bypassable utility-related charges (e.g., distribution rates) that a customer cannot avoid paying regardless of the supplier selected by the buyer. An example of this later charge would be mandated CFE that a buyer pays for in its utility rates, such as RPS generation procured by the state or state-supported CFE generation (nuclear), that is not supplied by an LSE and not included in LSE charges. RPS generation (and/or RECs) provided by an LSE should be included in the LSE's supply mix (emissions factors). Similarly, ratepayer funded CFE supplied by vertically-integrated utilities could be allocated to customers within the service area on a pro-rata load basis and included in the utility's supply mix (emissions factors) used to serve customer load.

More work needs to be done to allocate CFE properly to support both annual and hourly matching claims, while adhering to three guiding principles:

1. No "double counting" of clean energy attribute certificates,
2. No "double paying" by customers for clean energy, and
3. No cost-shifting among customer groups within service areas or within states.

CFE accounting needs to maintain the integrity of existing regulatory programs promoting the deployment of CFE resources. No double counting means that no certificate should be double issued, duplicated during transfer, double registered, double cancelled, or used more than once. At the same time, it is important that customers should not be required to "double-pay" for clean energy attributes. For instance, as an extreme case, if a customer already pays for a 100% clean or

nn Most jurisdictions with a current or recently updated RPS have set targets of at least 40%. However, recent RPS legislation has seen a push toward 100% clean or renewable energy requirements. To date, 10 states, Washington, D.C., Puerto Rico, and Guam have set 100% clean or renewable portfolio requirements with deadlines ranging between 2030 and 2050. https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

RPS requirement (as many states have targeted for future years), regardless of how it is funded or why such a requirement exists, is it reasonable to require that customer to separately buy additional clean energy attributes representing another 100% of their consumption to satisfy either recognition programs, ESG ratings, or other reporting requirements? Companies should be able to use certificates conveyed to them by their supplier, separately from the other CFE supply that they pay for in their utility rates. This would ensure equivalent treatment of clean EACs regardless of how they are sourced.[oo] In other words, buyers should get to count the EACs they "pay for," including all EACs that they purchase (and retire) directly and/or are retired on a customer's behalf.[pp] This also would better align the interests of buyers and local utilities seeking to decarbonize the electric grid. If buyers cannot "count" efforts to decarbonize their local grid, they will have less interest in these efforts. Similarly, the allocation of EACs should avoid cost shifting and respect the environmental attribute "property rights" of those who own and/or pay for these clean energy attributes. Likewise, buyers should not be able to claim "what they do not pay for." The following example highlights the importance of these three guiding principles.

Consider a buyer with 100 MWh of annual load who already pays for 60 MWh of annual clean energy attributes in its local utility rates regardless of the buyer's choice of electricity supply.[qq] The buyer needs to procure 100 MWh of supply to meet its annual consumption, but further work is required to more clearly define how the 60 MWh of CFE attributes that already has been "purchased" for the benefit of the buyer will be counted toward achieving a 100% annual CFE match goal or an hourly time-match goal.[rr] One assumes that the intent is to procure additional clean energy attributes "on top" of existing mandatory compliance markets (i.e., 40 MWh of clean energy attributes, and not another 100 MWh) to satisfy an annual 100% CFE match requirement. Similarly, one assumes the intent is to procure an additional X MWh of hourly time-matching "on top" the 60 MWh to achieve a 100% hourly CFE match goal. This hourly matching, however, requires that the existing 60 MWh of clean energy attributes that the buyer has already paid for on an annual basis (and will continue to pay for in the future) can be allocated to hours within the year. Tracking granular certificates associated with carbon-free electricity could facilitate hourly consumption matching to ensure there is no double-counting of certificates (i.e., no certificate can be used more than once). At the same time, customers should not be required to "double-pay" for clean energy (i.e., the customer in this example should not have to buy more than 40 MWh of clean energy if it is already paying for 60 MWh). A clean energy certificate could be used to satisfy an RPS requirement and satisfy an annual CFE100 or hourly match claim without double counting (i.e., the 60 MWh could be counted once while supporting multiple purposes – annual CFE100, RPS, hourly time match). Ideally, mandatory EACs should be allocated by the utility service area and reflect the requirements, if any, of the state or the non-discretionary supply mix of ratepayer-funded assets of a vertically integrated utility. Meanwhile, a customer should not be able to claim an EAC unless it can demonstrate that it paid for and either retired the EAC, the EAC was retired by another party on the customer's behalf, or no other buyer can use the EAC.

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oo Similarly, CRS explains that customers also can claim to be consuming renewable energy that they do not actively procure under certain circumstances. Standard Delivery Renewable Energy (SDRE) is defined as delivered energy as a result of an LSE's own renewable energy or carbon targets, a state government's renewable or clean energy standard, or circumstances where renewables are a cost-effective resource. In contrast to active procurement, SDRE is provided to all customers often to comply with a government mandate. Therefore, 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. There are a variety of data sources and methods for determining SDRE (e.g., documentation of LSE or state-wide compliance with regulatory mandates to supply a percentage of retail sales with renewable resources) but caution is required to avoid double counting of clean resources. (CRS, Standard Delivery Renewable Energy, CEAP).

pp For instance, if a buyer pays for EACs in either utility charges or LSE supply charges, and these EACs are retired on behalf of the customer load (or not able to be used by any other buyer), then the buyer should be able to include these energy attributes in its market-based inventory accounting.

qq This could be due to LSE RPS requirements, state-supported nuclear generation, state-procured RPS, and/or ratepayer funded generation from a vertically integrated utility.

rr This is also important for measuring carbon emissions associated with electricity use and carbon matching goals discussed later.

2.4 Granular Certificates

It is not possible in most cases to physically trace the source of generation on the electric grid used to serve a buyer's load. EACs are currently used to make reliable attributional claims without the risk of double counting. Today, these attributes are based on annual or monthly matching and do not record the time of production. But this allows solar from the summer to be claimed against consumption at night in the winter. Current EACs are priced the same regardless of the time of day. Adding a time-stamp to EACs has many potential benefits. First, it improves confidence in green claims by linking time of production to consumption. Second, it supports new carbon accounting methodologies (whether hourly matching for market-based Scope 2 reporting or maximizing avoided emissions), and third, it harnesses consumer demand for clean energy to send a price signal that drives investment in technologies needed to reach a carbon-free grid. EnergyTag, an independent, non-profit, industry-led initiative has established standards and guidelines to define and build a market for granular energy certificates (GCs).[ss] These GCs can play an important role in GHG accounting and reporting, as well as support the development of markets to trade time- and location-stamped clean energy attributes, which would enable buyers to meet their next generation electricity procurement goals more readily.

2.5 Geographic Market Boundary for Consumption Claims

The geographic market boundary defines the area from which certificates can be purchased and claimed for a buyer's Scope 2 accounting and reporting. The market for purchasing and selling electricity is typically a regional transmission organization (RTO), power pool, or balancing area, with exports and imports often broadening these markets. RECs were created in the late 1990s and by design separated the clean environmental attributes from the underlying electricity, disconnecting RECs from the physical deliverability of power to a purchaser. This framework promoted the development of renewable energy resources in the most economically viable locations – effectively encouraging buyers to minimize the dollars spent per renewable energy generated in MWh, regardless of location.[tt] As a result, Scope 2 market-based accounting allows buyers to rely on fossil generation from their regional grid while purchasing clean energy certificates far from their location of consumption. This can lead to criticisms that Scope 2 market-based accounting method does not accurately measure the emissions impact and carbon-related environmental risks associated with a buyer's electricity use, nor will it encourage the development of carbon-free electricity to be always available at all locations on the electric grid. As net-zero objectives are adopted to decarbonize electric grids and more organizations seek to better understand the carbon footprint associated with their electricity use, "re-connecting" clean energy generation with system (and buyer) consumption becomes necessary both in terms of timing and location. More granular geographic market boundaries are needed to better measure emissions and carbon-related environmental risks associated with electricity use. Therefore, applying a regional grid boundary to Scope 2 market-based accounting would represent a significant improvement in measuring emissions resulting from a buyer's electricity use.[uu]

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[vv] or ISOs[ww] (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

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ss *EnergyTag – Standard and Guidelines Launch*, March 31, 2022.

tt *Scope 2 Guidance*, page 64.

uu It is also valuable to consider market areas (or load/bidding zones) within regional grids considering transmission constraints. In the United States, bidding zones are analogous to market zones where the locational marginal price is the same (e.g., NYISO-Zone D in NYISO) within a regional grid. The link between clean energy attributes and physical energy deliverability increases as the definition of geographic market boundary becomes narrower. But as geographic granularity increases, issues may arise over the liquidity of clean energy attribute markets in these sub-areas.

vv 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.

ww 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.

and roughly two-thirds of total U.S. annual electricity demand. Each regional grid establishes its own rules and market structures, but there are many similarities. If no such structure exists, then the electricity balancing authority can be used.[xx, yy]

2.6 Verification and Audit Procedures for Consumption Claims

Verification and auditing of consumption matching claims should be done as an ex-post process based on *actual* load and *actual* CFE supply (and/or clean EACs). While supplier offers may be based on forecasted load and CFE supply, compliance should be tracked and verified using actual hourly consumption and actual hourly CFE supply. A buyer should be transparent about the time matching claim by communicating the time interval period (e.g., annual, month, hour, etc.), the geographical matching area, the proportion of consumption that has been matched in the report period, whether a minimum percentage of consumption was matched in each hour, and so forth.

