GREENHOUSE
GAS PROTOCOL

GHG Protocol Scope 2 Guidance

An amendment to the GHG Protocol
Corporate Standard

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1 Introduction

The Greenhouse Gas (GHG) Protocol is a multistakeholder partnership of businesses, nongovernmental organizations (NGOs), governments, and others convened by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD).

Launched in 1998, the GHG Protocol seeks to develop internationally accepted GHG accounting and reporting standards and tools to promote their adoption worldwide. To date, the GHG Protocol has released four standards that address how GHG emissions inventories should be prepared at the corporate, project, and product levels.

1.1 The GHG Protocol

- **Corporate-level.** The *GHG Protocol Corporate Accounting and Reporting Standard* (*Corporate Standard*) outlines a standard set of accounting and reporting rules for developing corporate inventories. The *Corporate Standard* identifies and categorizes the emissions from all of the operations that together comprise an organization (the term "company" is used to represent all types of organizations using the *Corporate Standard* and this *Scope 2 Guidance*).

  Building from the *Corporate Standard*, the *GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard* provides additional requirements and guidance on developing comprehensive inventories of other indirect (scope 3) emissions.

- **Project-level.** The *GHG Protocol for Project Accounting* (*Project Protocol*) describes how companies can quantify the GHG impacts of specific projects undertaken to reduce emissions, avoid emissions occurring in the future, or sequester carbon.

- **Product-level.** The GHG Protocol *Product Life Cycle Accounting and Reporting Standard* (*Product Standard*) describes how companies can develop GHG emissions inventories, including the entire life cycle of individual products or services—from raw material extraction to product disposal.

These publications, together with supplementary guidance for specific sectors or types of sources, are available from the GHG Protocol website (www.ghgprotocol.org).

1.2 The *Corporate Standard*'s approach to scope 2 emissions

The *Corporate Standard* requires organizations to quantify emissions from the generation of acquired and consumed electricity, steam, heat, or cooling (collectively referred to as "electricity"). These emissions are termed "scope 2" and are considered an indirect emissions source (along with scope 3), because the emissions are a consequence of activities of the reporting organization but actually occur at sources owned or controlled by another organization (here, they are owned or controlled by an electricity generator or utility).

Scope 2 represents one of the largest sources of GHG emissions globally: the generation of electricity and heat now accounts for at least a third[1] of global GHG emissions. Electricity consumers have significant opportunities to reduce those emissions by reducing electricity demand, and increasingly play a role in shifting energy supply to alternative low-carbon resources.

The methods used to calculate and report scope 2 emissions critically impact how a company assesses its performance and what mitigation actions are incentivized. To calculate scope 2 emissions, the *Corporate Standard* recommends multiplying activity data (MWhs of electricity consumption) by source and supplier-specific emission factors to arrive at the total GHG emissions impact of electricity use. It also emphasizes the role of green power programs in reducing emissions from electricity use.[2] Only if these forms of information about electricity supply are unavailable are companies advised to use statistics such as local or national grid emission factors.

1.3 Key questions on scope 2 accounting and reporting

Since the publication of the *Corporate Standard* revised edition, companies and their stakeholders identified conceptual and technical challenges with the existing recommendations on scope 2 accounting and reporting, including the fundamental question:

- **How should renewable energy purchases be reflected in scope 2 reporting?** Previously, some companies (particularly in the U.S.) adjusted their scope 2 emissions by using an estimate of the avoided fossil fuel emissions from the grid associated with their purchase of renewable energy certificates (RECs) and deducting this from their scope 2 total calculated by grid-average emission factors. Others treated purchases as an emission factor conveying a "zero emission rate" in scope 2 calculations rather than using avoided grid emissions. Still others treated participation in green power programs effectively as a donation, with no impact on the GHG inventory. The variety of accounting methods made it difficult for a company to consistently account and report scope 2 emissions across multiple countries.

Underlying this accounting and reporting question were three main types of questions, relating to:

Instruments

- **What constitutes a renewable energy purchase?** In several countries and energy markets around the world, new instruments have been developed to track energy production information (or its "attributes") separately from actual energy delivery. These instruments—termed here "energy attribute certificates"—typically flow from energy generation facilities to energy suppliers and ultimately energy consumers in order to support consumer claims about the type of energy used and its related attributes—such as GHG emissions—produced at the point of generation.

  Some certificates, such as the Guarantee of Origin (GO) in Europe, were envisioned as a way to support energy supplier disclosure and inform consumer choice as energy markets were liberalized. The renewable energy certificate (REC) in the United States and Canada serves a regulatory role in states with renewable energy supplier quotas, as well as a voluntary role for consumers who want to purchase and support renewables. The *Corporate Standard* did not state which of these types of instruments could be appropriate for a scope 2 consumer claim, or whether other types of contractual instruments—such as direct contracts with a renewable energy generator—could fulfill a similar role.

- **What is included in a supplier-specific emission factor?** Electricity suppliers compile emission rates for a variety of purposes. Some supplier emission rates may reflect only the emissions from utility-owned assets, while others also reflect power purchased by the utility from an independent energy generation facility. Many green power programs have been offered directly by utilities, segmenting different emission rates for different consumer classes. Supplier disclosure requirements and calculation methodology differ, making it difficult for consumers to consistently use this type of information.

- **How comparable are green power programs?** Companies operating in multiple countries identified differences in the eligibility criteria used in different green power products—that is, the specifications regarding the age of a generation facility, the type of technology, whether it received public subsidy or was entirely funded by voluntary purchases, etc. While these differences do not impact the actual GHG emission rate from energy production represented in the green power product, they may matter for companies with other environmental or social goals associated with their energy procurement.

Concept

- **How can a company claim to use only renewable energy if it uses inherently untraceable grid-distributed energy?** Most energy grids provide energy for hundreds of thousands of consumers over the course of a day with a blend of energy generation facilities, including a heavy share of fossil fuel plants in most grids. By design, energy attribute certificates like RECs and GOs are separate from the physical distribution of energy. They act as a tool to convey claims and influence market dynamics by allowing the expression and aggregation of consumer preferences for specific low-carbon energy products, which would not otherwise be possible. Consumers cannot choose what energy is generated on their grid at a given point in time, but contractual instruments allow for energy attributes such as GHG emissions to be allocated along the lines of contractual relationships among producers, suppliers, and consumers.
- **If green power is used by some companies, how does that impact the emissions reported by other consumers?** The *Corporate Standard* does not address potential double counting between consumers of emissions associated with green power instruments. But implementing a credible and robust system for GHG emission rate calculation and claims based on contractual instruments—such as GOs, RECs, or supplier-specific emission rates—would require that only one consumer reports the emissions from a given quantity of generation.

Impact on global emissions

- **Do green power programs directly or indirectly reduce GHG emissions over time?** Emissions from a grid region decrease over time due to a combination of lowered energy demand and changes in supply to lower-emitting facilities. The *Corporate Standard* acknowledges that linking consumer behavior and choices with a grid system's emissions is complex and nonlinear.[3] When it comes to green power products, a single company's purchase via a supplier or through a direct contract may not itself change overall grid emissions at the time of purchase. This is because most green power products are based on instruments from existing energy generation facilities. Most voluntary green power programs are designed to translate consumer demand for certain types of energy into changes *over time* in the supply of that energy. When demand increases, it pushes up the price of these attributes, therefore creating an incentive to expand the supply of low-carbon generation facilities. Whether a market for attributes actually results in new low-carbon supply depends on several factors, including the level of consumer demand and the supply of attributes available.[4]

The lack of clear and consistent guidance on these questions created uncertainty about emission reduction strategies and prevent company inventories from reflecting a true and fair account of emissions.

1.4 Purpose of this Guidance

This guidance acts as an amendment to the *Corporate Standard,* providing updated requirements and best practices on scope 2 accounting and reporting. It aims to answer the questions articulated in section 1.3. The revisions in this guidance should enhance the relevance, completeness, consistency, transparency, and accuracy of reported scope 2 totals. Companies can use these reported totals to set targets, reduce GHG emissions, track progress, and inform their stakeholders.

1.5 Guidance overview

This guidance codifies two distinct methods for scope 2 accounting, each with a list of appropriate emission factors. Both methods are useful for different purposes; together, they provide a fuller documentation and assessment of risks, opportunities, and changes to emissions from electricity supply over time.

A *location-based method* reflects the average emissions intensity of grids on which energy consumption occurs (using mostly grid-average emission factor data). A *market-based method* reflects emissions from electricity that companies have purposefully chosen (or their lack of choice). It derives emission factors from contractual instruments, which include 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.

See Box 1.1 for an overview of key terms related to scope 2 in this guidance.

1.5.1 New reporting requirements

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."

Not having contractual data for every site will not cause noncompliance with the GHG Protocol *Corporate Standard* and *Scope 2 Guidance*. As with scope 3, a range of data may be available. Companies should consult the hierarchy of emission factors for both location-based and market-based methods. Any data on those hierarchies (including using location-based emission factors in the absence of contractual information) is acceptable.

1.5.2 Scope 2 Quality Criteria for the market-based method data

To make the market-based method globally consistent and capable of producing accurate results, this guidance establishes required Scope 2 Quality Criteria that all contractual instruments must meet. These Scope 2 Quality Criteria are policy-neutral and represent the minimum features necessary for instruments to function together as a complete market-based emission allocation system for consumers. Companies without contractual instruments that meet the Scope 2 Quality Criteria may use other emission factors (listed in Chapter 6).

1.5.3 Other disclosure

To encourage transparency and improve comparability of energy and energy attribute purchases from different markets, this guidance also recommends additional reporting disclosure about the energy generation features and policy contexts in which the purchase occurs. Separately disclosing total electricity, steam, heat, and cooling consumed per reporting period (in kWh, MWh, BTU, etc.) can also enhance transparency and clarify changes in consumption vs. changes in supply.

1.6 Who should use this Guidance?

This guidance acts as an amendment to the *Corporate Standard,* so all organizations compiling a corporate GHG inventory following the *Corporate Standard*—including companies, governments, NGOs, and other organizations—should use this guidance. The term "companies" is used throughout this document as shorthand for any organization compiling a corporate inventory.

In addition, energy suppliers, utilities, grid operators, and marketers offering voluntary green power programs providing product information to consumers should read this guidance to understand the type of information that customers may be requesting to calculate their scope 2 inventories following the market-based method.

Government entities involved in regulating energy and/or establishing frameworks and rules for consumer electricity choices should be informed about the requirements of this guidance. The relationships between regulatory programs (such as supplier quotas or public subsidies for renewable energy) and voluntary consumer programs are explored in Chapter 10.

Box 1.1 Key terms

Some terms used in this guidance are used for precision but are synonymous with other more familiar terms. For example:

Contractual instruments: 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 attribute certificate: A category of contractual instrument that represents certain information (or attributes) about the energy generated, but does not represent the energy itself. This category includes a variety of instruments with different names, including certificates, tags, credits, or generator declarations. For the purpose of this guidance, the term "energy attribute certificates" or just "certificates" will be used as the general term for this category of instruments.

Energy generation facility: Any technology or device that generates energy for consumer use, including everything from utility-scale fossil fuel power plants to rooftop solar panels.

Energy supplier: Also known as an electric utility, this is the entity that sells energy to consumers and can provide information regarding the GHG intensity of delivered electricity.

Generators: Here used to mean the entity that owns or operates an energy generation facility.

Green power product/green tariff: A consumer option offered by an energy supplier distinct from the "standard" offering. These are often renewables or other low-carbon energy sources, supported by energy attribute certificates or other contracts.

1.7 How should I use this Guidance?

This guidance replaces requirements and guidance on scope 2 in the *Corporate Standard.* It is divided into two parts:

- Chapters 1 through 9 provide requirements and practical recommendations on how to establish accounting boundaries, how to calculate emissions, and how to report emissions totals according to both methods in conformance with the guidance.
- Chapters 10 and 11 are optional background reading that addresses the broader concepts, principles, and examples of how energy markets worldwide have used contractual instruments to convey energy attributes (the basis of the market-based method). These chapters address how consumers can use their voluntary procurement power to accelerate the deployment of low-carbon energy to reduce overall emissions from the electricity system, while retaining the necessary instruments to make GHG claims in a market-based scope 2 total.
- Readers should also consult a supplemental compilation of case studies describing how a variety of organizations have implemented the new requirements of this Scope 2 Guidance. (Available at: ghgprotocol.org.)

The term "electricity" in this guidance is used to represent all purchased energy, but the guidance is primarily on electricity accounting. Appendix A indicates how these methods apply to heat/steam/cooling accounting as well.

1.7.1 Terminology: shall, should, may

This guidance uses precise language to indicate accounting and reporting requirements, recommendations, and allowable options that companies may choose to follow.

- The term **"shall"** is used throughout this document to indicate what is required in order for a GHG inventory to be in conformance with the *Scope 2 Guidance* and by extension the GHG Protocol *Corporate Standard*.

- The term **"should"** is used to indicate a recommendation, but not a requirement.
- The term **"may"** is used to indicate an option that is permissible or allowable.

The term "required" is used in the guidance to refer to requirements. "Needs," "can," and "cannot" may be used to provide recommendations on implementing a requirement or to indicate when an action is or is not possible.

1.8 How was this Guidance developed?

This guidance represents a policy-neutral, collaborative solution guided by GHG Protocol principles. It was developed over four years of international consultation and discussion with participation from businesses, NGOs, GHG reporting programs, energy utilities and retailers, renewable energy certification programs, government agencies, and scientific and academic institutions from around the world. It included:

- **Scoping Workshops.** From December 2010 to May 2011, WRI and WBCSD launched this process through a series of workshops in Washington, London, and Mexico City using short discussion drafts.
- **A Technical Working Group (TWG).** Formed in summer 2011, the TWG contributed to discussion papers, conference presentations, and draft proposals on accounting and reporting solutions. Discussion papers included topics such as:
    - Defining the principles of market-based systems: attributes, ownership, eligibility (Winter 2011)
    - Identifying objectives, background, and challenges with scope 2 accounting (Summer 2012)
    - Analyzing the relationship between indirect emissions accounting and system-wide reductions (December 2012)
- **Public Comment Period.** Draft guidance was made available for public comment from March 2014–May 2014, including six webinars and three in-person workshops in London, Dusseldorf, and Washington.

1.9 Changes from the *Corporate Standard*

This guidance introduces accounting and reporting requirements related to scope 2 that replace and add to those in the *Corporate Standard.* It also sets Scope 2 Quality Criteria that contractual instruments **shall** meet in order to be used in the market-based method. To prepare an inventory in conformance with the *Corporate Standard,* companies **shall** follow all new requirements in this guidance. These changes are summarized in Table 1.1.

1.10 Relationship to the GHG Protocol *Corporate Standard* and *Scope 3 Standard*

To prepare an inventory in conformance with the *Corporate Standard,* companies **shall** follow all new requirements in this *Scope 2 Guidance*.

In turn, the *Scope 3 Standard* intersects with scope 2 in several ways:

- The *Scope 2 Guidance* impacts how companies will communicate their scope 2 emissions to other value chain partners downstream and what type of scope 2 data they may receive from its value chain partners.
- The *Scope 2 Guidance* impacts how a company assesses the upstream emissions associated with its energy use (category 3—upstream energy emissions not recorded in scope 1 and 2, scope 3).

In both cases, a company **shall** disclose whether a market-based or location-based scope 2 total is used as the basis for calculating scope 3, category 3 (fuel- and energy-related emissions not included in scope 1 or scope 2).

Table 1.1 Additions to scope 2 accounting introduced by Scope 2 Guidance

Topic	How addressed in the *Corporate Standard*	How addressed in the *Scope 2 Guidance*
Obtaining activity data (kWh)	Consult utility bills.	No change from *Corporate Standard*, but additional guidance for on-site consumption and sales including net metering programs (see Chapter 5).
Disclosing activity data (kWh)	No requirement.	Companies should disclose total consumed electricity within inventory boundary.
Emission factors	Hierarchy presented starting with source and supplier-specific, and then grid average.	Two distinct methods of scope 2 accounting required, each with their own hierarchy of emission factors.
Green power programs—which instruments can count?	Example of a company, IBM, working with a local electricity supplier, Austin Energy, to purchase renewable energy to reduce scope 2 emissions.[a] Example of a utility, Seattle City Light, providing emission rate information to customers.[b] Example of a company, Alcoa, purchasing RECs in the U.S. to reduce emissions, based on an avoided emissions estimation and deduction accounting approach.[c]	Market-based method goes beyond just green power programs and recognizes a category of contractual instruments that should be used when calculating a market-based scope 2 result. These instruments may not be for green power or even renewable energy. They include: • Energy attribute certificates (GOs, RECs) • Direct contracts such as power purchase agreements (PPAs), where other instruments or energy attribute certificates do not exist • Supplier-specific emission rates • Residual mix (e.g., the emissions rate left after the three other contractual information items are removed from the system) Guidance provides global examples of each contractual instrument type provided.
Contractual instrument requirements	No requirements given.	All contractual instruments shall meet Scope 2 Quality Criteria to be used in the market-based method calculation. If they do not meet the Scope 2 Quality Criteria, then other data (listed in Table 6.3) shall be used as an alternative in the market-based method total. In this way, all companies required to report according to the market-based method will have some type of data option.
Accounting of green power purchases	No direct requirement, but example of U.S. avoided emissions calculation and deduction approachto RECs.[d]	Any type of energy or energy attribute purchase via a contractual instrument shall be treated in scope 2 like all other product information—an emission rate in tons GHG/unit of output (here, kWh) rather than an avoided emissions estimation and deduction. Companies then apply the emission factor derived from the contractual instrument to a quantity of energy consumption (activity data), consistent with the usage boundaries of that instrument.

Table 1.1 Additions to scope 2 accounting introduced by Scope 2 Guidance (continued)

Topic	How addressed in *Corporate Standard*	How addressed in Scope 2 Guidance
Reporting requirements	Report one scope 2 result in CO_2e, as well as by GHG.	If companies have any operations in markets providing product or supplier-specific data in the form of contractual instruments, then companies shall account and 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 meeting Scope 2 Quality Criteria are met. If companies only have operations in markets without product or supplier-specific data, then only one scope 2 result shall be reported, based on the location-based method. Companies shall specify which method is used for goal-setting, tracking, and goal-achievement claims, and for scope 3 or product-level communication. Companies should disclose key features of contractual instruments, including any certification labels, characteristics of the energy generation facilities themselves, and policy context.

Notes:

[a] See *Corporate Standard* (WRI/WBCSD 2004), p. 14.
[b] See *Corporate Standard* (WRI/WBCSD 2004), p. 30.
[c] See *Corporate Standard* (WRI/WBCSD 2004), p. 63.
[d] See *Corporate Standard* (WRI/WBCSD 2004), p. 63.

1.11 What does this Guidance not address?

The market-based method codified in this guidance inherently requires systems for tracking and allocating electricity attributes from energy generators to end consumers. Most of these systems are formed by local or national policies, or interact closely with them. This guidance recognizes the role of these systems in providing information that meets the objectives of corporate GHG accounting: that is, reflecting the risks and opportunities associated with acquiring and consuming electricity and informing internal and external decisions to manage those emissions. However, like the *Corporate Standard*, this guidance is designed to be policy neutral. This means that it does not:

- Require the development of markets where none exist
- Make requirements or express preferences about the design of markets
- Address the non-GHG accounting aspects of energy policy or market-based accounting systems for consumers, including (a) social impacts and (b) financial costs or effectiveness relative to other policies at achieving specific climate abatement or other outcomes
- Define what should constitute "green" energy
- Identify "eligibility criteria" that would determine which types of electricity facilities should produce certificates or contractual instruments. The Scope 2 Quality Criteria in this Guidance relate to features required of the instruments themselves in order to support accurate accounting; the Criteria do not address which generation facilities should produce those instruments
- Promote specific energy generation technologies (such as renewable energy), or specific electricity labels or programs.

This guidance also does not list all contractual instruments, energy attribute certificates, or tracking systems used to date.

Endnotes

1. IPCC (2014), based on global emissions from 2010.
2. See the *Corporate Standard* (WRI/WBCSD 2004), pp. 27–28, 42, and 61.
3. See *Corporate Standard* (WRI/WBCSD 2004), Chapter 8.
4. Some research (Gillenwater et al. 2014) has indicated that the voluntary REC market in the U.S., when evaluated based on the price of RECs as an incentive for project developers, has not itself driven new renewable energy projects.

Table 1.2 Which parts of the Guidance should I read?

Question	Reference
What are the changes this guidance introduces from the *Corporate Standard*?	Ch. 1
What terms should I be familiar with to navigate this document?	Ch. 1, 4, 7, 10 and Glossary
What are the business goals for accounting for scope 2 in a corporate GHG inventory?	Ch. 2
What principles should guide my approach to accounting and reporting scope 2 emissions?	Ch. 3
What is the location-based method?	Ch. 4
What is the market-based method?	Ch. 4
What is the decision-making value of the results from each method?	Ch. 4
How do I determine what energy uses should be included in the scope 2 boundary?	Ch. 5
What are the calculation methods I should use for scope 2?	Ch. 6
What kinds of emission factor data can I use for calculating scope 2 according to both methods?	Ch. 6
How do I perform calculations according to both methods?	Ch. 6
What are the criteria that instruments shall meet to be used as emission factors in the market-based method?	Ch. 7
What are the reporting requirements of this guidance?	Ch. 7
What else should I disclose about my purchases?	Ch. 8
How do I show changes over time under both methods?	Ch. 9
How do I set or track goals under one or both methods?	Ch. 9
What is the background on the use of contractual instruments in tracking energy attributes?	Ch. 10
What is the relationship between voluntary purchases and instruments used for mandatory compliance?	Ch. 10 and 11
What is the relationship between offsets and energy attribute instruments?	Ch. 10
How does my contractual purchasing drive change in low-carbon energy supply over time?	Ch. 11
How does this guidance apply to accounting and reporting emissions from purchased heat, steam, and cooling?	Appendix A
How does this new scope 2 accounting and reporting requirement affect accounting for energy-related emissions in scope 3?	Appendix B

2 Business Goals

Before accounting for scope 2 emissions, companies should consider which business goal or goals they intend to achieve.

2.1 Business goals of scope 2 accounting and reporting

Before accounting for scope 2 emissions, companies should consider which business goal or goals they intend to achieve. Consistent with the *Corporate Standard* and *Scope 3 Standard*, companies consuming electricity may seek to:

- 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.

Each of these is elaborated below.

2.2 Identify and understand risks and opportunities associated with emissions from purchased and consumed electricity

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 (such as country-level policies banning nuclear), and changing consumer preferences for low-carbon products, as well as scrutiny from investors and shareholders over what energy choices a company 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 companies to different risks associated with the changing cost of energy and related GHG

emissions. Therefore, both methods can improve overall risk assessment and the ability to identify different opportunities to reduce that risk. Likewise, the results of only one scope 2 method may obscure GHG risks associated with energy use and miss mitigation opportunities. Finally, the disclosure of other key information about a company's energy procurement and usage will provide stakeholders insight and context into these risks (see Chapter 8 for a list of these disclosure items).

Risks

Some of these risks include:

Regulatory. Corporate exposure to regulatory risks in the electricity sector depends on regulatory policy design. For instance, CO_2 taxes on electricity consumption may be levied equally on all consumers regardless of their supplier or product choice; based on CO_2 in a supplier's delivered product; or only to certain consumer classes where exemptions may exist (for example, the UK's Climate Change Levy for nonresidential consumers, where a levy exemption certificate can be used to avoid the levy). In these circumstances, a contractual instrument for specified power may or may not shield companies from these additional costs. Customers of an electric utility generally bear the cost of environmental compliance for the resources owned by their utility, or the energy purchased by the utility, which would be shown in a utility-specific emission factor in the market-based method. Conversely, these costs and risks are not necessarily shared among all consumers equally on the same grid, which would otherwise be suggested by the location-based method.

Energy costs and reliability. Electricity suppliers may pass on to their customers the fluctuating prices of fossil or other fuel. The emissions from this supplier mix may be represented in that supplier's specific emission factor, making the market-based method an aligned representation of emissions and costs. At the same time, certain overall costs related to grid operation and maintenance could be allocated to all consumers regardless of their individual choice in electricity supplier, electricity product, or tariff. In addition, maintaining regional grid reliability often requires a mix of generation resources. The location-based method incorporates the GHG emissions of this mix into the grid average emissions factor, while the market-based method may allow users to only evaluate the GHG emissions associated with the energy generation represented in their purchased product—thereby missing some of the reliability risks faced by consumers in the entire grid.

Most companies reduce energy cost risks in part by reducing overall energy consumption. Some companies may be concerned that purchasing certificates annually allows for a "zero emissions" market-based total year-on-year, thereby lessening the impetus for companies to reduce their energy consumption. To mitigate this, the guidance recommends the separate reporting of overall energy consumption. Companies should also compare any additional costs associated with premiums for low-carbon energy supply documented in the market-based method, and compare how those can be reduced over time through decreased demand. In addition, purchasing and applying certificates to one year's inventory sets a precedent for continuing purchases in future years in order to report annual reductions, and cost ranges for certificates may vary each year.

Reputation. Prior to this guidance, companies may have reported scope 2 without fulfilling the Scope 2 Quality Criteria for the market-based method, leading to misleading claims and potential double counting between scope 2 inventories. Transparent disclosure about a company's energy procurement and its key attributes in the market-based method can help clarify the company's strategy and rationale.

Product and Technology. Companies may face decreased consumer demand for products made with high-GHG energy inputs. In turn, a company's competitors using low-GHG energy may see more competitive gains. Being able to compare companies' performances across similar scope 2 methods can help ensure that consumers understand the differences in a company's energy procurement choices.

Legal. Prior to this guidance, some companies with access to contractual information may have been only reporting location-based scope 2. However, many contractual instruments convey legally enforceable rights and claims that can affect how a company describes its purchases and its overall environmental performance. Neglecting to report a market-based scope 2 that aligns with those claims can expose companies to legal risks. In addition, if companies claim in scope 2 the use of instruments that do not meet the Scope 2 Quality Criteria (for example, not conveying an exclusive right to convey attribute claims), they may be inadvertently double-claiming emissions conveyed by other instruments to other parties.

Non-GHG environmental risks

Other environmental risks may be more localized than global GHG emissions affecting the world's climate. A company located in a grid with these types of energy production may also face operational or health/safety risks. A location-based result can help highlight a company's exposure to some of these geographic risks, including (a) air pollution such as sulfur dioxide (SO_x) or mercury from coal combustion; (b) the impact of hydropower on local waterways and aquatic life; and (c) the risks from nuclear waste disposal or emergencies.

Opportunities

Accounting and reporting scope 2 emissions will also highlight opportunities to improve performance and business operations. For many companies, energy use represents a significant cost. Reducing energy use is the "first" choice to reduce impact and costs. In most mixed-resource grids, reducing energy use also correlates with a decreased total in the location-based result (for example, smaller activity data value in the inventory year, while also contributing to lowering grid emissions over time).[1] Companies reducing energy consumption also pay proportionally less for any low-carbon supplier tariffs or premiums, or any unbundled certificates in the market-based method. Some examples of these opportunities are enumerated in Table 2.1.

