GREENHOUSE GAS PROTOCOL

WORLD RESOURCES INSTITUTE

GHG Protocol Scope 2 Guidance

A supplement to the GHG Protocol Corporate Standard

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TABLE OF CONTENTS

1. Introduction

1.1 The GHG Protocol

The Greenhouse Gas (GHG) Protocol Initiative is a multi-stakeholder partnership of businesses, non-governmental 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 mission of the GHG Protocol is to develop internationally accepted GHG accounting and reporting standards and tools for business, and to promote their adoption worldwide. To date, GHG Protocol has released 4 framework publications that address how GHG emissions inventories should be prepared at the corporate, project, and product levels.

- *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, which itemize the emissions from all of the operations that together comprise a company. Building from the Corporate Standard, the GHG Protocol Scope 3 Accounting and Reporting Standard ('Scope 3 Standard') provides additional guidance and requirements on developing comprehensive inventories of indirect (scope 3) emissions.

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

- *Product*: The GHG Protocol Product Life Cycle Accounting and Reporting Standard ('Product Standard') describes how companies can develop GHG emissions inventories of 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 need for Scope 2 Guidance

The generation of electricity and heat accounts for a significant portion of emissions worldwide (upwards of 30% globally). The provision of electricity contributes greatly to quality of life and economic development. Fossil fuel resources such as coal, oil and natural gas have been the primary energy resources combusted globally, but the need to reduce GHG emissions and other environmental impacts from these resources has spurred governments and businesses to explore low-carbon and renewable energy resources. The entire energy supply chain – including generators, suppliers, retailers, regulators and consumers—have sought new ways to contribute to emission reductions. The *Corporate Standard* stated preferences for source and supplier-specific emission factors, and highlighted the role of green power programs in reducing emissions from energy use[1]. But several important changes occurred since the publication of the *Corporate Standard* in 2004 which have impacted how to account for scope 1 and 2 emissions along the energy supply chain:

[1] See *Corporate Standard* p. 27, 28, 42 and 61.

- **Energy market liberalization and deregulation:** An increasing number of countries worldwide have deregulated or liberalized their electricity markets, creating new opportunities for generators and suppliers to compete for customers or provide products differentiated by both price and environmental qualities. These entities have used contractual instruments, including energy attribute certificates, to validate their product's attribute claims. These instruments also have been used to implement supplier disclosure regulations, increasing the transparency and consistency of the information received by consumers.

- **Increase in supplier energy source quotas and public subsidy:** To help grow renewable energy generation, national and sub-national governments have required suppliers to source an increasing percentage of their supply from specified renewable energy sources. Feed-in tariffs, tax breaks, levy exemptions and direct subsidies to renewable energy have also helped incentivize new project implementation.

- **Increase in distributed generation:** Traditional energy supply chains with centralized, utility-scale generation facilities have been complemented by the growth of smaller-scale renewable energy technologies that can provide on-site energy for the facility owner while selling excess generation to the grid. Facility owners may also sell certificates from that generation to a local energy supplier to meet its energy source quota or to others for voluntary claims.

- **Increase in voluntary renewable energy purchasing:** Motivated by both GHG reduction goals, other environmental commitments and falling costs of producing renewable energy, companies and consumers are choosing renewable energy products from their suppliers or entering into direct contracts with renewable energy generators.

- **Growth in smart grid technology and responsive information:** More real-time information and communication between grid operators and energy consumers has helped guide and in many cases automate consumer decisions on quantity and timing of energy use that reduces costs and better optimizes grid performance.

In total, these are significant changes to both markets and how claims about energy production and use are conveyed through the energy supply chain. Companies calculating scope 2 inventories have raised questions about how to discern whether contractual instruments can convey an emission factor describing their energy use, and what conditions need to be in place to support this calculation. These changes have also sparked conversations regarding the relative merits of treating energy as both a shared collective service bound to the physics of local production and distribution, as well as a product that can be specified by contractual instruments and subject to a degree of supply-and-demand market forces.

The lack of clear and consistent guidance on whether and how to reflect new market products and contractual arrangements in a scope 2 GHG inventory created uncertainty about emission reduction strategies and prevented company inventories from reflecting a true and fair account of emissions. To help corporate inventories fulfill the 5 GHG Protocol principles and to support a range of GHG reduction activities throughout the energy supply chain, the GHG Protocol developed this Guidance as a supplement to the *Corporate Standard.*

1.3 Purpose of this Guidance

This Guidance clarifies the scope 2 accounting methods and reporting requirements for corporate GHG inventories. It is designed to enhance the credibility, consistency and transparency of corporate inventories. The Guidance defines two methods for scope 2 calculation – a location-based method using mostly grid-average emission factor data, and a market-based method which derives emission factors from contractual instruments. It is designed to help companies understand the full impact of their energy use and focus efforts on the GHG reduction opportunities.

To make the market-based method reporting both consistent globally and rigorous, it identifies Quality Criteria based on the minimum features necessary to implement emissions claims through contractual instruments. It also identifies additional reporting information, some required and some recommended, to improve the transparency of company inventories and help stakeholders understand corporate action in the energy supply chain.

1.4 Who should use this Guidance?

Organizations compiling a corporate GHG inventory – including companies, governments, NGOs and other organizations—should use this Guidance. It primarily provides new requirements and guidance for those organizations with operations subject to a market-based method for GHG accounting in the energy sector. The term "companies" is used throughout this document as shorthand for any organization compiling a corporate inventory.

Energy suppliers, utilities and voluntary green power programs providing product information to consumers—particularly emission rate information—should read this Guidance to understand the type of information that customers may be requesting to calculate their scope 2 inventories.

The background provided by this Guidance on market-based consumer claims for energy use can also help policy makers understand the relationship between energy attribute instruments used for regulatory compliance and those used in voluntary markets, as well as what Quality Criteria are necessary to support consumer claims. The market-based method accounting framework works for any national, sub-national or regional jurisdiction, responsive to the fundamental policy decisions made by regulators and other national authorities.

1.5 How was this Guidance developed?

This Guidance represents a collaborative solution to fulfill GHG Protocol principles in response to a changing energy supply chain and market. It was developed over several years of international consultation and discussion with participation from businesses, government agencies, NGOs, and academic institutions from around the world. In December 2010, WRI and WBCSD launched this process through a series of workshops in Washington DC, London, and Mexico City based around short discussion drafts. A Technical Working Group (TWG) was formed consisting of approximately 50 active members (representing energy industries, renewable energy certification programs, energy utilities, companies, GHG reporting programs and other industry groups worldwide). Through a series of discussion papers and proposals, the TWG analyzed underlying concepts in energy attribute tracking, consumer claims, evaluating reductions in the electricity sector, the role of policy neutral GHG accounting guidance in a highly policy-sensitive context, among other topics.

To be continued after public comment

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

This Guidance provides new requirements for scope 2 consistent with the boundaries, concepts and methods outlined in the *Corporate Standard*. The *Scope 3 Standard* intersects with scope 2 at several points: the Scope 2 Guidance impacts how companies will communicate their scope 2 emissions to other supply chain partners downstream, and it impacts how a company assesses the upstream emissions associated with its energy use (category 3, scope 3). In both cases, a company must disclose whether a market-based or location-based scope 2 total is used as the basis for calculating category 1, scope 3 and is shared with customers or others in the value chain for the calculation of their scope 3 emissions.

1.7 What does this Guidance not address?

This Guidance does not address non-GHG accounting aspects of energy policy, markets or contractual instruments, including larger questions of policy cost-effectiveness or equity amongst consumers. It does not attempt to identify what should constitute "green" energy or what certificate programs, suppliers or policy makers should include as "eligibility criteria" in their respective programs (though any instruments intended for consumer scope 2 claims are required to meet this Guidance's Quality Criteria).

1.8 Which parts of the Guidance should I read?

What should I consider when setting out to account for and report scope 2 emissions?	Ch. 2
In short, what are the new changes and requirements for scope 2 accounting and reporting?	Ch. 3
How do I determine what energy uses should be included in the scope 2 boundary?	Ch. 5
What is the background on the use of contractual instruments in tracking energy attributes?	Ch. 6
What is the relationship between "voluntary" purchases and instruments used for mandatory compliance? (ch. 6)	Ch. 6
How can I direct my contractual purchasing to drive change in low-carbon energy supply over time?	Ch. 6
What types of decisions can I make to contribute to emissions reductions in the energy sector?	Ch. 6
What are the two methods for scope 2 calculation?	Ch. 7
What is the location based method?	Ch. 8
What is the market-based method?	Ch. 9
What are the criteria that instruments must meet to be used as emission factors in the market-based method?	Ch. 9
What else should I disclose about my purchases?	Ch. 9 and Ch. 11
How do I perform calculations according to both methods?	Ch. 10
How do I evaluate the data quality of emission factors used in either method?	Ch. 10
What are the new reporting requirements for scope 2?	Ch. 11
How do I show changes over time under both methods?	Ch. 12
How do I set or track goals under one or both methods?	Ch. 12

What are the energy attribute tracking systems used today across the world?	Appendix A
What is the relationship between offsets and energy attribute instruments?	Appendix B
What are the differences between different methods and boundaries for evaluating reductions in the energy sector?	Appendix C
What are the basic steps that data providers take to calculate a residual mix?	Appendix D

2. BUSINESS GOALS

2.1 Business goals of a scope 2 inventory

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 may seek to:

- *Identify and understand risks and opportunities associated with energy purchase and use;*
- *Identify 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.*

2.2 Identify and understand risks and opportunities associated with energy purchase and use

Each of the two methods for calculating scope 2 reflects a different dimension of risk. Some examples of GHG-related risks and opportunities related to scope 2 emissions are enumerated in Table 2.2 and 2.3.

Reporting according to **both** methods better reflects the full range of risks and opportunities associated with energy use. Some risks are more aligned with emissions from local production trends (such as grid stability and the need for "balancing" generation or spinning reserves), while others align with contractual rights and obligations in the market. With market-based method scope 2 accounting, companies have an opportunity to distinguish the actions they have taken based on the choices available in their market.

