WORLD RESOURCES INSTITUTE

Discussion Draft for GHG Protocol Green Power Accounting Workshop

Challenges and options in corporate inventories

Dec 8, 2010

Contents

Executive Summary

As more companies and organizations compile GHG inventories according to the *Corporate Standard*, they have raised questions regarding how to account for external mitigation instruments. In particular, companies have expressed interest in reducing the emissions associated with their electricity consumption through the use of a myriad of instruments in the US and global marketplace, including RECs, green tariffs, and offsets derived from renewable energy (RE) projects. To fully understand the impact of these instruments, this paper examines green power at the conceptual level, examining the two most common definitions and uses for these purchases in a corporate inventory – RECs as alternative emission factors and RECs as avoided emissions -- and what conditions need to be present to support these uses. In the U.S., RECs have been the primary mechanism to facilitate transactions in renewable energy, and form the basis of the discussion—though the concepts apply to energy more fundamentally.

RECS as alternative emission factors: This definition entails the use of a "0 emisisons/MWh" factor, rather than the grid system average default, in calculating scope 2. For this application to be conceptually sound, we propose three requirements: (1) a clear system of tracking and ownership, which is largely in-place already in the U.S.; (2) the adjustment of grid average emission factors to reflect the unique claiming of RECs and their associated emissions profiles by organizations,; and (3) and a clear role for additionality. The advantages and disadvantages of two possible interpretations concerning additionality are examined here:

> <u>The re-slicing approach.</u> No additionality requirements are made and any voluntary RE source could theoretically produce a REC (and therefore emission factor) that would be eligible for use in a corporate inventory. This approach would serve to re-slice the emissions of the grid in a way that leaves other grid users with more GHG-intensive rates, and may drive demand for cleaner slices over the long-term.
>
> <u>The strong financial additionality approach.</u> The RE installation must be additional. Unlike additionality definitions that apply to offset projects, where the "emissions avoided or reduced" are examined in a baseline or performance benchmark reference case, additionality applied here would simply seek to distinguish those projects which would not have been constructed but for the opportunity to sell zero-emissions energy profiles.

RECs as avoided emissions: This interpretation of a REC seeks to link the project with a quantitative impact on other GHG-emitting generators on the grid. While most organizations have noted that RECs are fundamentally different from offsets derived from RE projects, the underlying claim appears to be the same, raising questions regarding the reference case (avoided compared to what?) and the role of additionality as a means to causally connect the REC with the reductions. The rationale for different inventory scope applications is examined, along with concerns regarding the simplified methodology often used to estimate the avoided emissions (quantifying similar impacts for RE offsets typically uses more detailed methods).

REC applications in Carbon Constrained, Claimed and Other Circumstances: The two definitions of RECs discussed above are examined in terms of how they apply to three specific circumstances: (1) on-site RE installations that may not be fully integrated into grid emission factor calculations; (2) GHG-emissions capped power sectors; and (3) to RE offset projects whose emission rates may also be available as RECs. While it would appear that the "RECs as avoided emissions" definition would not be supportable in the later two circumstances, the role of RECs as alternative emission factors is examined in terms of its technical viability and consumer expectations. In both situations, the strong financial additionality approach to RECs would make issuing RECs from these projects challenging or unfeasible. The re-slicing approach may also not fully satisfy consumer expectations. The accounting practices surrounding how to treat allowances paired to voluntary RE are also examined.

Summary and Considerations: Despite the proliferation of different definitions and applications of energy products, any corporate claim associated with an external mitigation instrument should follow the same accounting and reporting requirements demanded of their corporate inventory. User feedback from a broad array of stakeholders and experts is sought to begin to clarify the accounting basis for these instruments, and how to best serve company reporting and mitigation efforts.

I. Objectives

The issues, challenges and options described in this paper are structured to provide a basis for stakeholder discussion and exchange. The ultimate objective of this stakeholder process is to identify and recommend clear and consistent accounting procedures for energy-related instruments, largely motivated by companies' desire to reduce the GHG emissions associated with their electricity consumption. Energy and energy-related commodities are regulated and influenced by numerous organizations, with the end result that rules, definitions and practices have varied geographically. These guidelines are not intended to supplant any particular regulatory or programmatic approach, but aim to act as a two-way opportunity that can clarify corporate GHG accounting and mitigation practices to ensure their credibility, and offer a stakeholder-based vision for how energy systems and commodities can best meet the needs of the voluntary market.

This paper is structured around an examination of key GHG accounting issues at play in buying green power, based mostly on the US experience with renewable energy credits (RECs) but also applying the energy accounting principles to renewable energy offsets. The questions, challenges and inconsistencies arising from corporate accounting experience with these instruments have posed pragmatic challenges not only for consumers, but for project developers and policy makers. As a policy-neutral initiative, the GHG Protocol has not been involved in creating or enforcing renewable energy or carbon policies: we approach these questions from the point of view of the corporate inventory framework, the concept and principles of which have been internationally recognized and implemented as the basis for corporate GHG measurement and management. In confronting the accounting needs within the corporate inventory, we have confronted the category of "scope 2" and the conceptual challenges therein. We have also drawn upon guidance from the GHG Protocol Initiative's *Project Protocol* and its supplementary guidance to better delineate the expectations of how to integrate project-based accounting within a corporate inventory framework.

Other countries' energy markets have confronted similar accounting questions, but have often ascribed different definitions, attributes and functions to the certificates and commodities of their systems. Closer examination of these markets, particularly those with advanced regulatory structures and policies such as Europe, will be a forthcoming area of focus. Underlying these questions are core conceptual and accounting principles whose clarification and elaboration can address the unique concerns and challenges of these systems.

The success and growth of renewable energy markets worldwide is critical in transitioning to a low or zero-carbon economy with a stable climate, and sound corporate GHG accounting practices can provide the clarity needed to mobilize broad voluntary participation.

II. Overview

Equipped with information about their GHG emissions, companies have set about designing reduction strategies that include both internal changes and purchases of commodities. Given the prominence of electricity emissions as an overall part of corporate GHG inventories, companies have expressed specific interest in reducing the emissions associated with these emissions, which are categorized as scope 2 by the GHG protocol. This category is defined as an indirect emissions source in that users are consuming a service – the electricity supplied—and estimating the consequences of those services that are taking place outside of the company's inventory boundary. The basic formula for calculating scope 2 emissions is described in Box 1:

BOX 1: Calculating scope 2 emissions
Consumed MWh X Grid Average Emission Factor = Total Emissions

The total emissions here are a function of the GHG-intensity of the emission factor associated with the reporting entity's grid consumption, as well as the total amount of electricity consumed.

This calculation of scope 2 represents an estimate of the physical emissions (or 'physical footprint') occurring on the grid from which the reporting entity is consuming electricity. It is the approach currently recommended by the GHG Protocol *Corporate Accounting and Reporting Standard* for calculating scope 2 emissions. It treats electricity as a "shared resource," wherein the emissions created during the process of generating electricity for the grid are averaged and reported as indirect emissions by all grid users in proportion to their consumption. Here, the emission factor used in the calculation is set by the physical mix of sources used on the grid, and is outside of the reporting entity's control. To reduce scope 2 emissions, one or more of the three components of the equation would need to show a decrease. These components are described in Box 2. Broadly, these changes could include the following:

BOX 2: Means of calculating and reducing scope 2 emissions		
Activity Data **x**	**Emission Factor** **=**	**Total Emissions**
Reduce MWh consumed [1]: • On-site energy • Efficiency improvements • Behavioral adjustments	*Reduce GHG-intensity of EF:* • Grid mix becomes "cleaner" over time • ***RECs?***	*Apply external reduction instrument*: • Offsets measured in tonnes CO_2e avoided/reduced • ***RECs?***

Changes in Activity Data: Internal operation changes such as energy efficiency improvements to buildings, behavioral adjustments and installing on-site renewable energy generation. These actions can both reduce the amount of grid-consumed electricity[2], as well as in electricity costs.

Changes in Emission Factors: Current GHG Protocol recommendations are to use emission factors representing the physical grid from which the reporting entity is consuming electricity. These emission factors can become more or less GHG-intensive over time depending on the consumer demand,

[1] Projects under the first column of "reducing MWh consumed" can arguably have an impact on the overall demand on the grid, and therefore impact the mix of energy sources used to supply energy (due to dispatch order). However, outside of substantial energy efficiency retrofits, the effect on the average grid factor is generally considered small and can be estimated separately using "project protocol" methodology.

[2] As described in the Box 2, a total reduction in reported scope 2 emissions is affected by both the activity data and the emission factor. Lowering activity data alone, while important in terms of cost-savings and reducing grid demand, does not guarantee a reduction in scope 2 emission—the grid average emission factor would need to stay the same or decrease for scope 2 reductions to be realized.

regulatory policies, and fuel choices of that grid. These are conditions outside of the direct control of the company.