Electricity markets in the United States and Canada are served by a variety of geographically-defined tracking systems. These systems were developed primarily to meet the needs of state-level renewable energy programs, and to facilitate electricity supply disclosure information (proof of sources of power) for LSEs in centralized (mostly competitive) electricity markets. They also serve voluntary renewable energy market participants. Most of these systems were developed by governmental or quasi-governmental agencies interested in using the systems for regulatory compliance. North American tracking systems can be either all-generation certificate tracking systems (NEPOOL GIS and PJM-GATS) or systems that track only renewable generation (the rest).

There is considerable diversity in the geographic scope, technology coverage and generation attributes recorded by today's tracking systems shown in Appendix Figure 7, though data transparency supports some degree of interregional tracking.

Systems used to track state and federal credits and demonstrate compliance need to be well structured to ensure environmental integrity. While systems vary in their geographic scope and types of generation covered, each system generally creates a serial-numbered, electronic certificate for those MWh generated and exchanged with neighboring regions that are included in the system. It records the environmental attributes and the certificate's eligibility to qualify for state RPS or CES programs. Retail electric suppliers may trade ownership and comply with state program requirements by demonstrating ownership. Currently, neither location and/or time matching with customer load is required to claim use of renewable clean energy attributes. The renewable energy claimed by voluntary purchasers cannot also be counted toward a state RPS program.

Generators generally produce certificates directly through an established registry account. RECs can be conveyed directly by contract. If reported to a registry, a certificate is issued. In some markets, a third party may also certify certificates based on an established standard that specifies what energy can produce certificates, an audit procedure to verify retail transactions, and other consumer protection features (e.g., voluntary certification programs include Green-e in North America). Certificates can be combined (or "bundled") with a contract for energy or may be sold separately. Certificates may be traded several times between the initial buyer and suppliers, or through open exchanges. For most certificates, the final purchaser or claimant will be an energy supplier or utility, or an end-use customer.

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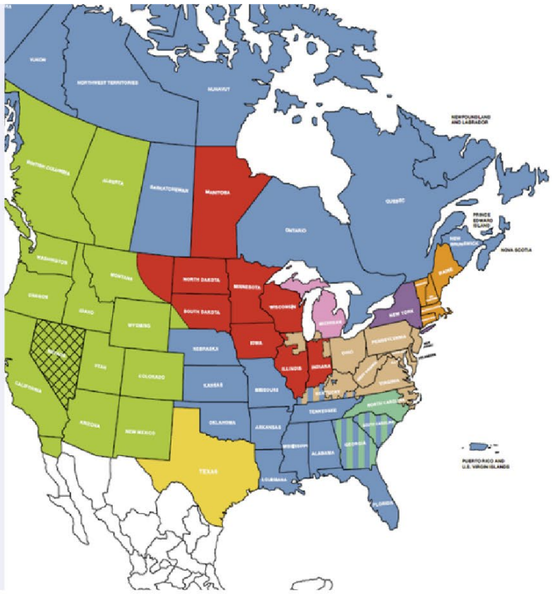
xx Balancing authorities are a functional role defined by the North American Electric Reliability Corporation (NERC) and are primarily responsible for balancing electricity supply, demand, and interchange on their electric systems in real time. This balance is needed to maintain the safe and reliable operation of the power system and includes managing transfers of electricity with other balancing authorities. https://www.eia.gov/todayinenergy/detail.php?id=27152

yy Regional grids and balancing authorities often exchange electricity with each other and imported generation could be the source of a buyer's emissions. Therefore, the regional grid supply mix and emissions factors should consider imports and exports taking into account power flows from neighboring grids. At a more aggregated level, local electricity grids are interconnected to form larger networks for reliability and commercial purposes. The United States power system in the Lower 48 states is made up of three main interconnections, which operate largely independently from each other with limited transfers of power between them. The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada. The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico. The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority. These interconnections help maintain the reliability of the power system. The actual operation of the electric system, however, is managed by balancing authorities.

Appendix Figure 7:

- 10 separate tracking systems
- 10 U.S. states without formally adopted systems
- 6 systems focused exclusively on renewables



- **ERCOT:** Electric Reliability Council of Texas
- **MIRECS:** Michigan Renewable Energy Certification System
- **M-RETS:** The Midwest Renewable Energy Tracking System
- **NAR:** North American Renewables
- **NC-RETS:** North Carolina Renewable Energy Tracking System
- **NEPOOL-GIS:** New England Power Pool Generation Information System
- **NVTREC:** Nevada Tracks Renewable Energy
- **NYGATS:** New York Generation Attribute Tracking System (in development)
- **PJM-GATS:** PJM's Generation Attribute Tracking System
- **WREGIS:** WECC's Western Renewables Energy Generation Information System

If a certificate serves a regulatory purpose, the claimant (usually an electricity supplier) will submit and retire the certificate to regulatory authorities to substantiate delivery of specified electricity to its customers as required by law. If the certificate serves a voluntary consumer claims purpose, the claimant will retire the certificate to facilitate a claim on behalf of its consumers (if a supplier) or itself (if a buyer).[zz]

While tracking systems have developed independently of each other in different jurisdictions, there are a few elements that all credible tracking systems have in common. Tracking systems have standardized certificate information. Certificates are issued to all qualified generation from registered generators, and no energy attribute certificates from registered generators are traded outside of the tracking system, to avoid potential double counting. To prevent double registration and issuance of certificates, tracking systems must be clear on the geographic boundaries within which generators have access to the tracking system, and ensure, through cooperation with other tracking systems, that generation facilities register in only one tracking system for certificate issuance. Independence and transparency of tracking systems help to maintain the integrity of the attribute market.[aaa]

Similar to existing REC tracking and verification systems, independent consumption verification bodies (either granular certificate issuers or auditors) are likely to review the consumption data and canceled time-stamped granular certificates to ensure the time matching claims of buyers in the future.

[zz] *Scope 2 Guidance*, Section 10.2.

[aaa] https://www.there100.org/sites/re100/files/2021-02/RE100%20Making%20Credible%20Claims.pdf

APPENDIX SECTION 3

Determining Avoided Emissions

The quantification of avoided emissions can be used to understand the consequence of a buyer's intervention on grid emissions. Calculating avoided emissions is dependent on input assumptions, and stakeholders have not yet arrived on a consensus set of best practices for calculating avoided emissions or in using such calculations to evaluate the ambition of company efforts and recognize leadership. Avoided emissions estimates may depend on both the current and future carbon intensity of the electric grid and it can be a challenge to discern exactly how much a company's individual transactions resulted in changes to the mix of resources that the grid relies on to operate.

Avoided emissions calculations are not necessarily tied to the timing or location of customer consumption but could be. For example, avoided emissions estimates can measure the impact of changes in customer consumption levels (energy efficiency) or consumption patterns (load shifting) at the place of load. Avoided emissions also could result from a buyer's decision to install a low-carbon energy generation facility on-site that sells energy to the grid or is consumed on site. Or a buyer could sign a purchase power contract from a new low carbon energy generation facility far from its load that would not be built without such a contract.