The risk of misleading claims about emissions, or other attributes from contractual instruments, can be significant. Companies who overstate the impacts or role of their purchases in driving change may be subject to backlash from consumers or environmental advocates. On the other hand, many contractual instruments convey legally-enforceable rights and claims that can affect how a company describes its purchases. Companies claiming attributes about their energy use without ownership of appropriate instruments may face legal action. Transparent dual reporting and adherence to a globally credible standard can strengthen risk assessments and provide critical information for stakeholders to understand the nuances of corporate energy strategy, procurement and consumption.

Table 2.2. Examples of GHG-related risks related to scope 2 emissions

Regulatory	GHG emissions-reduction laws or regulations introduced or pending in regions where the company, its suppliers, or its customers operate
Energy costs and reliability	Suppliers passing higher energy- or emissions-related costs to customers; energy supply chain business interruption risk
Product and technology	Decreased demand for products with relatively high GHG emissions; increased demand for competitors' products with lower emissions and resulting impact on costs and availability
Litigation	GHG-related lawsuits directed at the company or an entity in the value chain
Reputation	Consumer backlash, stakeholder backlash, or negative media coverage about a company, its activities, or how it has described its electricity emissions.

Table 2.3. Examples of GHG-related opportunities related to scope 2 emissions

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 product design.
Increase sales and customer loyalty	Low-emissions goods and services are increasingly more valuable to consumers, and demand will continue to grow for new products that demonstrably reduce emissions throughout the energy supply chain.
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.
Company differentiation	External parties (e.g. customers, investors, regulators, shareholders, and others) are increasingly interested in documented emissions reductions. A scope 2 inventory is 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

A comprehensive scope 2 inventory should serve as a consistent basis to set reduction targets progress towards them over time. Companies have used 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. Each method's scope 2 total can provide an important indicator of performance and show the context in which emission totals are changing. For instance, companies who undertake efficiency improvements that decrease energy demand will likely see their location-based method total decrease, and will also cut costs. Less energy usage also mean fewer certificate purchases or money spent towards green power premiums, where available.

Transparent reporting also allows for a more consistent comparison of performance over time and comparison with other reporting companies. This Guidance's framework addresses and prevents double counting between scope 2 inventories by method, improving the accuracy of reported results and ensuring every company can make progress towards its goals without double counting the purchases claimed by another company reporting by the same method.

2.4 Engage energy suppliers and partners in GHG management

Reducing emissions from the energy sector requires the participation of all entities in the supply chain –generators, suppliers, retailers and consumers. The two method outlined in this Guidance can help consumers engage with their energy supply 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 an appropriate site, 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. Each of those different roles carries a GHG accounting and reporting implication based on organizational and operational boundaries (e.g. the scopes), and a scope 2 inventory can help 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: on the one hand, any consumer using grid-distributed energy contributes to local demand and GHG impact, but the market for energy attribute claims works in tandem to allocate emission attributes to those consumers demanding specified energy sources. Reporting a single figure under either method could neglect critical information necessary for assessing corporate performance.

3. Summary of Changes and Reporting Requirements

This Guidance defines and distinguishes two accounting methods that the *Corporate Standard* implicitly references by way of their emission factors*:* a location-based method and a market-based method. It reflects a modification of the *Corporate Standard's* accounting and reporting requirements for scope 2, applicable to companies with operations in markets with choice in electricity product or supplier. Conformance with the *Corporate Standard* will require conformance with this Guidance.

3.1 Terminology: shall, should, may

This standard uses precise language to indicate which provisions of the standard are requirements, which are recommendations, and which are permissible or allowable options that companies may choose to follow. The term **"shall"** is used throughout this standard to indicate what is required in order for a GHG inventory to be in conformance with the *GHG Protocol Scope 2 Guidance*. 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 in the standard. "Needs," "can," and "cannot" may be used to provide guidance on implementing a requirement or to indicate when an action is or is not possible.

3.2 Summary of new accounting and reporting requirements

For companies with operations in markets *with* choice in electricity product or supplier: (see chapter 6, 9)

- Companies **shall** report scope 2 in two ways: one total based on the location-based method, and one total based on the market-based method where applicable and Quality Criteria are met.

- Companies **shall** ensure that contractual instruments used in the market-based method meet the Quality Criteria outlined in this Guidance. A statement shall be made by a 3rd party ensuring that these Criteria have been met, or a reference given to the certification program which has verified conformance with the Quality Criteria

- Companies **shall** disclose the relationship between energy attribute certificates used in the market-based method and compliance instruments present in the same market.

- Companies **shall** identify which scope 2 total – location-based method or market-based method – serves as the basis for goal setting and for scope 3 data uses.

- Companies **should** disclose key features about their contractual instruments for added transparency about the context of the procurement choices

- Companies **may** report avoided emissions from projects or actions separately from the scopes using project-level methodology.

For companies with operations in markets without choice in electricity product or supplier

Only one scope 2 total will be reported based on the location-based method. For most companies using the *Corporate Standard,* this represents no change in methodology or reporting.

For all companies

- All existing *Corporate Standard* reporting requirements **shall** be followed (see chapter 9 of the *Corporate Standard)*

- Companies **should** report energy consumption separately from the scopes (in kWh or MWh's), and **should** report on data quality using best practice data quality indicators (see chapter 10 of this Guidance)

4. ACCOUNTING AND REPORTING PRINCIPLES

GHG accounting and reporting a fair and true scope 2 inventory 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

The primary function of these five principles is to guide the implementation of the GHG Protocol Scope 2 inventory and the assurance of the scope 2 inventory, particularly when application of the standard in specific situations is ambiguous. Companies may encounter trade-offs between principles when completing an inventory and should strike a balance between these principles, depending on their individual business goals.

Trade-offs will be particularly common in relation to accuracy. A company may find that achieving the most complete inventory requires the use of less accurate data, compromising overall accuracy. Conversely, achieving the most accurate inventory may require the exclusion of activities with low accuracy, compromising overall completeness.

5. IDENTIFYING SCOPE 2 EMISSIONS AND SETTING THE SCOPE 2 BOUNDARY

This chapter describes the sources of scope 2 emissions (operational boundary) and how to establish the scope 2 boundary under different generational and distribution models

5.1 Organizational boundaries

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

5.1.1 Leased assets

Energy use in leased buildings or from leased electricity generation assets can be a significant emissions source. Determining the entity who owns, operates or exerts control over certain leased assets is critical in determining whether the assets' emissions are included in the inventory boundary and how they are categorized in scope 1, 2 or 3.[2]

All leases confer operational control to the lessee or tenants, unless otherwise noted.[3] Therefore, if a company is a tenant in a leased space or using a leased asset applies the operational control approach, any energy purchased or acquired from another entity (or the grid) must be tracked in scope 2. If a tenant they can demonstrate that they do not exercise operational control in their lease, they must 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 excluded or included in scope 3. For more information on organizational boundaries, see *The Corporate Standard,* Chapter 3: Setting Organizational Boundaries and Appendix E at www.ghgprotocol.org.

5.2 Operational boundaries

After a consolidation approach has been chosen and applied consistently across the inventory, companies can identify emissions from included sources. The *GHG Protocol 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 1, scope 2, and scope 3 are mutually exclusive for the reporting company, such that there is no double counting of emissions between the scopes. In other words, a

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[2] See Corporate Standard, p. 31

[3] 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.

company's scope 2 inventory does not include any emissions already accounted for as scope 1 or scope 3 by the same company. By properly accounting for emissions as scope 1, scope 2 and scope 3, companies avoid double counting within scope 1 and scope 2. (For more information, see the *GHG Protocol Corporate Standard*, chapter 4, "Setting Operational Boundaries.")

While a company has control over its direct emissions, it has *influence* over its indirect emissions. 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.

5.3 Defining scope 2

Scope 2 is defined as an indirect emission category that includes GHG emissions from the generation of purchased or acquired electricity, steam, heating or cooling consumed by the reporting company"[4]. GHG emissions from energy generation occur at discrete sources owned and operated by generators who track the generation emissions in their scope 1 inventory. Scope 2 includes emissions from generation only; other upstream emissions associated with the processing of upstream fuels, or transmission or distribution of energy within a grid, are tracked in scope 3, category 3.

5.3.1 Forms of energy use tracked in scope 2

At least four types of 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, and certain types of heating and cooling systems.

Heating: 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 heating or thermal combustion processes (as with a boiler or a thermal power plant).

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

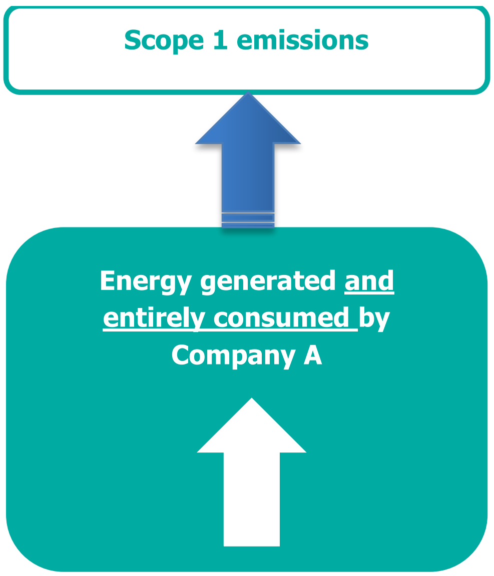
Steam: Formed when water boils, steam is a valuable energy source for industrial processes that use it for mechanical work.

5.4 Energy production and distribution

Once energy is generated, it is either consumed onsite or distributed to another entity. Energy can be distributed from one entity to another through a variety of means. These means can affect how the emissions from the generation of the energy are categorized (scope 1 and 2) and reported by different entities. The following scenarios outline the broad categories of energy production and distribution:

[4] *Corporate Standard,* 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.