Changes in Total Emissions: These can be affected through the application of external reduction instruments. Scope 1 emissions represent direct emissions to the atmosphere that can be "offset" by certified reductions created outside of the reporting entity's inventory boundary. These instruments, measured in tonnes CO_2e avoided/reduced, may also be applied as external mitigation instruments to other scopes, including scope 2.

<u>This paper examines the role of external instruments that could potentially impact either the emission factor used to calculate the scope 2 emissions, or "offset" total scope 2 emissions</u>. In the U.S., renewable energy credits (RECs) have been conceived of by different programs as fulfilling both of these functions, representing either an instrument embodying an alternative emission factor or an instrument representing avoided emissions. Even though both definitions would result in a reduction to scope 2 emissions, the exact reduction amounts vary between the two approaches, creating uncertainty in the market as well as variation for consumer interpretation and error. More fundamentally, they convey two different assumptions about the nature of the underlying projects from which the RECs are generated. The accounting implications of voluntary renewable energy, or VRE, under different policy scenarios such as a cap and trade regime also differ depending on the understanding of these REC definitions.

Section III of this paper provides further background on the definitions that different organizations have ascribed to RECs, Because the concept of additionality is of cross-cutting importance, it is summarized in Section IV. The paper then considers in depth the extent to which RECs can be used as alternative emission factors (Section V) or used to "avoided emissions" claims (Section VI). Finally, Section VII compares these two REC definitions under different energy ownership and policy scenarios to evaluate the corporate GHG accounting implications, particularly regarding concerns of double counting.

III. REC definitions and attributes

Practices have emerged to isolate individual qualities or attributes of electricity and treat them as a separate commodity from the underlying electrons supplied to the grid. In the U.S., the primary instrument to convey these non-electricity attributes has been RECs, which were largely used as a compliance tracking instrument for state renewable portfolio standards (RPS) requirements. In this regulatory setting, RECs are given to qualifying renewable energy generation facilities, which in turn submit the RECs to load serving entities, enabling those entities to demonstrate that a certain percentage of their total electricity load has been supplied from renewable energy. In this situation, the REC itself can be seen as an instrument measured in MWh and awarded based on the source of the energy, defined with slight variations in technology type and geographic location as per state RPS definitions. They provide proof that 1 MWh of renewable energy was produced and added to the grid.

To provide an additional revenue channel to support and grow RE, RECs have been made available to all consumers and constitute a voluntary market separate from RPS compliance (described throughout this paper as voluntary renewable energy, or VRE). RECs underlie most green power products available on the voluntary market, providing the means to track VRE transactions[3].

[3] Some support/utility programs offer a tariff or premium that provides support for RE development without tracing it to ownership of a commodity.

Voluntary RECs have been presented as a way to support and incentivize greater growth in renewable energy, as well as a mechanism for purchasers to reduce the emissions associated with their electricity consumption. To support claims around each of these functions, RECs have been described as having specific “attributes”, which represent the descriptive or performance characteristics of a particular generation resource. ETNNA have described these attributes in terms of **primary** and **derived** attributes.

Primary attributes: Primary attributes include those qualities associated with the identity and operation of an energy generation facility, including a description of its technology, location, energy output, and various emissions, among others. RECs tracked in renewable energy tracking systems (discussed below) record these attributes.[4]

Derived Attributes: Derived attributes relate to the impact of the energy generation installation. ETNNA notes that one derived attribute is the avoided emissions from the displacement of fossil fuel generation by renewable generation. In this case, the system-wide effects of renewable generation are included in the REC.

Implications for GHG emissions

The two categories of attributes—primary and derived—largely correspond to the two different definitions for RECs in corporate inventories. Owning a primary attribute such as an emissions rate could lead to the application of RECs as an alternative emissions factor. In contrast, owning an indirect attribute that represents the impact (avoided emissions) of a given project could lead to the application of RECs as ‘offsets’ (i.e. to deduct the amount of avoided emissions from the calculated scope 2 total). For a single instrument to carry two distinct and separate possible applications to a GHG emissions inventory presents challenges in terms of conceptual clarity and consistency in the marketplace. The distinction between these two definitions largely comes down to the issue of additionality, the background for which is provided below.

IV. Concept of Additionality

Additionality is a complex concept at the heart of defining GHG offsets, but its application to RECs has not been clearly drawn. Current programmatic interpretations have lead to confusion regarding the definition and role for additionality in RECs. For instance, Green-e states that its RECs do not have to meet additionality requirements, noting that the lack of additionality requirements for RECs is what distinguishes them from offsets.[5] Its requirements of source type and vintage (after 1997) are not described as additionality requirements; however, these same categorical requirements in the Climate Leaders program are described as determinations of additionality.

In the context of GHG offsets, additionality is defined by the *GHG Protocol for Project Accounting* as a criterion that stipulates that “project-based GHG reductions should only be quantified if the project activity ‘would not have happened anyway’” [6]. In other words, the project reductions should be evaluated against a reference case that represents a hypothetical scenario of what would have most likely occurred in the absence of any considerations about climate change mitigation.[7] More broadly, additionality can

[4] “Treatment of Environmental Attributes Across Tracking Systems.” Environmental Tracking Network of North America. 26 Nov 2008.

[5] Frequently Asked Questions, Green-e Climate http://www.green-e.org/getcert_ghg_faq.shtml

[6] WRI and WBCSD. *The GHG Protocol for Project Accounting.* 2005.

[7] WRI and WBCSD, *The GHG Protocol for Project Accounting,* 2005. p. 12.

also be thought of in statistical terms, or a means of controlling the number of false positives and negatives.[8] The ultimate goal is to screen out "free-riders" from receiving offset credits when those same projects would have taken place without the credit mechanism.

Under the *GHG Protocol for Project Accounting*, there are two fundamental approaches for establishing this reference case, including the project specific approach and the performance benchmark.

Project specific

Under the project specific approach, the baseline scenario is selected from a number of potential baseline candidates that represent realistic alternatives to the project activity, and may possibly even include the project activity; indeed, even absent the incentive of an offset, in some situations the project activity may be the most compelling choice. If the project activity is different from the selected baseline scenario, then it is deemed additional. Otherwise, it is not additional and the quantification/crediting process does not continue. The crafting of the BAU scenario is inherently vulnerable to subjective criteria: numerous economic, logistical, and regulatory variables influence what kinds of energy projects are currently pursued, and therefore what kinds are likely to be pursued in the future.

Performance standard

The performance standard simplifies the process of selecting the baseline scenario by establishing a performance benchmark that functions as the baseline scenario. For renewable energy (RE) projects, this benchmark could consist of an average GHG emissions rate from all baseline candidates, here most likely a rate from fossil fuel generators. Projects which have emission rates lower than this average would be deemed additional. This approach rests on the assumption that existing fossil-fuel combustion technology will almost *always* be the most likely choice for implementation—reflecting the reality that that RE still represents only a small percentage of grid-electricity—and that therefore this performance average reasonably functions as the *baseline scenario.* Individual incentives and conditions present for a given potential project or its alternatives are not formally analyzed in the performance standard approach. Instead, the performance standard approach assumes that anticipated revenues other than from the sale of offset credits (including RE tax credits, rebates, feed-in tariffs or other incentives) overall play a limited role and do not significantly change the number of "free-riders" that would be rewarded via offsets certified through the performance standard.

Supplementary tests

Both the project specific and performance standard approaches entail assumptions and subjective analysis. Because of the potential to reward "free riders" even within these established approaches, separate criteria to evaluate additionality are often recommended. It is particularly recommended that projects developed with the performance standard develop credible screening tests for additionality.[9] The *Project Protocol* notes that these tests aim to isolate the reasons for implementing a GHG project, and whether achieving GHG reductions was a "decisive reason" for implementing it. The excerpt from the *Project Protocol* below in Box 3.1 enumerates some of these "tests" or criteria.

---

[8] Gillenwater, Michael. "Redefining RECs (Part 1): Untangling attributes and offsets," *Energy Policy,* Volume 36, Issue 6, Issue 6, June 2008.

[9] WRI and WBCSD, *Guidelines for Quantifying GHG Reductions from Grid Connected Electricity Projects*, 2007. p. 9

The consistent theme throughout all these additionality tests relates directly or indirectly to project finances, as the multitude of reasons why a project might be pursued can be boiled down to its financial viability. Some have emphasized that this quality of financial additionality puts financial additionality at the heart of defining an offset: Gillenwater states that “An essential part of that definition is that a project’s eligibility must be contingent on it being additional, meaning that the project would not have happened in the absence of the incentive created by the opportunity to sell offset credits.”[10] While the concept of additionality forms the basis for offset frameworks and methodology, its application to RECs has not always been clear. The two definitions and uses of RECs introduced in these guidelines entail different assumptions and components of these offset additionality concepts.