Table 2.1 Examples of GHG-related opportunities related to scope 2 emissions

Example	Description
Efficiency and cost savings	A reduction in GHG emissions often corresponds to decreased costs and an increase in companies' operational efficiency.
Drive innovation	A comprehensive approach to GHG management provides new incentives for innovation in energy management and procurement.
Increase sales and customer loyalty	Low-emissions goods and services are increasingly more valuable to consumers, and demand will continue to grow for products made with low-carbon electricity.
Improve stakeholder relations	Improve stakeholder relationships through proactive disclosure and demonstration of environmental stewardship. Examples include demonstrating fiduciary responsibility to shareholders, informing regulators, building trust in the community, improving relationships with customers and suppliers, and increasing employee morale. *However, there may also be risks depending on whether company stakeholders are also invested in fossil fuel or high-GHG emitting resources.*
Company differentiation	External parties—including customers, investors, regulators, shareholders, and others—are increasingly interested in documented emissions reductions. Accounting and reporting scope 2 emissions with greater consistency and transparency about contractual instruments demonstrates a best practice that can differentiate companies in an increasingly environmentally conscious marketplace.

2.3 Identify GHG reduction opportunities, set reduction targets, and track performance

Comprehensive 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 GHG 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. For example, regional emission trends (shown in the location-based method) may change over time due to factors outside of a company's direct control, such as electricity supplier quotas for renewable energy, emission policies and regulations, the collective impact of energy efficiency or demand-side management, or voluntary demand for new renewables.

Transparent reporting also allows for a more consistent comparison of performance over time and comparison with other companies. This guidance's framework addresses and reduces double counting between scope 2 inventories when using the same method, improving the accuracy of reported results and ensuring every company can make progress toward its goals.

2.4 Engage energy suppliers and partners in GHG management

Reducing emissions from the energy sector requires the participation of all entities in the energy value chain, including energy generators, suppliers, retailers, and consumers. The two methods outlined in this guidance can help consumers engage with their energy value chain on key demand and supply issues. For instance, generators produce energy in response to local or regional aggregate demand, and individual scope 2 inventories (and recommended reporting of energy consumption separately) can help highlight how reductions in energy use can reduce both scope 2 emissions and contribute to reducing grid-wide demand.

On the supply side, new energy generation facilities require a combination of factors to be in place to come online, including siting appropriate for the technology and its capacity or size, financing, and a supplier or consumer to purchase the energy. Scope 2 accounting can provide a motivation for consumers to partner with suppliers offering low-carbon products, and to seek out opportunities to leverage a company's own financial resources to help develop new projects. Energy producers, suppliers, and consumers all account for GHG emissions based on organizational and operational boundaries (e.g. the scopes). Scope 2 accounting and reporting can help energy consumers identify the GHG emissions impact of different energy production and purchasing arrangements.

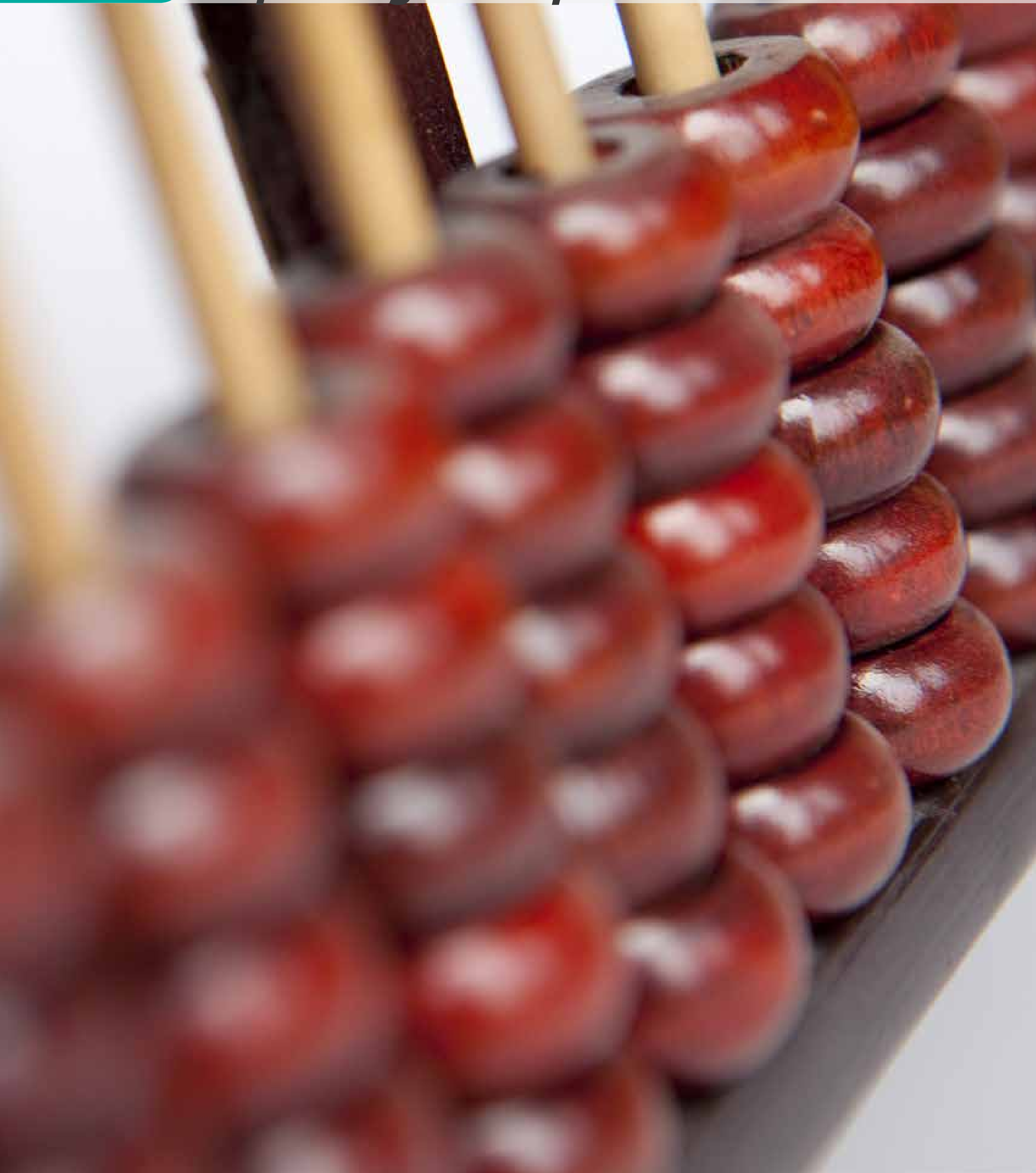
2.5 Enhance stakeholder information and corporate reputation through transparent public reporting

The markets for energy purchasing—as well as markets for energy attribute certificates—may be difficult to explain to stakeholders unfamiliar with attribute tracking, labeling, or claims systems. Reporting scope 2 according to both calculation methods can help describe the different dimensions of the grid more clearly. With the location-based method, consumers can represent that they are served by all the energy resources deployed on their regional grid. By contrast, a company's energy supply choices are shown in the market-based method total. This reflects the market for energy attribute claims which enables a choice of specific resources, and allocates emission attributes based on a company's contractual relationships, or what a company is paying for. Reporting both methods' results provides important information for assessing corporate performance.

Endnotes

1. For this reduction in a single company's consumption to impact grid generation and resulting emissions, this consumption would need to be significant and could not be offset by increases in energy consumption elsewhere in the grid. Therefore this guidance generally treats scope 2 reductions in energy consumption as part of the *collective* action that reduces emissions.

3 Accounting and Reporting Principles



As with financial accounting and reporting, generally accepted GHG accounting and reporting principles are intended to underpin and guide GHG accounting and reporting to ensure that the reported information represents a faithful, true, and fair account of a company's GHG emissions.

GHG accounting and reporting **shall** be based on the following principles:

- **Relevance.** Ensure the GHG inventory appropriately reflects the GHG emissions of the company and serves the decision-making needs of users—both internal and external to the company.
- **Completeness.** Account for and report on all GHG emission sources and activities within the inventory boundary. Disclose and justify any specific exclusion.
- **Consistency.** Use consistent methodologies to allow for meaningful performance tracking of emissions over time. Transparently document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.
- **Transparency.** Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.
- **Accuracy.** Ensure that the quantification of GHG emissions is systematically neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable. Achieve sufficient accuracy to enable users to make decisions with reasonable confidence as to the integrity of the reported information.

Guidance for applying the accounting and reporting principles

These five principles guide the implementation of the GHG Protocol *Scope 2 Guidance*, particularly when application of the guidance in specific situations proves ambiguous. Companies may encounter tradeoffs between principles when completing an inventory and should strike a balance between these principles based on their individual business goals. For instance, a company may find that achieving the most *complete* inventory requires the use of less accurate data, compromising overall accuracy. Over time, as the accuracy and completeness of data increase, the tradeoff between these accounting principles will likely diminish.

Companies should consider these requirements in the light of the overall principles to which they apply, such as:

- **Transparency.** A company may prepare a market-based scope 2 total and may not yet have access to a residual mix emission factor. If the company has contractual instruments such as energy attribute certificates or supplier-specific emission factors to cover all of its consumption, the absence of a residual mix may not impact the accuracy of the company's reported scope 2 total. But it can impact the overall accuracy of the emissions allocation within that market. Therefore, companies are required to disclose this absence transparently.
- **Relevance.** The guidance recommends that companies disclose key features of the contractual instruments they use, in order to enable a clear understanding of the market context of those purchases and a meaningful assessment of the company's procurement strategy (see Chapter 8). While this disclosure should support the principle of transparency, it should also focus on those purchases and features that are most relevant to the company and its goals, and can support its decision making.
- **Consistency.** The guidance seeks to ensure consistency in GHG reporting by requiring dual reporting, so that users of GHG information can track and compare GHG emissions information over time according to the same method assumptions. This better distinguishes trends and changes in performance. A company that begins reporting market-based method results for the first time may wish to provide additional transparent context for this total by indicating what percentage of their operations actually fall under this approach (based on energy usage) as compared with those where the same location-based method is used as a proxy.

- **Accuracy and Completeness.** Companies may identify contractual instruments in the market-based method—such as supplier-specific emission factors or energy purchase contracts—that do not meet the Scope 2 Quality Criteria. To maintain accuracy, companies **shall not** use these data to report a market-based scope 2 total, but should use other eligible data listed in the market-based method hierarchy. Companies may disclose the information separately. Working with electricity suppliers to clarify and ensure alignment of their data with the Scope 2 Quality Criteria will ensure both accuracy and a more complete market-based method result over time.
- **True and Fair.** Some policy makers or stakeholders using corporate GHG information may identify additional objectives for market-based electricity accounting in their national or subnational market. These objectives may reference concepts of social fairness or or equal treatment of different electricity consumer groups in the design of a voluntary low-carbon energy purchasing program. The GHG Protocol references that these five principles should help in developing fair and true inventories. The phrase "fair and true" is not intended to address these types of policies or objectives, but recommends that companies disclose key energy generation features about their contractual instruments in order to transparently disclose how its purchases reflect this policy context.

4 Scope 2 Accounting Methods

This chapter provides an overview of the two scope 2 accounting methods required by this guidance. It outlines how these methods' results can inform decisions that contribute to reductions in the electricity sector.

4.1 Approaches to accounting scope 2

Calculating scope 2 emissions requires a method of determining the emissions associated with electricity consumption. Primarily two methods have been used by companies, programs, and policy makers to "allocate" the GHG emissions created by electricity generation to the end consumers of a given grid. Consumer GHG accounting in scope 2 completes this allocation process through emission factors applied to each unit of energy consumption. This guidance terms these methods the (a) location-based and (b) market-based methods. In short, the market-based method reflects emissions from electricity that companies have purposefully chosen (or their lack of choice), while the location-based method reflects the average emissions intensity of grids on which energy consumption occurs.

Table 4.1 compares the methods in terms of their objectives and the aspects of corporate purchasing and consuming of electricity that are emphasized. Chapter 6 lists the emission factors associated with each method.

4.1.1 Location-based method

This method can apply in all locations since the physics of energy production and distribution functions the same way in almost all grids, with electricity demand causing the need for energy generation and distribution. It emphasizes the connection between collective consumer demand for electricity and the emissions resulting from local electricity production. This includes an overall picture of the mix of resources required to maintain grid stability (see Box 4.1). The location-based method is based on statistical emissions information and electricity output aggregated and averaged within a defined geographic boundary and during a defined time period.[1]

Grid average emission factors should be distinguished from supplier-specific emission factors. While utilities may be the sole energy provider in a region and produce a supplier-specific emission factor that closely resembles the overall regional grid average emissions factor, this utility-specific information should still be categorized as market-based method data due to the wide variation in utility service areas and structures. For instance, the utility service territory may

Table 4.1 Comparing market-based and location-based methods

	Market-Based Method	Location-Based Method
Definition	A method to quantify the scope 2 GHG emissions of a reporter based on GHG emissions emitted by the generators from which the reporter contractually purchases electricity bundled with contractual instruments, or contractual instruments on their own	A method to quantify scope 2 GHG emissions based on average energy generation emission factors for defined geographic locations, including local, subnational, or national boundaries
How method allocates emissions:	Emission factors derived from the GHG emission rate represented in the contractual instruments that meet Scope 2 Quality Criteria	Emission factors representing average emissions from energy generation occurring within a defined geographic area and a defined time period
Where method applies:	To any operations in markets providing consumer choice of differentiated electricity products or supplier-specific data, in the form of contractual instruments	To all electricity grids
Most useful for showing:	• Individual corporate procurement actions • Opportunities to influence electricity suppliers and supply • Risks/opportunities conveyed by contractual relationships, including sometimes legally enforceable claims rules	• GHG intensity of grids where operations occur, regardless of market type • The aggregate GHG performance of energy-intensive sectors (for example, comparing electric train transportation with gasoline or diesel vehicle transit) • Risks/opportunities aligned with local grid resources and emissions
What the method's results omit:	• Average emissions in the location where electricity use occurs	• Emissions from differentiated electricity purchases or supplier offerings, or other contracts

be a smaller region than the grid distribution area serving a given site of consumption; conversely, many utilities are in competitive markets where multiple suppliers can compete to serve consumers in the same region. Therefore, this method only looks at the broader energy generation profile for a region, regardless of supplier relationships.

4.1.2 Market-based method

The market-based method reflects the GHG emissions associated with the choices a consumer makes regarding its electricity supplier or product. These choices—such as choosing a retail electricity supplier, a specific generator, a differentiated electricity product, or purchasing unbundled energy attribute certificates—are conveyed through agreements between the purchaser and the provider.

Under the market-based method of scope 2 accounting, an energy consumer uses the GHG emission factor associated with the qualifying contractual instruments it owns. In contrast to the location-based method, this allocation pathway represents contractual information and claims flow, which may be different from underlying energy flows in the grid. The certificate does not necessarily represent the emissions caused by the purchaser's consumption of electricity. One company choosing to switch suppliers does not directly or in the short-term impact the entire operation of the grid and its emissions. Over time, the

Box 4.1 How scope 2 methods reflect variable energy

While renewable energy may be "zero emissions" at the point of generation, dispatchable fossil fuel resources are often required to maintain overall grid reliability when renewable resources like solar and wind are not available. Electricity system operators may be required to maintain "spinning reserves" to provide grid stability in the event of losses of production at major energy generation facilities or to regulate grid frequency. Most studies suggest that a balancing area can absorb up to 30 percent variable resources without special accommodation. Over time increases in variable renewable resources have led to the formation of larger balancing areas supported by expanded T&D infrastructure as well as increased grid flexibility and efficiency improvements. Improved short-term forecasting of variable resources and storage technologies will also minimize these challenges.

The location-based method reflects the role of these "balancing" resources and their emissions through grid average emission factors. These emission factors include emissions from all local energy generation. The market-based method may reflect these emissions in varying degrees: for instance a certificate for variable renewable energy will not likely report or show the GHG impacts of the other resources dispatched on the grid to complement that variability. However some utilities are designing certificates to be issued only from variable energy generated during periods when the "backup" resource is also zero emissions or when no back-up is needed. This requires the utility to be in a position to guarantee they inject at any moment enough zero emissions energy to cover demand (for instance, through hydropower). For example, TUV SUD certifies in their EE02 Standard that energy is supplied simultaneously to consumption.*

*See TUV SUD criteria: http://www.tuev-sued.de/plants-buildings-technical-facilities/fields-of-engineering/environmental-engineering/energy-certification/certification-criteria

collective consumer demand for particular energy types and their resulting attributes (e.g., zero GHG emissions from generation) can send a market signal to support building more of those types of generation facilities, just as purchasing any product sends the market signals to produce more of that product.

While only a few countries around the world have established markets for certificates that support this method, large electricity consumers in many other markets may find opportunities to purchase a differentiated product or enter into contracts directly. The market-based method has historically been associated with green power purchasing options. However, it is designed to integrate with, and include, existing systems for supplier portfolio disclosure and nonrenewable energy contract types as well. Since no market has instituted comprehensive energy tracking by contractual instruments,[2] this method uses some of the same energy production and emissions data from the location-based method for any energy not tracked by an instrument. 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.

With this method, individual energy consumers have the opportunity to make decisions about their product and supplier, which can then be reflected as a supplier or product-specific emission factor in scope 2.

4.2 Emission rate approach

These scope 2 accounting methods have several features in common, including:

- They use generation-only emission factors (e.g. emissions assessed at the point of energy generation), designed to label emissions associated with a quantity of electricity delivered and consumed. The emission factors do not include T&D losses or upstream life-cycle emissions associated with the technology or fuel used in generation. Instead, these other categories of upstream emissions should be quantified and reported in scope 3, category 3 (emissions from fuel- and energy-related activities not included in scope 1 or scope 2). In the case of supplier-specific emission factors, the emission factor should reflect emissions from all delivered energy, not just from generation facilities owned/operated by the utility.

- They represent emission rates that allocate emissions at generation to end-users. This type of treatment is consistent with corporate inventory approaches across other scopes, particularly with product-specific emission factors or labels. Both methods should be applied comprehensively to ensure all energy generation emissions within a defined region have been accounted for.
- This guidance does not support an "avoided emissions" approach for scope 2 accounting due to several important distinctions between corporate accounting and project-level accounting. However, companies can report avoided grid emissions from energy generation projects separately from the scopes using a project-level accounting methodology.

4.3 The decision-making value of each method's results

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. This is because 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.[3] Generally, 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.[4]

These two scope 2 accounting methods each provide a different "decision-making value" profile—that is, different indications of performance and risks, revealing different levers to reduce emissions and reduce risks. Ultimately, system-wide emission decreases are necessary over time to stay within safe climate levels. Achieving this requires clarity on what kinds of decisions individual consumers can make to reduce both their own reported emissions as well as contribute to emission reductions in the grid. Working backward from those decisions to the methods used to calculate emissions, there are three types of decisions companies can make that impact overall electricity grid emissions. These decisions include facility siting, the level and timing of demand, and supporting supply shifting.

While companies may make decisions related to these categories for non-GHG considerations, all the decisions carry GHG implications.

1. **Facility and operations-siting decisions**
   A company's decisions about where to locate its office buildings, industrial facilities, distribution centers, or data centers carries GHG implications. The physical location of these points of energy consumption impacts what existing, or future, energy resources may be able to be deployed to meet demand. For instance, locating new facilities on a GHG-intensive grid means that in the near term, energy demand will be met with a higher GHG emissions profile, assuming that the energy is consumed locally. By contrast, locating operations in areas with low-carbon natural resources, or additional benefits such as natural ambient cooling or heat, can reduce these GHG emissions risks (as shown in the location-based method).[5] Ambient heat/cooling will also be reflected in lower use of heat/cooling and will be seen in both the location-based and market-based methods. Companies considering electric transportation fleets also need to ensure the availability of charging infrastructure and the GHG-intensity of the grids where that transportation would occur.

   The physical location also aligns with a national or subnational set of regulatory rules governing what types of energy product or energy supplier choices a consumer can make. This location highlights different pathways and options for corporate influence over the energy supply mix over time (as shown in the market-based method).

   Therefore, a company's shift in facility location will result in changes in scope 2 based on:

   - **Location-based.** The use of a different grid average emission factor, and possibly a shift in energy supply overall, if the new location allows for on-site energy generation or is locating near an energy development where a direct line connection can be made.
   - **Market-based.** Changes in supplier (new utility service area), changes in other types of contractual instruments, actions of other consumers in the market, or the residual mix used in that location.

2. **Decisions on the level and timing of demand**
Once a company has established a location for its operations, it can reduce its emissions through energy demand reduction.[6] A company can reduce energy consumption through measures such as choosing an energy-efficient building, carrying out energy-efficient retrofits, using more efficient electronics or lighting, and making behavioral decisions. Increasingly, "smart grid"[7] information and systems are allowing more geographically and temporally precise data to support energy demand management at a consumer level, including end-use equipment timing (e.g., running dishwashers or washing machines during optimal times of day such as low-cost, or non-peak times). Utilities may also provide this type of data to energy-intensive consumers as part of demand-side management (DSM) programs and peak-shaving efforts. The location-based method assumes that local demand impacts local generation and distribution patterns, which ultimately impact total GHG emissions from the system (taking into account physical energy imports/exports). While demand is met with incremental resources, grid-average emission factors provide more readily available averages calculated over the course of a year.

Therefore, a company's shift in energy demand quantity and timing will entail changes in reported scope 2 primarily through activity data. In both methods, a decrease in electricity consumption can decrease total reported scope 2.

- **Location-based.** Collective changes in consumption contribute to changes in the the grid average emission factor over time. Shifting energy consumption to periods with of low-emissions generation on the grid (often non-peak hours) can further contribute to system-wide reductions. Advanced grid studies

can better highlight the emissions impacts of these individual consumption decisions (see Chapter 6).

- **Market-based.** Reducing electricity demand can minimize the additional costs associated with purchasing contractual instruments at a premium above standard electricity costs. However, the market-based method runs the risk of providing less visibility on energy demand reduction if the price of this premium (and therefore the price of achieving "zero emissions") is low. But efficiency can generally be pursued with financial gain regardless of the specific emissions associated with electricity consumption.

3. Decisions to influence grid mix of generation technologies

Many variables impact the mix of generation technologies on a given grid, including the historical regulatory, financial, and physical characteristics of the jurisdiction as well as the current market dynamics of supply/demand for particular resources. An electricity consumer can pursue a variety of actions to try to influence these factors directly or indirectly, conveying stronger or weaker market signals (see Chapter 11). If consumers want to support low-carbon technologies, they can:

- Create on-site low-carbon energy projects
- Establish contracts, that include certificates, such as PPAs directly with low-carbon generators
- Negotiate with their supplier or utility to supply low-carbon energy to the company
- Switch to a low-carbon electricity supplier or electricity product, where available
- Purchase certificates from low-carbon energy generation.

Substantially changing a grid's resource mix over time generally requires aggregate consumer decisions, or a large-scale corporate consumer representing a significant percentage of a utility's load. But all of these interventions benefit from, and depend on, a contractual instrument (e.g. certificate) that confers specific GHG-emission attribute claims associated with purchases, functioning as a demand-signaling mechanism.

Therefore, efforts to shift grid supply through procurement will entail changes in reported scope 2 based on:

- **Location-based.** Cumulative effect of consumer or supplier choices over time that change the grid average emissions factor. (Other factors such as economics and environmental regulation can also impact this.) But individual corporate choices regarding electricity contracts, supplier choices, or certificate purchases are *not* directly reflected in an individual's scope 2 inventories using the location-based method.
- **Market-based.** Individual corporate choices of electricity product or supplier, or the lack of a differentiated choice, which requires the use of a residual mix. Many market-based tracking systems currently only reflect renewable generation contractual instruments, but the method should reflect any type of contract or supplier-specific emission factor that meets the Scope 2 Quality Criteria. Chapter 11 addresses how companies can use the market-based method to drive supply change.

Endnotes

1. The International Energy Agency provides grid average data per country and per year. In some countries grid average data are available for much shorter periods. RTE in France provides grid average figures in real time for every 30 minutes period (http://www.rte-france.com/en/eco2mix/eco2mix-co2-en).
2. Only the NEPOOL and PJM regions of the U.S. use all generation certificate tracking.
3. It is assumed here that direct emissions tracked in scope 1 do reflect absolute reductions. However, it should be noted that a company may see its scope 1 emissions change due to outsourcing or acquisition/divestment, activities which do not in themselves "change" global GHG emissions but which simply change what company has responsibility for them.
4. *Corporate Standard* (WRI/WBCSD 2004), p. 59–60.
5. However, emissions associated with the relocation of a facility (building materials, demolition, trucking, etc.) unrelated to the new or old site's purchase of electricity or steam would generally be accounted for in scope 3
6. This is not as relevant for a totally new facility whose energy use would still reflect an increase on the grid. However, efficiency and demand reduction can remain a priority for consumption occurring in established buildings.
7. See EPRI (2008).

5 Identifying Scope 2 Emissions and Setting the Scope 2 Boundary

This chapter describes the sources of scope 2 emissions and how to establish a boundary for scope 2 accounting under different generation and distribution models and scenarios.

5.1 Organizational boundaries

As detailed in the *Corporate Standard,* a company can choose one of three consolidation approaches for defining its organizational boundaries for the entire corporate inventory, including equity share, financial control, and operational control. Companies should use a consistent consolidation approach over time for their entire inventory.

5.2 Operational boundaries

After a consolidation approach has been determined to define the organizational boundary, it **shall** be applied consistently across the inventory. Companies can then identify emissions from included sources and categorize them into direct and indirect emissions, and further by "scopes." The *Corporate Standard* divides a company's emissions into direct and indirect emissions:

- **Direct emissions** are emissions from sources that are owned and controlled by the reporting company. These emissions are considered scope 1.
- **Indirect emissions** are emissions that are a consequence of the activities of the reporting company, but occur at sources owned or controlled by another company. These include scope 2 and scope 3 emissions. Scope 2 includes emissions from energy purchased or acquired and consumed by the reporting company (see Section 5.3 for expanded definition). Scope 3 emissions include upstream and downstream value chain emissions and are an optional reporting category in the *Corporate Standard.* The *Corporate Value Chain (Scope 3) Accounting and Reporting Standard* (2011) outlines how to conduct a comprehensive scope 3 inventory.

For many companies, scope 2 and scope 3 represent the largest sources of GHG emissions. By allowing for GHG accounting of direct and indirect emissions by multiple companies in a supply chain, multiple entities can work to reduce emissions where they have influence.

The underlying framework of direct and indirect corporate emissions reporting means that one company's scope 1 is another company's scope 2 and/or 3. This is an inherent part of the reporting framework that enables multiple entities along a value chain to consistently report those

emissions. However, as stated in the *Corporate Standard,* companies should avoid double counting the same emissions in multiple scopes in the same inventory. In addition, double counting the same emissions within the same scope by multiple companies should also be avoided (see Section 5.5).

5.2.1 Leased assets

Energy use in leased buildings or from leased electricity generation assets can be a significant emissions source. To determine whether the assets' emissions are included in the inventory boundary and how they should be categorized by scope, companies should determine the entity that owns, operates, or exerts control over certain leased assets.[1]

As noted in the *Corporate Standard* and its supplemental Appendix F (available at ghgprotocol.org), all leases confer operational control to the lessee or tenants, unless otherwise noted.[2] Therefore, if a company is a tenant in a leased space or using a leased asset and applies the operational control approach, any energy purchased or acquired from another entity (or the grid) **shall** be reported in scope 2. On-site heat generation equipment, such as a basement boiler, typically falls under the operational control of the landlord or building management company. Tenants therefore would report consumption of heat generated on-site as scope 2. If a tenant can demonstrate that they do not exercise operational control in their lease, they **shall** document and justify the exclusion of these emissions.