Figure 5.1: Energy production and consumption from owned/operated generation



5.4.1 The same reporting entity produces and consumes energy:

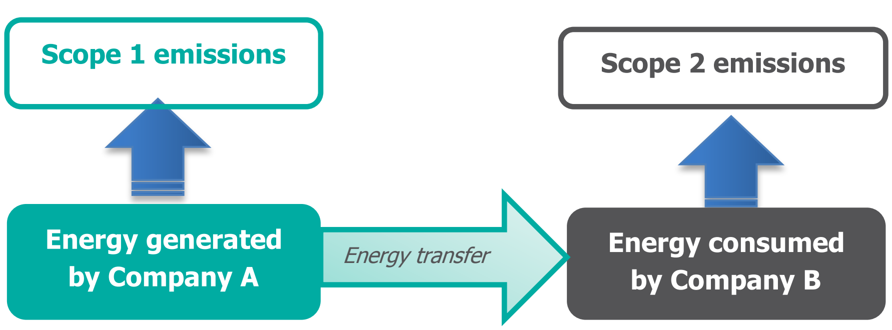
If energy is produced and consumed by the same entity (with no grid connection or exchanges), no scope 2 emissions are recorded, as any emissions occurring during the power generation are already recorded in scope 1. This may be the case for large industrial facilities that generate their own heat/steam/electricity on-site in owned/operated equipment. Companies should still separately record the total quantity of energy consumption in kWh or MWh's (see chapter 11 on reporting requirements and recommendations). This separate reporting also maintains transparency about the consumption vs. production activities of a company, which can become obscured as companies engage in both activities in differing arrangements. See Figure 5.1.

5.4.2 Different reporting entities producing and consuming energy:

Scope 2 emissions are recorded when a company obtains its energy from another entity, or sells an energy tracking and claims instrument from owned and consumed generation (see chapter 9 on the Market-based method). This energy distribution can occur through at least two means:

- ***Direct line*** (Figure 5.2): In this example, energy production is fed directly and exclusively to a single entity – here, Company B. This applies to direct lines between certain industrial facilities owned or operated by different parties, or to energy produced within a building (boilers, on-site solar) and sold to a separate party like a tenant. If all the energy generation is purchased and consumed, then Company B's scope 2 emissions will be same as Company A's scope 1 emissions.

Figure 5.2: Direct line energy transfer. Energy production at Company A, consumed directly by Company B

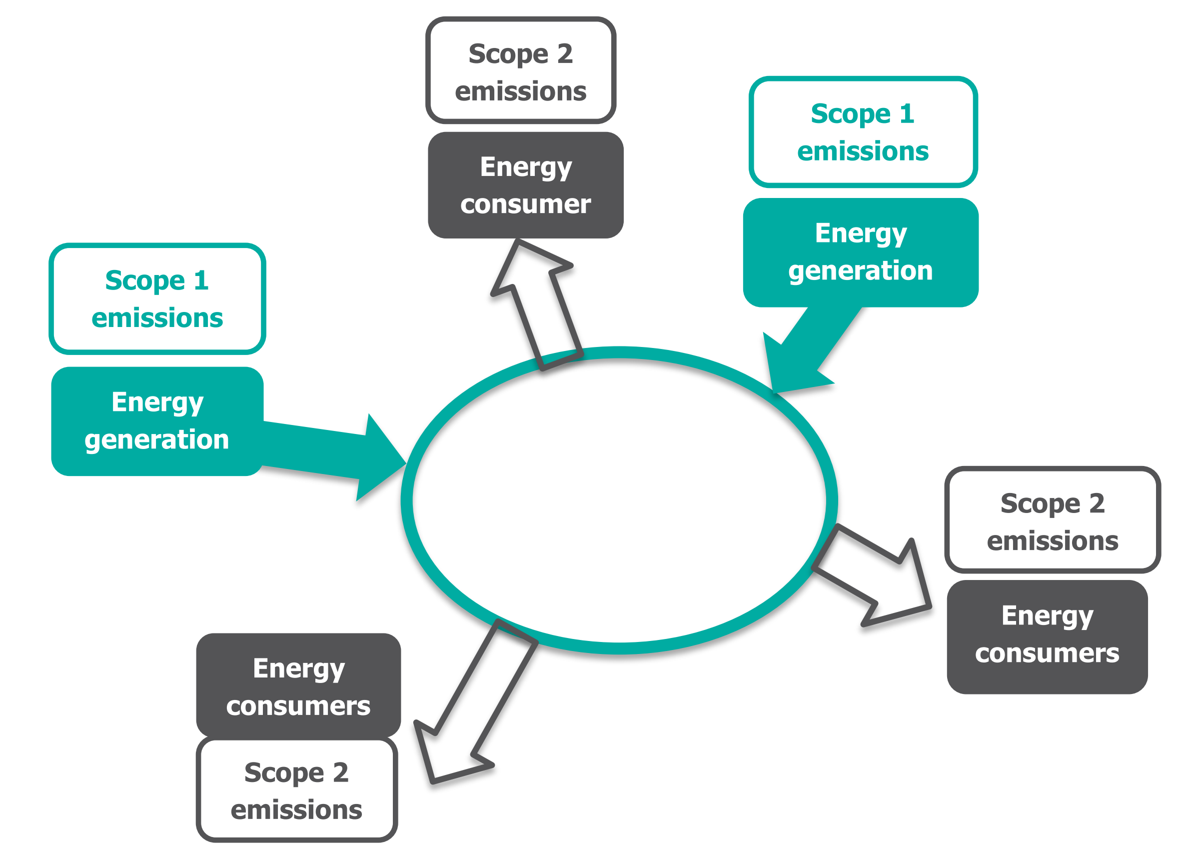


Leased assets: There may be cases where electricity is not transmitted through the grid, but is consumed wholly on-site and owned/operated by a separate entity, as with a rooftop solar panel that is owned by a 3rd party but leased to building owner or manager. The energy consumed from the energy generation unit should be considered scope 2 for the consumer since the energy is purchased or acquired from a separate entity.

Any third party financing institution that may own but not operate the energy generation unit would not account for any emissions from energy generation under the operational control approach.

- ***Grid distribution*** (Figure 5.3): Perhaps the most prominent means of conveying energy to consumers is through a shared distribution network called a grid. Depending on the grid, there may be a few central generation facilities providing energy to many consumers, or, there may be multiple generation facilities potentially representing different technology types (thermal power using coal or natural gas inputs, or wind turbines, solar photovoltaic cells or solar thermal, etc.). 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.

Figure 5.3 Grid-distributed energy, with multiple separate producers and consumers



Energy on the grid moves to the nearest point of use, and multiple regions can exchange power depending on the capacity and needs of these regions. Grid-distributed energy demonstrates several unique features, including:

- It can be defined as both a product and service
- It is distributed in real-time with limited storage
- Its distribution is limited geographically to a region defined by infrastructure and demand
- Decisions on deployment of different resources is made by grid operators or utilities, not individual consumers

5.4.3 The energy supply chain

The mechanics of energy distribution on any grid function largely the same way, and in all cases customers work with a utility or supplier to pay their energy bill and receive energy for their operations. But different regulatory structures at a regional, national and sub-national level can influence what entities are involved throughout the phases of energy generation, transmission, distribution and service. In order to determine which entities should account for which emissions, these structures should be clearly identified and mapped. Two primary energy structures that can differ slightly in accounting treatment include regulated and deregulated markets. Figure 5.4 represents a basic, regulated market where the utility represented in the diagram both owns the transmission and distribution infrastructure, and interfaces with the consumer to deliver energy. The consumer tracks the energy lost in this T&D process in scope 3, along with other upstream emissions in any fuel extraction and processing performed prior to energy generation.

Figure 5.4 Energy supply chain diagram

Box [5.5] Accounting for emissions from the production, transmission, and use of electricity

Figure [5.4] Emissions across an electricity value chain

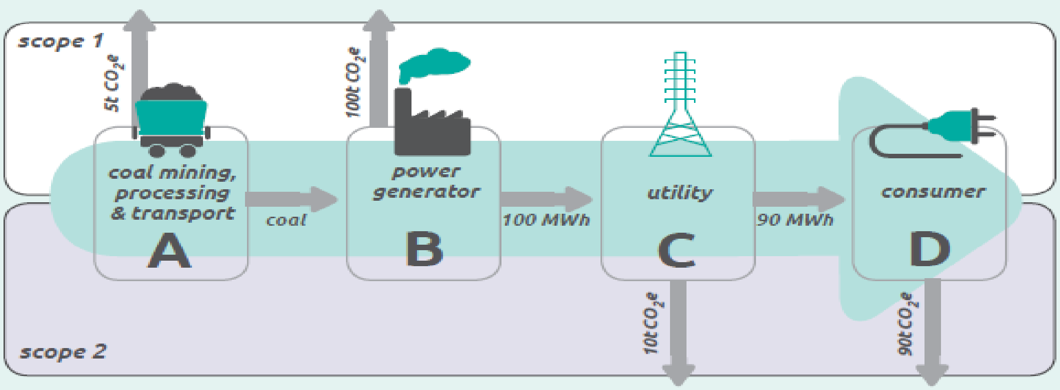


Figure 5.4 illustrates an electricity value chain. A coal mining and processing company (A) directly emits 5 metric tons of CO_2e per year from its operations and sells coal to a power generator (B), which generates 100 MWh of electricity and directly emits 100 metric tons of CO_2e per year. A utility (C) that owns and operates a T&D system purchases all of the generator's electricity. The utility consumes 10 MWh due to T&D losses (corresponding to 10 metric tons CO_2e of scope 2 emissions per year) and delivers the remaining 90 MWh to an end user (D), which consumes 90 MWh (corresponding to 90 metric tons CO_2e of scope 2 emissions per year).

Table 5.6 explains how each company accounts for GHG emissions. In this example, the emission factor of the electricity sold by Company B is 1 t CO_2e/MWh. All numbers are illustrative only.