[10] Gillenwater, Michael. “Taking green power into account.” *Environmental Finance: Special Report*. 2008.

BOX 3.1 Policy and the use of additionality "tests"

As noted in Chapter 2, many observers argue that the identification of a project activity's baseline scenario should be accompanied by an explicit demonstration of additionality using various additionality "tests." Some illustrative additionality tests are presented in Table 3.1. Generally, these tests try to isolate the reasons for implementing a GHG project—particularly whether achieving GHG reductions was a decisive reason for implementing it (even if only one among many). They involve evaluating objective conditions that are assumed to indicate reasons for initiating a project. They are intended only to help establish that the GHG project and baseline scenario are different, and are applied separately from the actual identification of a baseline scenario.

However, there is no agreement about the validity of any particular additionality test, or about which tests project developers should use. GHG programs must decide on policy grounds whether to require additionality tests, and which tests to require. Because their use is a matter of policy, the Project Protocol does not require any of these tests.

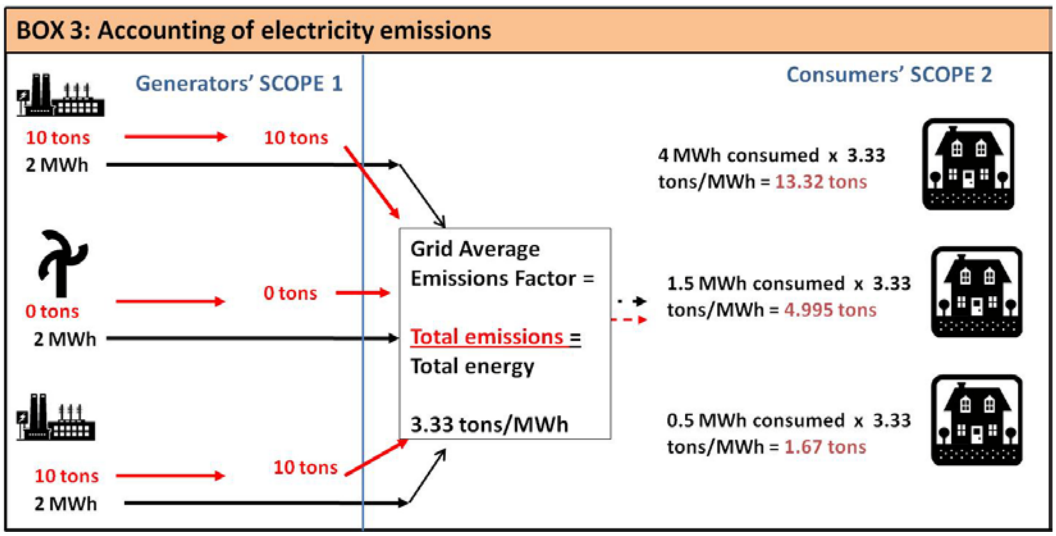
TABLE 3.1 Examples of possible "tests" for additionality

TEST	GENERAL DESCRIPTION OF THE TEST AS IT IS COMMONLY FORMULATED
Legal, Regulatory, or Institutional Test	The GHG project must reduce GHG emissions below the level required (or effectively required) by any official policies, regulations, guidance, or industry standards. If these reductions are not achieved, the assumption is that the only real reason for doing the project is to comply with regulations, and any claimed GHG reductions are not additional.
Technology Test	The GHG project and its associated GHG reductions are considered additional if the GHG project involves a technology that is not likely to be employed for reasons other than reducing GHG emissions. The default assumption is that for these technologies, GHG reductions are a decisive reason (if not the only reason) for implementing them. GHG projects involving other technologies could still be considered additional, but must demonstrate additionality through some other means.
Investment Test	Under the most common version of this test, a GHG project is assumed to be additional if it can be demonstrated (e.g., through the divulgence of project financial data) that it would have a low rate of return without revenue from GHG reductions. The underlying assumption is that GHG reductions must be a decisive reason for implementing a project that is not an attractive investment in the absence of any revenue associated with its GHG reductions. A GHG project with a high or competitive rate of return could still be additional, but must demonstrate additionality through some other means.
Common Practice Test	The GHG project must reduce GHG emissions below levels produced by "common practice" technologies that produce the same products and services as the GHG project. If it does not, the assumption is that GHG reductions are not a decisive reason for pursuing the project (or conversely, that the only real reason is to conform to common practice for the same reasons as other actors in the same market). Therefore, the GHG project is not considered to be additional.
Timing Test	The GHG project must have been initiated after a certain date to be considered additional. The implicit assumption is that any project started before the required date (e.g., before the start of a GHG program) could not have been motivated by GHG reductions. Under most versions of this test, though, GHG projects started after the required date must still further establish additionality through some other test.

Adapted from the GHG Project Protocol, 2005.

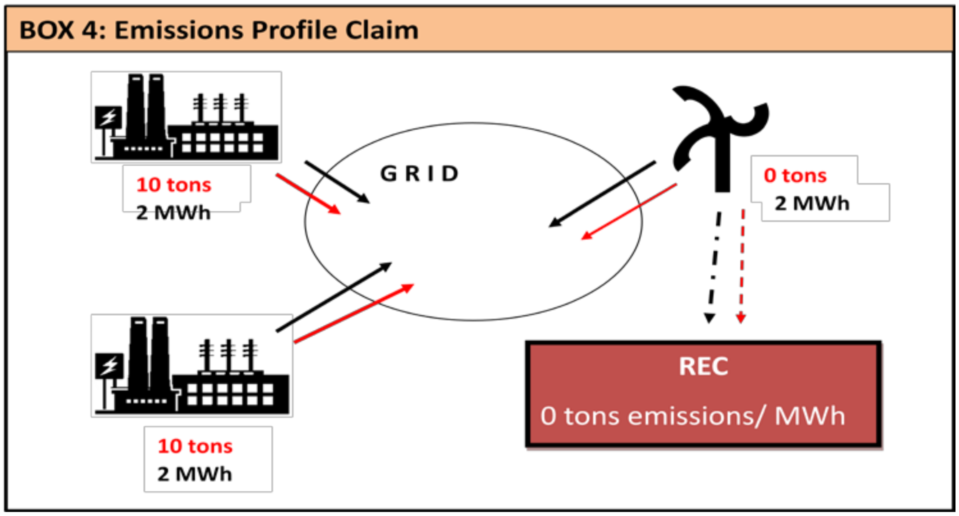
V. Applying RECs as an Alternative Emission Factor

Each energy source supplying the grid also produces different amounts of GHG emissions as part of its operations. When energy is placed on the grid, its underlying electrons flow indistinguishably to the nearest point of use. Because consumers cannot distinguish which energy sources have produced the electrons which they have specifically consumed, they cannot link their consumption with a particular source's emissions. Instead, consumers determine the emissions for which they are indirectly responsible through using an **average grid emissions factor.** Here, the total emissions associated with producing electricity from all of the sources supplying the grid are aggregated and then divided by the total amount of energy they have supplied (in MWh or kWh). Consumers multiply this average factor by the amount of electricity they have consumed in order to arrive at an estimate of the total emissions for which they are responsible. Box 3 provides an overview of how scope 2 emissions utilize these factors.



In principle, grid average emission factors are a means of allocating pooled emissions on an energy unit basis, and different energy generation sources can be grouped together to produce different average emissions profiles. In the U.S., eGRID aggregates emissions information based on sub-region, itself a boundary drawn a combination of NERC and ISO regions. Many utilities compile information about the generating sources that are serving their customers and can produce "utility-specific" average emission factors. GHG Protocol 's recommendation has been to select the most accurate and precise average grid emissions factor that reflects the impact of the electricity "locally" consumed. While this calculation practice provides a consistent means of tracking electricity emissions, it presents an inherent limitation to users: the emissions profile of the grid is largely out of their control. The profile may become more or less GHG-intensive due to choices and conditions occurring outside of their inventory boundary. One possible alternative to assuming assume this "default" emissions factor, is for consumers to actively select the emissions factor that will be associated with their electricity consumption (i.e., a primary attribute).

The most appealing emissions sources from a GHG standpoint would be those with a zero or low emissions factor. These sources would generally include renewable energy and nuclear. The question has been whether the profiles of these sources can be isolated and "sold separately," so as to allow for the selection of a different emission factor from that associated with local electricity consumption**.** This concept is illustrated in Box 4, where the REC is capturing the emissions rate associated with a wind installation.