Emissions from assets a company owns and leases to another entity, but does not operate, can either be included in scope 3 or excluded from the inventory. For more information on organizational boundaries, see The *Corporate Standard,* Chapter 3: Setting Organizational Boundaries, and Appendix F at www.ghgprotocol.org.

5.3 Defining scope 2

Scope 2 is an indirect emission category that includes GHG emissions from the generation of purchased or acquired electricity, steam, heat, or cooling consumed by the reporting company.[3] GHG emissions from energy generation occur at discrete sources owned and operated by generators that account for direct emissions from generation in their scope 1 inventory. Scope 2 includes indirect emissions from generation only; other upstream emissions associated with the production and processing of upstream fuels, or transmission or distribution of energy within a grid, are tracked in scope 3, category 3 (fuel- and energy-related emissions not included in scope 1 or scope 2).

5.3.1 Forms of energy use tracked in scope 2

Scope 2 accounts for emissions from the generation of energy that is purchased or otherwise brought into the organizational boundary of the company. At least four types of purchased energy are tracked in scope 2, including the following:

Electricity. This type of energy is used by almost all companies. It is used to operate machines, lighting, electric vehicle charging, and certain types of heat and cooling systems.

Steam. Formed when water boils, steam is a valuable energy source for industrial processes. It is used for mechanical work, heat, or directly as a process medium.

Combined heat and power (CHP) facilities (also called cogeneration or trigeneration) may produce multiple energy outputs from a single combustion process. Reporting companies purchasing either electricity or heat/steam from a CHP plant should check with the CHP supplier to ensure that the allocation of emissions across energy outputs follows best practices, such as the *GHG Protocol Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant (2006).*

Heat. Most commercial or industrial buildings require heat to control interior climates and heat water. Many industrial processes also require heat for specific equipment. That heat may either be produced from electricity or through a non-electrical process such as solar thermal heat or thermal combustion processes (as with a boiler or a thermal power plant) outside the company's operational control.

Cooling. Similar to heat, cooling may be produced from electricity or through the distribution of cooled air or water.

This guidance focuses on electricity accounting. Differences in accounting for heat, cooling, and steam are treated in Appendix A.

5.4 Distinguishing scopes reporting by electricity production/distribution method

Once energy is generated, it is either consumed on-site, or distributed to another entity by direct line transfer or through the electricity grid. These pathways, along with any contractual and/or certificate sales from electricity generation from owned/operated equipment, determine how the emissions from energy generation are accounted for and reported by different entities in scope 1 and 2. (Scope 3 accounting is addressed in Appendix B.) Scope 2 emissions are accounted for when a company obtains its energy from another entity, or when a company sells an energy attribute certificate from owned and consumed generation. See Chapter 10 for background on energy attribute certificates.

Under all four scenarios identified below, companies should report electricity consumption separately from the scopes as part of reporting the total quantity of energy consumption in kWh, MWhs, TJ, BTUs or other relevant units.

1. If the consumed electricity comes from owned/operated equipment (Figure 5.1)

If energy is produced and consumed by the same entity (with no grid connection or exchanges), no scope 2 emissions are reported, as any emissions occurring during the power generation are already reported in scope 1. This scenario may apply to large industrial facilities that generate their own energy on-site in owned/operated equipment.

Figure 5.1 Energy production and consumption from owned/operated generation

2. If the consumed electricity comes from a direct line transfer (Figure 5.2)

In this example, energy production is fed directly and exclusively to a single entity—here, Company B. This applies to several types of direct line transfers, including:

- An industrial park or collection of facilities, where one facility creates electricity, heat, steam, or cooling and transfers it directly to a facility owned or operated by a different party.
- For energy produced by equipment installed on-site (e.g. on-site solar array or a fuel cell using natural gas) that is owned and operated by a third party.
- For electricity, heat, steam, or cooling produced within a multi-tenant leased building (by a central boiler, or on-site solar) and sold to individual tenants who do not own or operate the building or the equipment. Tenants may pay for this energy as part of a lump rental cost and the tenant may not receive a separate bill.

In any of these scenarios:

- The company with operational or financial control of the energy generation facility would report these emissions in their scope 1, following the operational control approach, while the consumer of the energy reports the emissions in scope 2.
- Any third-party financing institution that owns but does not operate the energy generation unit **would not** account for any scope 1, 2, or 3 emissions from energy generation under the operational control approach, since they do not exercise operational control. Only the equipment operator would report these emissions in their scope 1 following an operational control approach. Equipment owners would account for these generation emissions in scope 1 under a financial control or equity share approach, however.
- If all the energy generation is purchased and consumed, then Company B's scope 2 emissions will be the same as Company A's scope 1 emissions (minus any transmission and distribution losses, though in most cases of direct transfer there will be no losses).[4]

3. If the consumed electricity comes from the grid (Figure 5.3)

Most consumers purchase or acquire some or all of their electricity through the electric grid, a shared electricity distribution network. Depending on the design of the grid, there may be a small number of central generation facilities providing energy to many consumers, or there may be a large number of generation facilities representing different technology types (thermal power using coal or natural gas inputs, or wind turbines, solar photovoltaic cells, or solar thermal, etc.).

Figure 5.2 Direct line energy transfer

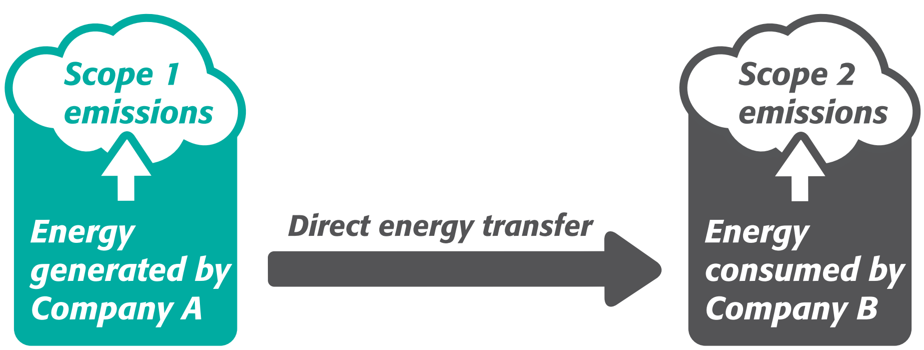
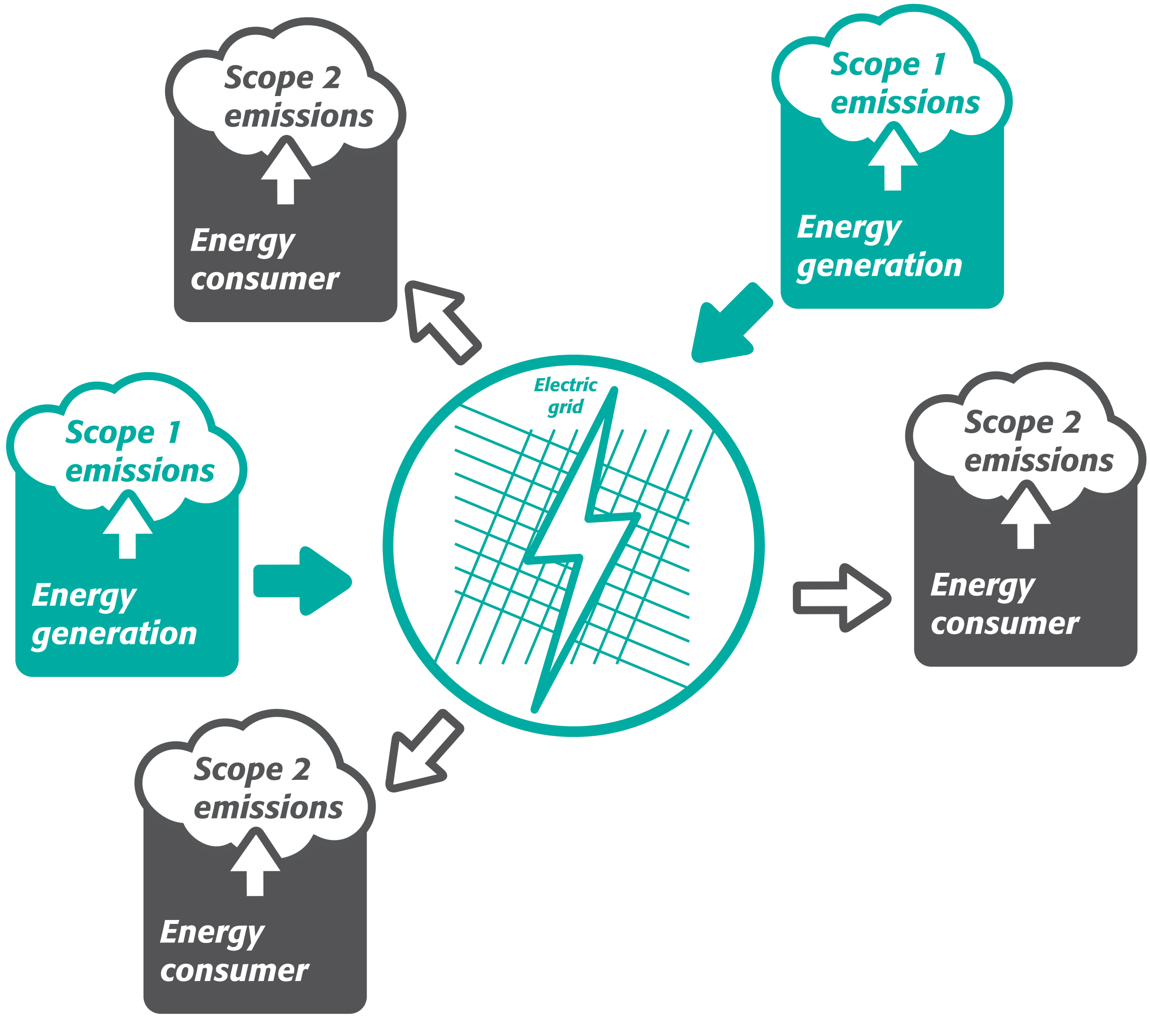


Figure 5.3 Electricity distribution on a grid



Electricity generators report any emissions from generation in scope 1, but most renewable or nuclear technology would report "zero" emissions from this generation. A grid operator or utility dispatches these generation units throughout the day on the basis of contracts, cost, and other factors. Because it is a shared network as opposed to a direct line, consumers may not be able to identify the specific power plant producing the energy they are using at any given time.[5] Use of specified generation on the grid can only be determined contractually. Energy on the grid moves to the nearest point it can be used, and multiple regions can exchange power depending on the capacity and needs of these regions. Steam, heat, and cooling can also be delivered through a grid, often called a district energy system. Such systems provide energy to multiple consumers, though they often have only one generation facility and serve a more limited geographic area than electricity grids.

4. If some consumed electricity comes from owned/operated equipment, and some is purchased from the grid (Figure 5.4).

Some companies own, operate, or host energy generation sources such as solar panels or fuel cells on the premises of their building or in close proximity to where the energy is consumed. This arrangement is often termed "distributed generation" or "on-site" consumption, as it consists of generation units across decentralized locations (often on the site where the energy output will be consumed, as opposed to utility-scale centralized power plants). The company may consume some or all of the energy output from these generation facilities; sell excess energy output back to the grid; and purchase additional grid power to cover any remaining energy demand.

The owners/operator of a distributed generation facility may therefore have both scope 1 emissions from energy generation, as well as scope 2 emissions from any energy purchased from the grid, or consumed from on-site generation where attributes (e.g. certificates) are sold. This arrangement impacts activity data as follows:

Activity data. Determining the underlying activity data (in MWh or kWh) in these systems may be challenging given the flux of electricity coming in or flowing out. Many markets utilize "net metering" for these systems, which allows grid purchases to be measured only as *net* of any energy exported to the grid. This net number may also be the basis for how costs are assessed.

For accurate scope 2 GHG accounting, companies **shall** use the total—or gross—electricity purchases from the grid rather than grid purchases "net" of generation for the scope 2 calculation. A company's total energy consumption would therefore include self-generated energy (any emissions reflected in scope 1) and total electricity purchased from the grid (electricity). It would exclude generation sold back to the grid.

If a company cannot distinguish between its gross and net grid purchases, it should state and justify this in the inventory.

Table 5.1 illustrates the difference between total energy consumption and net energy consumption (if the reporter is a net grid consumer rather than producer). A negative

Figure 5.4 **Facility consuming both energy generated on-site and purchased from the grid**

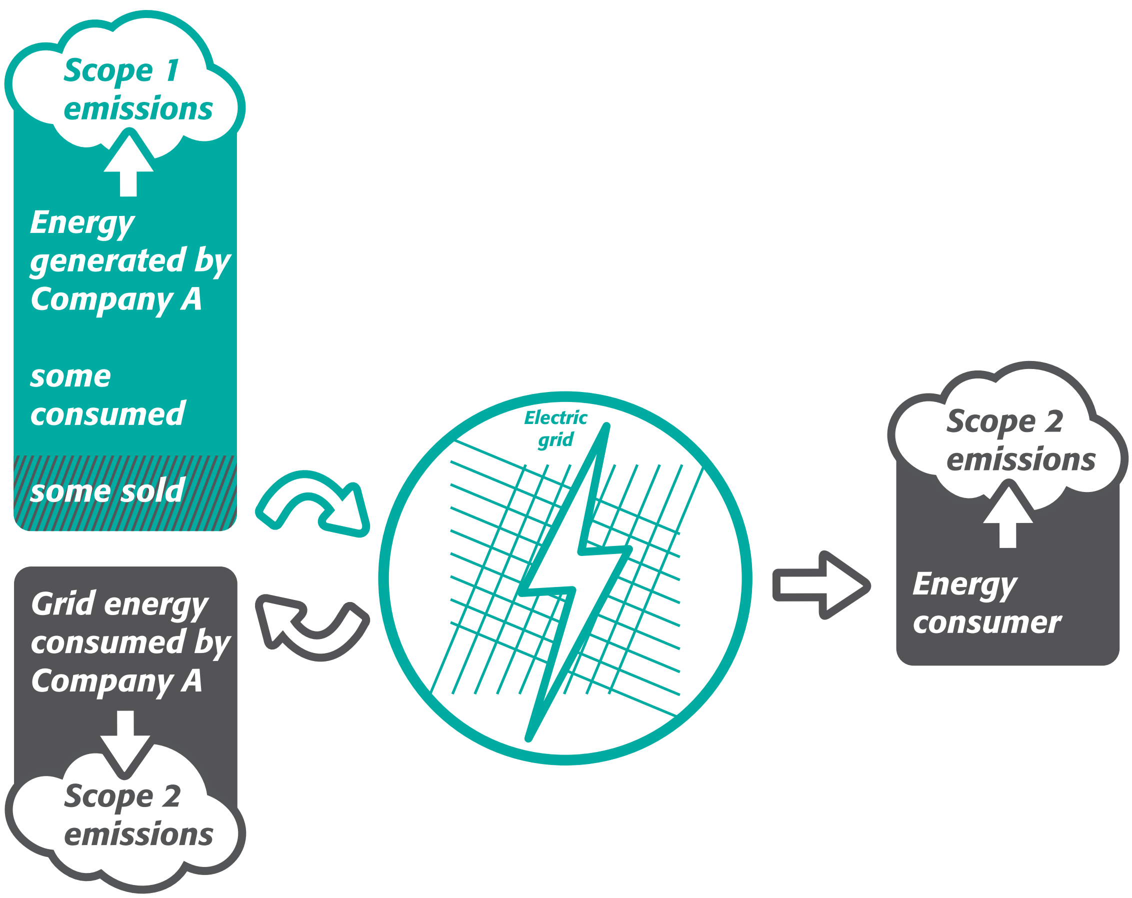


Table 5.1 Comparing gross and net energy consumption

Total energy production from on-site system	On-site energy consumption from on-site system	Energy exported from the on-site system to the grid	Energy imported from the grid
100 kWh	50 kWh	50 kWh	70 kWh
Total energy consumption (to be reported separately) = 120 kWh 50 kWh consumed from on-site system + 70 kWh imported from grid			
"Net" grid consumption= 20 kWh (70 kWh imported from grid - 50 kWh exported)			

consumption number for net energy exporters demonstrates the challenge of using net consumption information as activity data.

Because scope 2 reflects energy purchased from a separate entity outside the inventory boundary, energy consumed from owned/operated facilities may not be reported in scope 2, depending on the sale of attributes.

5.5 Avoiding double counting in scope 2

The dual reporting requirement in this guidance can complicate the understanding of whether double counting is occurring and whether it threatens an inventory's accuracy.

Table 5.2 details several scenarios of double counting, along with whether they introduce accuracy errors and how they are, or can be, addressed.

5.6 Avoiding double counting between owned energy generation assets (scope 1) and grid-delivered energy consumption in separate operations (scope 2)

Some companies such as electricity utilities or suppliers may own energy generation facilities that sell all their power into the local grid. Emissions from these generation facilities are reported in scope 1 of the utility's inventory. At the same time, the utility may have separate administrative, commercial, or industrial facilities or office buildings (apart from the generation facilities)[6] that consume electricity from the same grid to which the utility is supplying—which would be reported in scope 2. Following the *Corporate Standard* scopes framework, companies should avoid reporting the same emissions in scope 1 and 2 of the same company's inventory; but in the case of utilities, a scope 2 calculation according to *either* the location-based or market-based approach would likely include emissions from the generation assets reported in scope 1. This is because

Table 5.2 Additions to scope 2 accounting introduced by the *Scope 2 Guidance*

Type of double counting	Examples	How to prevent double counting
Between scope 1 and 2		
Between scope 1 and 2 in different inventories	A company reports emissions from grid-delivered energy use in scope 2, while a generation facility on the grid reports its facility's emissions in scope 1.	No double counting problem—this is an inherent part of the corporate reporting framework.
Between scope 1 and 2 in the same inventory	A company owns a natural gas fuel cell and consumes the output directly (with no grid transfers).	Depending on the consolidation approach chosen, emissions from owned/operated generation shall be reported under scope 1 (if any emissions occur). The emissions from consumed energy shall not be repeated in scope 2 since they have already been reported in scope 1.
Between multiple companies' scope 2 inventories		
Between multiple companies' scope 2 inventories based on different methods	In aggregate: The energy attribute certificates from a renewable generation facility are sold to a company who claims them and reports their emission rate in scope 2 (market-based). The grid emissions factor for the region will also reflect this facility's emission rate. Consumers using the grid emissions factor (location-based method) will be double counting the emission rate conveyed by the energy attribute certificate (market-based method).	This is an inherent condition of two methods. Each method's results shall not be added or netted. Each method represents a separate way of allocating energy generation emissions, so depending on geographic or market boundaries, each method's scope 2 result can reflect some of the same emissions reflected in the other method.
Between multiple companies' scope 2 inventories of the same method	May occur in the market-based method if energy attribute certificates are sold from an owned/ operated solar panel, but owner also consumes the energy and claims zero emissions rate.	If energy attribute certificates are sold from energy generation, companies shall treat consumed electricity as though it were purchased from the grid—using the hierarchies of emission factors indicated for both methods (Table 6.2 and Table 6.3). Sold energy attribute certificates may be reported separately. Scope 1 reporting shall still reflect any emissions from the generator.
	May occur in the location-based method if grid emission factors reflect different geographic boundaries (e.g. local, regional, national). May occur in the market-based method if instrument claims are unclear (see instrument tracking below), or if residual mix is not available	This is a function of data rather than the accounting framework. Companies shall use the most accurate and appropriate emission factors listed in the emission factor hierarchy for each method (see Chapter 6).
	Two different certificate types are generated from a single MWh (one for supplier quotas, one for supplier disclosure). Neither certificate is clear on whether energy attribute claims are included. If users assume they are, different suppliers may count the same attributes in their mix.	This guidance's Scope 2 Quality Criteria require consumers to ensure that only one instrument conveys a GHG emission rate claim to consumers, and that that claim be clearly conveyed with the instrument, or if multiple instruments convey the GHG emission rate claim, that all such instruments be owned and retired to substantiate a usage and scope 2 claim.

the owned generation facilities will be supplying the same grid region where their electricity consumption occurs.

Therefore, to minimize double counting between scope 1 and 2 within the same inventory, companies in this situation should treat their grid consumption as though it were supplied by their own generation facilities (e.g. as though they were an "on-site" source), with no additional emissions reported in scope 2 (see row 2 of Table 6.1 for this scenario). The grid-consuming facility should secure a contract or other instrument with its own generation unit(s) to convey the claim following the Quality Criteria in the market-based method, including ensuring that there have not been any sales from that production conveying claims to other parties. If possible, utilities should also remove from any supplier-specific emission factor or third-party data collectors the quantity of energy (and its emissions) supplied to or associated with these commercial/industrial operations.

Any energy consumption not covered by contractual arrangements with owned/operated generation units should be treated as grid-consumed energy in scope 2, reported according to both the location-based and market-based method emission factor hierarchies.

Endnotes

1. See *Corporate Standard* (WRI/WBCSD 2004), p. 31.
2. In some leased building arrangements, tenants do not pay for electricity individually. However, this should not exempt tenants from reporting the emissions from that energy use. As defined in the next section, scope 2 includes energy that is acquired and consumed.
3. *Corporate Standard* (WRI/WBCSD 2004), p. 25. The word "acquired" was added in the *Scope 3 Standard* (p. 28) to reflect circumstances where a company may not directly purchase electricity (e.g., a tenant in a building), but where the energy is brought into the organization's facility for use.
4. Line losses in Figure 5.2 can be separately reported in Company B's scope 3. If Company A owns the line, it does not need to report these line-loss emissions separately since they have already been reported in scope 1.
5. In rare situations, such as islands with a single, small grid, it may be possible to determine which power station was operating and providing power to the grid users.
6. These administrative buildings should be distinguished from auxiliary operations adjacent to generation facilities. Auxiliary operations may use electricity directly from the generation facility even before distribution and sales to the grid.

6 Calculating Emissions

This chapter outlines key requirements, steps, and procedures involved in calculating scope 2 emissions according to each method.

Once the inventory boundary has been established, companies generally calculate GHG emissions using the following steps:

- Identify GHG emission sources for scope 2 emissions
- Determine whether the market-based approach applies
- Collect activity data and choose emission factors for each method
- Calculate emissions
- Roll up GHG emissions data to corporate level.

Additional guidance on general calculation procedures and GHG Protocol calculation tools can be found in Chapter 6 of the *Corporate Standard.*

6.1 Identify GHG emissions sources for scope 2

Scope 2 includes emissions from all purchased/acquired and consumed electricity, heat, steam, or cooling. Companies can identify these energy uses on the basis of utility bills or metered energy consumption at facilities within the inventory boundary.

6.2 Determine whether the market-based method applies for any operations

Companies can determine whether the market-based method for scope 2 calculation applies to their inventory by assessing whether differentiated energy products in the form of contractual instruments (including direct contracts, certificates, or supplier-specific information) are available in a given market. Markets are increasingly developing and refining purchasing options, and the list is not exhaustive. Currently this includes EU member states and economic area, the U.S., Australia, most Latin American countries, Japan, India, and many others. Figure 6.1 illustrates this determination.

- The presence of contractual information in any market where a company has operations triggers the requirement to report according to the market-based method. The contractual instruments themselves must be assessed for their conformance with Scope 2 Quality Criteria. If they do not meet the Scope 2 Quality Criteria, then other data (listed in Table 6.3) **shall** be used as an alternative in the market-based method total. In this way, all companies required to report according to the market-based method will have some type of data option.

- If a multi-regional company has any operations within the corporate inventory where the market-based method applies, then a market-based method total **shall** be calculated for the entire corporate inventory to ensure completeness and consistency. For any individual operations in the corporate inventory where market-based method data on the hierarchy is not applicable or available, data from the location-based method should be used to represent the emissions from the facility (see Table 6.3). For these operations, the calculated scope 2 according to the market-based method will be identical to the location-based.

If no facilities in the entire organizational boundary of the reporting entity are located in markets with contractual claims systems, or where *no* instruments within those systems meet Scope 2 Quality Criteria required by this document, then only the location-based method **shall** be used to calculate scope 2.

6.3 Collect activity data

For electricity use disclosure required by this guidance, activity data includes all electricity purchased/acquired and consumed during the reporting period, including from owned/operated generation facilities that may not be included as activity data for scope 2 calculation.

For scope 2 calculation, activity data includes all energy purchased/acquired and consumed from an entity outside of the organization or from owned/operated generation facilities where energy attributes (e.g. certificates) have been sold or transferred. Table 6.1 indicates how different energy distribution methods should be treated.

To determine activity data, metered electricity consumption or utility bills specifying consumption in MWh or kWh units can provide the most precise activity data. In some cases these may not be available, as with consumption occurring in a shared space without energy metering. In these cases, estimations may be used such as allocating an entire building's electricity usage to all tenants on the basis of the reporter's square footage and the building's occupancy rate (called the Area Method).[1]

6.4 Identify distribution scenarios and any certificate sales

All of the distribution scenarios identified in Section 5.4 can entail the generation and sale of energy attribute certificates or other contractual instruments. The sale or retention of these instruments impacts the accounting of the consumed energy, as shown in Table 6.1.