In reality, grid-distribution systems can support electricity produced from many generation sources, which then become commingled. In deregulated markets, one difference can be that one entity may own the T&D equipment, another – an energy supplier or retailer—competes to sell the energy to customers. Because these entities purchase and sell, but do not produce or consume the energy, they therefore do not record either scope 1 or scope 2 emissions. See Appendix A of the *Corporate Standard* for more information on these relationships.

While deregulated markets may allow consumers to choose their supplier, consumers in a regulated market may still have a choice of energy *product* from their utility.

5.4.4 *Distributed generation and consumption (Figure 5.5):*

This model of generation and distribution illustrates how consumers on the grid may also function as producers by owning, operating or hosting distributed energy generation sources such as on-site solar panels or fuel cells. This is termed "distributed generation" as it consists of smaller generation units installed on-site across decentralized locations, as opposed to utility-scale centralized power plants. At certain times of the day, a distributed energy source might produce more energy than is consumed on-site, and this surplus energy is fed back to the grid. Suppliers in many markets have established the price by which the owners of the energy facility are compensated for their energy sales to the grid. At other points in the day, on-site demand for energy may exceed the on-site supply, and additional energy is purchased and consumed from the grid. The owners/operator of a single site may therefore have both scope 1 emissions from energy generation as well as scope 2 emissions from energy purchased from the grid.

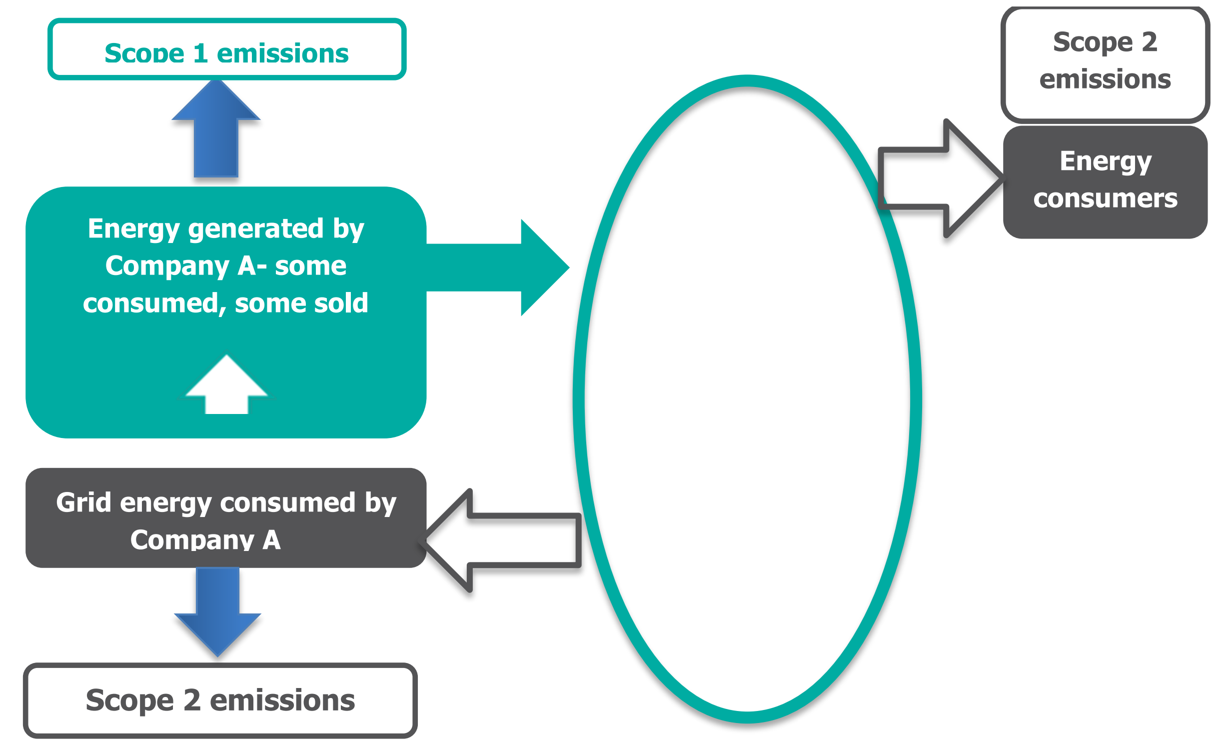
5.4.4.1 Determining activity data

Many markets utilize "net metering" to assess the energy consumption for which the distributed facility is responsible, allowing grid purchases to be measured only as net of production. While this can influence how cost is assessed, companies should seek to report total gross energy consumption (in kWh or MWh's) as separate reporting. This will be a combination of energy supplied by the on-site distributed source as well as purchases from the grid. Disclosure of this gross amount provides greater transparency regarding the total energy demand incurred by the company.

In theory, *all* grid purchased energy should be considered activity data for scope 2 – not just *net* energy purchases. However, many distributed sources and arrangements are "behind the meter," meaning that they have not been considered a grid resource tracked in grid average emission factors[5]. Therefore, due to a low chance of double counting, a net consumption quantity can be used as the basis for scope 2 activity data.

[5] Owners of energy facilities who want to sell certificates (voluntary or compliance) must register with tracking systems in order to be issued RECs. In addition, some states require that they register as a condition of receiving a subsidy. In these cases, two meters may be required.

Figure 5.4. Distributed generation (production, consumption, grid sales)



5.4.4.2 Energy attribute certificate sales

If energy attribute certificates are produced from the distributed energy source and sold off, the company can no longer consider their consumption from the distributed source to be from owned/operated sources. Instead, because the emission rate claims have been sold off to another entity, the consumer should apply a residual mix or grid average emission factor to the energy consumed on-site. Retaining certificates enables the company to prove consumption from the distributed source is supported by the specified source.

5.5 Accounting for upstream emissions in scope 3

Emission factors in this Scope 2 Guidance are *generation only*. When electricity is transmitted from a power plant to customers, a percentage of the generation is lost in the process and therefore the actual amount of electricity generated will be higher than the electricity consumed by customers alone. Consumers should account for these transmission and distribution losses in scope 3, category 3 – emissions from Fuel- and energy related Activities (not included in scope 1 or scope 2). As shown in Figure 5.4, this category also includes emissions from fuel extraction and processing prior to its combustion.

Making decisions between different electricity choices, it is important for customers to take into account not only the electricity generation captured in scope 2 but also the T&D losses captured in scope 3.

Companies shall disclose which scope 2 calculation method – location-based or market-based –serves as the basis for this scope 3 calculation, as well as which method's total is reported to downstream supply chain partners for their own emissions calculation for other scope 3 categories.

6. BACKGROUND ON ENERGY ATTRIBUTE TRACKING IN THE ELECTRICITY SECTOR

This chapter provides an overview of how different contractual instruments have been used in markets worldwide to track and convey energy attributes along the energy supply chain for a different of purposes. This practice underlies the Market-Based Method for scope 2 calculation, described in Ch. 9.

6.1 Introduction to energy attribute tracking

Energy generated and distributed in a grid system becomes indistinguishable once on the grid. But suppliers and consumers increasingly have demanded information about the *sources* producing that energy and attributes about the generation, such as GHG emissions, local air pollutants, nuclear waste risks, etc. Contracts between generators and suppliers have long been used for energy delivery transactions; by extension, many countries have developed a range of *contractual instruments* that convey attribute claims about energy at its point of production for use by suppliers and consumers. Not all instruments are explicitly designed for consumer claims; for example, some instrument may constitute only proof of generation and contain no attribute claims. But many instruments have indeed been designed so that attributes in the instrument can be translated a set of claims that owners of the instrument can make. When applied to a matching quantity of electricity delivery or consumption, these attribute claims serve as a means of "labeling" the consumed electricity. Contractual instruments providing emission factors for the market-based method must meet Quality Criteria to ensure their appropriateness for this purpose.

6.1.1 Contractual instruments.

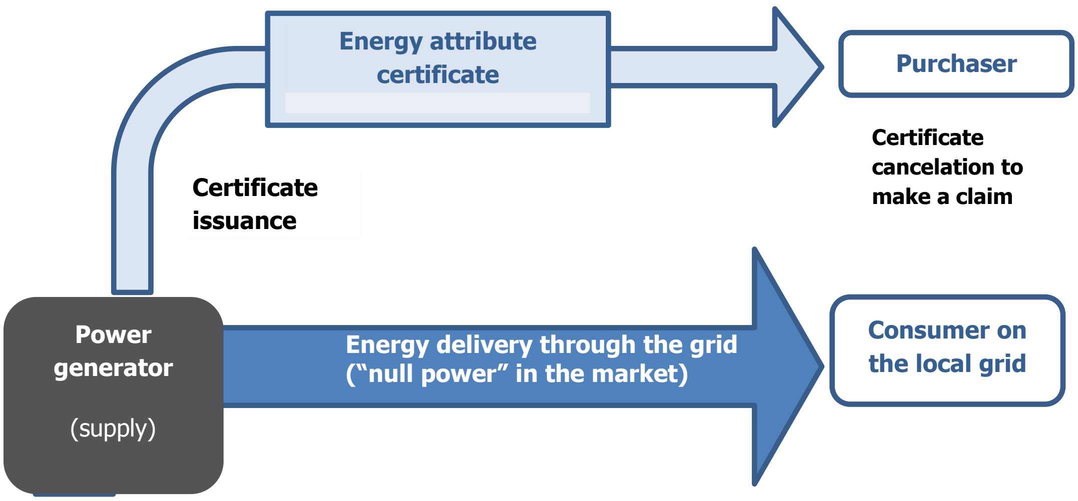
For this Guidance, a contractual instrument can be any type of contract between two parties for the purchase of energy or conveyance of attribute claims from that energy. This represents a broad category that can include power purchase agreements (PPAs), supplier-specific information, or energy attribute certificates.