Procuring and using a favorable emissions factor in calculating electricity emissions represents a contractual transaction, and can be thought of as the basis for a **contractual emissions factor**. While the wording around REC "claims" and retirement might not be framed explicitly in terms of its role as an alternative emissions factor, this procurement and calculation practice is part of what has taken place with regards to RECs in the U.S. Green-e describes RECs as providing the "contractual rights to the non-energy attributes of one MWh of renewable energy generation,"[11] but the application of these contractual rights in the calculation of scope 2 emissions requires an analysis of what emission factors represent and what they need in order to be properly used. As Green-e notes, "the broadly defined nature of claims and the intangible nature of RECs can result in problems with double selling and double counting."[12] Three main requirements emerge:

(1) A clear system of tracking and ownership requirements

The emissions represented in the grid average emissions factor (the numerator) are not "owned" by the consumers who report them as indirect emissions. However, if RECs are to function as contractual, alternative emission factors that are separated from this otherwise pooled data, then they should be treated as a uniquely-owned commodity. This provides the definition necessary to support specific claims by purchasers, and prevents double selling.

(2) Adjustment of average emission factors

If RECs are to be used as contractual emission factors, then the information they contain must be isolated from the pooled data that other users employ in scope 2 calculations. Otherwise, the emissions associated with the REC still contribute to the GHG grid average, even if the REC claims that these emissions are separate. This constitutes double counting of the emission rates.

(3) Clear role for additionality

Perhaps the most challenging questions in operationalizing the use of RECs as alternative emission factors concerns the types of projects which should be credited with a REC in the first place. Two distinct concepts emerge: one is that **any** energy generation source can produce contractual emission factors that can be made available for sale to any consumer, so long as those factors are subtracted from the pooled average used to calculate the indirect emissions of other grid consumers. The other concept suggests that only a sub-set of low or zero-emission profiles from new, additional projects should be made available for use as

[11] "Best practices for public claims in green power purchases and sales." Green-e, Center for Resource Solutions. 7 Oct 2010. http://www.green-e.org/docs/energy/Best%20Practices%20in%20Public%20Claims.pdf

[12] ibid

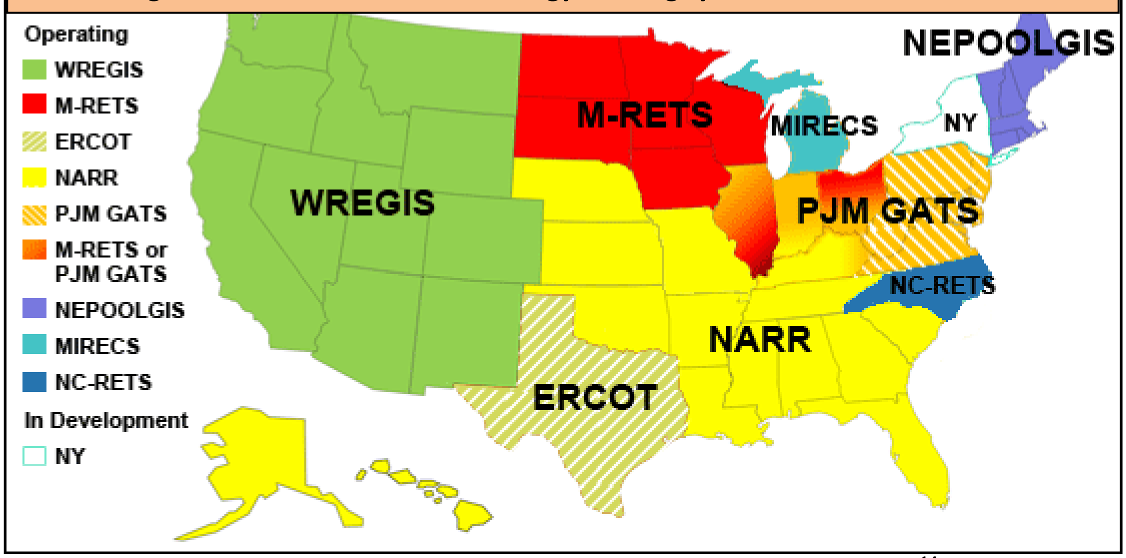
contractual emission factors. The first concept is based on the expectation that "re-slicing" the grid's average emissions allows consumers to be associated with their preferred profile and may drive demand for less GHG-intensive energy profiles over time. The second concept views the application of contractual emission factors as an instrument which should represent a distinct change in the GHG-intensity of the grid compared to what would have happened in the absence of the availability of the REC, and that the only eligible projects are those which would not have come about without the funding prospect of selling this emission profile commodity.

Each of these requirements is explored in further detail below.

1. Tracking and Ownership

Different mechanisms have emerged to ensure the tracking and unique ownership of different types of RECs, including those mechanisms created by voluntary REC vendors themselves and those mechanisms coordinated by regional systems for RPS compliance. Some of the regional RPS tracking systems also track information for voluntary REC vendors, serving as an additional layer of transparency.[13] The main purpose of all of these tracking systems is to provide a centralized, transparent clearing house for REC transactions. These tracking systems are separate from, though usually coordinated with, the transmission organizations that manage the physical electricity. This infrastructure is important to consider because it has the capacity to collect contractual information that has served both mandatory and voluntary markets. In the U.S., the firm APX has provided the infrastructure for each of the regional tracking systems. BOX 5 shows the regional RE tracking systems in current operation.

BOX 5: Regional renewable and other energy tracking systems



Adapted from GPP website (attribution here to Ed Holt & Associates)[14]

[13] The EPA Green Power Partnership notes that ""Tracking systems are not substitutes for product certification and verification, as tracking systems only monitor wholesale transactions — individual retail green power customers do not generally hold accounts in tracking systems unless they make very large purchases". EPA Green Power Partnership: Green Power Market, REC Market http://www.epa.gov/greenpower/gpmarket/tracking.htm

[14] EPA Green Power Partnership, http://www.epa.gov/greenpower/gpmarket/tracking.htm

In general, these systems operate so that qualifying RE sources submit their generation information, which is confirmed by a Qualifying Reporting Entity (usually the independent system operator of the region, or ISO) and which can be put in various accounts (normally those of utilities) to demonstrate RPS compliance. Because state RPS's have varying requirements for what constitutes a "qualifying RE source," the generation information entered into a tracking system generally includes:

(a) Energy source
(b) Generation/conversion technology
(c) Plant location
(d) Vintage (when certificate was created)
(e) Direct emissions from the facility

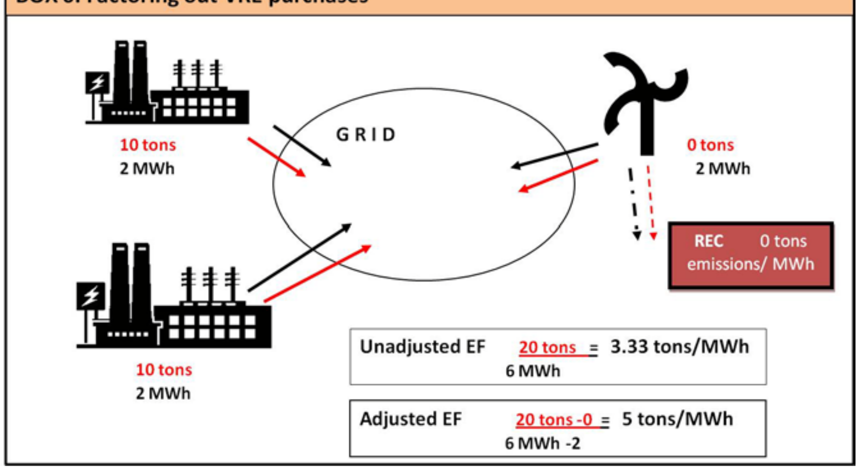
Example of All-Generation tracking: PJM-GATTS
In addition to tracking renewable energy information, two regional tracking systems in the U.S. track all the energy generation that takes place within their system: PJM-GATS and NEPOOL. All-generation tracking primarily facilitates fuel disclosure by utilities, but also serves the RE-tracking functions necessary for RPS compliance. In the case of PJM-GATS, a "system mix" can be calculated which demonstrates the relative contribution of various fuel sources to the overall system. If this system mix can incorporate information on the GHG emissions from those sources, then in essence it can represent a grid average emissions factor for the system. PJM-GATS also calculates a "residual mix" that can factor out RECs produced in the region which are retired for voluntary purposes. This kind of transparent tracking and adjustment could provide a model for REC transactions nation-wide.

While largely designed to serve utility and state policy purposes, these tracking mechanisms may offer the potential for greater application to VRE markets.