Avoided emissions is a measure of the total decrease in GHG emissions that occurs because of a company performing a particular action. Different time scales can be considered. Short-term operating impact (e.g., changing power plant production levels from one hour to the next) and/or long-term impact (e.g., new build or retirement of plants from one year to the next). All interventions are assessed for the degree to which they caused a change in grid emissions.[bbb]

Fortunately, many industry experts have been studying this important topic and have developed methods and models to calculate avoided emissions.[ccc, ddd, eee, fff, ggg] Approaches to quantify avoided emissions vary and can range from relatively simple[hhh] to extremely complex. Avoided emissions can be calculated with existing public data and use different geographic boundaries or time periods. Better more granular data can provide a more accurate climate impact assessment and lead to better decision making.

As a first step, a buyer needs to define the actions it has taken to reduce grid emissions in terms of the MWh impact by time and location (e.g., the output of a new CFE resource).[iii] Determining the appropriate emissions factor to apply to that change is a key ingredient in avoided emissions calculations.

bbb https://www.watttime.org/app/uploads/2021/08/GHG-Frameworks-WhitePaper-Tomorrow-WattTime-202108.pdf, page 6.

ccc Olivier Corradi, Gavin McCormick, Henry Richardson, Trevor Hinkle, *A Vision for how Ambitious Organizations can Accurately Measure Electricity Emissions to take Genuine Action*, https://www.watttime.org/app/uploads/2021/08/GHG-Frameworks-WhitePaper-Tomorrow-WattTime-202108.pdf

ddd Dr. David Luke Oates, REsurety / Dr. Kathleen Spees, The Brattle Group, *Locational Marginal Emissions A Force Multiplier for the Carbon Impact of Clean Energy Programs*, https://resurety.com/wp-content/uploads/2021/05/REsurety-Locational-Marginal-Emissions-A-Force-Multiplier-for-the-Carbon-Impact-of-Clean-Energy-Programs.pdf

eee Rudkevich, A. & Ruiz, Pablo, (2012), *Locational Carbon Footprint of the Power Industry: Implications for Operations, Planning and Policy Making*, https://www.researchgate.net/publication/302233428_Locational_Carbon_Footprint_of_the_Power_Industry_Implications_for_Operations_Planning_and_Policy_Making

fff Pieter Gagnon and Wesley Cole, *Planning for the Evolution of the Electric Grid with a Long-Run Marginal Emission Rate*, National Renewable Energy Laboratory, (March 2022), https://www.sciencedirect.com/science/article/pii/S2589004222001857

ggg Kevala et al, *Total Carbon Accounting: A Framework to Deliver Locational Carbon Intensity Data*, https://kevala.com/total-carbon-accounting

hhh For instance, avoided emissions could simply be calculated using EPA's AVERT annual avoided CO_2 rate (in pounds/MWh) for the particular CFE resource type and location multiplied by incremental annual CFE.

iii The duration of an incremental impact in emissions may depend on the type of action taken (e.g., a new CFE resource) and the financial arrangements used to support that change (e.g., a 15-year PPA contract).

3.1 Selection of Emissions Factor for Avoided Emissions

Emissions factors (known by various acronyms) are used to determine how company actions might affect emissions (both increases and decreases) on the electric grid. In general, one (or more) of three broad types of emissions factors are typically considered in an avoided emissions analysis.

1. **Short-run/operating marginal emissions rate** (sometimes referred to as SRMER, LMER, LME, or MER)[jjj] – represents the emissions per unit change in electricity consumption or injection of carbon-free generation, considering changes in power plant production levels from one hour to the next assuming no structural changes in the grid, such as plant retirements or additions.
2. **Long-run/build marginal emissions rate** (sometimes referred to as long-run marginal emission rate or LRMER) – represents the emissions per unit change in electricity consumption or injection of carbon-free generation, considering both operational (short-run) and long-term structural changes in the grid (e.g., the building and retiring of capital assets, such as generators).
3. **Hourly average emissions rates** – are sometimes used to calculate avoided emissions. As described earlier, there are several types of average emissions rates (total output, fossil, and non-baseload) that potentially could be calculated hourly.[kkk]

A buyer action can affect grid emissions across one or more timeframes and could have multiple marginal impacts. For example, capital investment decisions regarding generation, energy storage and transmission capacity are typically made years in advance based on long-term market price and other planning forecasts. Incremental and permanent actions are likely to have a long-term carbon impact. At the same time, a new resource could influence generator commitment decisions related to scheduling that are generally made in the short-run (day-ahead or at least several hours in advance of generation). Dispatch operating decisions about the level of output from a generator can be made in even shorter timeframes (e.g., minutes in advance), while balancing and regulation can adjust generation in seconds. Changes to the grid occur over different time dimensions and some avoided emissions estimates consider one or more of these effects on the grid. Therefore, in addition to better access and reporting of standardized emissions factors data, guidelines are needed to better determine the appropriate application of the different types of emissions factors to use in avoided emissions calculations. For example, long-term forecasts may be used for internal company decision-making, while GHG accounting and reporting could be based on actual empirical evidence from the prior year.

Without any modeling or analysis, it is reasonable to expect that the SRMER is likely to be the highest of these emissions factors because fossil fuel-fired power plants on the grid today are more likely to be the marginal plants operating at any point in time than carbon-free plants like solar, wind or nuclear. It is also reasonable to expect that the SRMER will exhibit considerable volatility throughout the year as generating units on the margin change frequently (e.g., every 5 minutes) from coal to natural gas and possibly renewable resources. Meanwhile, hourly average fossil and non-baseload emissions factors, both of which include resources on the margin (but exclude nuclear, wind, solar and hydroelectric generation), are likely to be similar to the SRMER but relatively more stable. The hourly total output system average emission rate (AER), including all forms of CFE resources (representing about 40% of total U.S. generation), is likely to be considerably lower than the SMER and relatively more stable as well. The LRMER is likely to be lower than the SRMER as coal plants retire, renewable resource penetration increases, and renewable resources are more frequently curtailed during more hours in the year.

Currently, hourly AER and SRMER are most commonly used in avoided emissions calculations. Both tend to consider the current state of the electric grid or a recent historical year. The regional or sub-regional grid AER measure is relatively simple to calculate but its primary disadvantage is that it largely ignores the impact of a buyer's actions on the marginal grid resource at the precise time and location of the buyer's

[jjj] Short-run marginal emission rate (SMER); locational marginal emission rate (LMER), locational marginal emission (LME); marginal emission rate (MER). Operating marginal emission rates related to minute-by-minute changes in generation output levels are sometimes distinguished from short-run marginal emissions rates associated with day-ahead unit commitment decisions.

[kkk] Hourly fossil or non-baseload emissions factors, which are higher than total output system average emissions factors, are sometimes used in avoided emissions analysis to serve as a proxy for marginal emissions factors when marginal emissions factors are not available.

action. For example, the resources used to serve new load often look very different than the average supply mix at any given time. Likewise, the amount of carbon displaced by incremental CFE is directly related to the emission rate of the marginal generator(s) at the CFE's point of connection. The grid's average emission rate (AER) does not accurately reflect what is happening at the margin. An *Electricity Journal* article illustrates the difference between the marginal emission rate (MER) and the AER for the Southern Company balancing area during a summer peak day.[lll] The day starts with low load met by natural gas combined cycle generators on the margin. As load starts to increase around 7am, the system starts to ramp up coal generators, which as reported in that paper cost more to operate than the natural gas combined cycle units and have high emission rates. Around noon, the system dispatches gas peaking generators with higher operating costs to meet peak demand. The gas peaking units, while more expensive to operate, have a lower carbon emission rate than coal.