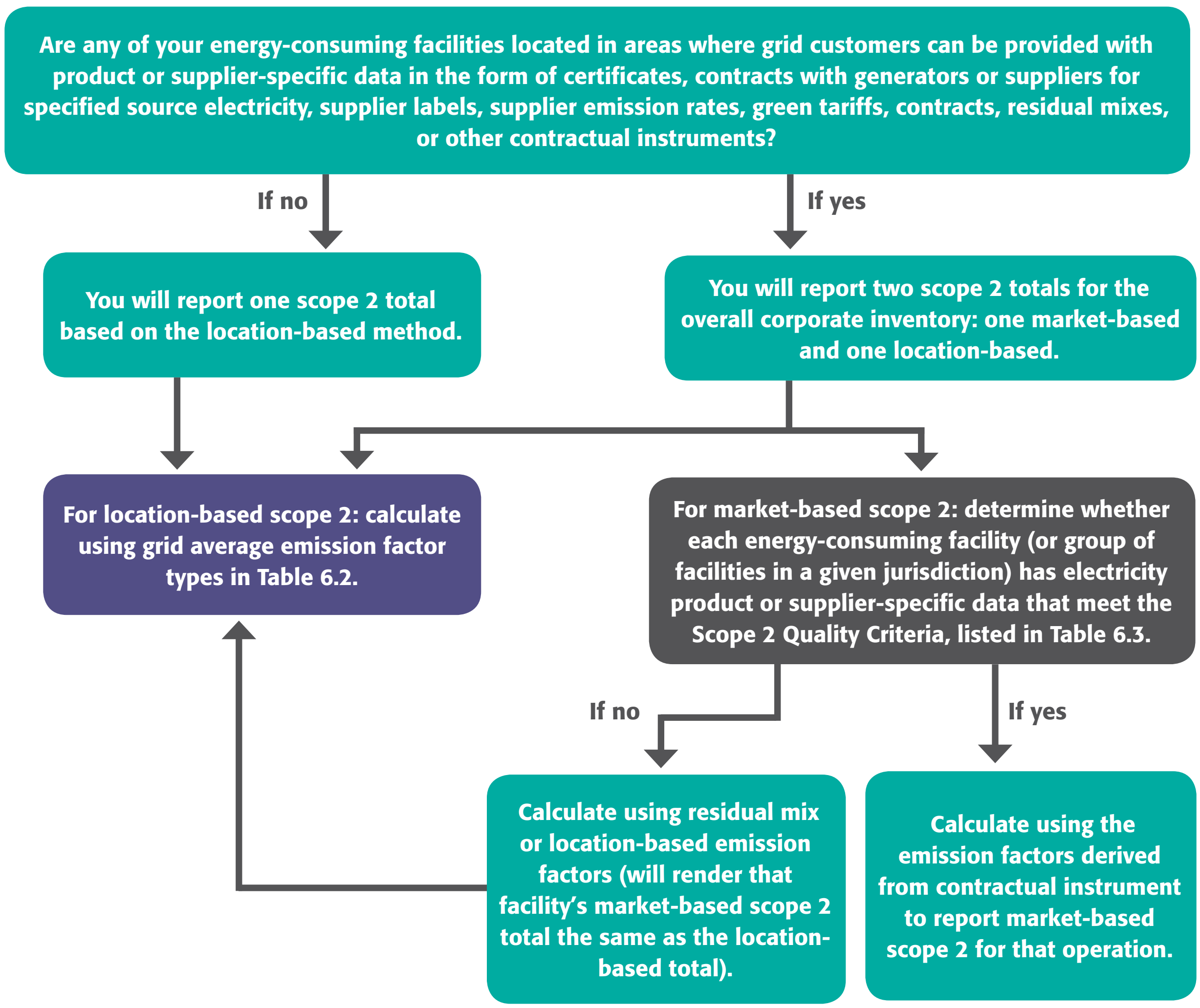
The creation of a certificate that conveys an energy generation attribute claim means that the underlying power—sometimes called "null power"—can no longer be considered to contain the energy attributes, including the type of energy (e.g., that it is "renewable") and its GHG emission rate (that it is zero emissions/MWh). By the conveyance of energy attributes or certificates to a third party separate from the electricity, users of the null power electricity cannot claim to be buying or using renewable energy in the absence of owning the certificate. Instead, companies consuming energy from owned/operated facilities or direct-line transfers where certificates are sold off, **shall** calculate that consumption using other market-based method emission factors such as "replacement" certificates, a supplier-specific emission rate, or residual mix (for the market-based method total) and the grid average emission factor (for the location-based total).

6.4.1 How certificate sales affect on-site energy consumption in the location-based method

Companies who are consuming energy directly from a generation facility that has sold certificates (either owned/operated equipment or a direct line) forfeit not only the right to claim those emissions in the market-based method (requiring the use of some other market-based data source such as other "replacement" certificates, a supplier-specific emission factor, or residual mix) but also the right to claim that emissions profile in the location-based method. Overall, the location-based method is designed to show emissions from the production supporting the local consumption without reference to any contractual relationships. However, the attributes contained in certificates usually carry legally enforceable claims, which should take precedence.

For instance, the U.S. Federal Trade Commission Green Guides[2] prevent any kind of claim about using, consuming,

Figure 6.1 **Determining which accounting methods to use for scope 2**



or hosting renewable energy or its attributes if the REC from that production has been sold off. This includes a claim in the form of location-based calculations of "zero emissions power consumption." Therefore, in the event of certificate sales from owned/operated energy production and consumption, companies should still use the location-based emission factor hierarchy (see Table 6.2).

Taken to its logical conclusion, these kind of legally enforceable rights and claims could call into question the validity of any kind of location-based reporting (since even a grid average will include a mix of power whose RECs have been claimed by someone else). However, for the purposes of a GHG inventory, location-based accounting and reporting are still required in order to improve comparability across multiple markets over time and to show risks/opportunities that are better evaluated based on average emissions in a grid. Companies should avoid using location-based totals for goal tracking where certificates convey these claims and/or carry legally enforceable claims.

6.5 Choose emission factors for each method

Companies should use the most appropriate, accurate, precise, and highest quality emission factors available for each method. Table 6.2 indicates these preferences for the location-based method, and Table 6.3 for the market-based method. Table 6.3 does *not* represent a preferred hierarchy

Table 6.1 Accounting for scope 2 with and without certificates sales

	Scope 2 with location-based method	Scope 2 with market-based method
Energy consumed from owned/operated generation (e.g. a company owns a solar panel and consumes the energy)		
No certificates generated or sold	No scope 2 reported for consumption from owned generation	
Certificates from generation facility retired/retained by the generation facility's owner who consumes the energy	Should report certificate retention separately, but no scope 2 reported for consumption of on-site generation	
Certificates sold to 3rd party	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Direct line (e.g. a company receives power directly from a generator, with no grid transfers)		
No certificates generated or sold	Use source-specific emission factor from direct line	
Certificates from generation facility purchased and retired/retained by the energy consumer	Use source-specific emission factor from direct line (same as certificate emission factor)	Use certificate emission factor (same as source- specific emission factor)
Certificates sold to 3rd party	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Grid-distributed		
No certificates generated or sold from any generation facilities on the grid	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Certificates purchased from grid generation facilities, or included in a supplier-specific emission factor	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Certificates from grid generation facilities sold to 3rd parties	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy

of procurement methods (e.g., purchasing renewable energy from a supplier vs. through a contract with a generator), as these are dependent on local market options and company-specific conditions. Instead, it represents a hierarchy of instruments based on the most precise (e.g., energy attribute certificates issued in units that match consumption units, e.g. MWh) to least precise (averages of attributes representing all unclaimed production in a region).

Companies using the market-based method **shall** ensure that any contractual instrument from which an emission factor is derived meets the Scope 2 Quality Criteria listed in Chapter 7. Where contractual instruments do not meet the Scope 2 Quality Criteria requirements, and no other market-based method data are available, the location-based data should be used.

Table 6.2 Location-based method emission factor hierarchy

Data forms listed here should convey combustion-only (direct) GHG emission rates, expressed in metric tons per MWh or kWh.

Emission factors	Indicative examples
Regional or subnational emission factors *Average emission factors representing all electricity production occurring in a defined grid distribution region that approximates a geographically precise energy distribution and use area. Emission factors **should** reflect net physical energy imports/exports across the grid boundary.*	eGRID total output emission rates (U.S.)[a] Defra annual grid average emission factor (U.K.)[b]
National production emission factors *Average emission factors representing all electricity production information from geographic boundaries that are not necessarily related to dispatch region, such as state or national borders. No adjustment for physical energy imports or exports, not representative of energy consumption area.*	IEA national electricity emission factors[c]

Notes:

a Although eGRID output rates represent a production boundary, in many regions this approximates a consumption or delivery boundary, as eGRID regions are drawn to minimize energy imports/exports. See: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

b See Defra: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224437/pb13988-emission-factor-methodology-130719.pdf.

c IEA emisison factors do not adjust for imports/exports of energy across national boundaries. See: http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=304.

Table 6.3 Market-based scope 2 data hierarchy examples

Data forms listed here should convey combustion-only (direct) GHG emission rates, expressed in metric tons per MWh or kWh. Reporting entities should ensure that market-based method data sources meet Scope 2 Quality Criteria. Instruments listed here are not guaranteed to meet Scope 2 Quality Criteria, but are indicative of instrument type.

Emission factors	Indicative examples	Precision
Energy attribute certificates or equivalent instruments (unbundled, bundled with electricity, conveyed in a contract for electricity, or delivered by a utility)	• Renewable Energy Certificates (U.S., Canada, Australia and others) • Generator Declarations (U.K.) for fuel mix disclosure • Guarantees of Origin (EU) • Electricity contracts (e.g. PPAs) that also convey RECs or GOs • Any other certificate instruments meeting the Scope 2 Quality Criteria	Higher
Contracts for electricity, such as power purchase agreements (PPAs)[a] and contracts from specified sources, where electricity attribute certificates do not exist or are not required for a usage claim	• In the U.S., contracts for electricity from specified nonrenewable sources like coal in regions other than NEPOOL and PJM • Contracts that convey attributes to the entity consuming the power where certificates do not exist • Contracts for power that are silent on attributes, but where attributes are not otherwise tracked or claimed	
Supplier/Utility emission rates, such as standard product offer or a different product (e.g. a renewable energy product or tariff), and that are disclosed (preferably publicly) according to best available information	• Emission rate allocated and disclosed to retail electricity users, representing the entire delivered energy product (not only the supplier's owned assets) • Green energy tariffs • Voluntary renewable electricity program or product	
Residual mix (subnational or national) that uses energy production data and factors out voluntary purchases	• Calculated by EU country under RE-DISS project [b, c]	
Other grid-average emission factors (subnational or national) – see location-based data	• eGRID total output emission rates (U.S.).[d] In many regions this approximates a consumption-boundary, as eGRID regions are drawn to minimize imports/exports • Defra annual grid average emission factor (UK) • IEA national electricity emission factors[e]	Lower

Notes:

a Because PPAs are the primary example of this type of instrument used in the markets consulted in this TWG process, this class of instrument may be referred to in shorthand as "PPAs" with the recognition that other types of contracts that fulfill a similar function may go by different names.

b See: http://www.reliable-disclosure.org/static/media/docs/RE-DISS_2012_Residual_Mix_Results_v1_0.pdf.

c The Norwegian authority also publishes a residual mix emission factor that can be found here: http://www.nve.no/en/Electricity-market/Electricity-disclosure-2011/.

d See: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

e See: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

6.6 Match emission factors to each unit of electricity consumption

Each unit of electricity consumption should be matched with an emission factor appropriate for that consuming facility's location or market. For the market-based method, this means choosing a contractual instrument or information source for each unit of electricity. For instance, if a company has purchased certificates to apply to half of a given operation's electricity use, it will need to use other instruments or information on the emission factor hierarchy to calculate the emissions for the remaining half.

Companies centrally purchasing energy attribute certificates on behalf of all its operations in a single country or region should indicate how they match these purchases to individual site consumption.

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

6.7 Calculate emissions

To calculate scope 2 emissions according to one or both methods, the following procedure applies:

1. Multiply activity data from each operation by the emission factor for that activity for each applicable GHG. Some electricity emission factor sets may include emission rates for CO_2, CH_4, and N_2O; others may only provide CO_2 emission rates (see Box 6.1)
2. Multiply global warming potential (GWP) values by the GHG emissions totals to calculate total emissions in CO_2 equivalent (CO_2e).
3. Report final scope 2 by each method in metric tons of each GHG (where available) and in metric tons of CO_2e.

Example calculations are provided for the location-based method and market-based method in Table 6.4 and Table 6.5, respectively.

Table 6.4 **Example calculation for location-based method**

Activity data per reporting period			**Emission factors**				**Calculated emissions**			
Facility	Location	Quantity of energy	CO_2 emission rate	CH_4 emission rate	N_2O emission rate	GHG emission factor source	CO_2 (mt)	CH_4 (kg)	N_2O (kg)	CO_2e (mt)
U.S. facilities	eGRID subregion NYUP	2,500 MWh	545.79 lb/MWh	16.3 lb/GWh	7.24 lb/GWh	eGRID year 2010	618.91	18.48	8.21	621.85
	eGRID subregion RFCE	2,500 MWh	1001.72 lbs/MWh	27.07 lb/GWh	15.33 lb/GWh	eGRID year 2010	1135.93	30.70	17.38	1141.96
EU facilities	Denmark	3,000 MWh	0.3152 $mtCO_2$/MWh	*	*	IEA Denmark, 2011	945.63	*	*	945.63
	Belgium	2,000 MWh	0.1957 $mtCO_2$/MWh	*	*	IEA Belgium, 2011	391.44	*	*	391.44
Total consumption		**10,000 MWh**								
Total scope 2 emissions for location-based method							**3091.908**	**49.179**	**25.596**	**3100.87**

* Non-CO_2 emission factors not available for IEA

Table 6.5 Example calculation for market-based method

Activity data per reporting period					**Emission factors**	**Calculated emissions**
Facility	Total energy consumption	Quantity of energy	Contractual instrument type	Meets Scope 2 Quality Criteria?	CO_2e emission rate	CO_2e (mt)
U.S. operations	5,000 MWh	1,000 MWh	PPA with REC retention	Yes Residual mix not available for U.S.	0 mt CO_2e / MWh	0 mt CO_2e
		2,000 MWh	REC purchase (bundled with energy)	Yes Residual mix not available for U.S.	0 mt CO_2e / MWh	0 mt CO_2e
		1,000 MWh	REC purchase (not bundled with energy)	Yes Residual mix not available for U.S.	0 mt CO_2e / MWh	0 mt CO_2e
		1,000 MWh (remaining energy without contractual instruments)	Grid Average (eGRID sub-region NYUP)	Yes Residual mix not available for U.S.	0.5 mt CO_2e / MWh*	500 mt CO_2e
EU operations	5,000 MWh	3,000 MWh	Supplier program	Yes	0.25 mt CO_2e / MWh	750 mt CO_2e
		2,000 MWh	Residual mix (RE-DIS II Belgium 2013)	Yes	0.5 mt CO_2e / MWh	1,000 mt CO_2e
Total energy consumption		**10,000 MWh**				
Total scope 2 emissions for market-based method						**2,250 mt CO_2e**

* Emission factors for CH_4 and N_2O not listed individually here for space considerations

6.8 Roll up GHG emissions data to corporate level

To report a corporation's total GHG emissions, companies will usually need to gather and summarize data from multiple facilities, possibly in different countries and business divisions. It is important to plan this process carefully to minimize the reporting burden, reduce the risk of errors that might occur while compiling data, and ensure that all facilities are collecting information on an approved, consistent basis. Ideally, corporations will integrate GHG reporting with their existing reporting tools and processes, and take advantage of any relevant data already collected and reported by facilities to division or corporate offices, regulators, or other stakeholders. The two basic approaches to gather data on GHG emissions from facilities include a centralized and decentralized approach. For more guidance on this process, see Chapter 6 of the *Corporate Standard.*

6.9 Optional: Calculate any avoided emissions and report separately

Companies can report the estimated grid emissions avoided by low-carbon energy generation and use, separately from the scopes. This type of analysis reflects the impacts of generation on the rest of the grid: for example, the emissions from fossil-fuel or other generation backed down or avoided due to the low-carbon generation. These avoided emissions estimations inherently represent impacts *outside* the inventory boundary. Avoided emissions estimations are not necessarily equivalent to global emissions reductions from additional projects and should therefore not be used to reduce a company's footprint. However, quantifying avoided emissions provide several technical and strategic benefits, including:

- Identifying where low-carbon energy generation can have the biggest GHG impact on system, based on the operating margin.
- Demonstrating that grid-connected generation provides a system-wide service in addition to conveying a specific emission rate at the point of production.

This estimation should follow project-level methodology; see GHG Protocol *Project Protocol* or *Guidelines for Grid-Connected Electricity Projects.* This may be most beneficial where a company has taken actions that avoid higher-carbon generation dispatch at the margins. These actions could include:

- Installing a low-carbon energy generation facility on-site that sells energy to the grid (any emissions from owned/operated facilities are reported in scope 1)
- Installing a cogeneration facility providing both heat and electricity outputs, which may increase a company's scope 1 reporting but reduce the electricity it needs to purchase from the grid
- Securing a contract to purchase power from a *new* low-carbon energy generation facility
- Undertaking a significant energy efficiency effort.

However, if the project operates in a jurisdiction with an emissions cap on the power sector, or comes from an energy generation facility also producing verified emission reductions (also termed a GHG offset), the company should not make public claims about avoided emissions. The avoided grid emissions will either be zero, in the case of a cap as regulated entities may emit up to the level of the cap,[3] or already represented in claims by the offset purchaser. Any offsets produced from the project, or any voluntary allowances retired on behalf of the purchase associated with the project, should be reported separately.

6.10 Location-based emission factors

The emission factors necessary to estimate location-based scope 2 emissions include GHG emission intensity factors for energy production in a defined local or national region. Where advanced studies or real-time information is available, companies may report scope 2 estimations separately as a comparison to location-based grid average estimation (see Box 6.2). Companies should be aware of the following caveats about location-based emission factors:

- **Location-based is not supplier-specific.** The location-based grid average emission factors should be distinguished from supplier-specific information, even if the electricity supplier is the sole energy provider in a region and produces a supplier-specific emission factor that closely resembles the overall regional grid average emission factor. In these cases, the service territory may still be a smaller region than the grid distribution area serving a given site of consumption; conversely, many utilities are in competitive markets where multiple suppliers can compete to serve consumers in the same region. Therefore, this method only looks at a broader grid emissions profile serving the local load, regardless of supplier relationships.

- **Grid average emission factors do not factor out contractual purchases.** Grid average emission factors in the location-based method should *not* reflect any adjustments or removals for market-based contractual claims by suppliers or end-users. By contrast, a residual mix in the market-based method should represent all unclaimed energy emissions, which is formulated by removing contractual claims data from energy production data (often the same as grid average data).

- **Grid average emission factors are different from marginal grid emission factors.** Grid average emission factors should represent all the emissions from energy generation occurring within a defined geographic region, and thereby best represent the purpose of the location-based method. By contrast, marginal emission factors only represent the emissions from those power plants operating "at the margin," which can be more useful for avoided emissions analyses. Companies **shall not** use marginal emission factors such as those provided by CDM for a location-based scope 2 calculation.

Box 6.2 Advanced grid studies

Companies may have access to detailed studies or software solutions linking their facility's time-of-day energy use patterns to the GHG emissions from local generation dispatching during those times. This emission data could be compiled over the course of a year for a consumer to record, match against temporal usage by location, and calculate scope 2 emissions. To date such studies or analyses have not been widely available or used, and have often been contained in proprietary databases with limited consumer access. However, the root components of this type of GHG emissions data, including facility-specific generation and emissions information, are becoming increasingly common as smart grid applications and distributed generation grow. This data can help inform specific demand-side actions more than grid-average emission factors, which may only incentivize overall demand reduction rather than targeted actions. For instance, while utilities may implement DSM measures in order to mitigate emissions, those consumers' demand-timing choices have not been commonly linked to that consumer's GHG emissions, even as those choices may be linked to pricing.

6.10.1 Grid average emission factors

The term "grid average" emission factors reflects a short-hand for a broad category of data sets that characterize all the GHG emissions associated with the quantity of electricity generation produced from facilities located within a specified geographic boundary. Many of these data sets have been compiled for purposes other than corporate accounting and can vary in their inclusion of energy-generation emissions (e.g., which GHG gases are included, and how biomass and CHP emissions are treated) and perhaps most significantly, in the spatial facility-inclusion boundaries. Greater consistency in grid average emission factors globally can improve location-based inventory results that encompass multiple global operations parameters. A simplified illustration of the type of data aggregation and calculation that contributes to a grid average emission factor is shown in Table 6.6.

- **Spatial boundaries.**
  The most appropriate spatial boundaries for emission factors serving the location-based method are those that approximate regions of energy distribution and use, such as balancing areas. All generation and emissions data within this boundary should be aggregated and any net physical energy imports/exports and their related emissions should be taken into account. For multi-country regions with frequent and significant exchanges of energy throughout a year (as measured by percent of that country's total generation), a multi-country regional grid average may be a better estimate than a production-only national emission factor without energy imports/exports adjustments. In turn, in a country with multiple distribution or balancing areas, these subnational regions would be a more precise spatial boundary for grid average emissions.

- **Other data quality.**
  Companies can evaluate emission factor data based on quality indicators including their reliability, completeness, and geographic, temporal, and technological representativeness. Grid-average emission factors in particular may face challenges with temporal representativeness due to time delays between the year in which energy generation and resulting emissions occurred, and the year in which the data is published and made available to users. For U.S. eGRID or IEA, these delays can be 2–3 years. This delay can make grid average emissions factors a less relevant indication of corporate performance or risk assessment when analyzed in the inventory year. Companies should take this into account when analyzing location-based scope 2 results.

6.11 Market-based emission factors data

Under the market-based method, different contractual instruments become carriers of GHG-emission rate information that function as emission factors for consumers to use to calculate their GHG emissions. To ensure this, instruments **shall** include the GHG emission rate attribute. If companies have access to multiple market-based emission factors for each energy-consuming operation, they should use the most precise for each operation based on the list in Table 6.3.

6.11.1 Energy attribute certificates

Certificates form the basis of energy attribute tracking in the market-based method, often being conveyed with contracts for energy and integrating into supplier-specific emission rates. See Chapter 10 for more background on certificate types and treatment.

Table 6.6 Example of grid average emission factor calculation

	Emissions from generation	Total generation in MWh
Energy Facility A (coal)	50,000 metric tons CO_2e	55,000
Energy Facility B (natural gas)	10,000 metric tons CO_2e	30,000
Energy Facility C (wind farm)	0 metric tons CO_2e	15,000
Totals within defined boundary	60,000 metric tons CO_2e	100,000
Total system emission rate ("grid average")	60,000 metric tons CO_2e/100,000	**0.6 mt CO_2e /MWh**

6.11.2 Contracts such as power purchase agreements (PPAs)

These types of contracts allow a consumer, typically larger industrial or commercial entities, to form an agreement with a specific energy generator. The contract itself specifies the commercial terms, including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project.

Where certificates are issued: In these cases, the certificates themselves serve as the emission factor for the market-based method. If the certificates are bundled with the contract, the purchaser can claim the certificates. If the certificates are sold separately, the power recipient *cannot* claim the attributes of the specific generator.

When certificates are not used in the jurisdiction or for the technology/resource: Where certificates are not issued by a tracking system, a PPA may nevertheless convey generation attributes if the PPA includes language that confers attribute claims to the power recipient. This more explicitly renders the PPA a GHG attribute-claims carrier. Where the PPA is silent on attributes and where attributes are not otherwise conveyed or tracked, the contract for power can be used as a proxy for delivery of attributes. As shown in the Scope 2 Quality Criteria, an audit trail or other mechanism is needed to demonstrate that no other entity is claiming the attributes from this generation.

When the power received in the PPA is resold: If the power purchased in a PPA is resold to the wholesale or retail market, then the company receiving-and-reselling the power cannot claim the "use" of the attributes in markets where certificates are not used. In markets with certificates, the company may retain the certificates from the power generation to use for its own claims while it resells the power.

To avoid double counting, companies making claims based on contracts (where no certificate system exists) should report the quantity of MWh and the associated emissions acquired through contracts to the entity that calculates the residual mix, and request that their purchase be excluded from the residual mix. Certain third-party certifications of renewable energy may do this automatically.

6.11.3 Supplier-specific emission rate

Electricity suppliers or load-serving entities function differently across markets. In some deregulated markets, there may be retail competition within the group of entities that interface directly with customers. In other regulated monopoly markets, a single utility may supply an entire service territory. In all cases, an energy supplier can provide information to its consumers regarding the GHG intensity of delivered electricity. The utility or supplier-specific emission factor may be a standard product offer or a differentiated product (e.g. a renewable energy product or tariff). When using a supplier-specific emission factor, companies should seek to ensure that:

- The emission rate is disclosed, preferably publicly, according to best available information, and where

Box 6.3 How the UK implements EU supplier disclosure requirements

In the EU system, the Fuel Mix Disclosure regulations require all suppliers to disclose the emissions associated with the power that they supply. To do so, U.K. suppliers present renewable energy guarantees of origin (REGOs) and Generator Declarations to the regulator for the jurisdiction, the Department for Energy and Climate Change (DECC). DECC then removes all claimed generation from the overall national average, which leads to the production 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. 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.

For more on U.K. requirements, see: https://www.ofgem.gov.uk/ofgem-publications/57972/12340-28205.pdf and https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/82783/Fuelmixdisclosure2013.pdf.

possible using best practice methods such as The Climate Registry Electric Power Sector Protocol. Methods for calculating and disclosing the mix and related attributes may also be specified by regulation.

- That the utility or supplier discloses whether and how certificates are used in the emission factor calculation, unless there is third-party certification of the utility product. In particular, companies should seek to ensure that if the supplier has a differentiated product (e.g. a renewable energy product or tariff), the certificates or other contracts used for that product should be used only for that product and not counted in the standard product offer.
- That the supplier-specific emission factor includes emissions from all the energy delivered by the utility, not just the generation assets owned by the supplier (e.g. what is required by some fuel mix disclosure rules). Many suppliers purchase significant portions of their energy from other generators via contracts, or through the spot market. The emission factor should reflect the emissions from all of these purchases. A supplier-specific emission rate can also reflect certificates retired for compliance purposes (such as U.S. state RPS programs) which also convey attributes for public benefit and claims.

Consumers should not attempt to calculate a supplier-specific emission rate themselves based on a fuel mix disclosure due to the variations in fuel mix disclosure rules, which may reduce the accuracy of the resulting GHG emission factor.

If an electricity supplier purchases offsets on behalf of their customers, the reporting customers should report the offsets separately from the scopes. The supplier-specific emission rate used for scope 2 should reflect supply only, and not purchased offsets.

6.11.4 Residual mix

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. 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.

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. In the U.S. overall, an estimation of the adjusted mix in 2009 did not differ significantly from the location-based grid average data. In fact, according to a paper by the Environmental Tracking Network of North America (ETNNA 2010), the difference is currently less than one half of one percent.[4]

Companies should not attempt to calculate their own residual mix.

- **If a residual mix is not available.** Other unadjusted grid average emission factors such as those used in the location-based method may be used. Companies

shall document in the inventory that a residual mix was not available.

6.12 Treatment of biofuel emissions

Biogenic materials—including biomass, biofuels, and biogas—are increasingly used as a resource for energy generation on-site and on the grid. While biomass can produce fewer GHG emissions than fossil fuels and may be grown and used on a shorter time horizon, it still produces GHG emissions and should not be treated with a "zero" emission factor. Based on the *Corporate Standard,* any CH_4 or N_2O emissions from biogenic energy sources use **shall** be reported in scope 2, while the CO_2 portion of the biofuel combustion **shall** be reported outside the scopes. In practice, this means that any market-based method data that includes biofuels should report the CO_2 portion of the biofuel combustion separately from the scopes.

For the location-based approach, most commonly used grid average emission factor—including those issued by EPA eGRID (U.S.), Defra (U.K.), and the International Energy Agency (for all countries worldwide)—do not note the percentage of biomass in the emission factor and do not separately report the biogenic CO_2, effectively treating it as "zero" emissions. Companies should document this omission in any grid average emission factors used.

Endnotes

1. See Chapter 14 of The Climate Registry's General Reporting Protocol.
2. See http://www.ftc.gov/news-events/media-resources/truth-advertising/green-guides.
3. See Chapter 10 on how to report this relationship. Allowance set-aside programs also allocate and retire allowances to restore an avoided emissions claim. In this case, where a set-aside for voluntary renewable energy is in place and where allowances have been retired, purchasers can make claims about avoided emissions.
4. ETNNA (2010). P. 14

7 Accounting and Reporting Requirements

This chapter identifies all the new accounting and reporting requirements introduced by this Guidance. Conformance with this Guidance is required in order to prepare an inventory in conformance with the *Corporate Standard*.