6.1.2 Energy attribute certificate ("certificates").

Energy attribute certificates are a category of contractual instrument that tracks certain information (or attributes) about the energy generated but does not represent the energy itself (see Figure 6.1). This category includes instruments which may go by several different names, including certificates, tags, credits, etc. For the purpose of this Guidance, the term "energy attribute certificates" or just "certificates" will be used as the overarching concept for all these different designations. Most certificates have only been issued from renewable energy generation, but it is possible for any and all energy generation's attributes to be tracked via certificates.

Certificates are issued for each unit of generation, tracked in a registry or other accounting system, and retired or canceled once a claim has been made or the final purpose for the certificate has been fulfilled. They are a type of contractual instrument and can be combined (or 'bundled') with other types of instruments such as a contract for energy, or supplier products. Certificates can be canceled, claimed or redeemed directly by consumers or through energy suppliers who procure them on behalf of customers. See Appendix A for a listing of tracking systems that help support certificate claims/cancelation.

Figure 6.1 Energy attribute tracking certificate flows



6.2 Certificate uses and program goals

Certificates have fulfilled a variety of regulatory and voluntary purposes in the electricity sector, including for programs such as supplier fuel mix and environmental disclosure, supplier energy source quotas, tracking receipt of public subsidy or tax/levy avoidance, and voluntary programs supporting consumer energy purchasing. It is possible for a certificate designed for any of these purposes to be used for GHG accounting, if it meets Quality Criteria (see chapter 9).

Understanding the differences in program design is important to understanding the differences between certificates and how they may be used. Most programs can be analyzed according to the program design questions in Table 6.1.

Table 6.1. Energy attribute certificate program design elements

1. What is the objective of the certificate program?
2. Who is implementing the program (certification bodies, policy makers)?
3. What, if any, registries are used for tracking and retiring of certificates or other instruments?
4. What type of generation facilities are eligible for certification in the program? (Eligibility criteria)
• *What energy resource types or technologies are accepted? Excluded?*
• *What age of facilities?*
• *In what geographic region(s) are energy facilities eligible, or is energy delivery required to a specified region?*
• *Other factors?*
5. What is the relationship between voluntary uses of the certificate and other programs in the jurisdiction? Some variations include: • *Voluntary instrument required to be above and beyond compliance quotas* • *Voluntary instrument can be combined with retired compliance instrument* • *Voluntary instrument not surplus to compliance instruments – multiple instruments may exist for each MWh*
6. Who can procure certificates? (e.g., certain suppliers, or directly by consumers?)

6.2.1 Supplier energy source quotas

To help incentivize growth in renewable energy resources, some nations or sub-national entities have established supplier energy source quotas and used energy attribute tracking certificates as the means of demonstrating compliance. Suppliers not in compliance often pay a fine or fee.

In Europe, national renewable energy targets are formulated as a percentage of national production compared to actual (physical) electricity consumption. Guarantees of Origin have generally not been used in fulfillment of national targets.

Supplier energy source quotas in the US and EU

In the US, individual states have established Renewable Portfolio Standards (RPS) that require a minimum percentage of supply to be sourced from qualifying renewables that the policy identifies. For example, California has a goal to increase its renewable portfolio to at least 20% by the end of 2010 with a goal of 33% by end of 2020. Policies identify what types of generation can achieve compliance (i.e., producing certificates that suppliers can use to demonstrate compliance). Policies can also identify a portion of the overall goal that must be met with specific resources (called a "carve out"), such as solar power.

However, in the case of Sweden and Norway, a joint regulatory target has been established. Both countries' suppliers are required to acquire El-cert certificates based upon the amount of electricity they supply to consumers. El-certs are issued at the point of generation, to prove a certain quantity of qualifying renewable energy has been produced. If suppliers in either country have more renewable production (compared to what they supply) then they have excess El-Cert certificates that they can sell to other suppliers with a deficit.

6.2.2 Tracking tax/levy exemptions

In the UK,[6] non-residential or non-domestic users – primarily large commercial or industrial energy users—are taxed for their energy use. Renewable energy, certain combined heat and power plants, and electricity produced from coal mine methane are exempt from the tax. Renewable energy generation facilities can issue Levy Exemption Certificates (LECs) which suppliers must acquire on behalf of their non-domestic customers to avoid the tax (evidence submitted to HM Revenue & Customs).

6.2.3 Supplier disclosure

In some markets, energy suppliers may be required to disclose to consumers the fuel mix and related environmental attributes associated with delivered supply.Suppliers may also disclose an emission rate associated with voluntary programs such as green power products or other differentiated product offerings.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.

6.2.3.1 Regulatory disclosure requirements

By example, the European Union has instituted requirements[7] 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 to

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6 See more at http://greenenergyscheme.org/index.php?page=about/tier3

[7] See 2003/54/EC and 2009/72/EC

calculate and disclose the energy source and attributes associated with supply, though the implementation and use of GO systems varies by member state.

In Japan, power suppliers are obligated to report their emission factors to the Japanese government, and the government evaluates and publishes the emission factors. Certificates have been used for supplier energy source quotas and voluntary green power programs.

6.2.3.2 Calculation methodology

The methodology used to calculate the GHG emission rate associated with a supplier's mix is specified by the regulation or other industry standards such as the Climate Registry Electric Power Sector Protocol. Suppliers should calculate an emission rate based on a combination of owned assets, purchased power and any other contractual instruments acquired on behalf of customers. See chapter 10 for more information on calculation methodology.

6.2.4 Voluntary programs

Around the world, energy attribute certificates have been used as a means for consumers to voluntarily purchase and claim the attributes associated with specific energy sources such as renewables. Such programs seek to both enhance consumer product choices and voluntarily leverage demand to increase the share of renewables on the grid over time. In the US, voluntary RECs can be obtained directly by a consumer ("unbundled" from energy purchases), through a supplier program, or "bundled" in a contract such as a PPA. In the EU, the GO (rooted in disclosure laws) have also been used for voluntary purchases and claims, but the eligibility criteria generally

6.3 Relationship between voluntary and regulatory instruments

Markets have defined the relationship between compliance instruments and voluntary contractual instruments in different ways. Companies may be asked whether their voluntary renewable energy purchase represents energy that is "surplus to" what suppliers may be already required to source, or whether the purchase has an impact on emissions in a capped power sector. A few key relationships between voluntary and regulatory programs are highlighted below.

1. Relationship to supplier quotas (compliance instruments)

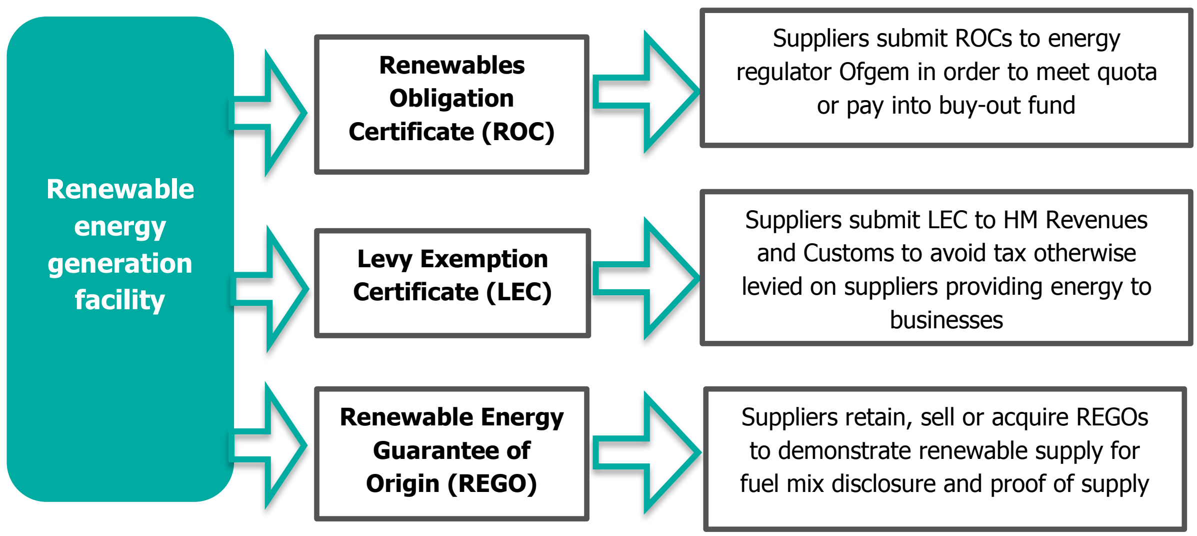
In the US following the Green-e national standard[8], only one renewable energy certificate (REC) is generated from a given MWh, to be used for either compliance or voluntary purposes (but not both). If that REC meets eligibility criteria for a supplier's quota, it may be purchased and used by the supplier to demonstrate compliance or the REC can be used for voluntary purchases. This means that renewables purchased on the voluntary market can only be claimed by the purchaser, not the state or the utility with RPS obligations to meet.[9]

[8] See Green-e National Standard Version 2.3, *http://www.green-e.org/docs/energy/Appendix%20D_Green-e%20Energy%20National%20Standard.pdf*

[9] Ibid.

But in some markets (e.g., the UK) compliance instruments have not conveyed energy attribute claims, and instead multiple instruments or certificates issued from the same MWh can fulfill different purposes (see Figure 6.2), including energy source quotas as well as levy exemption and fuel mix disclosure. Therefore, to ensure transparency and clear understanding, companies using voluntary contractual instruments must disclose the type of relationship between that contractual instrument and regulatory compliance instruments, if they exist. In the EU, Directive 2009/28 notes that GO's are explicitly not intended to have an effect on target compliance.

Figure 6.2 Multiple certificates issued from a single MWh



Voluntary certificates used in the market-based method should achieve "regulatory surplus,"[10] meaning that they are in addition to energy suppliers are required by regulation to source. See chapter 11 for reporting on this relationship.

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 prior to any individual use. For instance, in Germany if a generation facility receives subsidies, then a GO must be created and canceled immediately on behalf of the German consumer. The rationale is that the German consumer has paid for the energy through taxes, and should therefore collectively own the attributes. Similarly in Japan, once renewable electricity that receives a FiT is sold to utilities, voluntary green energy certificates cannot be issued.