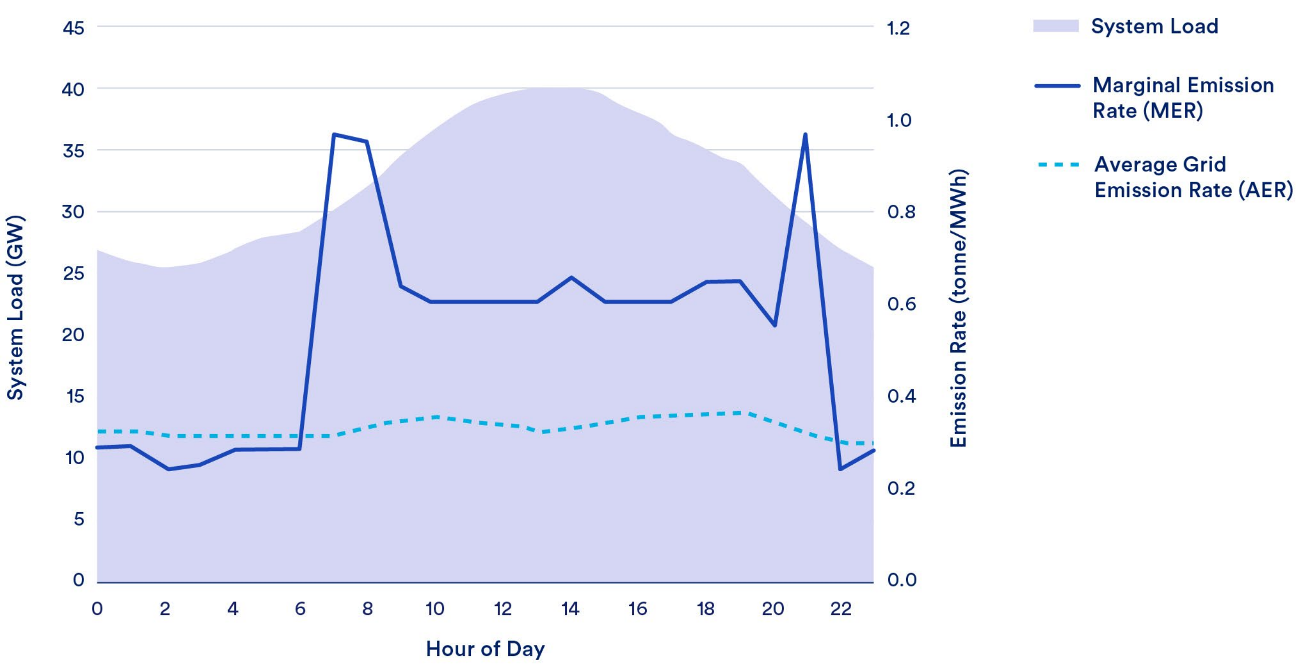
Depending on the type of CFE added (e.g., wind versus solar) and the timing of that generation (supply profile), the carbon impact on the grid will be different. In this day, a solar farm that produces relatively more generation during daylight hours when marginal emissions factors are relatively high, will displace more carbon than a similar-sized wind facility with relatively more generation at night when marginal emissions are low. As illustrated below, the marginal emissions rate may differ significantly from the average emissions rate and the marginal emissions rate can change dramatically throughout the day.

As a result, locational marginal emissions (LME) rate factors are commonly used in avoided emissions estimates when available.

The LME is a metric that measures the tons of carbon emissions displaced by 1 MWh of clean energy injected to the grid at a specific location and a specific point in

Appendix Figure 8: Difference Between MER and Hourly AER

Example: Southern Company Balancing Area on a Peak Summer Day



lll Hua He et al, *Using Marginal Emission Rates to Optimize Investment in Carbon Dioxide Displacement Technologies*, Tabors Caramanis Rudkevich, 2021, Electricity Journal.

time. LMEs are calculated at each power system node in a manner very similar to the Locational Marginal Prices (LMPs) used to set wholesale electricity market prices. LMEs measure emissions by identifying the marginal generators: the generators that would have been producing energy but for the renewable injection to the grid at that location at that moment. If the renewable resource can displace output from a coal plant, the LME would reflect a high carbon impact of the clean energy injection; if the renewable resource is injecting power in an oversaturated region where renewables are already being curtailed, the LME would show a low or zero carbon impact from the clean energy injection. Timing, location, the physics of the power grid, and power market economics all affect the carbon abatement value of different clean energy projects.[mmm]

The historical operating marginal emissions rate for a given location is calculated by multiplying the average emissions rate for the individual marginal unit by the corresponding percentage change in output for that unit to meet a given increase in demand.[nnn] This *operating* marginal emissions factor does not consider how the structure of the grid may change over time (e.g., with new transmission, new renewable capacity, or coal plant retirements). Long-run marginal emissions rates (LRMER) for long-term buyer interventions (e.g., 5 years or longer) attempt to forecast structural, as well as operational, changes in the electric grid. This may be useful to buyers as a tool to estimate and compare the possible energy and emission impacts of alternative procurement actions. But a weakness of this approach is that it requires a modeled forecast of how the electric grid will change over time and is therefore only as good as those projections, which are likely to be increasingly uncertain when looking further out into the future. In contrast, AER or SRMER can be derived from more objective empirical methods.

Tomorrow (now known as electrictyMap) and WattTime, two organizations involved in calculating avoided emissions, published a joint whitepaper that highlights several important qualities of good avoided emissions calculations:

- ***Accuracy –** Results will therefore be more accurate if they minimize the amount of assumptions, and thus rely on measured, real-world data as much as possible.*
- ***Timing –** Results will better reflect grid conditions if they use emission factors with a high temporal resolution (at least hourly) to account for this variability.*
- ***Interconnectors –** Results will therefore be more accurate if they use emission factors that incorporate the import and export of electricity to account for this interdependence.*
- ***Physicality –** Results will therefore represent the underlying physical emissions more accurately if they use emissions factors from the time and place of the physical electricity in question.*
- ***Relevance –** Results will be more accurate if they use operating margin emissions factors for small, short-term changes in load, and use build margin emissions factors for interventions that have a longer-term impact on the electricity system, such as the construction of new generation assets.*[ooo]

While electric grid dynamics are certainly complex and vary significantly by time and location, more work is needed so that users can more readily determine the carbon impact of their actions using a more standardized approach. Much work has already been done in specific case studies. Detailed modeling and analyses demonstrate that carbon impact can vary by several hundred percent depending on the timing, location, and the type of resource added. Improvement, and not perfection, should be the goal. Use of these techniques and data need to be socialized and made more accessible so that they can be applied more broadly to more electricity buyers.

"Marginal emission rate provides a more accurate and defensible way to evaluate carbon displacement from renewable investments. MER is mathematically similar to the calculation of the utility's system lambda and LMP calculations. As a result, MER can be calculated in real time by the same economic dispatch algorithms that ISO/RTOs and utility companies use to operate power systems and calculate the market prices (for example, PJM now publishes real time nodal MER

[mmm] Dr. David Luke Oates, REsurety / Dr. Kathleen Spees, The Brattle Group, *Locational Marginal Emissions A Force Multiplier for the Carbon Impact of Clean Energy Programs*, page 1, https://resurety.com/wp-content/uploads/2021/05/REsurety-Locational-Marginal-Emissions-A-Force-Multiplier-for-the-Carbon-Impact-of-Clean-Energy-Programs.pdf

[nnn] PJM started to provide marginal emission data in 2021 to help inform stakeholders and policy makers as to the real-time conditions of the system. https://www.pjm.com/-/media/etools/data-miner-2/marginal-emissions-primer.ashx

[ooo] Olivier Corradi, Gavin McCormick, Henry Richardson, Trevor Hinkle, *A Vision for how Ambitious Organizations can Accurately Measure Electricity Emissions to take Genuine Action*, pages 7-8, https://www.watttime.org/app/uploads/2021/08/GHG-Frameworks-WhitePaper-Tomorrow-WattTime-202108.pdf

data)…The calculation and publication of marginal emission rates associated with the real-time operation and dispatch of power systems would be a first step toward the development of an effective Federal Energy Efficiency and Clean Electricity Standard. It would enable government authorities to track the actual emission impacts of efficiency and clean electricity investments made in compliance with the standard."[ppp]

3.2 Examples of Organizations Considering Avoided Emissions

i. Boston University

Boston University worked with the renewable energy supply team and researchers from Carnegie Mellon University to find a project that best aligned the timing of a wind energy generation project located in South Dakota with the more carbon intense (marginal) emissions on the grid.[qqq] The emissions data used is maintained by the Climate and Energy Decision Making Center in the Department of Engineering and Public Policy at Carnegie Mellon University.[rrr]

ii. Microsoft

Microsoft is using its Azure IoT Central platform that connects energy generation with data from smart meters that measure consumption in real-time. They then modify current Guarantees of Origin (GOs) accounting. Currently, GOs, an electronic document that provides proof of the source of a given quantity of renewable energy, matches consumption and production over a year. The new approach matches this hour by hour, keeping in line with the GO system and established frameworks for carbon reporting by canceling GOs based on the hourly matching. This represents a move from yearly-based to hourly-based, time-stamped RECs that will be carbon-stamped as well. The carbon stamping methodology leverages available zonal data, and Microsoft intends to eventually upgrade the methodology to locational marginal emissions (LME).[sss]

iii. Nucor

On November 13, 2020, Nucor announced a contract to buy new solar power located in Texas via a 15-year virtual PPA. The Nucor project is the largest PPA yet signed worldwide for off-site renewable energy projects in the steel industry. "Nucor engaged WattTime to conduct an avoided emissions analysis of proposed solar and wind projects to help the company better understand and evaluate the avoided greenhouse gas (GHG) emissions, reduced pollution, and improved health outcomes associated with various projects. This analysis enabled Nucor to co-optimize its investment decision alongside traditional metrics such as financial and risk-related considerations."[ttt]

iv. Salesforce

For projects under consideration, Salesforce calculates hourly anticipated generation of a project and the marginal emissions rate of the grid region where the project is located using data available through WattTime or AVERT.