2. Adjustment of Average Emission Factors

Preventing the double counting of the emission profiles (or any "pooled" attribute) requires that the emissions rate be isolated or factored out of the average emissions' rate. Otherwise, the average rate that is shared among all grid consumers includes the low or zero GHG emissions profile of RE projects, which have been separately sold in the form of a REC. This adjustment procedure is described in Box 6.

BOX 6: Factoring out VRE purchases



Currently, the primary emission factor information source recommended by the GHG Protocol—eGRID—is not designed to integrate market information such as renewable energy purchases. Rather, it is designed to calculate the emissions output from electricity generation on a geographic basis. Moreover, most systems of tracking renewable energy purchases are not all-generation tracking systems that would be capable of producing adjusted emission factors. This leaves the question: what are the prospects for facilitating this adjustment and validating voluntary renewable energy purchases?

Where would the adjustment occur?

As noted above, emission factors can be theoretically compiled to reflect the emissions from different geographic or corporate groupings. Utility-specific emission factors would generally offer the most geographically-precise emission factors, while national averages would offer the broadest. While a single system for tracking and adjusting emission factors would provide consumers clarity and confidence in calculating scope 2 emissions, there may be ways in which existing entities could further enhance information sharing and provide cross-checking and verification functions. The following are three entities who currently track some of the information necessary for adjustment, and the strengths/limitations that their adjustment offers.

(a) **eGRID:** Because GHG Protocol currently recommends that U.S. organizations utilize eGRID output emission rates to calculate scope 2 emissions, eGRID would seem to be a logical channel in which adjustment could occur while maintaining the current scope 2 data source recommendations. However, the average emission output rates are designed to reflect emissions information from designated geographic regions; incorporating information about voluntary market transactions would require coordination with regional REC providers and regional tracking systems. Because eGRID is a technical database, this requirement may be outside of eGRID's designed purpose.

(b) **Utilities:** Many utilities are currently required to disclose their fuel mix to the customers they supply, and can produce emission factors associated with this mix. Users calculating scope 2 emissions may be able to obtain these factors in order to calculate a more geographically precise emissions footprint for their electricity use. Utilities may also be able to transparently track RECs that are generated by their suppliers and those that are purchased from outside of their system (for use in green power pricing programs, etc.) Because the practice of utility disclosure of emission factors is not prevalent, and because REC transactions so frequently cross utility jurisdictions, relying on utilities to facilitate adjustment may be impractical.

(c) **Regional energy tracking systems:** These systems may hold the most potential for executing emissions factor adjustments, particularly for those systems that are all-generation tracking. Renewable energy-only systems could theoretically group together data on yearly VRE purchases by eGRID sub-region, and calculate an adjusted emission factor for those sub-regions based on eGRID emissions output rates. All-generation tracking systems would be able to facilitate factoring out more easily, as they would already have both sets of data—generation data as well as REC transactions—for their region. This region would likely not coincide with the eGRID subregion demarcations, and this may require a modification on the part of companies who currently use eGRID emission factors.

Does the scale of impact matter?

Several organizations have noted that while the adjustment of emission factors could theoretically bring greater transparency and accuracy to renewable energy transactions, the small percentage of renewable energy purchases relative to the total grid energy supply makes this adjustment inconsequential. Expending time and resources to resolve adjustment concerns that ultimately have negligible impacts may not be perceived as a worthwhile endeavor. However, three points argue otherwise:

(a) **Need for quantitative analysis:** It may be the case that the cumulative effect of VRE adjustment would not change eGRID sub-region emission factors by an amount that would show up in other grid users' scope 2 calculations. But there is currently limited quantitative analysis to support these conclusions, constraining the information needed for decision-making by REC vendors and GHG reporting organizations. Greater quantitative analysis here would provide a clearer mapping of the present VRE landscape and provide a basis to define what constitute "consequential" changes over time.

(b) Designing a system prepared for the market's growth: If one of the ultimate goals of the VRE market is to increase the percentage of RE as part of the overall electricity supply, then the tracking and adjustment infrastructure should be designed to support rather than hinder that growth. Even if current VRE purchases are deemed modest in their impact and not meriting the time and effort necessary for grid EF adjustment, the question remains: at what point will those purchases merit adjustment, and how would such a mechanism operate? In their Climate Registered program, the Climate Registry has addressed this question of timing by setting a threshold that would trigger further inquiry into EF adjustment possibilities. Here, they note that if the total VRE purchases for reporting members within given energy grid regions would change that region's average EF by more than 5%, then The Climate Registry would itself provide adjusted figures for those regions. This procedure offers a way to define impact and balance the demands of EF adjustment, but there may be further market benefits to proactively designing a system for country-wide VRE purchases and adjustment.

(c) Addressing consumer concern: VRE consumers expect that their purchase conveys unique and exclusive rights to a low or zero-emissions profile, as advertised by REC vendors. Without an acknowledgement of the issue of average emission factor adjustments, this basic claim appears misleading. More fundamentally, stating that the impact of VRE purchases currently has an inconsequential impact on the grid's emission profile presents a conflict for consumers: if purchases have no impact on the grid, are they fulfilling their advertised promise? Transparently providing adjusted factors, even if they do not differ significantly from the unadjusted factors, indicates to consumers that their purchases are taken seriously and that this sector's growth is anticipated.

How to Address Data and Timing Challenges?

A more fundamental challenge in conducting adjustment of emission factors may be insufficient published data on both REC transactions and average emission factors. This appears most acute at broader geographical levels: for instance, eGRID's most current factors already contain significant time delays, while energy tracking systems or utilities collect and report information more frequently to serve different market purposes. Even absent considerations of reflecting VRE purchases, these time delays present a disconnect terms of matching an organization's yearly electricity consumption data with the emission factor reflecting the grid conditions from that year. While the GHG Protocol has recommended using the most current factors available, no formal procedures have been identified to "re-calculate" scope 2 emissions from prior years once the emission factors for that year's data become available.

For instance, a company that calculates scope 2 for calendar year 2009 may draw upon emission factors published in 2007, which reflect data and grid conditions from 2005. When data for 2009 become available (following the delay pattern, this could be published in 2011), would there be value for a company to re-calculate its 2009 inventory based on the emission factors representing that year? While representing greater accuracy in the inventory, this revision would likely prove burdensome and ultimately not advance the company's GHG management goals, as the EF is outside of their control. However, if one of the purposes of adjusting EFs for VRE purchases is to in fact provide clear ownership of VRE emission rates in relation to the rest of the grid, the time delay throws off the alignment of these claims. Companies could purchase and claim VRE in 2009, while the adjustment of the VRE's grid may not take place or show up until several years later. The visibility of the grid adjustment to other users on the grid (i.e., being left with a more GHG-intensive EF) should theoretically serve as motivation for more users to purchase VRE, but the data and time alignment challenges may further reduce this.

While adjustment provides the basis for claiming RECs as emission factors, technical challenges in conducting this at the right level and with the right frequency remain. Further discussion and collaboration is needed between grid users, VRE purchasers and these potential channels of adjustment.

3. Role for additionality

Even if technical approaches in tracking and adjustment could take place, a fundamental question remains regarding the requirements of the VRE projects whose emission factors would be available for use as scope 2 mitigation instruments. As noted above, REC retailers and voluntary GHG programs have addressed the additionality issue for RECs differently. For conceptual clarity, we will examine two distinct approaches: one that requires no additionality tests for RECs—in practice, serving as a means of **re-slicing** the emission factors currently on the grid, embedded in the system average— and one which requires **strong financial additionality** screening.

The re-slicing approach

In a sense, the grid average emission factors currently recommended for scope 2 calculations represent a "slicing" of total electricity emissions based on geographic groupings (i.e., physical grids). But if all energy—not just VRE—can be separated into two streams consisting of underlying electrons and emissions, then those emissions can be "re-sliced" according to contractual emission rate purchases rather than physical grid aggregation.

Under this scenario, **any** VRE installation (or theoretically, any energy generation source) could produce contractual emission factors which are available for sale to consumers, so long as those factors are subtracted from the pooled average used to calculate the indirect emissions of other grid consumers. Every energy generation source would inherently produce an EF certificate that would either be purchased by an individual consumer for calculation of their scope 2 emissions, or submitted ("bundled") with their underlying electricity and mingled into the grid average. While such a system could operate simply through the VRE adjustment procedures described above, the concept could also be expanded to include all energy sources on the grid whose emission rates are captured in "certificates," constituting a more comprehensive accounting system. In the UK and other European countries, the infrastructure for this kind of tracking already exists as part of generating Guarantees of Origin.

Other aspects of the re-slicing approach include:

(a) **Additionality.** The re-slicing approach would not explicitly address or require RECs to come from additional projects. The REC would therefore not represent a change in the grid average EF compared to what would have happened without the incentive provided by the REC.