Companies **should** disclose their use of any contractual instruments from generation facilities that receive a public subsidy.

[10] This can 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.

3. Relationship to cap and trade programs

In emissions-capped power sectors, renewable energy generation is incentivized through creating a limit (cap) on fossil-fuel emissions. However, voluntary renewable energy purchases (as well as other actions such as efficiency upgrades or energy conservation) may not contribute as directly to reducing system-wide emissions in ways that are expected in non-capped regions. Because the total system's emissions have been pre-determined by the cap, many have noted that these actions simply "free up" allowances for other emitters to acquire, resulting in no net GHG reductions. This means consumers cannot claim that their purchase resulted in emission reductions; only by retiring allowances would electricity consumers be able to support that claim. Consumers may see their purchase of a certificate as effectively subsidizing electricity generating companies.

Allowance set-asides: To maintain support for voluntary renewable energy purchases, many states participating in the US Regional Greenhouse Gas Initiative (RGGI) and the California cap and trade program have designated that a small portion of total emission allowances be set aside and retired on behalf of voluntary REC 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.

Contractual instruments can still convey emission rate claims under an emissions-cap (e.g., renewable energy still produces zero emissions/MWh). To increase transparency about the relationship between the purchase and cap-and-trade policies, 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 contractual instrument. The tons of GHG emissions represented in any retired allowances should be reported separately. This Guidance does not recommend treating retired allowances 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.[11] 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).

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

6.4 Using voluntary purchases to increase low-carbon energy supply throughout a market

Many voluntary certificate programs have been designed with a goal of leveraging voluntary consumer demand to increase the supply of low-carbon energy based on a market model of aggregate supply and demand. Certificates serve as a market for the attributes of energy and the ability to claim them, separate from the transactions for underlying energy flows. The market for energy attributes is based on a set of finite attributes from energy generated within a defined period. Because it is finite, a claim is made *at the expense of others* who must in turn "take on" the remaining (typically more GHG-intensive) attributes of the unclaimed energy. If demand for low-carbon energy exceeds existing supply, the pressure or incentive to build additional supply grows, with certificates serving as an additional revenue stream to help signal that demand.

However, labeling electricity and establishing a system for claims may *or may not* result in demonstrable change in supply; it is intended to reflect an allocation of consumer preferences as determined by the market. Labeling alone may not necessarily result in new low-carbon energy. For instance, one study[12] suggests that the voluntary REC market in the US, 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 indicates that the effect of voluntary demand on new renewable energy project development is not based on the *price* of RECs so much as it is on the presence of long-term contracts for RECs and energy from projects as yet unbuilt (see Box 6.1)

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**.** However, this Guidance also aims to support the larger mission of GHG reduction activities throughout energy supply chains. It views the market-based method not only in terms of *individual consumer choices* about suppliers, contracts or *individual instruments* but how the market can *in aggregate* change global GHG emissions.

To that end, there are several approaches to using a market-based energy attribute tracking system to grow low-carbon energy supply:

1. This Guidance: This Guidance supports the voluntary demand-driven supply change through several means:

- *Requiring market-based method reporting:* By requiring all companies to report scope 2 according to the market-based method where applicable, more major consumers transparently document their market-based footprint and demonstrate actions taken

- *Recognizing a range of contractual instruments:* In many markets, new projects have been supported by supplier investments in new technology, as well as direct long-term PPAs. Supplier-specific emission rates and contracts (or contracts bundled

[12] Gillenwater, M., Lu, X. & Fischlein, M. Additionality of wind energy investments in the U.S. voluntary green power market. Renewable Energy 63:452–457 (2014)

Box 6.1. Strengthening the role of RECs

A recent publication by the US National Renewable Energy Laboratory (NREL)* noted that there are several ways that purchasers, marketers, and policymakers that 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 decisions.
- Increase renewable energy targets. Increased demand would lead to stronger REC prices.
- Limit eligibility of supply. 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.

*Edward Holt, Jenny Sumner and Lori Bird. *The Role of Renewable Energy Certificates in Developing New Renewable Energy Projects .* National Renewable Energy Laboratory, June 2011.

with certificates) can all be used under the market-based method, recognizing the diverse ways consumers can express demand for new projects.

- *Requiring Quality Criteria to be met:* By ensuring that only contractual instruments designed for and able to uniquely define how consumer claims are recognized, reliability of data can be improved, supporting increased demand and uptake.

- *Requiring disclosure on regulatory relationships:* Disclosing the relationship between voluntary and compliance instruments brings greater awareness of the instruments and incentives already in place by law, and whether voluntary instruments represent energy above, beyond or unclaimed for those public purposes.

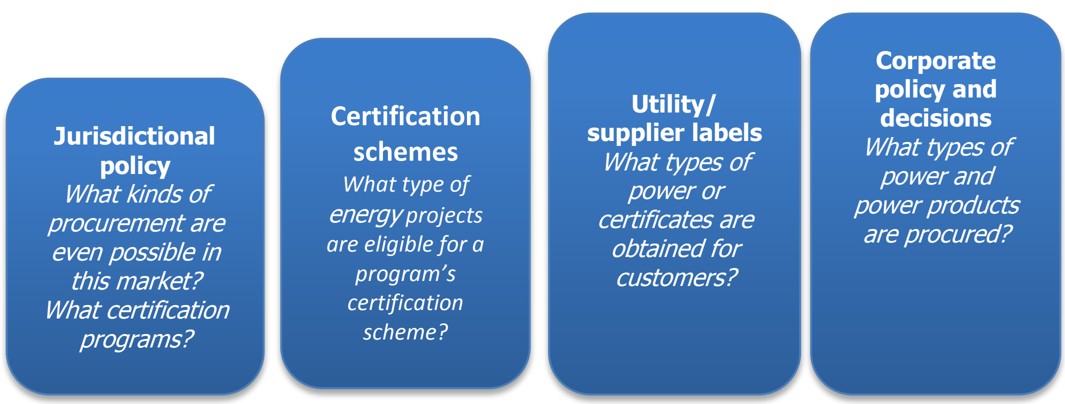
- *Recommending regulatory surplus:* To drive demand beyond the low-carbon supply required by regulation, this Guidance recommends that voluntary certificate programs where applicable recognize purchases that are beyond regulatory requirements.

- *Recommending purchase feature disclosure:* When companies disclose information about the energy generation reflected in their contractual instruments, including facility age, location, its receipt of public subsidy, etc., company decision-makers and stakeholders can get a clearer picture about how well the purchase aligns with other company goals including driving new low-carbon energy projects.

2. Enacting eligibility changes throughout the supply chain: This Guidance recognizes that because of the significant variations across markets in terms of technical, geographic, economic and regulatory factors, the exact conditions that help low-carbon energy flourish due to consumer demand may be highly specific, change over time, and be designed to support the development of low-carbon generation in the near-term, but may not be a requirement that can be sustained in the long-term. However, multiple pathways may be used by different entities in the energy supply chain to ensure that in the near-term, individual choices more effectively drive the development of new low-carbon energy generation beyond existing production or supplier requirements and reduce global GHG emissions.

If programs, policy makers, suppliers or consumers seek to achieve goals such as stimulating growth of new low-carbon energy projects in a relatively short time frame, several different decisions throughout the electricity supply chain can help direct demand towards a narrower set of project specifications. These are illustrated in Figure 6.3.

Figure 6.3 Eligibility Decisions Made Throughout the Electricity Supply Chain



3. Emphasizing project-based interventions
Some have suggested that voluntary certificates should function more like offsets, so that each purchase, each project leads to extra or additional low-carbon generation. Indeed, many voluntary green power program eligibility criteria align with, or have been inspired by, "additionality" criteria in offset project accounting. The claim that X metric tons of GHG emissions have been avoided can only be credible if the offset credit was the "intervention"[13] which made the project happen—and that, without that intervention, that project would not have occurred. This requires proof of cause-effect.

[13] Gillenwater, Michael. "What is Additionality? Part 1: A long standing problem." Discussion paper. February 2011. *http://ghginstitute.org/wp-content/uploads/content/GHGMI/AdditionalityPaper_Part-1(ver3)FINAL.pdf*

Companies should consider using their available financial and technical resources to pursue and support new energy generation projects, seeking opportunities where their intervention can be a decisive reason for a project to go through. However, the contractual instruments identified in the market-based scope 2 accounting method should be clearly distinguished from offset credits[14]. While voluntary certificate programs and offsets both "monetize" demand for low-emissions energy generation that reduces grid emissions, offsets represent a unique, global GHG reduction rather than an emission rate associated with energy generation (see Appendix B for further differences from offsets). In addition, the market-based method for scope 2 accounting is designed to recognize all types of contractual instruments (conveying both low and high GHG-emissions) that convey claims to consumers, and to function under a variety of market conditions. Therefore, this Guidance does not require instruments to meet offset-based additionality in order to be used in the market-based method for scope 2 accounting.

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

7. IDENTIFYING SCOPE 2 CALCULATION METHODS

This chapter provides an overview of the two scope 2 calculation methods emphasized in this Guidance, and their history from the Corporate Standard. It outlines the range of consumer decisions that can reduce overall GHG emissions over time in the electricity sector, as well as how each method's results can inform each of these decisions. This chapter also addresses how these two approaches each address double counting.

7.1 Approaches to calculating scope 2

Calculating scope 2 emissions requires a method of determining the emissions associated with or resulting from, energy consumption. For grid-delivered electricity, two primary methods have been used by companies, programs and policy makers to "allocate" the GHG emissions occurring at generation to consumers on a given grid. These scope 2 calculation approaches include the **location-based** and **market-based methods**, outlined in chapter 8 and 9 respectively. From a consumer's point of view, allocation comes in the form of a GHG emission factor associated with their energy purchase and consumption. All scope 2 accounting methods should be able to be applied comprehensively to account for all generated emissions. Methods are based on differing assumptions regarding how the boundaries of electricity (as either a product or service) should be defined; whether and how the attributes associated with energy generation can be functionally separated and allocated to electricity consumption; how tradable/transferrable these attribute claims are or should be for consumers.