This Guidance provides a new set of requirements applied to the *Corporate Standard* in calculating and reporting scope 2 emissions. Therefore, conformance with this Guidance is required in order to prepare an inventory in conformance with the *Corporate Standard*. In addition to all existing *Corporate Standard* accounting and reporting requirements (see Chapter 9 of the *Corporate Standard*), companies **shall** calculate and report scope 2 in the following ways:

7.1 Required information for scope 2

For companies with operations only in markets that do not provide product or supplier-specific data or other contractual instruments:

- Only one scope 2 result **shall** be reported, based on the location-based method.

For companies with any operations in markets providing product or supplier-specific data in the form of contractual instruments (Markets are increasingly developing and refining purchasing options, and the list is not exhaustive. Currently this includes the EU Economic Area, the U.S., Australia, most Latin American countries, Japan, and India, among others.)

- Companies **shall** account and 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.
- Many companies' GHG inventories will include a mix of operations globally, some where the market-based method applies and some where it does not. Companies **shall** account for and report all operations' scope 2 emissions according to both methods.
  - To do so, emissions from any operations in locations that do *not* support a market-based method approach **shall** be calculated using the location-based method (making such operations' results identical for location-based and market-based

methods). Companies should note what percentage of their overall electricity consumption reported in the market-based method reflects actual markets with contractual information.

Scope 2 Quality Criteria. Companies **shall** ensure that any contractual instruments used in the market-based method total meet the Scope 2 Quality Criteria specified in Table 7.1. If instruments do not meet the Criteria, then other data (listed in Table 6.3) **shall** be used as an alternative in the market-based method total. In this way, *all* companies required to report according to the market-based method will have some type of data option.

- Companies **may** provide a reference to an internal or external third-party assurance process, or assurance of conformance provided by a certification program, supplier label, green power program, etc. An attestation form **may** be used to describe the chain of custody of purchased certificates or other contractual instruments.
  - If a residual mix is not currently available, reporters **shall** note that an adjusted emissions factor is not available or has not been estimated to account for voluntary purchases and this may result in double counting between electricity consumers.

Inventory totals. For companies adding together scope 1 and scope 2 for a final inventory total, companies **may** either report two corporate inventory totals (one reflecting each scope 2 method), or **may** report a single corporate inventory total reflecting one of the scope 2 methods.

- If reporting a single corporate inventory total, the scope 2 method used should be the same as the one used for goal setting. Companies **shall** disclose which method was chosen for this purpose.

Table 7.1 Scope 2 Quality Criteria

Further explanation on select Scope 2 Quality Criteria can be found in Section 7.5.

All contractual instruments used in the market-based method for scope 2 accounting shall:
1. Convey the direct GHG emission rate attribute associated with the unit of electricity produced. 2. Be the only instruments that carry the GHG emission rate attribute claim associated with that quantity of electricity generation. 3. Be tracked and redeemed, retired, or canceled by or on behalf of the reporting entity. 4. Be issued and redeemed as close as possible to the period of energy consumption to which the instrument is applied. 5. Be sourced from the same market in which the reporting entity's electricity-consuming operations are located and to which the instrument is applied.
In addition, utility-specific emission factors shall:
6. Be calculated based on delivered electricity, incorporating certificates sourced and retired on behalf of its customers. Electricity from renewable facilities for which the attributes have been sold off (via contracts or certificates) shall be characterized as having the GHG attributes of the residual mix in the utility or supplier-specific emission factor.
In addition, companies purchasing electricity directly from generators or consuming on-site generation shall:
7. Ensure all contractual instruments conveying emissions claims be transferred to the reporting entity only. No other instruments that convey this claim to another end user shall be issued for the contracted electricity. The electricity from the facility **shall not** carry the GHG emission rate claim for use by a utility, for example, for the purpose of delivery and use claims.
Finally, to use any contractual instrument in the market-based method requires that:
8. An adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly shared electricity shall be made available for consumer scope 2 calculations, or its absence shall be disclosed by the reporting entity.

Methodology disclosure. Companies **shall** disclose methods used for scope 2 accounting. For the market-based method, companies **shall** disclose the category or categories of instruments from which the emission factors were derived, where possible specifying the energy generation technologies.

Base-year information. Companies **shall** disclose the year chosen as the base year; the method used to calculate the base year's scope 2 emissions; whether historic location-based data is used as a proxy for a market-based method; and the context for any significant emission changes that trigger base-year emissions recalculation (acquisitions/divestitures, outsourcing/insourcing, changes in reporting boundaries or calculation methodologies, etc.)

Disclose basis for goal setting. If a company sets a corporate inventory reduction goal and/or a scope 2-specific reduction goal, the company **shall** clarify whether the goal is based on the location-based method total or market-based method total.

7.2 Recommended disclosure

Annual electricity consumption. Companies **should** report total electricity, steam, heat, and cooling per reporting period separately from the scopes totals (in kWh, MWh, BTU, etc.), which should include all scope 2 activity data as well as the quantity of energy consumed from owned/operated installations (which may be only reported in scope 1 and not in scope 2.)

Biogenic emissions. Companies **should** separately report the biogenic CO_2 emissions from electricity use (e.g. from biomass combustion in the electricity value chain) separately from the scopes, while any CH_4 and N_2O emissions should be reported in scope 2.

- Companies **should** document if any GHG emissions other than CO_2 (particularly CH_4 and N_2O) are not available for, or excluded from, location-based grid average emissions factors or with the market-based method information.

Other instrument retirement. Companies **should** disclose additional certificate or other instrument retirement performed in conjunction with their voluntary claim, such as with certificate multipliers or any pairing required by regulatory policy.

Basis for upstream scope 3. The reporting entity **should** identify which methodology has been used to calculate and report scope 3, category 3—upstream energy emissions not recorded in scope 1 and 2, scope 3.

Instrument features. Where relevant, companies **should** disclose key features associated with their 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. These features are elaborated in Chapter 8.

Role of corporate procurement in driving new projects. Where relevant, companies **should** elaborate in narrative disclosure how any of the contractual instruments claimed in the market-based method reflect a substantive contribution by the company in helping implement new low-carbon projects.

7.3 Optional information

Scope 2 totals disaggregated by country. This can improve transparency on where market-based method totals differ from location-based.

Avoided emissions estimation. Consistent with Chapter 8 of the *Corporate Standard,* companies **may** separately report an estimation of GHG emissions avoided from a project or action (also see Section 6.9). This quantification should be based on project-level accounting, with methodologies and assumptions documented (including to what the reduction is being compared). See the *GHG Project Protocol* and *GHG Protocol Guidelines for Grid-Connected Electricity Projects* for example methodologies.

Advanced grid study estimations. Where advanced studies (or real-time information) are available, companies **may** report scope 2 estimations separately as a comparison to location-based grid average estimations, and companies 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, companies should ensure that any data used for this purpose has addressed data sourcing and boundaries consistent with the location-based method.

Scope 2 results calculated by other methods. If companies are subject to mandatory corporate reporting requirements for facilities in a particular region/nation that specify methodologies other than the two required for dual reporting, these companies **may** report these results separately from the scopes.

Disclose purchases that did not meet Scope 2 Quality Criteria. If a reporting entity's energy purchases did *not* meet all Scope 2 Quality Criteria, the entity **may** note this separately. This note should detail which Criteria have been met, with details of why the remaining Criteria have not. This will provide external stakeholders with the information they require, and allow the reporting entity to disclose the efforts made to adhere to the guidance. (As noted in Chapter 6, location-based method data will be used as proxy emission factors in the market-based method total.)

See the *Corporate Standard* Chapter 9 for more information about optional information and how to use ratio indicators and other performance metrics in reporting.

7.4 Dual reporting

Dual reporting allows companies to compare their individual purchasing decisions to the overall GHG-intensity of the grids on which they operate. In addition, reporting two separate scope 2 figures using two different methods provides several benefits:

- Distinguishes changes in choices vs. changes in grid emissions intensity
- Provides for a more complete assessment of the GHG impact, risks, and opportunities associated with energy purchasing and consumption
- Provides transparency for stakeholders
- Improves comparability across operations (on location-based method) where the company's GHG inventory includes operations in markets *without* contractual instruments
- Facilitates participation in programs with different reporting requirements.

This guidance's framework addresses and reduces double counting between scope 2 inventories when using the same accounting method, improving the accuracy of reported results and ensuring clear performance tracking toward goals.

The UK represents an example of the differing demands of the various stakeholders, where organizations (especially those trading internationally) have complex demands from their stakeholders. The carbon inventory is often reviewed by investors based in the United States, where there is an expectation to report using the market-based approach. However, the prevailing guidance from the UK government is to report using the locational-based approach, in part due to concerns regarding subsidy levels for renewables and double counting concerns. For these organizations, dual reporting provides disclosure in a way that allows all stakeholders to be satisfied.

7.4.1 Other methods

Some jurisdictions may recommend methods other than the location-based or market-based method as the basis for its consumer claims and scope 2 accounting, in order to achieve specific policy objectives. For instance, Ademe[1] in France has calculated different grid GHG emission rates according to different end uses by consumers. This represents a different emissions allocation approach than the location-based method presented in this guidance, although it is derived from it. It recommends companies reporting to Ademe apply these end-use factors to the different types of energy end uses, in order to better estimate the average GHG impact of specific consumption activities.

Companies required by regulation to use a method other than those listed in this guidance should do so for those required reports. To maintain consistency with the GHG Protocol *Corporate Standard* and this *Scope 2 Guidance,* companies may additionally and separately report any scope 2 totals calculated for other mandatory reporting rules applying to that region/nation's facilities.

7.4.2 Gross/net reporting

The two method totals (location-based and market-based) should not be viewed as "gross/net," since a net calculation typically implies that external reductions such as offsets have been applied to the inventory. While many contractual instruments in the market-based method represent a zero emission rate from renewable energy and generally serve to lower the GHG intensity of the reporter's electricity use, the market-based method should also include other contractual instruments representing fossil fuel or mixed-resource emission factors as well. The method is designed to reflect a range of instruments that together allocate overall emissions across the grid. For instance, a supplier-specific emission rate that includes a mix of generation technologies also is a valid market-based method emission factor.

However, companies can report avoided emissions estimations from generation separately from the scopes and indicate if these have been used in program-specific gross/net reporting (such as Defra Corporate guidelines[2]).

7.5 Additional guidance on Scope 2 Quality Criteria

The environmental integrity of the market-based method depends on ensuring that contractual instruments reliably and uniquely convey GHG emission rate claims to consumers. Without this, a resulting market-based scope 2 total lacks the accuracy and consistency necessary to drive corporate energy procurement decisions. In addition, the lack of a reliable system for tracking or assuring claims poses risks of inaccurate consumer claims regarding a product's actual attributes, and weakens the ability for consumer decisions to influence market supply.

Therefore, this guidance identifies a set of minimum criteria that relate to the integrity of the contractual instruments as reliable conveyers of GHG emissions rate information and claims, as well as the prevention of double counting. They represent the *minimum* features necessary to implement a market-based method of scope 2 GHG accounting. *Programs or jurisdictions may have additional requirements that reporting entities should consult and follow.*

Criteria 1. Conveying GHG emission rate claims. Many instruments already include specific language about the ownership or ability to claim specific attributes about the product (energy) being generated. In the U.S., most states (and the Green-e Energy National Standard) define RECs as conveying "all environmental attributes" associated with the MWh of energy generation. This type of claim is considered "fully aggregated," meaning that no other instrument can be generated from that MWh which conveys consumer claims regarding any of the environmental attributes of the energy. (In specific cases of multipliers or issuance of multiple instruments from the same MWh, then all instruments **shall** be retired for a full claim on that MWh.) Tracking systems themselves support only fully aggregated certificates.

In some markets it may be possible for attribute claims about energy generation to be separated out explicitly into different certificates that could be used for different purposes. This guidance does not address program design elements in markets with multiple certificates, but requires that only one instrument (or discrete set of instruments applied all at once) convey attribute claims about the energy type and its GHG emission rate.

If certificates do not specify attributes: Certificates that do not currently specify what, if any, energy attribute claims are conveyed, may still convey a claim implicitly through proving the second point: that no consumer is claiming the same energy generation attributes. Evidence of this may be achieved through attestations from each owner in the chain of custody or equivalent procedures providing the same information.

If the attribute emission rate itself is not specified and the technology is not zero emissions, the reporting organization should seek from the generating entity a specific emission rate from that generation facility. Otherwise, a default factor from IPCC or other government publications may be used and disclosed.

Biofuel generation facilities producing certificates should specify the CO_2, CH_4, and N_2O emissions produced at the point of generation. The scope 2 reporter reports the CH_4 and N_2O emissions in scope 2, while the CO_2 from biofuel is reported separately from the scopes.

Criteria 2. Unique claims. If other instruments exist that can be used for attribute claims by other electricity consumers, companies must ensure that the one being used by the reporting entity for a GHG emission rate claim is the only and sole one that does so. Where multiple instruments carry the GHG emission rate attribute claim, some jurisdictions or programs may require acquisition and "pairing" of the multiple certificates to support a voluntary consumer GHG emission rate claim. Companies should check with their electricity supplier or relevant policy-making bodies to ensure that the certificates are claimed, paired, or retired in compliance with applicable jurisdictional or program requirements.

The underlying electricity (or megawatt-hour) minus the instrument, sometimes called "null power," **shall** also not reflect the same GHG emission rate, but should be assigned residual mix emissions for the purpose of delivery and/or use claims in the market-based method.

In some cases, ensuring unique GHG emission rate claims may require arbitration regarding the validity and enforceability of a claim where multiple instruments exist and remain unclear on attribute claims.

Criteria 3. Retirement for claims. Ensuring that instruments are retired, redeemed, or claimed to support a consumer claim can be done through a tracking system, an audit of contracts, third-party certification, or may be handled automatically through other disclosure registries, systems, or mechanisms. These practices help guarantee that only consumers make a claim, even as an instrument may change hands through trading.

Criteria 4. Vintage. Vintage reflects the date of energy generation from which the contractual instrument is derived. This is different from the age of the facility. In order to ensure temporal accuracy of scope 2 calculations, this criteria seeks to ensure that the generation on which the emission factors are based occurs close in time to the reporting period for which the certificates (or emissions) are claimed. This timing should be consistent with existing standards for the market where the contractual instruments exist. Contractual instruments should clearly display when the underlying electricity was generated.

Criteria 5. Market boundaries. The market boundary criteria address the geographic boundary from which certificates can be purchased and claimed for a given operation's scope 2 accounting and reporting.

Distinguishing other relevant electricity boundaries: The market for purchasing and selling electricity is typically a regional transmission organization, power pool, or balancing area, with exports and imports often broadening these markets. By definition, certificates are separated from underlying electricity flows, and markets for unbundled certificates have often been less constrained than those for electricity itself. This larger market boundary for certificate use promotes broader areas of consumer choice and the building of renewable energy resources in the most economically viable locations.

To determine market boundary: Companies should check whether the regulatory authorities and/or certification/issuing bodies responsible for certificates have established the boundaries in which certificates may be traded and redeemed, retired or canceled, and should follow these market boundaries.

If the market boundary is not specified or not clear: Markets for certificates are typically determined by political or regulatory boundaries rather than just physical grid interconnection. This means market boundaries can be limited to a single country or group of countries that recognize each other's certificates as fungible and available to any consumers located therein. The United States, for example—despite differences in state law, local regulatory policy, and variation in physical interconnection within these regions—operates under broad federal laws and regulations, and therefore has constituted a single market for use of certificates. The EU represents a multi-country market united by a set of common market rules and a regional connection.

Where multiple countries or jurisdictions form a single market, a consistent means of tracking and retiring certificates, and calculating a residual mix, needs to be present in order to prevent double counting of GHG emission rates among electricity consumers. Accurate residual mixes should take into account the energy and emission mixes of all geopolitical entities engaged in trading certificates.

Additional geographic sourcing considerations: In addition, if not already specified by regulation or program, contractual instruments should be sourced from regions reasonably linked to the reporting entity's electricity consumption. These regions may grow over time as more interconnections and larger balancing areas are formed to improve grid reliability and integrate intermittent renewables.

Criteria 6. Supplier or utility-specific emission factors. As part of the calculation, the utility or supplier should disclose whether and how certificates are used in the emission factor calculation, unless there is third-party certification of the utility product. The utility or supplier-specific emission factor may be for:

a. A standard product offer or
b. A differentiated product (e.g., a low-carbon power product or tariff).

The supplier-specific emission factor should be disclosed (preferably publicly) according to best available information. Where possible, this should also follow best practice methods, such as The Climate Registry Electric Power Sector Protocol.

Criteria 7. Direct contracts or purchasing. In the absence of energy attribute certificates, the contract and claim associated with it should be verified by a third party to convey a unique or sole ownership right to claim a GHG emission rate.

Criteria 8. Residual mix. To ensure unique claims by all electricity users, an adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly shared electricity is necessary. This residual mix should be based on combining national or subnational energy and emissions production data with contractual instrument claims. If a residual mix is not currently available, companies **shall** disclose that an adjusted emissions factor is not available or has not been estimated to account for voluntary purchases and this may result in double counting between electricity consumers. Reporters may provide other information about the magnitude of this error, where it is available and where it puts the scale of the residual mix adjustment into a context of other sources of error in grid emission factor calculation.

Endnotes

1. See: http://www.basecarbone.fr/data/rapport_methodo_co2_elec_2012.pdf
2. See: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/206392/pb13944-env- reporting-guidance.pdf

8 Recommended Reporting on Instrument Features and Policy Context

This chapter describes additional information that companies should disclose about the features and policy context of their energy purchases. This disclosure can improve transparency and inform stakeholders.

8.1 Instrument feature disclosure

Markets currently differ as to what types of energy generation facilities produce instruments that are recognized in the market-based method for corporate GHG inventories. Different programs establish their own *eligibility criteria* that determine what energy generation facilities can produce certificates that are recognized in the program. (See Chapter 10 for background on these differences).

This variation can make it difficult to compare and understand the procurement choices a company has made in different markets. However, when companies disclose information about the energy generation facilities and policy context reflected in their contractual instruments, company decision makers and stakeholders can get a clearer picture about how well the purchase aligns with other company goals. In particular, stakeholders evaluating a company's contribution to mitigating global emissions may be interested in how a company is driving change in supply.

If information on these features or policy context is not made available on or with the certificate, companies can ask the certification program, tracking system, or supplier for further information. Lacking other information, a company may disclose the overall criteria identified by the certificate program (e.g. Green-e Energy certified RECs are from facilities installed in the last fifteen years on a rolling basis).

8.1.1 Instrument feature disclosure formats

Companies can disclose features about their contractual instruments in a variety of formats depending on the intended audience, communication channel (summary report vs. full extended report), etc. Companies may find a checklist approach may help maintain clarity on the features associated with each contractual instrument, depending on the number of energy-consuming facilities and different instruments in the inventory. See Table 8.1 for a list of these features and policy contexts. In cases where companies have undertaken strategic or iconic projects, a more narrative format can be useful to highlight the project's features in the context of a larger history.

Table 8.1 Example instrument features and policy context

Instrument labels
Certification or label name (if applicable). This can include certification such as Green-e Energy (U.S.), EcoLogo (Canada), or labels such as EKOenergy and Naturemade in the EU. The certification or label name should also specify what is being certified, e.g. in the U.S. Green-e Energy certifies against a set of requirements described in their National Standard.
Incremental funding programs. This should specify whether the instrument is associated with a certification label or supplier program that contributes incremental funding to new projects, and if so what quantity of funding is included with the company's contractual purchase.
Energy generation facility features
Energy resource type. Instruments should clearly identify the resource generating the certificate. For supplier-specific emission rates, the resource type could be "mix" for standard offers, "multiple renewable" for certain green power products, or cite the specific resource used. Residual mix will typically be a "mix."
Facility location. Depending on the information available from the certificate, supplier, or contract, the generation facility location could be identified at a national or subnational level (either geopolitical such as a U.S. state, and/or a grid region such as a North American Electric Reliability Corporation (NERC) region.
Facility age. Stakeholders may wish to know whether the purchase consists largely of generation attributes from older facilities or more recently constructed projects. Companies should note the year the generation facility that created the certificate/contract was first operational or substantially repowered.
Policy context
Supplier quotas. The contractual instrument claimed will relate differently to instruments used for supplier quotas, depending on the market. Companies should note the relationship between their contractual instruments following the list of options in Table 10.2.

• **Cap and Trade.** Is the facility that produced the instruments you claim affected by a cap and trade policy? (Y/N)
  • If yes, does the cap and trade program allocate allowances for retirement on behalf of voluntary renewable electricity purchases from this facility? (Y/N)
  • If yes, were allowances retired on behalf of your voluntary purchase of instruments from this facility? (Y/N) If so, these allowances should be reported (in metric tons) separately from the scopes.

Funding/Subsidy Receipt. The funding disclosed here can highlight recent funding or subsidy policies directly and substantially affecting the generation facility.
Offsets. Is the facility producing offset credits from the same MWh reflected in the contractual instrument? (Not applicable to contractual instruments in most industrialized electricity markets).
Other policy instruments. This includes any other policy instruments bundled/retired voluntarily by the company itself, a certificate certification program, supplier label, etc.

8.2 Reporting on the relationship between voluntary purchases and regulatory policies

This guidance does not require contractual instruments claimed in scope 2 to be "in addition to," or independent from, regulatory policies such as subsidies, tax exemptions, or supplier quotas. Due to the design of renewable energy production targets, achieving "regulatory surplus" with voluntary purchases may not always be possible. For transparency, companies should disclose the relationships between instruments claimed in scope 2 and regulatory policies, as part of the disclosure of overall instrument features and policy context to improve transparency and stakeholder understanding of the voluntary purchase. Companies should also disclose additional certificates or other instrument retirement performed in conjunction with their voluntary claim. These relationships and reporting options are elaborated below.

8.2.1 Relationship to supplier quotas

Where relevant, companies should state the relationship between the energy claimed in the market-based method and any compliance instruments used for supplier quota regulations. Six example relationships can be found in Table 8.2.

8.2.2 Relationship to subsidy receipt

In some countries, renewable energy projects that receive a public subsidy such as a feed-in-tariff (FiT) must have the certificate from that project retired or canceled, preventing any individual consumer claim. For instance, in Germany if a generation facility receives subsidies, then all generation attributes must be either canceled or retired on behalf of all German consumers under the rationale these consumers have paid for the energy through taxes, and should therefore collectively own the attributes. (This is in contrast to other European member states, which allow for individual consumer attribute ownership in addition to national subsidies.) In Japan, once renewable electricity that receives a FiT is sold to utilities, voluntary renewable

Table 8.2 Relationships between voluntary and supplier quotas

Reporting Option	Example
If there is no supplier energy source quota in contractual instrument's market	
1. No supplier quota in instrument's market	
If there is a supplier quota in the jurisdiction of the contractual instrument:	
2. Energy from claimed instrument also used to meet supplier quota	Multiple certificates from same MWh conveying different attributes
If there is a quota and the energy from the claimed instrument is not directly used to meet it:	
3. Claimed instrument not directly reflecting quota	Fossil contract or residual mix
4. Claimed instrument includes the supplier quota	Supplier-specific emission factor that includes compliance instruments
5. Claimed instrument above and beyond supplier quota	Voluntary U.S. RECs
6. Claimed instrument paired with retired compliance instrument issued from same unit of energy generation	*No applied examples to date

energy certificates cannot be issued. Accordingly, for the purpose of achieving regional fairness, the value of zero emissions energy generated from FiT-supported renewable electricity is allocated to each utility in accordance with sales amounts because FiT represents a public subsidy. In practice, this leaves subsidized energy a "public good" whose attributes are included in a system mix used for supplier reporting.

Reporting options: In jurisdictions where energy supported by recent or substantial renewable energy production subsidies is not excluded from voluntary programs or claims, companies should disclose subsidy receipt (available on GO).

8.2.3 Relationship to emissions trading programs

In emissions-capped power programs such as the European Emissions Trading Scheme, low-carbon energy generation is incentivized through creating a limit (cap) on fossil-fuel emissions. But all energy attribute certificates, including voluntary energy attribute certificates and other contractual instruments can still convey emission rate claims under an emissions cap (e.g., renewable energy still produces zero emissions/MWh at the point of generation). The presence of a cap does not directly impact or prevent market-based accounting based on contractual instruments.

However, because the total system's emissions have been predetermined by the cap, these actions may simply "free up" allowances for other emitters to acquire, resulting in no net global GHG reductions. This means consumers cannot claim that the generation purchased resulted in global emission reductions on the grid; only by affecting the allowance cap by retiring or reducing available allowances would electricity consumers be able to support that claim. Voluntary low-carbon energy purchases (as well as other actions such as efficiency upgrades or energy conservation) without allowance retirement could be seen as an essential and expected means of contributing to meeting the system-wide cap, or as "subsidizing" the overall sector's costs for meeting the cap.

Allowance set-asides. Many states participating in the U.S. Regional Greenhouse Gas Initiative (RGGI) and the California cap-and-trade program have created an allowance set-aside program. These programs designate that a portion of total emission allowances available in a given compliance period be set aside and retired on behalf of voluntary REC purchases. This combined REC purchase and allowance retirement is designed to preserve or strengthen the global carbon benefits and impacts for voluntary renewable energy purchases. In theory, allowances could be retired by any entity trying to demonstrate environmental commitment, as a reduction in available allowances for emitting entities can create scarcity (and theoretically, behavior change) in the marketplace. Retiring allowances effectively lowers the cap.

Reporting options. Companies claiming contractual instruments in an emissions-capped power sector should disclose whether an allowance set-aside program is in place, and whether any allowances have been retired along with the voluntary certificates. The tons of GHG emissions represented in any retired allowances should be reported separately from the scopes.

Caveats. This guidance does not recommend treating allowances retired as part of a voluntary renewable energy set-aside as though they were offsets. 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 (e.g. during a period of economic downturn), the value of retiring an allowance might be minimized.[1] Further, if allowance retirement becomes common practice and significantly increases the price of allowances, cost containment measures in cap-and-trade policies may be triggered so that regulators increase the total volume of available allowances (and therefore nullify the reduction impacts of the retirement).

8.2.4 Relationship to offset credits

Offsets generated from renewable energy facilities remain a popular project type in offset schemes such as the Clean Development Mechanism (CDM), as well as voluntary standards. These programs are designed to provide a revenue stream that enables a project to be built that—in the absence of the offset sales—would be unfeasible. The offset represents a quantity of global GHG emissions reduced or avoided by the project compared to a baseline scenario of what emissions would have occurred in the absence of the offset-funded project.

Distinguishing attributes and claims. Offsets, and their global avoided emissions claim, represent a different instrument and claim from the energy attributes associated with energy production.[2] Offsets convey tons of avoided CO_2 using project-level accounting, but they do *not* convey information about direct energy generation emissions occurring at the point of production, like contractual instruments do (see Box 4.3). An offset credit does *not* confer any claims about the use of electricity attributes applicable to scope 2. For example, to distinguish avoided emissions and emission rates, a natural gas facility newly established in a largely coal-based grid will *avoid* operating margin emissions as fossil fuel plants with higher operating costs are backed down. But the natural gas plant still emits at a fixed rate (emissions/MWh), which consumers of that energy can document in scope 2.