> *Renewable energy projects avoid emissions by displacing fossil-fuel based generation that would have otherwise produced electricity. Adding one megawatt-hour of electricity from a new renewable energy project to a power grid at a specific time and place displaces the power plants that would have otherwise produced power at that specific time and location – the marginal generators. Because the type of generators serving the grid vary, the emissions reduction of a potential project can change dramatically based on its location and production profile… Not every megawatt-hour (MWh) is created equal. Some MWhs of renewable energy are more effective than others in avoiding emissions*

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ppp Hua He et al, *Using Marginal Emission Rates to Optimize Investment in Carbon Dioxide Displacement Technologies*, Tabors Caramanis Rudkevich, 2021, Electricity Journal, pages 3, 7.

qqq https://www.bu.edu/sustainability/projects/bu-wind/

rrr Azevedo IL, Donti PL, Horner NC, Schivley G, Siler-Evans K, Vaishnav PT (2020). Electricity Marginal Factor Estimates. Center For Climate and Energy Decision Making. Pittsburgh: Carnegie Mellon University. http://cedmcenter.org; https://cedm.shinyapps.io/MarginalFactors/

sss https://group.vattenfall.com/press-and-media/pressreleases/2019/vattenfall-and-microsoft-pilot-worlds-first-h-ourly-matching-247-of-renewable-energy

ttt https://www.watttime.org/app/uploads/2020/12/WattTime-Nucor-Case-Study-202012-vFinal.pdf; https://www.solarpowerworldonline.com/2020/11/steel-producer-nucor-signs-massive-ppa-for-250-mw-of-new-solar-energy-in-texas/

depending on their location and production timing. By assessing the avoided emissions of different renewable energy projects, organizations can identify and select projects that are particularly effective at reducing emissions.[uuu]

In their evaluation guidance, Salesforce (and WattTime) list the basic steps to determine the avoided emissions of a project, calculate (1) the hourly anticipated generation of the project (i.e., the project's estimated annual hourly generation profile), and (2) the marginal emissions rate of the grid region where the project is located (some data available through WattTime, AVERT, or the Azevedo's group Electricity Marginal Factors Estimates). Multiply these together to get each project's projected avoided emissions. Based on this avoided emissions assessment, each project can be scored on a one through five scale, prioritizing projects with the greatest impact.

3.3 Available Resources and Data

Buyers typically rely on other sources and organizations to assist them with their avoided emissions analysis. An increasing number of public and proprietary sources of emissions data have been developed to assist with these calculations. These are summarized below with links to their websites.

Government / RTO

Avoided Emissions and Generation Tool (AVERT) (Avoided Emissions Rates)

- Website: https://www.epa.gov/avert
- Data: https://www.epa.gov/avert/download-avert
- Source Category: Government (EPA)
- Approach: AVERT represents the dynamics of electricity dispatch based on the historical patterns of actual generation in one selected year. AVERT's Statistical Module uses hourly "prepackaged" data from EPA's Air Markets Program Data (AMPD) and National Emissions Inventory to perform statistical analysis on actual behavior of past generation and emissions data given various regional demand levels. Annual avoided emission rates generated from AVERT can be used to quickly estimate the magnitude of emission impacts within an AVERT region for six categories: onshore wind energy, offshore wind energy, rooftop-scale photovoltaic installations, utility-scale photovoltaic installations, portfolio EE programs, and baseload EE programs.[vvv] EPA has used AVERT to produce marginal emission rates for each AVERT region and a weighted average for the nation each year from 2007 to 2021.

Appendix Table 1: Overview of Available Resources

Type	AER	SRMER	LRMER
Characteristics	• Average • Historical	• Marginal • Historical	• Marginal • Forecast
Examples	• AVERT • eGrid (including total, non-baseload and fossil fuel averages)	• PJM • WattTime • ElectricityMap • REsurety • Singularity/Carbonara • CA SGIP	• WattTime • NREL Cambium • Singularity/Carbonara • CA SGIP

uuu https://c1.sfdcstatic.com/content/dam/web/en_us/www/assets/pdf/sustainability/sustainability-more-than-megawatt.pdf, page 10, Procurement Matrix Spreadsheet, https://quip.com/GsCbAJ7wgEB3#OYNACAvDyX9

vvv https://www.epa.gov/avert/how-avert-works, https://www.epa.gov/avert/avert-user-manual

California Self-Generation Incentive Program (SGIP GHG Signal) (Marginal Operating Emissions Rate – MOER

- Website: https://sgipsignal.com/
- Data: https://sgipsignal.com/download-data
- Source Category: Government (California PUC and WattTime)
- Approach: SGIP is a program that incentivizes the installation of new distributed energy resources. SGIP signal reports the real-time and forecasted marginal greenhouse gas emissions data for participants in the program.

Emissions & Generation Resource Integrated Database (eGRID) (Annual Non-Baseload, Fossil Fuel, and Total Output Emissions Rates)

- Website: https://www.epa.gov/egrid
- Data: https://www.epa.gov/egrid/data-explorer
- Source Category: Government (EPA)
- Approach: eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. eGRID is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government. eGRID uses data from the Energy Information Administration (EIA) Forms EIA-860 and EIA-923 and EPA's Clean Air Markets Program Data. Emission data from EPA are integrated with generation data from EIA to produce reported emissions per MWh of electricity generation (lb/MWh). eGRID provides aggregated data by state, U.S. total, and by three different sets of electric grid boundaries (i.e., balancing authority area, NERC region, and eGRID subregion).[www]

National Renewable Energy Laboratory (NREL) / Cambium (Long-Run Marginal Emissions Rates – LRMER)

- Website: https://www.nrel.gov/analysis/cambium.html
- Data: https://scenarioviewer.nrel.gov/
- Source Category: Government
- Approach: Cambium data sets contain hourly emission, cost, and operational data for modeled futures of the U.S. electric sector with metrics designed to be useful for long-term decision-making. A long-run marginal emission rate is the rate of emissions that would be either induced or avoided by a long-term (i.e., more than several years) change in electrical demand, incorporating both the operational and structural consequences of the change. It is therefore distinct from the more commonly known short-run marginal, which treats grid assets as fixed. Cambium uses outputs from The Regional Energy Deployment System (ReEDS), which uses a least-cost framework to project structural changes in the U.S. electric sector under different possible futures, and PLEXOS, which is a commercial production cost model that it uses to simulate the hourly operation of the future electric systems projected by ReEDS.[xxx]

PJM (Marginal Emissions Rate)

- Website: https://dataminer2.pjm.com/feed/fivemin_marginal_emissions/definition
- Data: https://dataminer2.pjm.com/feed/fivemin_marginal_emissions
- Source Category: Regional Transmission Organization
- Approach: The marginal emissions rate for a given location is calculated by multiplying the average emissions rate for the individual marginal unit by the corresponding percentage for that unit. These rates are then added together to create the marginal emissions rate for the given location. For a location representing a collection of individual locations (such as a transmission zone, or all of PJM), the rates for the locations are averaged together in the same way that LMPs for larger areas are averaged together to form the LMP for the area.[yyy]

Commercial

ElectricityMap (formerly Tomorrow)

- Website: https://electricitymap.org/
- Data: Request via website.
- Source Category: Commercial
- Approach: electricityMap takes data from a variety of public sources, including transmission system operators, balancing entities, and market operators, and consolidates this information with carbon intensity data from the IPCC. Their system then standardizes and aggregates the data, accounting for electricity imports and exports using their

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www https://www.epa.gov/egrid/egrid-questions-and-answers, https://www.epa.gov/system/files/documents/2022-01/egrid2020_technical_guide.pdf

xxx https://www.nrel.gov/docs/fy22osti/81611.pdf

yyy https://www.pjm.com/-/media/etools/data-miner-2/marginal-emissions-primer.ashx flow-tracing methodology. The data can be accessed historically, in real time, or as a forecast for the next 24 hours. Their model, using more than 1,000 variables, uses machine learning to estimate the marginal origin of electricity.