7.1.1 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[15] 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 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 should follow the calculation procedure outlined therein and disclose other mandatory reporting for that region/nation's facilities separately.

7.1.2 Emission rate approach

All scope 2 methods described in this Guidance have several features in common, including:

- They are **generation-only** emission factors designed to label electricity consumption. They 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.

[15] See http://www.basecarbone.fr/data/rapport_methodo_co2_elec_2012.pdf

- 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.

- 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 (see Appendix C).

The emission factors recommended for each method are detailed in chapters 7 and 8.

7.2 Dual reporting

This Guidance requires that companies calculate scope 2 in two ways, based on the location-based method and the market-based method where applicable and Quality Criteria are met (see chapter 8). Companies with no operations in markets with applicable instruments would only report one location-based method figure. This reporting requirement represents a departure from the *Corporate Standard*, which only required a single scope 2 total. However, reporting two separate scope 2 figures using these different methods provides several benefits:

- Accurately represents important dimensions of the emission source—energy generation—and the reality of how consumers can evaluate the impact of their purchase and consumption.

- Ensures greater comparability over time and across inventories according to similar methods and metrics.

- Provides complementary information for a more complete assessment of the GHG impact, risks and opportunities associated with energy purchasing and consumption.

7.2.1 Gross/Net Reporting

The two method totals (location-based and market-based) should not be viewed as "Gross/Net," as a net calculation typically conveys external reductions such as offsets that have been applied to the inventory. While many contractual instruments in the market-based method indeed represent a zero emission rate from renewable energy and generally serve to lower the GHG-intensity of the grid, the market-based method is designed to reflect a range of instruments that together allocate overall emissions across the grid.

7.2.2 Program decisions

Voluntary or mandatory GHG reporting programs may make requirements that emphasize one of these two method characteristics in order to fulfill program goals. In addition, programs or policy makers may shape the types of instruments available for the market-based method and therefore impact the results reported for the market-based method. More detail on how the market-based method can be shaped by country-specific policy can be found in chapters 6 and 9.

7.3 Comparing approach results

In markets where the market-based method is applicable, companies will report two scope 2 figures (see chapter 11 for more on reporting requirements). The totals according to each method should <u>not</u> be summed but may be compared to inform different types of decisions (see chapter 8 and 9 for detail on how each method informs key GHG-reducing actions). In addition, a clear understanding of the differences between each method may clarify the context for the results.

Table 7.1 Comparing scope 2 accounting methods

	Location-based	Market-based
Basis	Inferring emission attributes based on locational grid emissions	Claiming emission attributes conveyed by contractual instruments or information
Where applicable?	All locations	Only those markets with instruments that meet Quality Criteria
Level of control (decision-making value)?	Emission factor changes due to aggregate impact of variables on grid, largely outside of company's direct control	Emission factor changes due direct procurement decisions or lack thereof
Causal relation with incurred emissions?	Company energy demand contributes to the aggregate demand in region, causing increased energy production	Not based on caused emissions but on claimed emissions. *Market* causality over time may shift supply

7.4 Decision-making value of each method

The decision-making value of each of the method's results should be evaluated on how effectively they reflect and motivate those decisions that drive reductions across the entire electricity sector over time, understanding that it is possible for an individual scope 2 inventory to show *reductions* over time that are not reflected in historic, system-wide GHG emission reductions in the local power sector (see Appendix C for more on evaluating reductions). This is inherent in allocating grid emissions to individual consumers in an indirect emissions category, and may be more acute with certain market-based contractual claims systems.

These consumer decisions fall into three categories: facility siting, demand, and supply shifting. GHG-reducing actions in these categories can individually and collectively impact GHG emissions from electricity production systems and will be shown to varying degrees within each method. While companies may make decisions related to these categories for non-GHG considerations, all the decisions carry a GHG implication. Chapters 8 and 9 detail the decision-making value of each method.

7.4.1 Facility-siting decisions

The location of the facility where a company operates and consumes energy carries GHG implications. Any facility that uses grid-distributed energy contributes to the overall demand in that region and therefore the GHG emissions associated with the production mix in that area. A decision to locate production in a low GHG-intensity grid means that using electricity locally will produce few emissions. However, if companies have supply choices within this region, a facility-siting decision would also need to take into account how generation emissions are effectively distributed to end-users within that jurisdiction as well as what market options a consumer can exercise: see bullet on influencing supply mix.

7.4.2 Demand-related decisions

Once a location has been chosen, a company can choose an energy-efficient building or carry out energy-efficient retro-fits, make behavioral decisions regarding its electricity consumption as well as using more efficient equipment. In addition, more temporally-precise information on electricity use (a possibility through some smart grid and other utility programs) can also help consumers use equipment during low-cost and low-GHG emitting periods, to optimize local grid load and related emissions.

7.4.3 Decisions to influence grid mix of resource technologies

The mix of generation technologies on a given grid is the result of many variables, including the historic regulatory, financial and physical characteristics of the jurisdiction, as well as the current market dynamics of supply/demand for particular resources. A company can pursue a variety of actions to try to influence these factors directly or indirectly, including where it acts as:

- An investor (investing in new low-carbon technologies)
- A project developer (creating onsite or other generation projects)
- An advocate (using available political or other channels to advocate for low-carbon technology-promotion policies, etc.)
- A consumer

The consumer role aligns most closely with the activity and information captured in scope 2. Where market-based consumer options are available, a company can express demand for low-carbon technologies by:

- Establishing contracts such as PPAs directly with low-carbon generators (often overlapping with the "project developer" role)
- Negotiating with its supplier or utility to supply more low-carbon energy
- Switching to a low-carbon electricity supplier, where available
- Purchasing certificates from low-carbon energy generation

Depending on a variety of economic and policy circumstances, these actions may vary in their effectiveness at creating changes in the mix of generation technologies within a short time-scale. Most require *aggregate* consumer decisions about product or supplier in order to substantially change the resource mix over time. But all of these benefit from, and may depend on, a market-based, contractual accounting system that confers specific GHG-emission attribute claims associated with purchases, functioning as a demand-signaling mechanism.

7.4.4 Decision-making and goal setting:

To most effectively and efficiently reduce reported emissions in both scope 2 methods, market procurement decisions should reduce GHG emissions in scope 2 as well as help lower the GHG –intensity of the grid as measured by grid average emission factors. More guidance on goal setting can be found in chapter 12.

7.5 Double counting

As stated in the *Corporate Standard,* double counting of the same emissions within the same scope or between scopes in the same inventory should be avoided. Several variations of possible or perceived double counting may be of concern to reporting entities but may be avoided following the guidance in Table 7.2.

Table 7.2 How to avoid double counting in the electricity sector

Type of double counting	Situation Description	Accounting treatment to prevent double counting
Scope 1 and 2 definitions		
Between scope 1 and 2 in different inventories	A single energy generator produces energy, and a separate entity reports those same emissions in scope 2	**No double counting problem – this is the correct definition of scope 2 as a reporting of generation emissions**
Between scope 1 and 2 in the same inventory	A company owns generation assets whose energy output they also consume.	The emissions from generation should be reported under scope 1 (if any emissions occurring), but the emissions from "consumed electricity" should not be repeated in scope 2. For owned generation equipment, document total electricity consumption from own-generated <u>and</u> grid purchases (Guidance recommendation). Only report in scope 2 the emissions from grid-purchased electricity – <u>not</u> repeating emissions consumed from energy already documented in scope 1.
Between scope 2 inventories		
Between multiple scope 2 inventories based on different methods	A new renewable energy project in a given grid will be reflected in the emission factor for one company's location-based method, but also in the market-based method total of another company who acquires certificates from the project	Each method represents an allocation of the same underlying energy generation emissions; requiring both methods clarifies difference.
Between multiple scope 2 inventories of the same method	May occur if instrument claims are unclear or if residual mix is not available	Quality Criteria require a residual mix to be made available in order to reduce double counting of contractual instrument claims.
Instrument tracking (Market-Based Method)		
Two end-users counting same emissions from same MWh based on unclear instrument claims	Multiple tracking instruments may be produced from the same MWh, and multiple instruments used by different reporting entities to support a scope 2 calculation.	In example, only one of these instruments (if any) should convey a GHG emission rate claim to end-users; others may be appropriate for other regulatory or informational purposes. This Guidance's Quality Criteria require that only <u>ONE</u> instrument convey a GHG emission rate claim to consumers, and that that claim be clearly conveyed with the instrument. Regulatory relationship disclosure is also required to clarify if instrument is above/beyond supplier quotas.
Attributes are sold from self-generation generation, but consumer of energy still claims the GHG emission rate (vs. null power /residual mix)	Energy projects where an energy attribute tracking certificate has been sold off that conveys claim about energy's emissions to another consumer (i.e., another scope 2 inventory), but project owner also consumes energy and counts it as "zero emissions"	If energy tracking certificates are sold from energy generation, companies should treat consumed electricity as though it were purchased from the grid – using residual mix or grid average.

8. Location-based Method

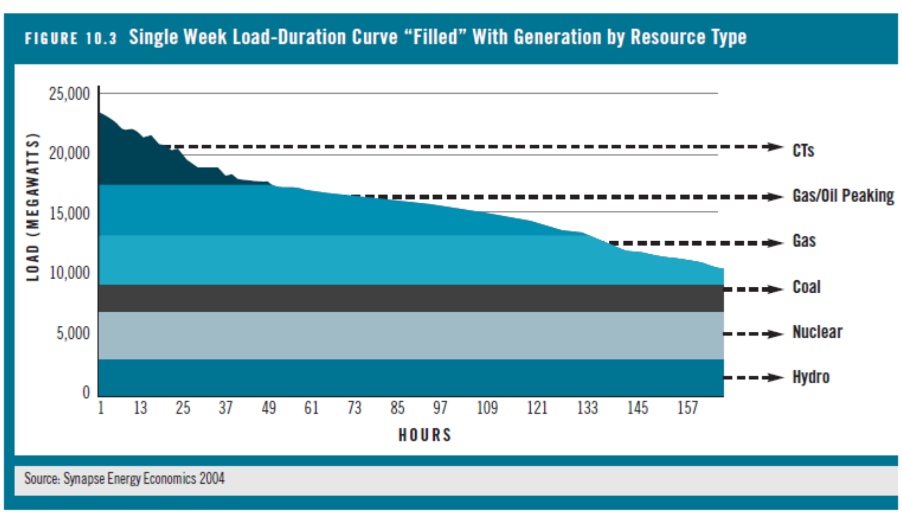
This chapter describes the location-based method for scope 2 accounting and reporting, including example emission factors and the decision-making value of location-based method results.