(b) **Theory of Change**. By allowing consumers (or utilities) to chose the emission factors associated with their energy consumption, the low or zero-emissions/MWh profiles will be purchased by those consumers with the highest demand for low-carbon energy, and other consumers on the grid will in turn have a more GHG-intensive average emissions factor. Over time, demand for low or zero emissions/MWh energy will increase as more consumers seek to purchase RE. Further demand could grow from other consumers seeking to change the "dirtier" average with which they are now left.

(c) Concerns. A re-slicing approach to emission factors provides simplicity in its approach, avoiding the complex questions of additionality. While this "re-slicing" may be technically feasible, one concern is that it inherently does not represent "mitigation" in the near-term and therefore should not be considered a means of reducing GHG impact. Purchasing a low or zero-emisisons profile may "reduce" scope 2 emissions compared to what would have been calculated with a grid average emission factor, but it does not represent a change or "reduction" that is currently happening on the grid. Re-slicing emission factors may simply shift the indirect "ownership" and distribution of emission profiles, but not the overall GHG-intensity of the grid. Even for consumers who envision their purchase contributing primarily to the long-term (vs. short-term) increase in demand for less GHG-intensive energy sources, numerous variables and other market forces may limit the desired collective effect.

The strong financial additionality approach

The strong financial additionality approach suggests that while the concept of contractual EFs may be sound, it is incomplete or insufficient to serve as a mitigation instrument for scope 2. Instead, only a sub-set of low or zero-emission profiles from new, additional projects should be made available for use as contractual emission factors. Additionality criteria, as broad and multi-purposed as they are, could establish a stronger casual link between consumer purchases and changes in GHG-intensity on the grid. In particular, financial additionality can provide the link between the purchase and the effect on the grid.

How does the strong financial additionality approach look different from the re-slicing approach? The average grid emissions factor (or system mix) may continue to become less GHG-intensive as renewable energy projects are brought online for RPS compliance or general financial viability. But only projects passing rigorous financial additionality testing would be available for voluntary purchase as a contractual emission factor that can substitute for the grid average emission factor. A strong additionality approach could theoretically give consumers a meaningful channel through which to influence the grid mix, and could minimize the concerns regarding the efficacy or appropriateness of REC purchases reducing scope 2 emissions. One would also anticipate that rigorous additionality screening would increase the price (and value) of RECs. Finally, it has been observed that long-term purchase contracts are one of the clearest ways to provide financial stability and predictability to new renewable energy projects.[15] RECs from such projects would likely pass additionality screenings or criteria as defined in the *Project Protocol*, *if such contr*acts stipulated ownership of RECs.

Various challenges exist in applying the strong financial additionality approach. These include:

(a) Clarity. Additionality criteria can be identified and applied independently of emissions quantification—the tests or criteria themselves are simply ways to isolate the reasons for implementing a given GHG project. However, because offset methodology first arrives at additionality through the crafting of a baseline scenario or performance benchmark, it may not be conceptually clear how individual criteria might apply absent this "anyway" comparison. Also, because these concepts come from offset methodology designed ultimately to quantify avoided/reduced emissions, their application to RECs which function as emission factors rather than instruments embodying avoided emissions may not be clear.

[15] Ibid.

(b) What methods to test? Ensuring that RECs are the "decisive" financial reason for the project requires a clear procedure to evaluate a project's finances. The methods that have been employed to test for this currently vary among different RE offset methodologies.

(c) What time horizon to apply? With RE offsets, the avoided emissions are quantified and credited for a set period of time, usually limited to a few years into the future. Here, uncertainty increases the further out into the future one projects "what would have happened."[16] For VRE projects that are deemed additional, for how long a period of time would they be eligible to sell their RECs as contractual emission factors? Would they simply be added back into the grid average after that time had passed? These operational parameters would need to be clearly established in the context of continuing to "reward" what is financially additional.

(d) Actual reductions may be incurred that are inherently not embodied in the application of a REC as an emission factor. Inherently, if VRE projects are additional, they should bring renewable energy onto the grid that would not have been established but for the potential to sell a REC. While the direct emissions from fossil fuel generators may have been avoided by an additional VRE project, they are not directly quantified and certified by the REC. Instead, the scope 2 calculation and the average grid rate becomes the vehicle through which purchasers of RECs demonstrate the "impact" of their purchase.

4. Summary and Considerations

RECs as EFs offers a viable application to scope 2, with proper adjustment, but questions remain regarding how and who can do this adjustment, and what types of projects would be eligible to produce this kind of REC.The question of additionality arises in terms of the instrument being used to "mitigate" scope 2 emissions: the re-slicing approach is technically feasible, but does not guarantee that that the users' purchase of the REC caused new energy to be added to the grid. Financial additionality screening could provide greater certainty in fulfilling this claims, but poses challenges in terms of identifying proper tests and timing. More fundamentally, because bringing on additional RE should entail emission reductions from fossil plants compared to what would have otherwise occurred, consumers may feel that they are functionally purchasing an "offset" rather than an emissions rate, even though the latter would still serve as a reduction instrument (for scope 2 emissions). In part, this explains the reasoning behind the "avoided emissions" claims examined next in Section VI.

VI. RECs as an avoided emissions instrument

Some mandatory and voluntary programs have argued that RECs should in fact function like an "offset" instrument – that is, an external mitigation instrument that represents a claim that emissions from fossil fuel generation sources elsewhere on the grid were avoided or reduced. This "derived" attribute has been distinctly emphasized by REC marketers, voluntary programs and state RPS rules.[17]

Though most organizations have made a point to distinguish RECs from offsets, the act of quantifying and claiming avoided emissions is common to both. Some have further distinguished that RE offsets meet requirements not needed for RECs—namely, additionality—and can apply to different scope categories. Also, where RECs have generally used simplified methodology to quantify these avoided emissions, RE

[16] WRI and WBCSD. *The GHG Protocol for Project Accounting*. 2005.
[17] See Green-e, the EPA Climate Leaders, and EPA Green Power Partnership.

offsets generally follow more detailed procedures to estimate operating and build margins. The question is, are the avoided emissions claims from RECs fundamentally different from RE offsets, and do the elements of additionality, scope application and quantification methods justify this distinction?

a. Issues of additionality ("avoided" compared to what?)

When an energy project claims to avoid or reduce emissions, the first question is "avoid compared to what?" With RE offsets, this question is answered through the two different approaches of a baseline scenario (project-specific) and a performance benchmark. However, the comparison case for RECs has not been clearly defined. The Climate Leaders program advised that the RECs used by its reporting Partners pass additionality tests through the performance-standard approach. But, in fact, its general designation of eligible renewable resources does not fully align with how performance standard benchmarks would be compiled for project accounting.[18] In the absence of an identified reference scenario, the reference case may simply become an evaluation of what fossil fuel emissions would be occurring in the absence of the project (in offset methodology, this would be the operating margin). Under this reasoning, any source operating on the grid—including fossil fuel plants—could be analyzed in terms of its contextual impact, revealing what would be running or built if this facility were not in existence. But the value in this methodological exercise is clearest when the alternative (the given facility *not* running) is deemed to be likely. If the project *not* running was never a realistic or likely possibility—in short, if the project was not additional—then this analysis presents a conflict in terms of the viability of the avoided emissions claim.

For a REC to maintain a claim that emissions were avoided compared to what would have likely happened requires a causal link between ownership of the REC and a clear reference case. Without this link, a REC purchaser has limited grounds to demonstrate that the "avoided emissions analysis" described above is more than an elaboration of an energy load duration curve. The absence of this link also means that various other entities (the government or other investors) could make the same claim that the "part" of the project that they own *caused* emissions to be avoided. RECs' secondary attributes have been defined in such a way as to limit others from making these claims (by containing "all the attributes"), but the fundamental causation link still remains an important question in order for the claim to be factually valid.

If additionality is needed in order to justify an avoided emissions claim, then RECs that are not additional cannot make avoided emissions claims.

b. Application to different scopes

Some programs have stated that the avoided emissions embodied in a REC are different from offsets in that they can only be applied to scope 2. In other words, where the atmospheric emissions reductions provided by offsets can be used to mitigate direct, scope 1 emissions, the avoided emissions embodied in RECs would only serve to mitigate indirect emissions. Some have noted that this distinction implies an unjustifiably weaker "standard" [19] for indirect mitigation instruments; but a more fundamental question is whether this distinction is conceptually valid.

[18] See EPA Climate Leaders, *Optional Modules Methodology for Green Power and Renewable Energy Certificates (RECS).* Nov 2008 and *The GHG Protocol for Project Accounting,* 2005.

[19] See Gillenwater, Michael. "Redefining RECs (Part 1): Untangling attributes and offsets," *Energy Policy,* Volume 36, Issue 6, Issue 6, June 2008.