Box 8.1 Attributes and claims from renewable energy offsets

Offsets are designed to be fungible (or interchangeable) globally, derivable from a variety of project types (forestry, renewable energy, etc.) and should only convey metric tons of avoided GHG emissions to the purchaser. To date, offsets have not conveyed any other attributes about the project generating the offset or about the electricity—including a "renewable energy use" claim. While offset projects through CDM are designed to also provide a variety of social and sustainable development benefits, most offset standard methodologies do not quantify these other characteristics or benefits of the project, or transfer or convey them with the offset credit. Those social benefits are designed to "stay" within the community, even as the avoided carbon is sold globally. Users should not infer from the offset any unquantified, unverified, or unspecified other claims about the project.

Coexistence of offsets and scope 2 accounting. Unless otherwise adjusted by local rules, renewable energy generation facilities producing and selling offsets will inherently still provide energy attribute information—directly and indirectly—to other entities in the local energy supply system, including energy consumers reporting scope 2 emissions. For instance, the energy output from generation facilities producing offsets would still be subject to energy supply contracts between generators and suppliers, and still support the local grid's operation. This means that the zero emission rate from the generation facility will likely be reflected in several emission factors:

- Grid average emission factors (location-based)
- Supplier-specific emission factors (market-based)
- Any PPAs between the generator and consumer of the energy (market-based)

The contractual information such as PPAs and supplier-specific emission factors may meet the Scope 2 Quality Criteria and qualify as conveyers of energy generation emission rates under the market-based method. This can provide accurate scope 2 accounting independent of the fact that certain facilities associated with those contracts will have also produced offsets (reflecting the impact of that generation on the rest of the grid). Therefore, the zero emission rate from the project will likely be reflected in the local grid's data for both the location-based and market-based method for scope 2, as illustrated in Figure 8.1. However, in most industrialized energy markets, a given MWh of renewable energy generation can either produce energy attribute certificates or an offset credit (if certain criteria such as additionality are met), but could not produce both.

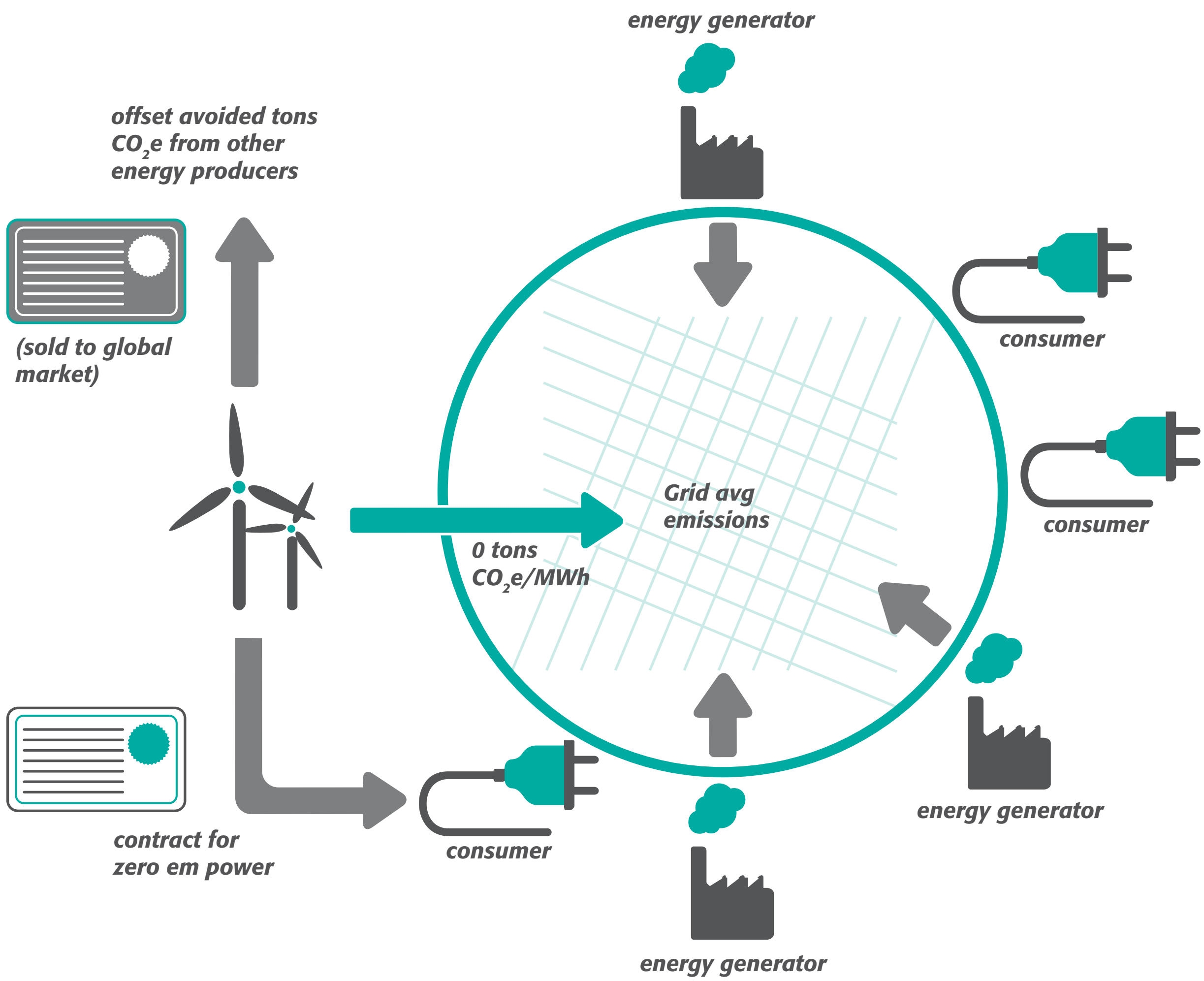
Reporting options: Companies should disclose whether their contractual instrument used in a market-based method (such as a supplier-specific emission rate or PPA) is generated from, or includes, the energy output of a facility that also produces GHG offsets. This may be most relevant in non-Annex I countries generating CDM offsets.

In turn, following the *Corporate Standard,* companies purchasing and claiming offsets should document these purchases outside of the scopes, ensuring that the offset meets offset quality criteria.

Caveats: The coexistence of offsets does not inherently prevent electricity suppliers or companies from reflecting the zero emissions attributes in their scope 2 reported totals. However, local or international regulation may preclude accounting for these emissions, either by:

- Adjusting a grid-average emissions factor to "add back in" the sold offset to the total emissions produced in the region. This increases the GHG intensity of the grid-average emission rate, effectively reflecting the business-as-usual (BAU) scenario of the offset.

Figure 8.1 Offsets and energy attribute certificates on a grid



- Requiring provisions in energy purchase contracts that the attributes associated with the energy generation, while not contained in the offset, should be retired from usage so that no consumer can use contractual instruments to make market-based scope 2 claims.

Historically, voluntary consumer green power purchasing programs have not been implemented in emerging economies generating offsets. This may change over time as local consumers demand low-carbon energy options from their suppliers. (Generally, offsets from the power sector are not possible where the emission caps or other significant low-carbon policies impact the sector.) Where voluntary green power consumer programs coexist with offset issuance, the offset additionality criteria requires that the offset be the decisive reason a project was developed.

Endnotes

1. See Kollmuss and Lazarus (2010).
2. It may appear that the GHG emissions benefit of the offset is "double counted" with any scope 2 allocation procedures for the project's grid, but the differences in methodology and the boundaries for evaluating reductions minimize this possibility.

9

Setting Reduction Targets and Tracking Emissions Over Time

This chapter provides guidance on setting GHG reduction targets for both methods' reported totals, tracking emissions over time, and how other energy goals can be set as part of a holistic approach to energy.

9.1 Setting a base year

A meaningful and consistent comparison of emissions over a GHG reduction goal period requires that companies establish a base year against which to track performance. When companies set a target relative to a base year, companies should specify their reasons for choosing that particular year. Companies reporting according to the market-based method should choose a year in which both market-based data and location-based data are available. Companies that have already set a base year for scope 2 **shall** specify which method was used to calculate it, in order to allow for clearer comparison over time.

For companies calculating a GHG inventory for the first time, the *Corporate Standard* guidance on choosing a base year applies (see Chapter 5 of the *Corporate Standard*).

Once a base year is selected, a reporting entity **shall** set a base-year recalculation policy and clearly articulate the basis and context for any recalculations. Whether base-year emissions are recalculated depends on the significance of the changes. A significance threshold is a qualitative and/or quantitative criterion used to define any significant change to the data, inventory boundaries, methods, or any other relevant factors.

9.2 Recalculating base-year emissions

The *Corporate Standard* notes that recalculation may be necessary when changes to base-year emissions would exceed the company's established significance threshold. This may occur when a company restructures its operations (acquisition/divestments/mergers), discovers calculation errors, or identifies changes in calculation methodology or improvements in data accuracy over time. This guidance's new requirement to report scope 2 according to two different methodologies—location-based and market-based—constitutes a change that could trigger base-year recalculation.

Companies should ensure that the base-year inventory includes both a location-based and market-based scope 2 total, if applicable and feasible. This ensures "like with like" comparison over time.

- If the scope 2 base year chosen was calculated only according to the location-based method, the reporting entity should also recalculate a market-based total if contractual information or residual mix totals are available for the base year. If not, companies should state that the location-based result has been used as a proxy since a market-based result cannot be calculated.
- If the scope 2 base year chosen was calculated only according to the market-based method, companies should ensure that the contractual instruments used in the base year meet the Scope 2 Quality Criteria. If not, this should be disclosed and a location-based total stated in place of the market-based method total. In addition, companies should calculate a location-based method total in the base year using emission factors appropriate for that year.

9.3 Setting GHG targets

A key component of effective GHG management is setting a GHG target. Companies are not required to set a scope 2 reduction target, but should consider setting a target in the context of their business goals, the decision-making value for each method's results and how to drive change through supply choices. As noted, reductions in reported scope 2 emissions can occur due to a change in emission factor unrelated to specific corporate action—for example, a reduced grid average emission factor, or reduced residual mix emission factor.

If setting a target, companies shall specify which method is used in the goal calculation and progress tracking, including the method used for the base-year calculation. Where certificates or contractual instruments convey legally enforceable claims, companies setting goals should use the market-based method total for goals. Two targets, one for each method's results, can help prioritize new low-carbon energy projects that will reduce both totals' emissions over time (if contractual instruments are retained from the project).

Several types of targets are possible and require consideration of:

- **Target type.** Whether to set an absolute or intensity target
- **Target completion date.** The duration of the target (e.g., short term or long term target and base year and goal year)
- **Target level.** The numerical value of the reduction target, framed as a change in emissions or absolute level of emissions to be achieved.

Companies seeking to drive change in the overall grid supply in a short period of time should consult the range of procurement options described in Chapter 11.

9.4 Energy targets

Some companies have energy use, procurement, or production targets in addition to GHG reduction targets. Energy targets can be useful in maintaining a focus on efficiency and isolating the role of consumption as compared with the changes in emissions resulting from supply changes.

- **Energy intensity goals**. Reducing the amount of energy per square foot of office/building space, or per product or output, can help maintain a focus on efficiency practices and set the overall energy performance of operations.
- **Renewable energy procurement goals**. Some companies have set the goal to be powered or supplied by 100 percent renewable energy. The framework for scope 2 emissions accounting, with a separation by method, can be applied here as well. This would require companies to clarify which method their renewable energy goal is based on: a location-based assessment of production on the grid, or a company's contractual procurement using instruments that convey a claim to consumers regarding the resource identity and use.

9.4.1 Achieving 100 percent renewable energy when supplier quotas apply

For utilities under a supplier quota requirement (such as an RPS in the U.S.), structuring a green power product that covers 100 percent of a customer's electricity load may combine voluntary and compliance instruments up to the level of the quota, provided those compliance instruments convey energy use claims. For example, if a utility is required to procure and deliver renewables for 20 percent of its total retail load, then voluntary contractual instruments would be required to account for the remaining 80 percent of the delivered energy.

- **Renewable energy production goals**. Companies that own/operate energy generation facilities providing on-site power to their operations may wish to set goals around the amount of energy produced from these facilities (for example, to produce 100 percent renewable energy in X facilities). Emissions from these facilities would be reported in scope 1, but the production and its attributes may or may not be tracked in scope 2 depending on energy sold to the grid, or certificate sales from the energy which would preclude any consumption claims on the generation. Publicly communicated goals about on-site energy production should indicate the distinction between this metric and energy consumption reflected in scope 2.

10

Key Concepts and Background in Energy Attribute Certificates and Claims

This chapter provides an overview of the key concepts, theories, and uses of energy attribute tracking and claims, which underpins the market-based method for scope 2 accounting. It explains the interactions between voluntary consumer programs and policies directly or indirectly supporting low-carbon energy.

10.1 Introduction to energy attribute tracking

Consumers of grid-supplied electricity cannot link, force, or otherwise direct a specified unit of electricity from its point of generation to its point of final use. Consumers are reliant on grid operators to make decisions about dispatch throughout the day. In addition, grid-supplied electricity consumers cannot directly or physically distinguish the energy generation facilities that are supplying their consumption at any given point; once energy is generated and distributed in a grid system, it becomes physically indistinguishable. In these types of systems, where attributes are not clear at the point of usage, allocation of energy attribute information is necessary to facilitate product-specific consumer claims. Suppliers and consumers increasingly have demanded information about the sources producing their energy, and "attributes" about that production—that is, characteristics such as the GHG emissions, local air pollutants, nuclear waste quantities, etc.

10.1.1 Contractual instruments

Contracts and other contractual instruments have been used historically to transact energy and convey information about energy generation attributes throughout an energy supply system, separately from the underlying energy flows. Depending on the contractual instrument, suppliers or their customers may be able to make claims about the source and attributes of energy they have purchased. These contractual instruments are necessary in order to allocate attributes of production (including GHG emissions) to individual users. By contrast, the "location-based method" indirectly allocates these emissions based on statistical averages, which do not convey attributes or legally enforceable claims about those attributes, or support broader programs for consumer choice.

A range of contractual instruments may be used to convey these attributes directly or indirectly to consumers, including energy attribute certificates, direct contracts such as PPAs, and supplier-specific emission rates. Of all of these, energy attribute certificates underlie most transactions and

attribute claims. They can be used alone or can be bundled with PPAs, contracts, and supplier labels. Once attributes are codified and conveyed in a certificate, the underlying energy generation technically becomes “null power,” or without attribute identity. Users of the null power electricity cannot claim to be buying or using renewable energy in the absence of owning the certificate. Instead, null power should be assigned residual mix emissions for the purpose of delivery and/or use claims in the market-based method.

10.2 Defining energy attribute certificates

Energy attribute certificates are a category of contractual instrument that represents certain information (or attributes) about the energy generated, but does not represent the energy itself (see Figure 10.1). This category includes instruments which may go by several different names, including certificates, tags, credits, or generator declarations. For the purpose of this guidance, the term “energy attribute certificates” or just “certificates” will be used as the general term for this category of instruments. Historically, most certificates for policies or consumer programs have been generated from renewable energy resources, driven by demand for these resources in particular, but depending on their intended purpose or usage certificates can be generated from any or all generation technology types. For example, all-generation certificate tracking exists in the northeast U.S.

10.2.1 Defining GHG attributes and claims

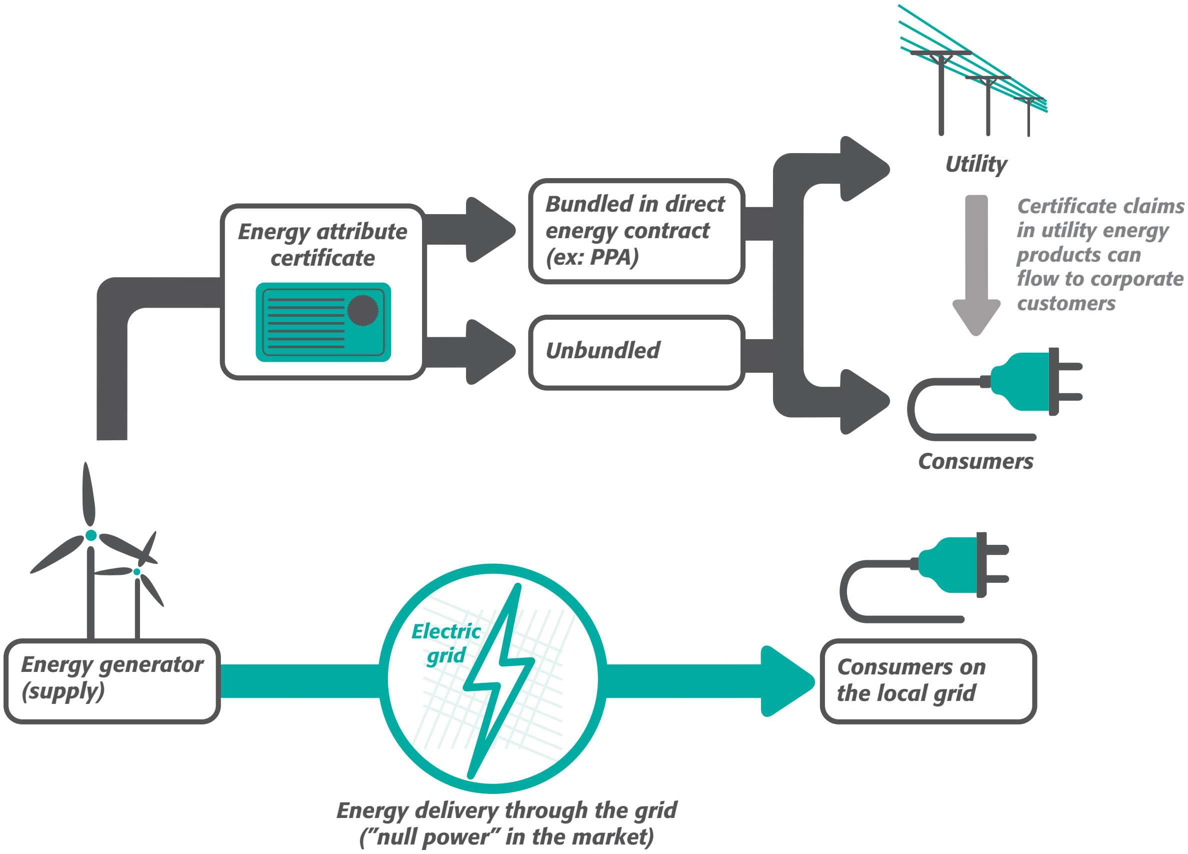
All energy generation has a GHG emission rate attribute, even if that attribute is “zero emissions/ MWh” at the point of generation.

Attribute aggregation. It is theoretically possible to disaggregate different energy generation attributes across multiple certificates, where each certificate conveys different information and related claims. For example, one certificate could convey that the energy comes from a “renewable” resource, while another conveys a claim about the GHG emission rate associated with the production, or claims about the emissions of other pollutants like NO_x and SO_x (see Box 10.1). But attribute disaggregation has generally not occurred in the programs surveyed in this guidance. In the U.S., most states define RECs for RPS purposes as encompassing “all environmental attributes,” including the attribute of the fuel type/ generation technology as well as GHG emission rate, and U.S. tracking systems do not support separating individual attributes. This “all attributes” approach effectively prevents the same MWh being used to create multiple consumer claims from renewable energy projects in the U.S.

Where no attributes for consumer claims are conveyed. Some certificates designed for regulatory uses such as supplier quotas do not convey any generation attributes for consumer claims. These are not intended to support consumer claims; instead, they serve only as documentation that a specific quantity of energy has been generated pursuant to the policy’s requirements. In this scenario, other certificates could be generated that do convey attributes about the energy generation to characterize consumption.

Claims about attributes. Ensuring the validity of consumer claims associated with certificates requires many of the same safeguards as other environmental commodities: accuracy, exclusivity, and enforceability. These form the basis of the Scope 2 Quality Criteria for

Figure 10.1 Energy attribute certificate pathways



claims regarding GHG emissions in the scope 2 market-based method (see Chapter 7). In many cases, there are independent standards and certifications available to enforce these safeguards. A certificate purchaser can make a claim about attributes when applied to a quantity of actual electricity consumption.

10.2.2 Steps in certificate issuance, tracking, and claiming

Most certificates follow the pathway from issuance to claims as follows:

1. **Certificates produced.**
   Certificates are generally produced for one unit of generation (a MWh).

   Energy generators generally produce a certificate directly through registering an account in a registry or other tracking system. Generators report production data (MWh) to the tracking system as well as data about energy attributes, which should meet whatever measurement and verification protocols are required by that system . In the U.S. a generator actually creates the REC, and it can be conveyed by bilateral contracts. If the generation data is reported to a tracking system, the tracking will formally issue a certificate. Each certificate has a unique tracking number. Entities that wish to participate in the market and trade and own certificates must also register with a tracking system and open one or more accounts. Trading can occur, but each certificate can reside in only one account at a time to avoid double counting.

In some markets, a regulator or independent third party can serve as an "issuing body" that documents the creation of a certificate. See Box 10.1 on energy attribute tracking systems, and Figure 10.2 for an illustration of the different tracking systems in North America. See Box 10.2 for a discussion of the separation of roles in these systems to support independent issuance.

Box 10.1 Energy attribute tracking systems

A certificate tracking system or certificate registry is a tool to help execute energy attribute certificate issuance, retirement, and claims. It issues a uniquely numbered certificate for each unit of electricity (usually one MWh) generated by a generation facility registered in the system, tracks the ownership of certificates as they are traded among account holders in the tracking system, and records certificates that are redeemed or retired in order for users to make claims based on the certificate's attributes. Because each MWh has a unique identification number and can only be in one owner's account at any time, this reduces ownership disputes and the potential for double counting. Tracking systems are designed to ensure that no other entity is issuing certificates for the same MWh, and that all the attributes of that unit of generation remain with the certificate and are not sold as a separate instrument or right of ownership. Certificates may be imported to or exported from these tracking systems, and may also be retired within the tracking system on behalf of a purchaser whose corporate offices and facilities are located outside the footprint of the tracking system. They do not operate as exchanges or trading platforms for the certificates they issue, track, and redeem or retire.

2. **Third-party certification and labeling.** 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. Some examples of voluntary certification programs include Green-e (North America) EcoLogo (Canada), and GreenPower accreditation (Australia). Electricity labels such as EKOenergy serve a similar function by specifying a set of criteria that can be applied to determine which certificates can receive the label.

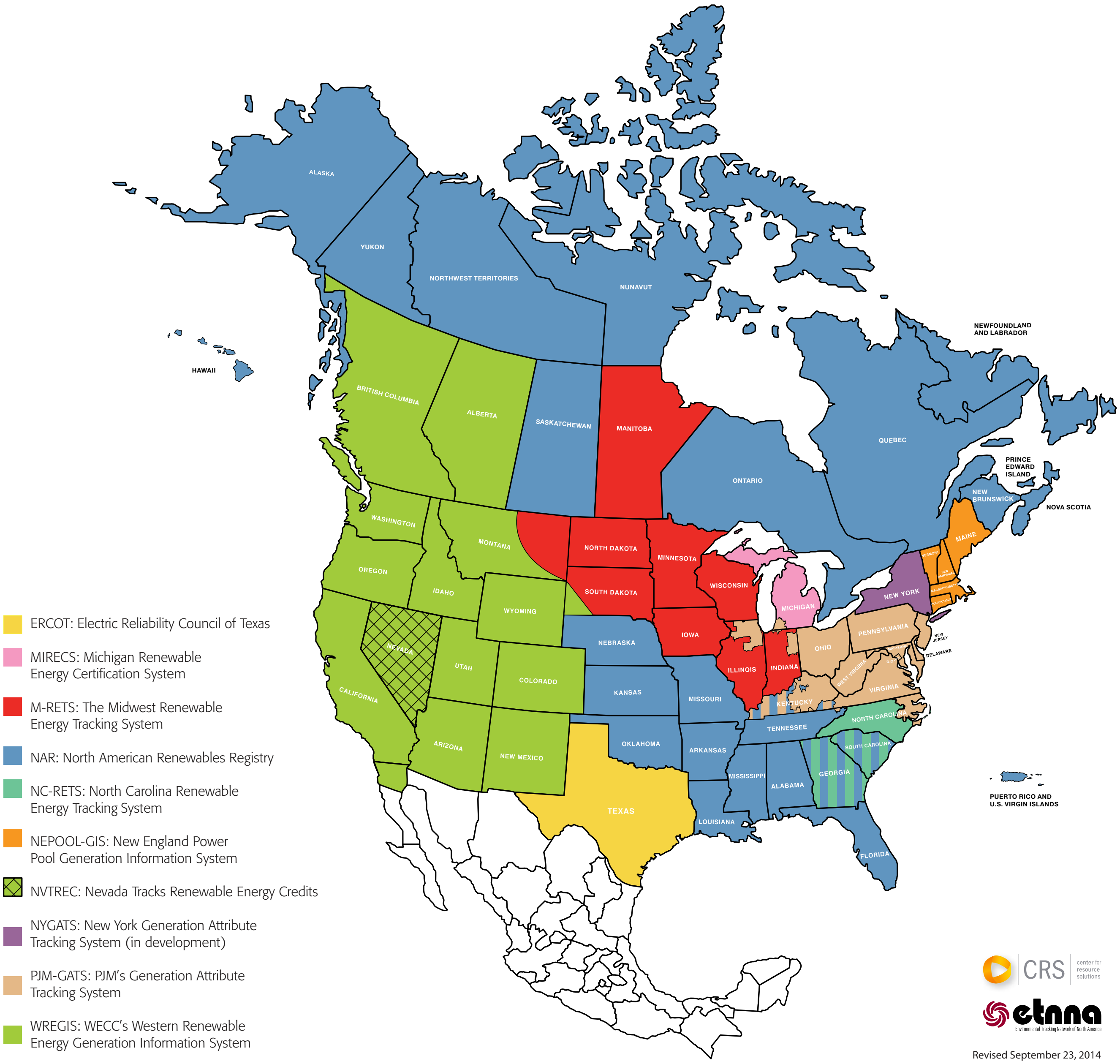
3. **Purchase and retirement by suppliers or consumers.** Certificates can be combined (or "bundled") with a contract for energy, or may be sold separately.[1] Certificates may be traded several times between the initial buyer and suppliers, or through open exchanges. For most certificates, the final purchaser or claimant will be an energy supplier or utility, or an end-consumer. 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 in order to facilitate a claim on behalf of its consumers (if a supplier) or itself (if an energy consumer).

Box 10.2 Best practices to ensure independent issuance

In order to ensure the fair competition of issuance, redemption, and use of contractual instruments, most markets have established a clear distinction between the management and ownership of the tracking system and the market players and consumers using the instruments. The ability to transfer contractual instruments and redeem the contained attributes should be possible without direct intervention from the certificate issuer or registry owner. The production facility owner is typically in direct control of the creation of the contractual instruments and will be the single owners of the created instruments until they decide to release their ownership to another third party. The owners of the tracking system or contractual instrument registry **should not** also be active in the market for the same contractual instruments. The documentation of the tracking system should be publically available and open to public consultation.

Figure 10.2 Energy attribute tracking systems in North America

Renewable Energy Certificate Tracking Systems in North America



10.3 Certificate uses

Certificates generally serve four main purposes, including:

- Supplier disclosure
- Supplier quotas, for the delivery or sales of specific energy sources
- Levy exemption
- Voluntary consumer programs

Each program or policy will establish their own eligibility criteria. These criteria specify certain energy generation facility characteristics, such as type of technologies, facility ages, or facility locations. Certificates must come from facilities meeting these criteria in order to be eligible for use in that program. In addition, individual country markets or policy-making bodies (referred to in this guidance as "jurisdictions") may accomplish these different functions using a single certificate system or a multi-certificate system.