REsurety (Locational Marginal Emissions – LME)

- Website: https://resurety.com/solutions/locational-marginal-emissions/
- Data: https://resurety.com/locational-marginal-emissions-white-paper/
- Source Category: Commercial
- Approach: LMEs are calculated at each power system node in a manner very similar to the Locational Marginal Prices (LMPs) used to set wholesale electricity market prices. LMEs measure emissions by identifying the marginal generators: the generators that would have been producing energy but for the renewable injection to the grid at that location at that moment. REsurety calculates the historical carbon emissions or abatement at each node with hourly granularity.

Singularity / Carbonara

- Website: https://singularity.energy/
- Data: https://carbonara.singularity.energy/app/home
- Source Category: Commercial
- Approach: Singularity uses advanced machine learning to help analyze and predict changes in grid carbon emissions and carbon impact of any decarbonization measures. Singularity integrates real-time data from all major ISOs in North America. Some of its data is historical, but most is real-time.

WattTime (Marginal Operating Emission Rate – MOER)

- Website: https://www.watttime.org/
- Data: https://www.watttime.org/api-documentation/#login-amp-obtain-token
- Source Category: Commercial
- Approach: WattTime uses the EPA's Continuous Emissions Monitoring System's data for hourly electricity generation and emissions at every major fossil fuel fired power plant in the United States. It then uses an empirical regression-based model (requiring almost no assumptions) to determine which plants are likely to increase or decrease their output with a change in demand. They then apply the emissions factors to the plants they determine are likely to operate.[zzzz] WattTime API provides access to real-time, forecast, and historical marginal emissions data for electric grids around the world.

[zzzz] https://www.watttime.org/marginal-emissions-methodology/

APPENDIX SECTION 4

Carbon Facts Label – Putting It All Together

This paper discusses the importance of disclosures related to a buyer's emissions reductions from electricity use, tied to the timing and location of a buyer's electricity use, as well as disclosures related to emissions reductions from a buyer's actions to decarbonize electricity grids, which may occur within the same grid as a buyer's load or in grids far from load. In other words, the market boundary to evaluate changes in the former are tied to the location of customer load, while the market boundary for the latter is much broader and could be considered globally. Currently, there is not agreement among stakeholders on the metrics that are needed to appropriately assess these two different types of emissions reductions, the methodology to best calculate each metric, or how metrics, once calculated, should be compared in evaluating a buyer's electricity procurement actions.

4.1 Emissions Reductions from Electricity Use and Buyer Actions

The emissions resulting from electricity use (expressed in metric tons of CO_2) could be calculated using a buyer's load multiplied by the average grid emissions factors (to establish a location-based inventory for attributional accounting) and marginal emissions factors (to establish a carbon baseline for consequential accounting). Alternatively, a buyer's action to reduce emissions from electricity use could be disclosed using a modified Scope 2 market-based accounting that considers a buyer's purchases of EACs and supply more closely tied to the timing and location of consumption (attributional accounting), while a buyer's actions to reduce grid emissions could be disclosed by describing

Appendix Table 2A: Measuring Emissions from Electricity Use (Attributional Accounting)

Metric	Tech	Location	Timing	Emissions Factors
Emissions from Use (not accounting for buyer purchases and claims of others on grid)				
Location-based (LB) (load @ grid avg. EF)		Sub-region / grid / balancing authority	Annual to hourly	Average Emissions Factors (EF)
Emissions from Use (accounting for buyer purchases)				
RE100	RE only	U.S. & Canada RECs	Annual	RECs (0)
Scope 2 Market-Based (MB)	All CFE (if in LSE supply EF)	U.S. RECs	Annual	• Purchased EACs • Contracts / PPAs from specified sources • Supplier / utility EF • Residual mix (generally not available in U.S.) • Grid average EF
Modified Scope 2 MB	All CFE	Regional grid / sub-area EACs	Annual to hourly	• Purchased or allocated EACs • Same as above, except fossil or non-baseload EF (not grid avg. EF) would be used as a last resort when nothing else is available
Modified Scope 2 MB+	All CFE	LMP Market Zones	Hourly	Same as above

Appendix Table 2B: Measuring Decarbonization Impact (Consequential Accounting)

Metric	Location	Timing	Emissions Factors
Emissions from Use (not accounting for buyer purchases)			
Load @ MER	Customer node / sub-region / grid / balancing authority	Annual to hourly	Marginal emissions rate (MER) (Annual fossil or non-baseload if MER not available)
Description of Incremental Decarbonization Impact			
Incremental CFE (all types)	MW, MWh (including new CFE, life extension, repowering, uprate) • Incremental firm (MW, MWh) • Incremental new tech (MW, MWh)		
Other Actions	• Incremental storage • Transmission (expansion, new)		
Change in Use	Energy efficiency, load shifting, load relocation, etc. (shows up in analysis of emissions from use with changes in load)		
Avoided Emissions Factor(s) (tied to timing/location of buyer actions)			
Empirical	Annual AVERT (EPA avoided emissions rates)		
	Hourly or Annual Average Emissions Rate (regional grid or sub-area) [RTO or eGrid subregion] • Total output EF • Fossil EF • Non-Baseload EF		
	Short-Run Marginal Emissions Rate (regional grid, market area, supply node)		
Forecast Simulation Model	Long-Run Marginal Emissions Rate (regional grid, market area, supply node)		

any incremental CFE added and other actions taken by a buyer along with a quantification of the associated avoided emissions.[aaaa] Both emissions inventories and avoided emissions can be calculated with greater precision using more granular data.[bbbb] The different approaches to calculating metrics to support disclosures related to a buyer's emissions reductions from electricity use as well as disclosures related to a buyer's actions to decarbonize electricity grids are summarized in Appendix Tables 2A and 2B.

Matching CFE supply with electricity use and/or with carbon-intensive generation, while not mutually exclusive, may at times involve different objectives. But in both approaches, location and timing of CFE generation matter. Matching CFE supply with electricity use emphasizes more immediate CFE technology development necessary to balance supply and demand to achieve longer term deep decarbonization goals while carbon matching emphasizes maximizing more immediate emission reductions that are urgently needed. Some of the key differences in the two approaches are summarized in Appendix Table 3.

Appendix Table 3: Key Differences in Consumption vs. Carbon Matching

Characteristics	Electricity Use Matching (24/7)	Carbon Matching (Emissionality)
CFE supply matches	**Timing and location of customer electricity use** (e.g., hourly)	**Timing and location of high carbon-emitting generation** (sub-hourly)
Carbon impact	**Low-Medium-High**, depends on grid mix where customer load is ($/t$CO_2$ avoided helps prioritize projects)	**High** ($/t$CO_2$ avoided helps prioritize projects)
Key metrics	**Hourly CFE %** & $/t$CO_2$ avoided	**T of CO_2 avoided/MWH** & $/t$CO_2$ avoided
Location of buyer supply contracts	**Same grid** / load zone / considers CFE deliverability to customer	**Global**, not tied to customer location
Near term focus	**Stimulate development of firm, flexible CFE resources, storage, and demand**	**Maximize CO_2 reductions**
Demand signal for emerging technologies	**High**	**Low**
Incremental CFE / load change	**Optional**	**Required**
Values overall grid decarbonization, not just buyer contracts	**Yes**	**Yes**
Product complexity	**High**, need balanced portfolio (could be "**Low**" if full requirements outsourced)	**Medium**, can rely on intermittent wind/ solar PPAs (unit power)
Energy price exposure	**Low**, hedges buyer's energy costs	**High**, not an effective hedge

[aaaa] Some suggest that emissions reductions based on marginal emissions factors can be compared with market-based inventories based on average emissions factors, effectively combining consequential and attributional approaches, while others suggest that average and marginal emissions facts should not be used for comparison purposes. Most stakeholders agree that an hourly calculation of inventories and emissions reductions, if feasible, would be more accurate than an annual calculation.