The emissions that are avoided by an RE offset project are the direct emissions of fossil fuel plants. Likewise, the emissions avoided by a project producing a REC are still direct fossil fuel emissions. While RE projects achieve this avoidance indirectly (due to the nature of the grid), the claims relate ultimately to direct, atmospheric emissions. Consequently, any instrument that demonstrates an avoidance of these direct emissions should be eligible for mitigating scope 1 emissions. If RE offsets and RECs both represent avoided fossil fuel emissions, then it does not make sense to restrict the use of RECs to scope 2.

Additionally, if RECs are framed as "consuming the electricity directly,"[20] then one would expect similar procedures to be employed for calculating RECs as for calculating directly consumed grid electricity. When companies calculate and report in scope 2the emissions associated with grid-consumed electricity, they do not evaluate what they are *avoiding* through their consumption: they reflect the indirect emissions associated with their consumed electricity. Calculating what a given project avoids constitutes a separate and distinct application from evaluating the RECs analogously to other grid-consumed electricity. The latter is what has been traditionally captured in scope 2.

c. Methodology

Unlike RE offsets which are measured in tons of avoided CO_2e, RECs are measured in MWhs. This means consumers must calculate the emissions that were avoided due to the running of the RE plant, requiring information about the grid where the REC was generated. But isolating and evaluating the impact of any one source often proves challenging. Where quantification methods for RE offsets generally entail detailed analysis of operating and build margins,[21] those methods for RECs generally follow a simpler approach. The quantification method that REC marketers and programs recommend[22] to estimate avoided emissions generally involves applying a marginal, or "non-baseloaded" emission rate. This rate represents an estimate of the emissions (per MWh) of sources that are operating on the margin, and which would therefore most likely be displaced by a new renewable energy source. eGRID currently compiles these non-baseloaded rates in addition to average output rates, and describes them as a "slice of the system total mix, with a greater weight given to plants that operate coincident with peak demand for electricity."[23] eGRID also notes that non-baseloaded emission rates do not fully capture the intermittent impact of sources like wind.[24] Given the large number of voluntary RECs from wind sources, this presents a challenge in terms of the application of this methodology.

d. Summary and Considerations

RECs have been distinguished from RE offsets in terms of the requirements for additionality, the accounting scope applications, and the estimation procedures. But the underlying claim remains the same between the two products: emissions from fossil fuel plants on the grid were avoided due to the RE project. In the case of RE offsets, the reference case identifying "avoided compared to what?" is structured in terms of project specific or performance benchmarking procedures, and the RE project must be different from—or "additional to"—this reference case in order to even be quantified. This reference

---

[20] See Green-e Climate "Frequently Asked Questions: What is the difference between a renewable energy certificate (REC) and a carbon offset?" http://www.green-e.org/getcert_ghg_faq.shtml

[21] See WRI and WBCSD, *Guidelines for Quantifying GHG Reductions from Grid Connected Electricity Projects*, 2007.

[22] See EPA Climate Leaders, *Optional Modules Methodology for Green Power and Renewable Energy Certificates (RECS).* Nov 2008 and *The GHG Protocol for Project Accounting,* 2005.

[23] Rothschild, Susy S. et. al. *The Value of eGRID and eGRIDweb to GHG Inventories.* December 2009.

[24] As stated: "Non-baseload values may be less appropriate when attempting to determine the emissions benefits of some intermittent resources, such as wind power." Rothschild, Susy S. et. al. *The Value of eGRID and eGRIDweb to GHG Inventories.* December 2009. p. 6.

case, and in turn additionality, has not been clearly or consistently defined for projects producing RECs, challenging the basis of avoided emissions claims. Even if emissions were avoided due to the project compared to an established reference case, linking the REC as a "decisive reason" for the project would still appear to be necessary in order for this instrument to uniquely carry the claim. If the underlying avoided emissions claims are the same between RECs and RE offsets, then their application in different parts of the GHG inventory would not seem to be supportable. Methodological limitations also contribute to the challenges posed by this application.

A fundamental question remains: if RECs could be demonstrated to be additional and serve as the decisive reason for a project, then are they simply offsets in another form?

VII. REC Applications in Carbon Constrained, Claimed, and Other circumstances

So far, this paper has examined two major definitions for RECs – RECs as a contractual emission factor and RECs as an instrument conveying the right to claim avoided emissions. Other concerns related to the use of RECs exist, including:

(1) Accounting for RECs from on-site installations
(2) Accounting for RECs from offset projects
(3) Accounting for RECs from a capped power sector

Because of the conceptual conflicts described earlier when attaching avoided emissions to RECs, these issues are explored using only the "REC as a contractual emission factor" definition.

a. RECs from on-site RE installations

Renewable energy (such as solar panels) may be installed on-site and provide electricity to the host facility, and possibly the grid when generation exceeds the hosts' demand. The accounting of RECs from such on-site installations in part depends on whether the underlying energy is consumed on-site or sent back to the grid.

i. Energy consumed on-site

Consuming energy from an on-site installation reduces the amount of energy the host requires from the grid, thereby lowering the "activity data" of consumed MWh of grid electricity. Since an RE installation such as solar panels does not emit GHGs, it would not be reported as an emissions source within a corporate inventory. For transparency, many organizations have reported the emissions rate (usually 0 tons CO_2e/MWh) associated with the electricity they consume, even though it is not part of the "grid average."

If an organization has generated a voluntary REC through this on-site production and wishes to sell it as a 0 tons CO_2e/MWh emissions rate, then it cannot retain the use of this emissions rate in its GHG inventory. The organization that owns REC would be the only one who may use 0 tons CO_2e/MWh emissions factor to calculate their scope 2 emissions. Instead, one approach for the host would be to multiply the activity data (number of consumed MWh from the on-site installation) by the grid average emission factor. Methodologically, this may provide a reasonable approximation of the indirect emissions associated with the grid energy it otherwise would have been using in the absence of the RE installation.

One accounting question here would be whether the sale on-site REC would necessitate grid average adjustments, as would be the case for other RECs. Because the underlying electricity was never actually added onto the grid, but rather consumed on-site, it would not appear that any further grid adjustment is needed. In effect, by providing electricity exclusively to the on-site host, the electricity and emissions from the installation have already been “excluded” from the grid average calculation.

Under the **re-slicing** approach, the RECs could come from any VRE source. By contrast, the **strong financial additionality** approach would limit the types of installations that would qualify to sell RECs into the market.

iii. Energy sent back to the grid

The emissions rate from electricity that is fed into the grid should theoretically be reflected in the grid average emission factor used by all grid consumers; however, the calculated grid average emission factor may not always reflect this contribution. If an on-site installation sends energy back to the grid, and the host wishes to sells the RECs associated with that same electricity, those RECs should be factored out of the grid average in order to provide a zero emissions/MWh claim to the REC purchaser.

b. RECs from Offset Projects

Every energy source feeding the grid can be said to carry an emissions factor (i.e. to have a specific emissions profile); renewable energy projects would be no different, even if they are from new and additional projects that receive offset credits. If these factors are not isolated/sold separately, they simply blend into the grid average for their region and all grid consumers share the “benefit” of a less GHG-intensive EF. In other words, the “impact” of credited projects may already be partially reflected in the less GHG-intensive emission factor that is used by grid consumers. Under the **re-slicing approach**, any RE offset project could be used as the basis for contractual emission factors as long as the appropriate adjustment of the grid average emissions rate takes place. Here, the zero-emissions energy rate (the REC) could be purchased as a contractual emission factor in scope 2, while the offset could be sold separately and used to mitigate scope 1 emissions. However, under the **strong financial additionality approach**, projects that receive funding from the sale of offset credits would not likely be deemed financially additional and therefore would be ineligible as a basis for contractual emission factors.