- **Single certificate systems**
  In a single certificate system, only one certificate can be issued for each MWh generated and contain attributes associated with that unit of energy generation. This means that a certificate could fulfill multiple purposes—for example, it could be the evidence of supply pursuant to a supplier energy source quota, or be part of standard supplier products as well as voluntary programs or tariff offerings. An example of a single certificate system is the U.S. REC, where a REC may be used for supplier quotas where present (requirements or "eligibility" varies by state), voluntary consumer programs, or in supplier disclosure where supplier quota or voluntary consumer programs or labels are included.
- **Multi-certificate systems**
  A multi-certificate system can have multiple certificates issued for the same unit of energy, each conveying different attributes or claims for each function they serve (see an example of this for the U.K. in Figure 10.3). However, program policies and rules still determine what certificates may be eligible for the program. For the purposes of market-based scope 2 accounting, consumers in multi-certificate systems **shall** identify which certificate, if any, conveys GHG emission attributes to end users, and ensure that only one certificate, or jurisdictionally defined combination of certificates, does so (following the Scope 2 Quality Criteria in Chapter 7). A system could not, however, have multiple certificates each conveying the same consumer claims attributes; this would constitute double counting.

10.4 Supplier disclosure

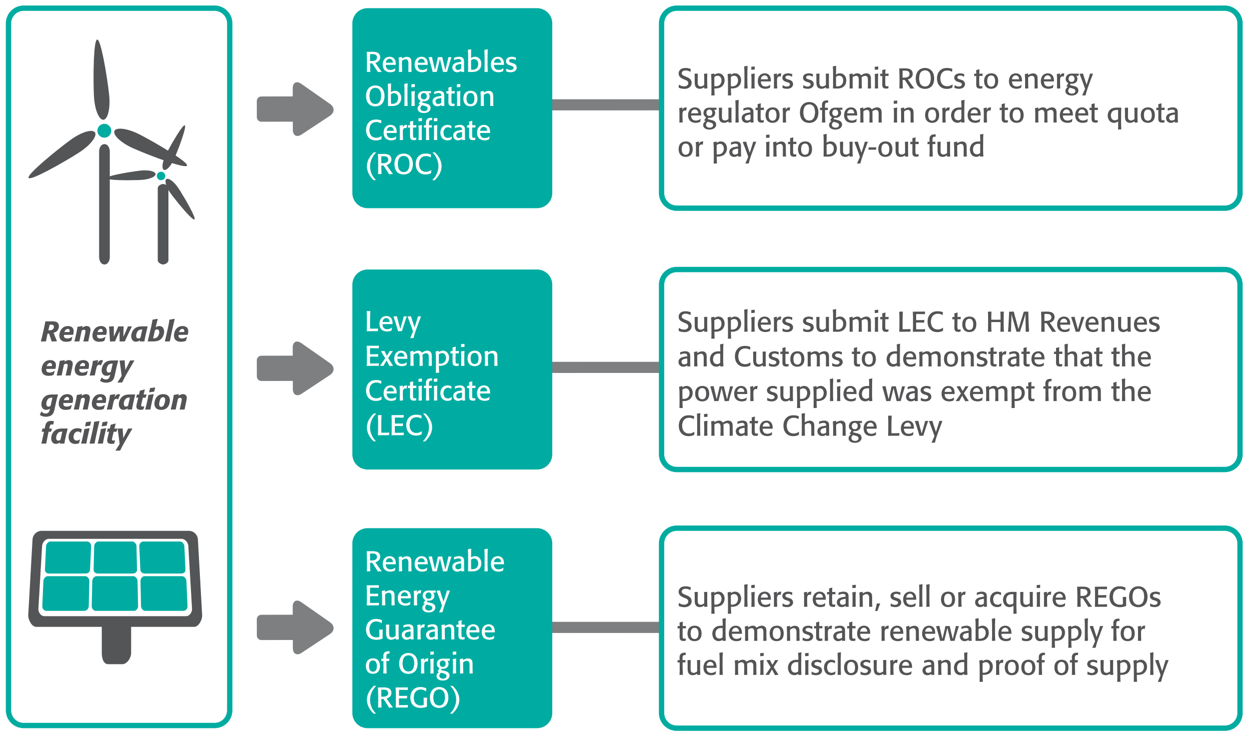
Energy suppliers may be required to disclose to consumers the fuel mix and related environmental attributes associated with delivered supply. Certificates have been used to track energy from production to the supplier, in order for a supplier to contractually demonstrate the source of the energy that is delivered to customers. Suppliers may disclose an emission rate associated with voluntary programs such as renewable or low-carbon energy products (often termed a green pricing program, green power tariff, or green power label), or other differentiated product offerings. In some countries, all consumers are required to make a choice about their electricity product, and information about the electricity product—including its resource mix, CO_2 emissions, and other environmental effects such as radioactive waste—is available on electricity bills.

Some supplier disclosure requirements may not explicitly require the use of certificates. For instance, in Japan power suppliers are obligated to report their supply mix and its associated emission factors to the Japanese government, and the government evaluates and publishes these emission factors.

Example of supplier disclosure

EU electricity market liberalization enabled consumers for the first time to choose their electricity supplier. This prompted the need for more standardized supplier disclosure about their energy supply and its attributes, allowing consumers to compare suppliers on metrics beyond just cost. The EU instituted requirements for all electricity suppliers to disclose their fuel mix to customers, along with the CO_2 quantity and radioactive waste. The Guarantee of Origin certificate has been used as the basis for suppliers to calculate and disclose the energy source and attributes associated with supply. It is also used as the basis for voluntary consumer labels.

Figure 10.3 **UK: Example of multiple certificates for distinct purposes**



10.5 Supplier quotas, for the delivery or sales of specific energy sources

To help incentivize growth in renewable energy resources, some nations or subnational entities have required electricity suppliers to source an increasing portion of their load from specified or "eligible" renewable energy resources by a specific date. Eligibility criteria may specify the age or location of generation facilities, specific technologies, etc. These supplier energy source quotas may require suppliers to obtain and submit energy attribute certificates to cover the specified portion of their overall supply. Suppliers not in compliance often pay a fine or fee. Some of these supplier energy source quota programs are called "support schemes" as they financially support generators who can sell compliance certificates to suppliers. But as a category, supplier energy source quota policies should be distinguished from other types of support policies such as tax credits or feed-in tariffs associated with production. The latter are direct payments to generators as opposed to revenue received by a generator from the sales of a certificate, and feed-in tariffs do not need to be tracked through certificates. The latter are thus not tied to quotas at a supplier level (for example, there is no "minimum" amount that must be produced). In addition, there is no delivery requirement and thus no need to track generation with certificates.

10.5.1 Certificate multipliers

Some jurisdictional compliance programs provide additional incentive for specific energy sources by providing a "credit multiplier" to a certificate when it is redeemed for compliance with program requirements. The multiplier is applied only when the certificate is redeemed for supplier quota compliance. For instance, a credit multiplier of 1.5 means that when a certificate is retired and claimed for compliance, it is counted toward compliance as if it were 1.5 certificates. Suppliers using certificates for disclosure should use the attributes stated in the certificate (per MWh) and not its multiplication for policy compliance.

Examples of supplier quotas

In the United States, states can set renewable energy portfolio (RPS) standards obligating suppliers to source a minimum share of renewable energy certificates (RECs) from qualifying sources that the policy identifies. For example, California requires that 20 percent of retail sales be supplied with renewable energy by 2013, 25 percent by 2016, and 33 percent by 2020. Policies identify what types of generation can achieve compliance. Policies can also identify a portion of the overall goal that must be met with specific resources (called a "carve out").

In the EU, Directive 2009/28 requires that member states meet renewable consumption targets by 2020 (called national targets). According to current EU law, GOs alone cannot be used as compliance instruments for suppliers to demonstrate fulfillment of national targets. Instead, other instruments such as Green Electricity Certificates in Belgium, Certificati Verdi in Italy, the Elcertifikat in Norway-Sweden, or Renewable Obligation Certificates (ROCs) in the UK, may be used by suppliers.

10.6 Tracking tax/levy exemptions

Tax credits or reductions for producers of specified energy sources (generally renewable or low-carbon) can improve the cost competitiveness of new projects that would otherwise face financial barriers. In addition, certain energy consumers may also be subject to taxes on their energy use relating to environmental externalities of conventional energy production (e.g., a CO_2 tax). Purchasers of renewable or other specified energy may be exempted from these taxes if they can prove their consumption through certificates.

Example of tracking tax/levy exemptions

In the UK, non-residential or "non-domestic" users—primarily large commercial or industrial energy users—are taxed for their energy use. But renewable electricity and electricity produced from coal mine methane are exempt from the tax. Renewable energy generation facilities are issued Levy Exemption Certificates (LECs), which suppliers must acquire on behalf of their non-domestic customers to avoid the tax (with LECs serving as evidence submitted to HM Revenue & Customs).

10.7 Voluntary consumer programs

Energy attribute certificates have been used as a means to promote voluntary consumer demand for the attributes of renewable or low-carbon energy and to support the consumer claims around those choices. These voluntary programs may be offered by an electricity supplier as a special tariff or product in addition to their standard offering; or, consumers in some jurisdictions may have competitive choice in their supplier and select a supplier offering exclusively specified energy products, such as an "all renewable" label. Consumers in all jurisdictions may also have the ability to directly purchase certificates (outside of their electricity delivery arrangement with local suppliers) to enable a claim. Voluntary consumer programs generally seek to both enhance consumer product choices and voluntarily leverage demand to increase the share of renewables on the grid over time.

Examples of voluntary consumer programs

- In the U.S., voluntary RECs can be obtained directly by a consumer ("unbundled" from energy purchases), or "bundled" through a supplier program or in an electricity contract such as a PPA.
- In the EU, GOs (rooted in disclosure laws) have also been used to support voluntary renewable energy purchases and claims.
- In Australia, the voluntary GreenPower program uses RECs in its accreditation label, which is supported and managed by state governments in Australia.
- Globally, The International REC Standard creates standardized attribute tracking certificates for the purposes of voluntary corporate disclosure. The legislative basis for the certificate issuance may be different in each country where the standard is active.

10.8 How jurisdictional policies affect the role and impact of voluntary programs

In most jurisdictions, voluntary consumer purchasing programs (and therefore market-based claims) will reflect attributes from energy generation that interacts with local or federal policies. This is consistent with the fact that in most markets, all energy—be it fossil, renewable, or low-carbon—is regulated to some extent and benefits from direct and indirect financial support. Renewable or low-carbon energy production and consumption in particular may benefit directly or indirectly through subsidies, cap-and-trade programs, supplier energy source quotas, etc.

However, the relationship between voluntary consumer purchasing programs and regulatory policy may be more sensitive or subject to stakeholder scrutiny. For instance, stakeholders may ask whether the purchased energy reflected in the voluntary certificate has "received a subsidy," or "helps lower the emissions cap on the power sector," or represents energy purchased in surplus of the electricity supplier's quota. These objectives can reflect a desire for voluntary consumer programs to ensure equal consumer benefit sharing—that is, that subsidized energy remains a publicly claimed benefit rather than one available for individual consumer claims. They can also reflect a desire for consumer action to have an impact on the market for low-carbon energy that goes beyond the incentives and trends dictated by policy.

Most of the relationships between voluntary programs and regulatory incentives or policies will be determined at the jurisdictional policy-making level, since regulators typically determine what types of certificates are issued for what policy purposes. The decision to use a single-instrument system may automatically address some of these voluntary policy interactions by ensuring the attributes of each unit of energy are only used for one purpose. The single-instrument scenario in the U.S. is sometimes termed "regulatory surplus,"[2] sincethe renewable energy claimed by voluntary purchasers cannot also be counted toward a state RPS program that delivers renewable energy to customers. Jurisdictions may also choose to:

- **Exclude voluntary claims from policy-supported energy generation.** This means that certificates used for voluntary claims may not also be used for supplier quota compliance targets, for claiming a direct subsidy, or for producing an offset.
- **Require pairing of the voluntary certificate with a regulatory certificate.** This means requiring multiple certificates to be "paired" together in order to enable voluntary consumer claims from certain types of power, even if a single instrument alone may technically convey the attributes necessary for claims. This could entail suppliers being required to retire both the certificate they use for disclosure along with the certificate used for levy exemption. Voluntary allowance set-aside programs in emissions-capped power sectors also serve as a type of "instrument pairing" to fulfill goals beyond scope 2 accounting.

Companies should check with their electricity supplier or relevant policy-making bodies to ensure that voluntary certificates are claimed, paired, or retired in compliance with jurisdictional requirements. Companies should report these relationships separately (see Chapter 8).

Endnotes

1. For example, the U.S. Federal Trade Commission (FTC) has not recognized a distinction with respect to marketing or consumer claims between purchasing a bundled product or unbundled certificates and electricity separately.
2. This has also been termed "regulatory additionality," though this Guidance distinguishes between the specific use of the term "additionality" in offset accounting and the diverse types of objectives and criteria that can be applied to energy attribute certificates.

11 How Companies Can Drive Electricity Supply Changes with the Market-Based Method

This chapter describes how market-based consumer actions and claims can drive change in electricity generation supply over time, and clarifies why this guidance does not establish requirements on policy relationships or "market impact" criteria. It elaborates how companies can use their procurement power to substantively contribute to new low-carbon energy supply.

11.1 Energy attribute supply and demand

The four certificate uses described in Chapter 10, though distinct, are all generally designed to support growth of low-carbon energy by increasing demand for specific attributes. As demand grows, it will push up the price of these attributes, which in turn can stimulate supply. This theory underlies the basis of market-based accounting in scope 2, as it reflects an allocation of consumer preferences (demand) for the GHG attributes from a given supply of attributes available for those claims. Because these energy attributes are finite, a voluntary energy purchase and attribute claim prevents others from making the same claim on those MWh and requires other consumers to source from the remaining unclaimed (and typically more GHG-intensive) energy attributes. In short, if demand for low-carbon energy, which on a shared grid can only be expressed using certificates and contracts, begins to approach existing supply, the pressure or incentive to build additional supply grows, with certificates also serving as an additional revenue stream to help signal that demand. This is the same theory that underlies all other markets and is also the basis of scope 3 accounting: all individual purchases contribute to overall demand for a product or type of product, and the more purchases are made, the more this demand will drive changes in production.

The market-based method for scope 2 accounting represents an internationally applicable framework allowing suppliers and consumers to express and aggregate demand for specific types of generation. It treats market-based accounting as an allocation procedure, with the understanding that the effect of the market on grid makeup will depend on the level of demand vs. supply of renewable energy, program eligibility, degree of uptake, policy interactions, and other variable factors. It provides several pathways by which corporate procurement can drive new low-carbon energy development.

11.2 Relationship between voluntary program impact and scope 2 accounting

Consumers who voluntarily claim low-carbon attributes in scope 2 may expect their individual purchase or program participation to result in new generation that lowers system-wide GHG emissions. However, like other markets and products, individual voluntary purchases and consumer programs may or may not result in changes in low-carbon supply, depending on supply and demand dynamics. For instance, one paper[1] suggests that the voluntary REC market in the U.S., when evaluated based on the price of RECs as an incentive for project developers, has not itself driven new renewable energy projects.

Another market analysis[2] indicates that the effect of voluntary demand on new renewable energy project development is not based on the price of those RECs so much as it is on the presence of long-term contracts for RECs and energy from projects as yet unbuilt.

Given that voluntary markets for renewable energy aggregate consumer demand in order to affect supply changes, some stakeholders and voluntary programs have incorporated additional specifications or criteria to stimulate growth of low-carbon supply. For example, these criteria could include requiring voluntary consumer claims to be above or in surplus to supplier energy source quotas, or to be independent from the receipt of public funds, or for market-based scope 2 accounting rules to be aligned with offset credit additionality requirements in order to ensure that each voluntary energy purchase claimed in scope 2 represents a unit of "additional" low-carbon generation or emission reductions. This could mean requiring that an individual voluntary purchase and claim, or a voluntary certificate program, be the decisive reason new low-carbon energy projects are built.

Even in the absence of such requirements, the market-based method accurately reflects an allocation of generation attributes among consumers, which is important for reflecting individual actions and purchase decisions as well as for recognizing action to affect demand-side change. In the absence of such requirements, and if there is insufficient demand to drive overall change on the grid, stakeholders may be concerned that the market-based method results only in a reallocation of attributes between those consumers who care about claiming low-carbon energy, and those who are unaware of or uninterested in the opportunity to make these claims.

11.3 The role of "additionality"

This guidance does *not* require that contractual instruments claimed in the market-based method fulfil criteria such as offset "additionality" or prove the overall market impact of individual purchases or supplier programs result in direct and immediate changes in overall supply. This follows the same reasoning applied to purchased products in scope 3 accounting, including that:

- **The market-based method for scope 2 accounting applies to all energy generation in a defined grid**, not just "low-carbon" or renewable energy from projects supported by a specific company's financial support. It concerns the larger allocation process of all energy emissions across all end users. All energy has a direct emissions factor associated with generation, and the use of that emissions factor does not depend on whether the generation facility is existing or new, or why the generation has occurred. This guidance lays out the policy-neutral mechanics of a market-based method for scope 2 accounting, so that regardless of what causes the project to be built, the energy attribute certificate still serves as the instrument conveying claims about the attributes of the underlying energy generation for consumers purchasing that generation.
- **Offset additionality criteria are not fundamental to, or largely compatible with, the underlying rules for market-based scope 2 accounting and allocation.** In GHG accounting, additionality is a term specifically associated with offsets and project-level accounting, which is distinct from corporate GHG accounting. The claim that X metric tons of GHG emissions have been avoided at a global level can only be credible if the offset credit was the "intervention"[3] that made the project happen—and that, without that intervention, that project would not have occurred. Such a claim requires proof of cause-and-effect and is critical to support the integrity of offset credits. However, offsets represent a different claim (avoided GHG emissions

compared to a baseline scenario) than energy generation attributes (X GHG emissions from Y unit of energy generation). Scope 2 reporting is a report of usage and as such is independent of issues associated with additionality.

In short, voluntary programs have been designed in different ways across jurisdictions, and with differing relationships to other policies promoting the growth of low-carbon energy supply. Maximizing the speed and efficacy of voluntary initiatives in driving new low-carbon development is an important, complex, dynamic, and evolving process for program implementers, regulators, and participants. Jurisdictional policy makers, certification programs, supplier labels or tariffs, or consumers are best situated to identify and execute policies in pursuit of these goals. The role of this guidance is to identify the core requirements of accurate market-based accounting (Scope 2 Quality Criteria) that can apply to any jurisdiction's range of contractual instruments, while ensuring sufficient transparency in corporate reports to allow internal and external stakeholders to assess performance and how effectively corporate energy procurement achieves broader company goals—including accelerating the growth of new low-carbon energy in a short period of time.

11.4 How can companies go further?

While not a part of criteria for market-based scope 2 accounting, suppliers and companies can make energy procurement choices that can shift a company's impact from "aggregate" to more directly spurring an increase in new, low-carbon energy generation facilities in a short period of time, consistent with the ambition needed to avoid dangerous climate change. Many of these choices are summarized in box 5.1, highlighting both the policy changes and the individual consumer choices that could, in the case of the U.S., strengthen the impact of voluntary REC products.

In effect, these choices can be framed as a range of stronger and weaker market signals, with the strongest signals being for *new* projects where a company can play a *substantive role* in helping a project go through. Companies can identify procurement choices aligned with new projects (helping to decrease system-wide emissions in a shorter period of time) where the company can bring to bear its financial resources, creditworthiness, scale of consumption, technical knowledge, collaboration, or other approaches in order to help overcome traditional barriers to scaling the development of low-carbon energy. Some of these choices are elaborated below; options for reporting on these efforts are discussed in Chapter 8.

1. **Contract directly with new low-carbon energy projects**
   Long-term power purchase agreements or other contracts for energy procurement often provide the stable revenue structure needed to help attract the additional financing to complete new projects. In order to make a claim on any purchased energy, companies **shall** retain any certificates associated with the energy production because they convey GHG emission rate attributes. In markets without certificates, the contracts themselves may be written to convey these attributes, provided that the energy is not resold to other entities who would make similar claims, and provided that the Scope 2 Quality Criteria are met.
2. **Work with electricity suppliers for new projects**
   Customers of a utility typically have standing in—and thus the ability to influence—proceedings that affect the generation resources owned and/or used by the utility from which they buy power. Consumers can demand low-carbon energy tariffs or purchasing options based on or supporting new low-carbon energy projects that also meet the reporting requirements for scope 2. This model can also allow for collaboration and aggregation of multiple consumers' demand. Customers that individually or collectively represent a large percentage of a utility's load may be most influential in these measures.
3. **Establish "eligibility criteria" for corporate energy procurement, relating to specific energy generation features or policy interactions that align with new low-carbon energy projects.**
   When consumer demand is targeted at a narrower set of criteria, that demand is more likely to meet existing supply and prompt stronger market signals for new facilities meeting specific criteria. For instance, companies can establish their own instrument featuring requirements around criteria such as

technology type, facility age or facility siting, the energy generation's relationship to supplier quotas, etc.

In addition to the certificate policies established by jurisdictional policy makers, other key actors in the energy supply system can also, through their voluntary choices, impact how claimed energy in voluntary programs interacts with policy instruments, depending on the jurisdiction. These key actors include issuing bodies, voluntary certificate standards, or electricity supplier labels or tariffs, or individual companies (see Figure 5.1).

4. Incremental funding or donations

Some voluntary certificate programs or supplier labels or tariffs may structure their product so that a dedicated portion of the revenue from the program is applied as "incremental funding" for new projects identified by the program. This type of fund model, exemplified by GO2,[4] EKOenergy,[5] and TrackmyElectricity[6] in Europe, can help directly contribute to the growth of new low-carbon energy projects. Companies providing this type of donation can document this separately.

Box 11.1 Strengthening the role of RECs as a standalone product

A 2011 publication by the U.S. National Renewable Energy Laboratory (NREL)* noted that there are several ways that purchasers, marketers, and policy makers could "strengthen the role of RECs in both compliance and voluntary markets." Here, strengthening the role of RECs translates, in practice, to an improved ability of purchasers to, in aggregate, create change in global GHG emissions. Some of these options include:

- Encourage long-term contracts for RECs. Long-term contracts can offer the security and certainty that many projects need to obtain financing.
- Host periodic solicitations for medium- to long-term contracts with smaller projects. Smaller projects need a more standardized market, and auctions also increase REC market liquidity and price transparency.
- Adopt a REC price floor. This would ensure a minimum level of support and reliable revenues for new projects.
- Increase renewable energy targets. Increased demand would lead to stronger REC prices.
- Limit eligibility of supply (e.g. by limiting the eligible project age, project location, etc.). Restricting eligible supply also tends to increase REC prices.
- Support greater price transparency. Price transparency increases confidence in current and future REC prices and could lead to a greater recognition for RECs as a potential revenue stream.
- Contribute funds for project development. Primarily an option for the voluntary market, having incremental costs funded up front would reduce the risk for projects that are above-market price.
- Take an equity position in new projects. Direct investment in itself is strong evidence of making new projects happen and has several other advantages. This approach could work for utility-scale projects or for installation of on-site distributed generation.

Source: *Holt, Sumner, and Bird (2011).

Endnotes

1. Gillenwater, Lu, and Fischlein (2014).
2. Holt, Sumner, and Bird (2011).
3. Gillenwater (2012).
4. See GO2 product by ECOHZ at: http://www.ecohz.com/products/products/ecohz-go%C2%B2.
5. See EKOenergy label and criteria at: http://www.ekoenergy.org/our-results/climate-fund/.
6. See Bergen Energi product at: http:// www.trackmyelectricity.com.

Appendices

Appendix A
Accounting for Steam, Heat, and Cooling

The scope 2 accounting concepts, methods, and examples referenced in this guidance are drawn primarily from, and apply primarily to, electricity purchasing and use. However, steam, heat, and cooling energy systems may also use contractual instruments to convey attributes and claims. For instance, companies may have contracts to receive heat or steam from providers that specify the fuel source and emission rate associated with their received energy. In addition, "green heat" certificates generated from biogenic fuel sources may be issued and traded independently from the energy flows and injection into the distribution grid.

Companies **shall** report emissions from the purchase and use of these energy products the same as for electricity: according to a location-based and market-based method, if the contractual instruments used meet the Scope 2 Quality Criteria as appropriate for gas transactions. These may be the same total where direct line transfers of energy are used.

Companies should follow Table 6.1 accounting for scope 2 with and without certificates sales to determine the treatment of direct line energy transfers (e.g., receiving heat/steam/cooling directly from another facility) or energy used from local steam/heat/cooling distribution systems. A location-based emission factor for such systems should characterize the average GHG intensity of the fuels used to generate the heat/steam/cooling, as well as the efficiency of that generation.[1]

Steam, heat, and cooling as a "waste" product.

Emissions from steam, heat, or cooling that is received via direct line as "waste" from an industrial process should still be reported based on the underlying emissions from the original generation process. Some companies may wish to account for these as zero emissions because the steam/heat/cooling would have been vented instantaneously if not used. However, accurate emissions accounting requires the actual emissions associated with the production of this waste to be reported.

Endnotes

1. An emission factor per unit energy for purchased steam or heat is equal to the emission factor per unit energy of the fuel used divided by the thermal efficiency of the generation. An emission factor for purchased cooling that is generated by an electric chiller is equal to the emission factor for the electricity consumed in the chiller divided by the chiller's coefficient of performance (COP).
2. See EPA RFS2 Regulations Final Rule (2010).

Portland General Electric/Flickr


Tambako The Jaguar/Flickr

Appendix B
Accounting for Energy-Related Emissions Throughout the Value Chain

Accounting in a grid-connected electricity value chain

For scope 2 reporting, differences in the regulatory structure of electricity supply chains can impact overall energy procurement options and what emissions are included in a supplier-specific emission factor. They also determine which entity reports which emissions in the energy value chain, as shown below.

The mechanics of electricity distribution on any grid function largely the same way, with the four supply chain phases including: (1) material or fuel extraction and processing; (2) generation; (3) transmission and distribution; and (4) sales to, and consumption by, end users. Different regulatory structures at a regional, national, and subnational level can influence what entities are involved throughout the phases of energy generation, transmission, distribution, and service. For instance:

- In some markets, the utility owns the generation assets, transmission and distribution (also known as T&D) infrastructure, and interfaces with the consumer to deliver energy. These entities would report all generation emissions in scope 1, and no T&D losses would be reported separately since the emissions would be already reported in scope 1.
- In others, power generators may be independent entities from which the utility buys power.
- In fully deregulated or competitive markets, each activity in the supply chain could be conducted by a different company. For instance, a customer may interface with energy retailers or suppliers who only sell electricity but who do not own generation assets or T&D equipment. Because these entities purchase and sell, but do not produce or consume the energy, they do not record either scope 1 or scope 2 emissions from the energy they sell.

Figure B.1 illustrates in which scope each entity in the electricity supply system (depicted in the rows) accounts for the emissions occurring during these different phases of electricity generation, distribution, and use (depicted as phases in the column).