[bbbb] This includes more granular load, supply/attribute and emissions factor data in terms of time and location (e.g., hourly and/or by market area, sub-region or regional grid) as opposed to calculations based on annual data over broad geographic areas (e.g., national).

The revised and additional carbon disclosures outlined in the paper – including those related to electricity use and/or carbon matching – are designed to improve accuracy and relevance, while incentivizing and rewarding electricity use and procurement decisions that better optimize decarbonization impact. These disclosures rely on more granular data and seek to establish the appropriate metrics for more standardized reporting of a buyer's emissions reductions from electricity use as well as disclosures related to emissions reductions from a buyer's actions to decarbonize electricity grids.

4.2 An Example: Carbon Facts Labels for Three Procurement Scenarios

For example, in Section 6 of this paper, we considered a buyer who purchases an amount of clean EACs equal to its annual load but is choosing among three different procurement strategies. If we assume the buyer is in Texas (ERCOT), has annual consumption equal to 8,760 MWh (1 MW average load) with a big box store load profile, we can calculate the current Scope 2 location-based and market-based inventories based on the assumptions for the following three procurement scenarios.

Appendix Table 4: Summary of Three Procurement Strategies and Current Scope 2 Inventories

	Strategy A (VPPA out of market)	Strategy B (PPA in market)	Strategy C (24/7 in market)
Procurement Strategy	VPPA for incremental solar in California = 8,760 MWh output (with California supply profile)	PPA for incremental solar with RECs in ERCOT = 8,760 MWh output (with Texas supply profile)	Contract with competitive supplier for 24/7 [existing nuclear (45%), incremental wind (45%), incremental solar (10%)]
Current Scope 2 Inventories			
Location-Based[cccc]	3,204 tCO_2	3,204 tCO_2	3,204 tCO_2
Market-Based	0 tCO_2	0 tCO_2	0 tCO_2

Under current Scope 2 accounting guidance, the buyer can report the same location-based inventories and zero market-based inventories in all three procurement scenarios.[dddd] The current disclosures provide little or no valuable information to the buyer (or to other stakeholders) seeking to evaluate the emissions associated with a buyer's electricity use and the carbon impact of these alternative procurement actions. For example, to what extent does the buyer rely on clean energy to serve its load?[eeee] Does adding new solar generation in Texas or California have greater impact on carbon reductions? What difference does it make where and what type of incremental CFE generation is added in terms of the emissions associated with the buyer's electricity use and in actual reductions in grid emissions? How does matching CFE supply with the buyer's consumption on a 24/7 basis impact carbon reductions? The alternative procurement strategies could be evaluated based on better and more relevant information as shown in the Carbon Facts labels presented below.

cccc The location-based method not only ignores a buyer's electricity procurement actions but also ignores the electricity procurement actions and clean energy attribute claims of other buyers on the regional grid. Therefore, it is not necessarily the case that a buyer who does not take any electricity procurement actions can rely on the average carbon intensity of the regional grid to serve its load, especially once the environmental claims of other buyers are considered. In other words, the market-based inventories could be higher or lower than the buyer's location-based inventories depending on the emissions intensity of the particular generators with which it has contracted or the residual mix generation after other buyer claims are considered.

dddd The buyer can report zero Scope 2 inventories even if the buyer relies entirely on fossil generation from the ERCOT grid in Strategy A (in all hours of consumption) and Strategy B (when its contracted solar generation is not available).

eeee While typically it is not possible to physically trace electricity flows from a specific generation source on the electric grid to a specific customer load, granular EACs (time- and location-stamped) could be more closely tied to the timing and location of customer consumption, much like the underlying supply obligations of electricity supply.

Appendix Table 5: Scenario A: Buyer in ERCOT – RE100 Solar in California (Illustrative)

Current Scope 2 Inventories

Location-Based	3,204 tCO_2
Market-Based	0 tCO_2

Carbon Facts 2.0 Reported for Prior Calendar Year		
Annual Consumption (By Regional Grid / Balancing Authority)		8,760 MWh
Supply Sources (% of Annual Consumption) (by resource type)		
• Supply Contract / Utility Tariff CFE		**0%**
▪ Wind	0%	
▪ Solar	0%	
▪ Nuclear	0%	
• Supply Contract / Utility Tariff Non-CFE		**100%**
▪ Natural Gas	69%	
▪ Coal	31%	
• Allocated Carbon-Free Electricity (CFE)		0%
• Unspecified Grid Supply (residual mix, if any)		0%
Unbundled Energy Attribute Certificates		0%
CFE Supply % Matching Consumption (Track consumption matching goals)		
Time Interval Used for Matching (and Scope 2 Reporting)		**Hourly**
Annual Average CFE % (average across all hours)		**0%**
Hourly Minimum CFE % (0-100%)		0%
Modified Scope 2 Emissions (Track emissions from use and climate risk exposure)		
Location-Based (load * grid average EF; absent contracts)		3,198 tCO_2
Market-Based (with RECs/EFECs, LSE contracts & grid supply)		5,301 tCO_2
MB vs. LB [MB/LB-1]		**+66%**
Annual CFE/EAC Purchases (Not by Regional Grid / Balancing Authority)		
Total Annual CFE (Track RE100 or CFE100 purchasing goals)		100% of consumption
Decarbonization Impact and Avoided Emissions (Track carbon reduction goals)		
Incremental Total CFE (new solar in CA)		**3.1 MW / 8,760 MWh**
• Incremental Firm CFE		0 MW / 0 MWh
• Incremental New Technology		0 MW / 0 MWh
Describe Other Buyer Actions (energy storage, load management, etc.)		
Avoided Emissions		
• Carbon Baseline [CB] (load @ marginal EF; absent buyer contracts)		5,301 tCO_2
• Avoided Emissions [AE] (0.432 tCO_2/MWh)		3,786 tCO_2
• Net Emissions [CB]-[AE]		1,515 tCO_2
Avoided Emissions Impact [(CB-AE)/CB-1]		**(71)%**

Appendix Table 6: Scenario B: Buyer in ERCOT – RE100 Solar in ERCOT (Illustrative)

Current Scope 2 Inventories

Location-Based	3,204 tCO_2
Market-Based	0 tCO_2

Carbon Facts 2.0 Reported for Prior Calendar Year		
Annual Consumption (By Regional Grid / Balancing Authority)		8,760 MWh
Supply Sources (% of Annual Consumption) (by resource type)		
• Supply Contract / Utility Tariff CFE		**57%**
▪ Wind	0%	
▪ Solar	57%	
▪ Nuclear	0%	
• Supply Contract / Utility Tariff Non-CFE		**43%**
▪ Natural Gas	30%	
▪ Coal	13%	
• Allocated Carbon-Free Electricity (CFE)		0%
• Unspecified Grid Supply (residual mix, if any)		0%
Unbundled Energy Attribute Certificates		0%
CFE Supply % Matching Consumption (Track consumption matching goals)		
Time Interval Used for Matching (and Scope 2 Reporting)		**Hourly**
Annual Average CFE % (average across all hours)		**57%**
Hourly Minimum CFE % (0-100%)		0%
Modified Scope 2 Emissions (Track emissions from use and climate risk exposure)		
Location-Based (load * grid average EF; absent contracts)		3,198 tCO_2
Market-Based (with RECs/EFECs, LSE contracts & grid supply)		2,349 tCO_2
MB vs. LB [MB/LB-1]		**(27)%**
Annual CFE/EAC Purchases (Not by Regional Grid / Balancing Authority)		
Total Annual CFE (Track RE100 or CFE100 purchasing goals)		100% of consumption
Decarbonization Impact and Avoided Emissions (Track carbon reduction goals)		
Incremental Total CFE (new solar in ERCOT)		**3.5 MW / 8,760 MWh**
• Incremental Firm CFE		0 MW / 0 MWh
• Incremental New Technology		0 MW / 0 MWh
Describe Other Buyer Actions (energy storage, load management, etc.)		
Avoided Emissions		
• Carbon Baseline [CB] (load @ marginal EF; absent buyer contracts)		5,301 tCO_2
• Avoided Emissions [AE] (0.550 tCO_2/MWh)		4,822 tCO_2
• Net Emissions [CB]-[AE]		479 tCO_2
Avoided Emissions Impact [(CB-AE)/CB-1]		**(91)%**