Some may find it problematic that a single project can provide two separate commodities, feeling that the benefits of the project are “double counted.” However, even if RECs were not certified and made available from the offset project (which would otherwise “benefit” one individual, the REC purchaser), the emission rate of the RE still contributes to a lower grid average emission factor and thereby “benefits” all consumers. Some may be more comfortable with the concept of the emissions rate being shared by all grid users rather than be isolated and made available for individual sale. Another approach would be for *no entity*, whether individual or collective, to use the emissions rate from the RE offset project—that is, that the REC should be retired **and** the grid average rate adjusted to factor out the RE. This alternative approach may pose a host of technical challenges, including whether to “factor back in” the emissions rate after the duration of the RE offset’s crediting period, and whether at that time a REC might also become available for purchase.

i. Ownership and Enforceability

A fundamental challenge that applies to both REC “avoided emissions” claims and RE offset projects concerns ownership and enforceability: can an RE offset quantify and own reductions that are actually taking place in the facilities of other entities (i.e., fossil fuel plants). The grids in which RE projects are sited may include a range of other generation plants, and identifying and enforcing ownership of particular reductions presents significant challenges. Again, offsets are designed to represent emission reductions compared to a hypothetical reference case, not an historical corporate inventory analysis of fossil fuel generation—but in certain cases, fossil fuel plants on the grid may see the scope 1 emissions in their corporate inventory decreasing over time, while the new RE projects on the grid have quantified and sold those same reductions as part of the "impact" of the project. The challenge of making such reduction claims unique and enforceable has not been addressed to date, and presents an important area for further discussion.

c. RECs from a Capped Power sector

Much analysis has been done on the question of how RECs operate in a capped sector such as RGGI. The concept is that because emissions are pre-determined, RE does not change energy dispatch choices, but rather simply frees up allowances. This means consumers cannot claim that their purchase resulted in emission reductions; only allowances, and retiring them by non-emitting entities, would be able to demonstrate that kind of reduction. If we consider RECs simply as a contractual emission factor under the **re-slicing approach**, then purchasing RECs from a capped environment simply means that the grid average emissions factor from that region (the numerator of which is predetermined), is increased as the emission profiles are re-shuffled. However, this exacerbates consumer concerns about their purchase "making a difference." This same principle would theoretically apply in the **strong financial additionality approach,** since both approaches do not evaluate RECs in terms of avoided emissions. However, most capped sectors would theoretically present above-average financial incentives to build RE, making the space for additional projects more limited. Also, whereas the consumer expectation with an additional REC would be that emissions are likely avoided (even if they are not quantified in the REC), that expectation could not be validated in a capped scenario. Consumers could see such a purchase as effectively subsidizing emitting facilities by helping them reach compliance more easily, as their REC else has paid for new RE to help meet demand.

As a policy solution to maintain support for VRE, RECs from these capped sectors have been paired with allowances. In theory, allowances could be retired by anyone trying to demonstrate environmental commitment, cause a reduction in available allowances for emitting entities and thereby create scarcity (and theoretically, behavior change) in the marketplace.

i. Accounting for a retired allowance

What is not yet clear is how these allowances would be treated in corporate GHG inventories. Conceptually, allowances could be seen to function as offsets in that they represent tons of CO_2e that were avoided compared to what would have happened without the purchase and retirement of the allowance. While the reference case in this analysis would be the emissions cap for the sector, it has not always been clear that this cap inherently represents "what would have happened" and that the allowance retirement is therefore additional. On their own, most emission caps are intended to reduce emissions compared to what would have been occurring in the sector: but in oversupplied allowance markets, where the cap level closely follows or even exceeds what would have been occurring anyway, the value of retiring an allowance might be minimized.[25]

[25] See Kollmuss, Anja and Michael Lazarus, *Buying and selling allowances as an alternative to offsets for the voluntary market: a preliminary review of issues and options.* OECD and Stockholm Environment Institute, August 2010.

ii. Accounting for VRE paired with the allowance

If RECs are paired with an allowance, the reporting entity would theoretically be able to use the emissions rate from the REC to calculate their scope 2, assuming an adjusted grid average emissions factor. However, the same concerns about this practice mentioned above (namely, consumer expectations about their instrument, reflected in both the **re-slicing** and **strong financial additional** approaches) would need to be resolved in accounting for ownership of these emission profiles.

iii. Matching VRE with allowances

The procedures to match MWh's of VRE with an appropriate amount of allowances have generally relied on marginal emission rates, or an estimate of the emissions this VRE would be avoiding or displacing at the margin. As noted in Section VI(c), this methodology represents a simplified estimate that may not capture the full effects of various RE projects. Given that the allowance and the VRE would require separate accounting procedures in terms of their reflection within the corporate inventory, the methodology in this matching process may present concerns in terms of consumer expectations.

d. Summary and Considerations

As more states and regions in the U.S. participate in initiatives involving a cap on power sector emissions, the GHG accounting and reporting of VRE products requires greater specificity. While most have deemed that "avoided emissions" claims with VRE cannot be supported in these environments, the accounting and reporting procedures for RECs paired with retired allowances has not yet been assessed within the framework of corporate inventory practices. The use of RECs as emission factors, as elaborated in Section V, does not entail claims or assumptions about avoided emissions—but the strong financial additionality approach would presumably have this effect in an uncapped sector, whereas it would not in a capped. RE offsets also pose the fundamental challenges of ownership and enforceability of reductions that inherently occur off-site of the project; even for emission factor claims, consumer expectations regarding the impact of their purchase need to be clear, as ownership of the "zero-emissions" rate from an RE project that has already produced an offset may be deemed problematic for use as a mitigation instrument in a corporate inventory. Finally, RE projects on-site would need to distinguish the energy consumed from the energy sent back to the grid in terms of delineating ownership of a REC.

VIII. Conclusion

We have examined the two different definitions and uses of RECs on corporate GHG inventories, including their application as contractual emission factors and as instruments representing avoided emissions. The challenges surrounding the use of RECs as emission factors primarily concern the operational logistics of adjusting grid average emission factors to validate the claims. While this approach to contractual emission factors could be viewed as a "re-slicing" of grid emissions and driving demand for cleaner slices, the concern is that such reshuffling does not ensure enough meaningful change to grid conditions to be justified as a means to mitigate scope 2 emissions. Tests of additionality might help alleviate this concern by drawing a stronger link between the REC purchase and the incentive for new RE projects. In terms of the avoided emissions impacts of VRE projects producing RECs (the "derived" attribute), the ambiguity between these claims and those made by RE offsets presents a conceptual conflict. Avoided emissions claims can only be relevant through a clear designation of *compared to what,* which RE offset projects address through project-specific or performance standard approaches. In the absence of this, or other formal additionality tests, RECs may not offer the promise to consumers that emissions have been avoided by their purchase. Further complications arise in terms of the quantification procedures that have been used to estimate these avoided emissions. As these two definitions are applied in emissions constrained/claimed circumstances, such as with the simultaneous pairing with RE offsets and or within an emissions-capped power sector, the "REC as avoided emissions" claim becomes more difficult to support. The path forward to resolution depends greatly on the consistent understanding and application of VRE instruments. The following set of questions seeks to drive greater discussion and deliberation on these critical accounting practices.

Questions and Considerations

RECs as emission factors

- Technical
  - What are the data limitations and needs of electricity consumers in trying to reflect these purchases in a corporate inventory?
  - What are the prospects and possibilities for performing this kind of emission-factor adjustment on the grid? Where could, or should, this adjustment occur?
  - Does the scale of this impact matter in terms of how much to prioritize this requirement?

- Conceptual
  - Does the "re-slicing" approach present problems in terms of consumer expectations for a scope 2 mitigation instrument?
  - Does the strong financial additionality approach seem applicable for this definition of RECs? Would consumers understand what they are receiving?
  - What methods would best test for strong financial additionality?
  - What time horizon could apply for how long organizations could sell their EFs?
  - If the new energy projects under the strong financial additionality approach did result in GHG reductions from other fossil fuel plants, would consumers be OK with this? (that is, an atmospheric reduction taking place on-site at other entities as a consequence of their REC purchase, even as the REC emission factor results in reductions in scope 2?)

RECs as avoided emissions

- Conceptual
  - Do RECs reasonably identify the reference scenario against which their avoided emissions are compared?
  - Does the reasoning that "avoided emissions" claims are fundamentally the same for both RE offsets and RECs and therefore should not applied in different scopes, seem sound?
  - Similar to EF definition above: if RECs are additional, and can be demonstrated to result in emission reductions compared to what would have occurred in the absence of the REC from the project, then how are they different from offsets?
- Technical
  - How important are the methodological concerns around estimating avoiding emissions?

RECs from on-site RE

- Are there additional concerns or practices surrounding RECs from on-site installations that are not acknowledged here?

RECs from RE offsets

- Would the REC-as-emission-factor definition under the re-slicing approach meet consumer expectations?
- Is it a fair interpretation that the application of the REC-as-emission-factor definition under the strong financial additionality approach would inherently mean that offset projects would not issue RECs for sale?
- Is it problematic that the whole grid "benefits" from the reduced GHG-intensity of the emission factors brought about by an RE offset project? Should that emissions rate be factored out and not made available for anyone's use?
- Given that many RE offset projects take place in other countries through CDM, would this kind of adjustment be feasible or realistic?

RECs from a capped power sector

- Is it theoretically possible for RECs under the re-slicing approach to come from capped power sector regions?
- If the VRE (paired with an allowance) were used as an alternate EF in scope 2, how would the allowance be accounted for?
- What other corporate accounting recommendations and practices are needed and recommended here?