See Appendix A of the *Corporate Standard* for more information on these relationships.

Accounting for energy-related emissions in scope 3

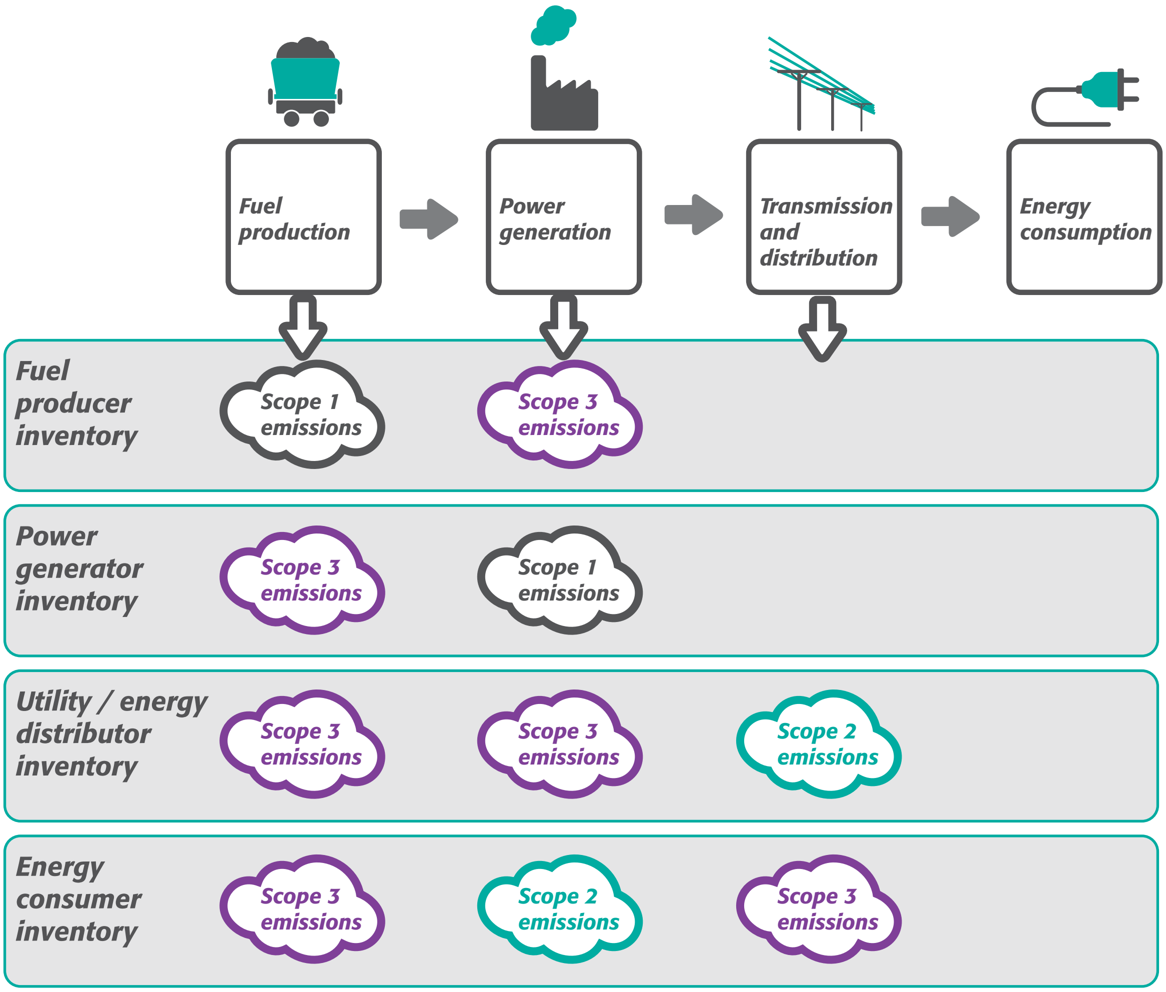
Scope 2 emissions from different value chain partners form the basis of almost all fifteen scope 3 categories. Therefore, companies obtaining energy emissions data from their suppliers to be used in scope 3 calculation should ask which scope 2 method was used to calculate the results. In turn, companies should be transparent about which scope 2 method total they share with others in their value chain.

Category 3: Upstream fuel and energy-related activities

For an energy consumer, category 3 includes upstream emissions from fuel extraction and processing prior to its combustion (known as the cradle-to-gate emissions) as well as the energy consumed (e.g. "lost") during transmission and distribution. Because of T&D losses, the actual amount of electricity generated at a power plant will be greater than the total electricity consumed by customers alone.[1] On-site generation does not incur T&D losses, as there is virtually no "line" in which transmission and energy losses occur.

The energy quantity consumed and reported in scope 2 serves as the basis for determining T&D activity data. One example of how this can be calculated is by applying the grid loss factor (ex: 7 percent grid loss rate for 100MWh consumption would mean 7MWh lost in T&D).Companies may also get information on line losses from the entity that controls the lines. Companies would need to apply an emissions factor to that line loss consumption to determine emissions associated with the loss. Companies should disclose which calculation method they are using to calculate and report T&D losses in scope 3 category 3, but do not need to "dual report" this. For instance, if companies, their suppliers, or other value chain partners have purchased energy attribute

Figure B.1 Accounting for electricity emissions throughout the supply system



certificates to cover the quantity of grid losses, they can report this calculation based on the market-based method procedures in this Guidance. If not, companies should use the location-based method emission factors.

Companies should also disclose which scope 2 results—location-based or market-based—they are using as the basis for calculating upstream fuel extraction and processing emissions. For example, a scope 3 category 3 assessment based on the results of a location-based scope 2 report could reflect the upstream profile of the mix of grid resources (natural gas, coal). A category 3 assessment based on the results of a market-based scope 2 report could reflect the upstream emissions associated with producing renewable energy.

Category 15. Investments.

Any investments in energy generation facilities or other projects not associated with a contractual arrangement reflected in scope 2 can report emissions from these investments in category 15.

For scope 3 calculation procedures, see GHG Protocol *Value Chain (Scope 3) Standard* and *Scope 3 Calculation Guidance.*

Endnotes

1. Companies are not required to account for line losses due to unauthorized connections or energy theft, which make up a significant percent of T&D losses in many jurisdictions.

Abbreviations

CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
GHG	Greenhouse Gas
GWP	Global Warming Potential
HFCs	Hydrofluorocarbons
IAS	International Accounting Standard
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
LCA	Life Cycle Assessment
LFGTE	Landfill-gas-to-energy
MSW	Municipal Solid Waste
MWh	Megawatt-hour
NGO	Non-Governmental Organization
N_2O	Nitrous Oxide
PFCs	Perfluorocarbons
QA	Quality Assurance
QC	Quality Control
SF_6	Sulphur Hexafluoride
t	Metric tons
T&D	Transmission and Distribution
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Glossary

Activity data	A quantitative measure of a level of activity that results in GHG emissions. Activity data is multiplied by an emissions factor to derive the GHG emissions associated with a process or an operation. Examples of activity data include kilowatt-hours of electricity used, quantity of fuel used, output of a process, hours equipment is operated, distance traveled, and floor area of a building.
Additionality	A criterion often applied to GHG project activities, stipulating that project-based GHG reductions should only be quantified if the project activity "would not have happened anyway"—i.e., that the project activity (or the same technologies or practices that it employs) would not have been implemented in its baseline scenario.
Allocation	The process of assigning responsibility for GHG emissions from a specific generating unit or other system (e.g., vehicle, business unit, corporation) among its various users of the product or service.
Allowance	A commodity issued by an emissions trading program that gives its holder the right to emit a certain quantity of GHG emissions.
Annex 1 countries	Defined in the International Climate Change Convention as those countries taking on emissions reduction obligations: Australia; Austria; Belgium; Belarus; Bulgaria; Canada; Croatia; Czech Republic; Denmark; Estonia; Finland; France; Germany; Greece; Hungary; Iceland; Ireland; Italy; Japan; Latvia; Liechtenstein; Lithuania; Luxembourg; Monaco; Netherlands; New Zealand; Norway; Poland; Portugal; Romania; Russian Federation; Slovakia; Slovenia; Spain; Sweden; Switzerland; Ukraine; United Kingdom; and the United States.
Attribute	Descriptive or performance characteristics of a particular generation resource. For scope 2 GHG accounting, the GHG emission rate attribute of the energy generation is required to be included in a contractual instrument in order to make a claim.
Audit trail	Well-organized and transparent historical records documenting how the GHG inventory was compiled.
Avoided emissions	An assessment of emissions reduced or avoided compared to a reference case or baseline scenario.
Base year emissions	GHG emissions in the base year
Base year emissions recalculation	Recalculation of emissions in the base year to reflect a change in the structure of the company or a change in the accounting methodology used, to ensure data consistency over time.
Baseline scenario	A hypothetical description of what would have most likely occurred in the absence of any considerations about climate change mitigation. For grid-connected project activities, the baseline scenario is presumed to involve generation from the build margin, the operating margin, or a combination of the two.
Baseload	A type of power plant that operates continuously (or nearly continuously) to meet base levels of power demand that can be expected regardless of the time of day or year.

Biofuels	Fuel made from plant material, such as wood, straw, and ethanol from plant matter.
Biogenic CO_2 emissions	CO_2 emissions from the combustion or biodegradation of biomass.
Biogenic gas (biogas)	Methane that is produced from a biomass resource, such as animal waste, agricultural waste, landfill gas, municipal waste, or digester gas.
Biomass	Any material or fuel produced by biological processes of living organisms, including organic non-fossil material of biological origin (e.g., plant material), biofuels (e.g., liquid fuels produced from biomass feedstocks), biogenic gas (e.g., landfill gas), and biogenic waste (e.g., municipal solid waste from biogenic sources).
Build margin (BM)	The incremental new capacity displaced by a project activity. The build margin indicates the alternative type of power plant (or plants) that would have been built to meet demand for new capacity in the baseline scenario.
Bundled	An energy attribute certificate or other instrument that is traded with the underlying energy produced.
Cap-and-trade system	A system that sets an overall emissions limit, allocates emissions allowances to participants, and allows them to trade allowances and emission credits with each other.
Certificate	See energy attribute certificate
Certified Emission Reductions (CERs)	A unit of emission reduction generated by a CDM project. CERs are tradable commodities that can be used by Annex 1 countries to meet their commitments under the Kyoto Protocol.

Clean Development Mechanism(CDM)	A mechanism established by Article 12 of the Kyoto Protocol for project-based emission reduction activities in developing countries. The CDM is designed to meet two main objectives: to address the sustainability needs of the host country and to increase the opportunities available to Annex 1 Parties to meet their GHG reduction commitments. The CDM allows for the creation, acquisition, and transfer of CERs from climate change mitigation projects undertaken in non-Annex 1 countries.
CO_2 equivalent (CO_2e)	The universal unit of measurement to indicate the global warming potential (GWP) of each greenhouse gas, expressed in terms of the GWP of one unit of carbon dioxide. It is used to evaluate releasing (or avoiding releasing) different greenhouse gases against a common basis.
Cogeneration unit/Combined heat and power (CHP)	A facility producing both electricity and steam/heat using the same fuel supply.
Company	The term company is used in this standard as shorthand to refer to the entity developing a GHG inventory, which may include any organization or institution, either public or private, such as businesses, corporations, government agencies, nonprofit organizations, assurers and verifiers, universities, etc.
Consumer	The end consumer or final user of a product.
Contractual instrument	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 meet the Scope 2 Quality Criteria.
Control	The ability of a company to direct the policies of another operation. More specifically, it is defined as either operational control (the organization or one of its subsidiaries has the full authority to introduce and implement its operating policies at the operation) or financial control (the organization has the ability to direct the financial and operating policies of the operation with a view to gaining economic benefits from its activities).
Direct emissions	Emissions from sources that are owned or controlled by the reporting company.
Dispatch	The coordination of power plant operations in order to meet the load on a grid. A "dispatchable" power plant is one that can be directly called upon by grid operators to produce power, and whose output can be modulated in response to real-time fluctuations in demand for electricity.
Distributed generation	Decentralized, grid-connected, or off-grid energy facilities located in or near the place where energy is used.
Double counting	Two or more reporting companies claiming the same emissions or reductions in the same scope, or a single company reporting the same emissions in multiple scopes.

Electric utility	An electric power company whose operations may include generation, transmission, and distribution of electricity for sale. Also called electricity or energy supplier.
Eligibility criteria	Features or conditions defined by a policy or program that determine which energy generation facilities can participate in the program or whose certificates will fulfill programmatic requirements.
Emission factor	A factor that converts activity data into GHG emissions data (e.g., kg CO_2e emitted per liter of fuel consumed, kg CO_2e emitted per kilometer traveled, etc.).
Emissions	The release of greenhouse gases into the atmosphere.
Energy	Formally, energy is defined as the amount of work a physical system can do on another. In this Guidance, energy refers to electrical energy generated by power plants and delivered to energy users over a power grid.
Energy attribute certificate	A category of contractual instruments used in the energy sector to convey information about energy generation to other entities involved in the sale, distribution, consumption, or regulation of electricity. This category includes instruments that may go by several different names, including certificates, tags, credits, etc.
Energy generation facility	Any technology or device that generates energy for consumer use, including everything from utility-scale fossil fuel power plants to rooftop solar panels.
Equity investment	A share of equity interest in an entity. The most common form is common stock. Equity entitles the holder to a pro rata ownership in the company.
Equity share approach	A consolidation approach whereby a company accounts for GHG emissions from operations according to its share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to the risks and rewards flowing from an operation.
Feed-in tariff	A policy mechanism offering a fixed price to renewable energy producers for output.
Finance lease	A lease that transfers substantially all the risks and rewards of ownership to the lessee and is accounted for as an asset on the balance sheet of the lessee. Also known as a capital or financial lease. Leases other than capital/financial/finance leases are operating leases.
Financial control	The ability to direct the financial and operating policies of an entity with a view to gaining economic benefits from its activities.
Financial control approach	A consolidation approach whereby a company accounts for 100 percent of the GHG emissions over which it has financial control. It does not account for GHG emissions from operations in which it owns an interest but does not have financial control.
Fuel mix disclosure	A report by energy suppliers to their consumers disclosing the generation resources and associated attributes (such as GHG emissions and nuclear waste quantities) provided by that supplier. Disclosure laws often aim to enable informed customer choice in deregulated or liberalized markets.
Generation	The electrical energy produced by a power plant or project activity.

GHG program	A generic term for: (1) any voluntary or mandatory, government or nongovernment initiative, system, or program that registers, certifies, or regulates GHG emissions; or (2) any authorities responsible for developing or administering such initiatives, systems, or programs.
GHG project	A specific activity or set of activities intended to reduce GHG emissions, increase the storage of carbon, or enhance GHG removals from the atmosphere. A GHG project may be a standalone project or a component of a larger non-GHG project.
Global warming potential	A factor describing the radiative forcing impact (degree of harm to the atmosphere) of (GWP) one unit of a given GHG relative to one unit of CO_2.
Green power	A generic term for renewable energy sources and specific clean energy technologies that emit fewer GHG emissions relative to other sources of energy that supply the electric grid. Includes solar photovoltaic panels, solar thermal energy, geothermal energy, landfill gas, low-impact hydropower, and wind turbines. Resources included in a given certification, reporting, or recognition program may vary.
Green power product/ green tariff	A consumer option offered by an energy supplier distinct from the "standard" offering. These are often renewables or other low-carbon energy sources, supported by energy attribute certificates or other contracts.
Greenhouse gas inventory	A quantified list of an organization's GHG emissions and sources.
Greenhouse gases (GHG)	For the purposes of this standard, GHGs are the seven gases covered by the UNFCCC: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6), and nitrogen triflouride (NF_3).
Grid	A system of power transmission and distribution (T&D) lines under the control of a coordinating entity or "grid operator," which transfers electrical energy generated by power plants to energy users—also called a "power grid." The boundaries of a power grid are determined by technical, economic, and regulatory-jurisdictional factors.
Grid operator	The entity responsible for implementing procedures to dispatch a set of power plants in a given area to meet demand for electricity in real time. The precise institutional nature of the grid operator will differ from system to system. The grid operator may be alternately referred to as a "system dispatcher," "control area operator," "independent system operator," or "regional transmission organization," etc.
Indirect GHG emissions	Emissions that are a consequence of the operations of the reporting company, but occur at sources owned or controlled by another company. This includes scope 2 and scope 3.
Intensity target	A target defined by reduction in the ratio of emissions and a business metric over time e.g., reduce CO_2 per metric ton of cement by 12 percent between 2000 and 2008.
Intergovernmental Panel on Climate Change (IPCC)	An international body of climate change scientists. The role of the IPCC is to assess the scientific, technical, and socioeconomic information relevant to the understanding of the risk of human-induced climate change
Inventory boundary	An imaginary line that encompasses the direct and indirect emissions included in the inventory. It results from the chosen organizational and operational boundaries.

Inventory quality The extent to which an inventory provides a faithful, true, and fair account of an organization's GHG emissions.

Jurisdiction A geopolitical region under a single legal and regulatory authority. For market boundaries for certificate use and trading described in this uidance, jurisdictions are typically countries but may be multi-country regions.

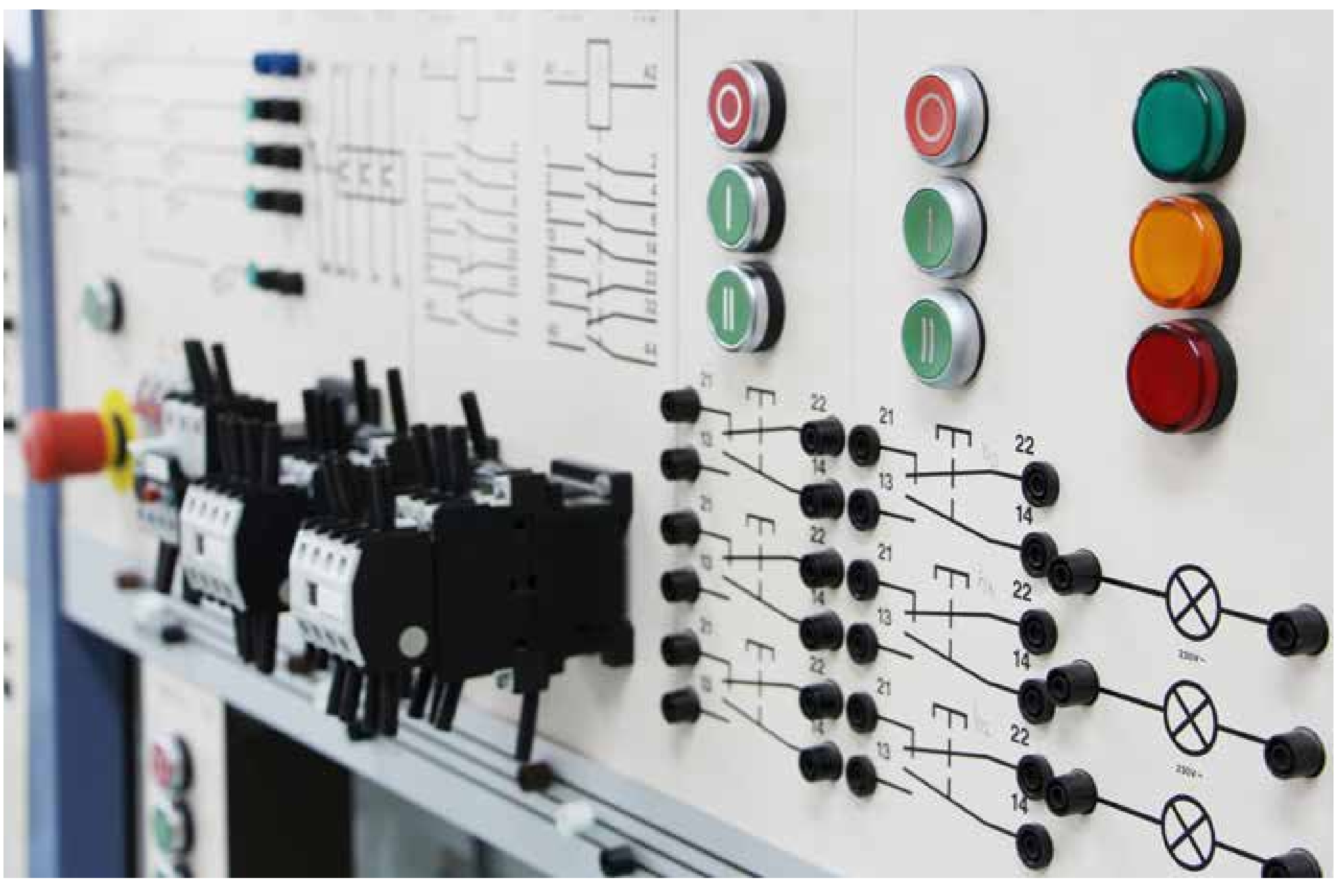
Levy Exemption Certificate (LEC) Certificates used in the U.K. to provide energy suppliers with evidence needed to demonstrate to HMRC that electricity supplied to U.K. business customers is exempt from the Climate Change Levy.

Life cycle Consecutive and interlinked stages of a product system, from raw material acquisition or generation of natural resources to end of life.

Life cycle assessment (LCA) Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product system throughout its life cycle.

Location-based method for scope 2 accounting A method to quantify scope 2 GHG emissions based on average energy generation emission factors for defined locations, including local, subnational, or national boundaries.

Market-based method for scope 2 accounting A method to quantify scope 2 GHG emissions based on GHG emissions emitted by the generators from which the reporter contractually purchases electricity bundled with instruments, or unbundled instruments on their own.



Megawatt (MW)	A unit of electrical power. One megawatt of power output is equivalent to the transfer of one million joules of electrical energy per second to the grid.
Megawatt-hour (MWh)	A unit of electrical energy equal to 3.6 billion joules; the amount of energy produced over one hour by a power plant with an output of 1 MW.
Net metering	A method for energy suppliers to credit customers for electricity that they generate on site in excess of their own electricity consumption and sell back to the grid. Any electricity purchases from the gird are deducted (or "netted") from the generation sent to the grid. The specific financial rules for net metering may vary by country and state.
Null power	Energy from which energy attribute certificates or other instruments have been separated and sold off, leaving the underlying power without specific attributes. Also called "commodity electricity."
Offset credit	Offset credits (also called offsets, or verified emission reductions) represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for GHG emissions occurring elsewhere, for example to meet a voluntary or mandatory GHG target or cap. Offsets are calculated relative to a baseline that represents a hypothetical scenario for what emissions would have been in the absence of the mitigation project that generates the offsets. To avoid double counting, the reduction giving rise to the offset must occur at sources or sinks not included in the target or cap for which it is used.
On-site generation	Electricity generated by a generation facility located where some or all of the energy is used. If the generation facility is owned and operated by the consuming company, it can be called "self-generation." On-site generation is a form of distributed energy generation.
Operating lease	A lease that does not transfer the risks and rewards of ownership to the lessee and is not recorded as an asset in the balance sheet of the lessee. Leases other than operating leases are capital/financial/finance leases.
Operating margin (OM)	The set of existing power plants whose output is reduced in response to a project activity. These power plants are the last to be switched on-line or first to be switched off-line during times when the project activity is operating, and which therefore would have provided the project activity's generation in the baseline scenario.
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by the reporting company.
Operational control	A consolidation approach whereby a company accounts for 100 percent of the GHG emissions over which it has operational control. It does not account for GHG emissions from operations in which it owns an interest but does not have operational control.
Organizational boundaries	The boundaries that determine the operations owned or controlled by the reporting company, depending on the consolidation approach taken (equity or control approach).

Power purchase agreement (PPA)	A type of contract that allows a consumer, typically large industrial or commercial entities, to form an agreement with a specific energy generating unit. The contract itself specifies the commercial terms including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project. In order for the consumer to say they are buying the electricity of the specific generator, attributes **shall** be contractually transferred to the consumer with the electricity.
Renewable energy	Energy taken from sources that are inexhaustible, e.g. wind, water, solar, geothermal energy, and biofuels.
Renewable energy certificate (REC)	A type of energy attribute certificate, used in the U.S. and Australia. In the U.S., a REC is defined as representing the property rights to the generation, environmental, social, and other non-power attributes of renewable electricity generation.
Renewable Portfolio Standards (RPS)	A state- or national-level policy that requires that a minimum amount (usually a percentage) of electricity supply provided by each supply company is to come from renewable energy.
Residual mix	The mix of energy generation resources and associated attributes such as GHG emissions in a defined geographic boundary left after contractual instruments have been claimed/retired/canceled. The residual mix can provide an emission factor for companies without contractual instruments to use in a market-based method calculation.
Retailer (also retail provider)	The entity selling energy to final consumers, representing final process in the delivery of electricity from generation to the consumer. Also known as electric service provider, competitive power supplier or power marketer depending on the national or subnational regulation.
Scope 1 emissions	Emissions from operations that are owned or controlled by the reporting company.
Scope 2 emissions	Indirect emissions from the generation of purchased or acquired electricity, steam, heat or cooling consumed by the reporting company.
Scope 2 Quality Criteria	A set of requirements that contractual instruments **shall** meet in order to be used in the market-based method for scope 2 accounting.
Scope 3 emissions	All indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions.
Scope 3 category	One of the 15 types of scope 3 emissions.
Self-generation	On-site generation owned or operated by the entity that consumes the power.
Significance threshold	A qualitative or quantitative criterion used to define a significant structural change. It is the responsibility of the company, GHG program to which the company is reporting, or the company's verifier to determine the "significance threshold" for considering base-year emissions recalculation. In most cases the "significance threshold" depends on the use of the information, the characteristics of the company, and the features of structural changes.
Supplier	An entity that provides or sells products to another entity (i.e., a customer). For this guidance, refers to electricity supplier.

Supplier quota — Regulations requiring electricity suppliers to source a percentage of their supply from specified energy sources, e.g. Renewable Portfolio Standards in U.S. states. Regulations generally defined eligibility criteria that energy facilities must fulfill in order to be used to demonstrate compliance.

Supplier-specific emission factor — An emission rate provided by an electricity supplier to its customers, reflecting the emissions associated with the energy it provides. Suppliers offering differentiated products (e.g. a renewable energy product) should provide specific emission rates for each product and ensure they are not double counted with standard power offers.

Supply chain — A network of organizations (e.g., manufacturers, wholesalers, distributors and retailers) involved in the production, delivery, and sale of a product to the consumer.

Tracking system — A database or registry that helps execute energy attribute certificate issuance and cancellation/retirement/claims between account holders in the system. It can track information on certificates or generation occurring throughout the defined system. They are typically tied to geopolitical or grid operational boundaries.

Unbundled — An energy attribute certificate or other instrument that is separate, and may be traded separately, from the underlying energy produced.

Utility — See electric utility.

Vintage — The date that electric generation occurs and/or was measured, from which an energy attribute certificate is issued. This should be distinguished from an energy facility's age (e.g. date that a generating unit commenced operation).

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Recognitions

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Natural resources are at the foundation of economic opportunity and human well-being. But today, we are depleting Earth's resources at rates that are not sustainable, endangering economies and people's lives. People depend on clean water, fertile land, healthy forests, and a stable climate. Livable cities and clean energy are essential for a sustainable planet. We must address these urgent, global challenges this decade.

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