Appendix Table 7: Scenario C: Buyer in ERCOT – 24/7 Supply Contract in ERCOT (Illustrative)

Current Scope 2 Inventories

Location-Based	3,204 tCO_2
Market-Based	0 tCO_2

Carbon Facts 2.0

Reported for Prior Calendar Year

Annual Consumption (By Regional Grid / Balancing Authority)		8,760 MWh
Supply Sources (% of Annual Consumption) (by resource type)		
• Supply Contract / Utility Tariff CFE		**100%**
▪ Wind	45%	
▪ Solar	10%	
▪ Nuclear	45%	
• Supply Contract / Utility Tariff Non-CFE		**0%**
▪ Natural Gas	0%	
▪ Coal	0%	
• Allocated Carbon-Free Electricity (CFE)		0%
• Unspecified Grid Supply (residual mix, if any)		0%
Unbundled Energy Attribute Certificates		0%
CFE Supply % Matching Consumption (Track consumption matching goals)		
Time Interval Used for Matching (and Scope 2 Reporting)		**Hourly**
Annual Average CFE % (average across all hours)		**100%**
Hourly Minimum CFE % (0-100%)		100%
Modified Scope 2 Emissions (Track emissions from use and climate risk exposure)		
Location-Based (load * grid average EF; absent contracts)		3,198 tCO_2
Market-Based (with RECs/EFECs, LSE contracts & grid supply)		0 tCO_2
MB vs. LB [MB/LB-1]		**(100)%**
Annual CFE/EAC Purchases (Not by Regional Grid / Balancing Authority)		
Total Annual CFE (Track RE100 or CFE100 purchasing goals)		100% of consumption
Decarbonization Impact and Avoided Emissions (Track carbon reduction goals)		
Incremental Total CFE (new wind and solar in CA)		**1.6 MW / 4,818 MWh**
• Incremental Wind		1.3 MW / 3,942 MWh
• Incremental Solar		0.3 MW / 876 MWh
• Incremental Firm CFE		0 MW / 0 MWh
• Incremental New Technology		0 MW / 0 MWh
Describe Other Buyer Actions (energy storage, load management, etc.)		
Avoided Emissions		
• Carbon Baseline [CB] (load @ marginal EF; absent buyer contracts)		5,301 tCO_2
• Avoided Emissions [AE] (0.537 tCO_2/MWh)		2,585 tCO_2
• Net Emissions [CB]-[AE]		2,716 tCO_2
Avoided Emissions Impact [(CB-AE)/CB-1]		**(49)%**

Appendix Table 8: Summary Information for the Three Electricity Procurement Strategies

	Strategy A (VPPA out of market)	Strategy B (PPA in market)	Strategy C (24/7 in market)
Procurement Strategy	VPPA for incremental solar in California = 8,760 MWh output (with California supply profile)	PPA for incremental solar with RECs in ERCOT = 8,760 MWh output (with Texas supply profile)	Contract with competitive supplier for 24/7 [existing nuclear (45%), incremental wind (45%), incremental solar (10%)]
Modified Scope 2 Inventories[ffff] (By Regional Grid / Balancing Authority)			
Location-Based (LB)	3,198 tCO_2	3,198 tCO_2	3,198 tCO_2
Market-Based (MB)	5,301 tCO_2[gggg]	2,349 tCO_2[hhhh]	0 tCO_2
MB vs. LB (MB/LB-1)	+66%	(27%)	(100%)
Annual Average CFE %	0%	57%	100%
Annual CFE/EAC Purchases (Not by Regional Grid / Balancing Authority)			
Annual CFE/EAC Purchases %	100% (RE100)	100% (RE100)	100% (CFE100)
Incremental CFE	Solar 3.1 MW / 8,760 MWh	Solar 3.5 MW / 8,760 MWh	Solar 0.3 MW / 876 MWh; Wind 1.3 MW / 3,942 MWh
Carbon Baseline (CB)	5,301 tCO_2	5,301 tCO_2	5,301 tCO_2
Avoided Emissions (AE)	3,786 tCO_2	4,822 tCO_2	2,585 tCO_2
Avoided Emissions Impact [(CB-AE)/CB -1]	(71%)	(91%)	(49%)

This information is summarized for comparison across electricity procurement scenarios in the table above.

The modified Scope 2 inventories, where only CFE in the same regional grid counts, looks quite different across procurement scenarios. A zero Annual Average CFE % corresponds with a high market-based inventory (5,301 tCO_2) while a 100% Annual Average CFE % corresponds with a zero market-based inventory. Strategies A and B would meet the existing RE100 program requirements, while Strategy C would require a new CFE100 recognition program. Both Strategies A and B add 8,760 MWh of incremental solar generation, but new solar generation in ERCOT displaces more fossil generation that adding solar generation in California.[iiii] In this example, Strategy C has an Annual Average CFE 100%

[ffff] This was calculated using hourly customer load and hourly CFE supply in the same regional grid (if any), and the hourly ERCOT fuel mix and associated emissions factors for different fuel types.

[gggg] This assumes that the buyer purchases RECs out-of-market equal to its annual consumption (enabling the buyer to report zero Scope 2 inventories under the current accounting system), while the supply relied upon on the local grid to serve the buyer's consumption is met by fossil generation. If the buyer purchased wind or solar electricity from the local grid minus the associated RECs, sometimes called "null power," this would be assigned the residual mix emissions for the purpose of delivery and/or use claims in the market-based method.

[hhhh] This assumes that the buyer purchases RECs in-market equal to its annual consumption (enabling the buyer to report zero Scope 2 inventories under the current accounting system), while the supply relied upon on the local grid to serve the buyer's consumption is met by fossil generation when its contracted solar supply is not available.

[iiii] More granular time and location data on avoided emissions (marginal emissions factors) within ERCOT and California would improve these estimates. In the interim, annual estimates can be calculated from EPA AVERT figures or could be calculated based on annual or hourly fossil generation emissions factors (assuming that fossil generation is being displaced by incremental zero carbon generation).

matching score, but results in lower avoided emissions than in both Strategy B and Strategy A, since 45% of its CFE is coming from existing generation. If the buyer relied exclusively on incremental resources in Strategy C, the buyer could report higher avoided emissions along with a 100% electricity use matching score.[jjjj]

The major differences between current Scope 2 reporting and the information provided in the Carbon Facts label are highlighted in Appendix Table 9.

Appendix Table 9: Major Differences in Scope 2 Reporting vs. Carbon Facts Label Approach[kkkk]

Modified Scope 2 (Location-Based)
Use more granular time-based calculations (hourly if possible)
Modified Scope 2 (Market-Based)
Only count EACs representing carbon-free generation that are owned and/or retired on behalf of customers located in the same regional grid or balancing authority as load
Do not allow CFE attributes used for inventory calculations to exceed load in any time interval
Use more granular time-based calculations (hourly if possible)
Apply fossil or non-baseload average emissions rates as last resort if residual mix or other emissions rates are not available
Count buyer's share of CFE / EACs in same grid that buyer pays for in utility / LSE rates while following three principles: no double counting, no double paying or no cost shifting
Decarbonization Impact (In addition to Modified Scope 2 disclosures)
Describe incremental CFE (firm, intermittent, new tech), energy storage, load management or other buyer actions that could impact grid emissions
Quantify avoided emissions based on prior year incremental CFE supply and AVERT avoided CO_2 or marginal emissions factors (if available)

jjjj In some instances, it was possible to calculate metrics shown in the Carbon Facts using available data with alternative methods. For instance, current Scope 2 location-based figures could be based on the average annual 2021 ERCOT system load weighted fuel mix for all generation and load, which is reported by hour in ERCOT, or using the annual 2020 eGrid total output emission factor and annual load of the buyer. Alternatively, it could be calculated using the hourly load profile of the buyer and the hourly generation fuel mix in ERCOT. But none of these differences materially change the overall conclusions.

kkkk The authors do not purport to have all the answers to what an improved rules and reward ecosystem designed to better drive grid decarbonization ultimately will look like. They do, however, hope to contribute to the ambition and substance of the debate.