8.1 Description of the method

This method requires energy users to estimate emissions based on the mix of generating units that are dispatched to serve the grid location where the consumption occurs. This method also assumes that the emissions associated with generation (the attributes) remain "embedded" in the electricity and cannot be traded separately to differentiate and trade electricity based on type of generation, and it does not reflect the contractual agreements for purchasing electricity or providing differentiated energy products to consumers. A grid average emission rate takes into account the fact that some generation technologies like wind or solar may be intermittent, and therefore requires other technologies to be deployed to balance supply and demand. On the contrary, contractual accounting systems have generally issued instruments for renewables, leaving these "balancing emissions" as part of the residual mix.

Rationale: Because electricity follows the "path of least resistance," it is generally the case that local demand is met with a set of relatively local generation resources. In addition, electricity is imported and exported across "balancing areas" and used by balancing authorities to help match generation with customer demand.[16] In most grids, a grid operator or utility controls the order in which different local generating units are dispatched onto the grid to meet changing levels of consumer demand throughout the course of a day. The resources are organized and dispatched by the balancing authority based on a dispatch curve and limitation of power flows on the transmission grid. The dispatch of grid-connected generation falls outside of a consumers' direct control, but dispatch decisions are influenced by market forces (contracts and costs) as well as aggregate consumer demand for electricity. Figure 8.1 illustrates how different generation resources provide power for different times of the day.

Figure 8.1 Load Duration Curve figure, from *GHG Protocol Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*, 2007**.**



[16] See NERC website, "Understanding the Grid": http://www.nerc.com/page.php?cid=1|15

Increasingly, "smart grid"[17] 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). This has also been linked with end-use equipment automation as well. The location-based method suggests that *local demand* impacts *local generation and distribution* patterns, which ultimately impact total GHG emissions from the system. Utilities may also provide this type of data to energy-intensive consumers as part of demand-side management (DSM) programs and peak-shaving efforts.

Box 8.1 Summarizing the location-based method

- ✓ **Definition:** A method to quantify scope 2 GHG emissions based on average energy generation emission factors for defined locations, including local, sub-national or national boundaries.
- ✓ **Rationale:** Demand for grid-distributed energy is met through a mix of energy generation sources deployed in a geographic area. The GHG emissions associated with energy consumption can be evaluated on a locational basis, averaging the emissions from grid generation dispatched to meet demand. This method:
  - Reflects the balancing that occurs between different resources (particularly for intermittent resources)
  - Reflects the connection between local demand and emissions from local energy production
  - Shows grid delivered energy as a shared or collective resource
- ✓ **Decision-making value**: Companies can reduce their location-based scope 2 figure primarily by reducing demand for grid-distributed energy, which decreases scope 2 activity data (MWh consumption), or by moving to a region with cleaner local resources. Specifically, companies can:
  - Manage their demand to occur during periods of the day dominated by low-GHG-emitting generation (facilitated by advanced or smart grid information)
  - Install on-site low-carbon generation, reducing the consumption of grid-distributed energy*
  - Become involved in regional, sub-national or national generation resource mix decisions (regulatory and voluntary) that would over time decrease the grid average emission factor

* Assuming the energy is consumed on-site and not sold to the grid

8.2 Emission Factors

The emission factors necessary to represent the activity of consuming electricity in a specific region can range from highly precise to imprecise, based on geographic and temporal specificity. Under the best data availability scenario of advanced grid studies, a locational emission factor would link emissions with the time-of-day usage and local demand patterns, modeling the electricity that is generated, distributed and consumed in local regions.

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[17] See *The Green Grid : Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid.* EPRI, 2008. http://www.smartgridnews.com/artman/uploads/1/SGNR_2009_EPRI_Green_Grid_June_2008.pdf

However, more commonly the location-based method has relied on "grid average" emission factors, based on annual averages of generation over a large geographic region.

If a company acquires energy from a direct line energy transfer, emissions from the direct line energy transfer can be calculated using the source-specific factor, and any grid purchases can be calculated grid calculated using the emission factors listed in Table 8.1.

Table 8.1. Location-based Method Emission Factor Hierarchy and Indicative Examples

EMISSION FACTORS	INDICATIVE EXAMPLES
Advanced grid studies on real-time information	*Currently academic inquiry only*[18]
Regional or sub-national emission factors *Average emission factors representing all electricity production occurring in a defined grid distribution region that approximates a geographically-precise energy consumption area. To better approximate a consumption area, emissions factors should reflect energy imports/exports across the boundary.*	*eGRID total output emission rates (US)*[19] In many regions this approximates a consumption or delivery boundary, as eGRID regions are drawn to minimize imports/exports Defra annual grid average emission factor (UK)
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 imports or exports, not representative of energy consumption area.	IEA national electricity figures[20]

- ***Advanced grid studies***

Currently, the advanced grid studies that link the GHG emissions associated with local generation, distribution and consumer use patterns are not widely available or widely used, and are often contained in proprietary databases that are only recently being made available to consumers. This data can link emissions from generation on a temporal and spatial basis, demonstrating the emissions associated with the different generation units dispatched throughout the time-of-day when the consumer is using electricity. This emission data can be compiled over the course of a year for a consumer to record, match against temporal usage by location, and calculate Scope 2 emissions. 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 (particularly of renewable resources) grow. However, the application to scope 2 accounting is not yet widely used. For instance,

[18] See Fromman, Kurt and Evan DiValentino, *Calculation and Application of Hourly Emission Factors for Increased Accuracy in Scope 2 Emission Calculations.*Transaction of the Canadian Society for Mechanical Engineering. Vol 36, No. 2, 2012. http://www.tcsme.org/Papers/Vol36/Vol36No2Paper3.pdf

[19] http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

[20] http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=304

while utilities may implement DSM measures[21] 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[22].

However, because of the current lack of widespread availability of this type of data, grid average data continue to be the primary type of emission factor for the location-based method.

- ***"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. These data sets 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. A simplified illustration of the type of data aggregation and calculation that contributes to a grid average emission factor is shown in Table 8.2.

Therefore, the most appropriate spatial boundaries for this type of aggregation would be those that approximate regions of *electricity consumption* to demonstrate to consumers the average emissions incurred from consuming energy in that region. A consumption-based boundary would be drawn to reflect grid distribution regions such as balancing areas. All generation and emissions data within this boundary are aggregated and any energy imports/exports and their related emissions are taken into account.

An electricity production boundary would not be adjusted for imports/exports.

Table 8.2 Example of grid average emission factor calculation

	Emissions from generation	**Total generation in MWh**
Energy Facility A (coal)	50,000 metric tons CO2e	55,000
Energy Facility B (natural gas)	10,000 metric tons CO2e	30,000
Energy Facility C (wind farm)	0 metric tons CO2e	15,000
Totals within defined boundary	60,000 metric tons CO2e	100,000
Total system emission rate ("Grid Average")	60,000 metric tons CO2e/100,000	**0.6 mtCo2e/MWh**

Ideally, a given spatial boundary methodology would be applied consistently across the regions where electricity is imported/exported (national or even trans-national).Grid average emission factors at a regional, sub-national or national level to date have not uniformly captured the same data. Many of these data sets have been compiled for purposes other than corporate accounting. Greater consistency in grid average emission factors globally can improve location-based inventory results encompassing multiple global operations. Table 8.3 compares four grid average emission factor data sets across several parameters.

[21] Consumers have also estimated the *impact* of demand measures in terms of the emissions *avoided* from the avoidance of marginal generation source dispatch. However, the scope 2 accounting approach described here would not estimate grid-wide *impact* but instead would directly link consumption with the emissions from the localized generation resources dispatched.

[22] *The Smart Grid: An Estimation of the Energy and CO2 Benefits.* US Department of Energy, PNNL, January 2010. http://energyenvironment.pnnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf

Table 8.3. Comparison of four "grid average" emission data sets

Emission factor	Spatial boundaries	Temporal boundaries	Imports/ Exports across defined geographic boundaries	CHP included/ excluded	Generation -only vs. T& D included	Biomass	GHGs included
eGRID	Production within sub-regional boundaries, based on power control areas within NERC regions[23]	Annual	Not reflected, but sub-regional boundaries designed to approximate balancing areas that minimize imports/exports	CHP excluded	Generation only	Excluded from the emission factor	CO_2, CH_4, N_2O
Methodology Reference	*Total, Non-baseload, eGRID Subregion , Guidance on the Use of eGRID Output Emission Rates, 2008.* http://www.epa.gov/ttnchie1/conference/ei18/session5/rothschild.pdf						
IEA	Electricity production within national boundaries	Annual	Not reflected, top-down production data	Included in previous editions, but changed in 2012 edition to *exclude* CHP, making it "electricity only" emission factor	Generation only	Excluded from emission factor	CO_2 only
Methodology Reference	*CO2 Emissions from Fuel Combustion Highlights, 2012 edition.* IEA, 2013. http://www.iea.org/publications/freepublications/publication/CO2emissionfromfuelcombustionHIGHLIGHTSMarch2013.pdf						
GHGP China	Electricity production within 6 regional grids	Annual	Not reflected (top-down production data)	Included	Generation only	Excluded from emission factor	CO_2, CH_4, N_2O
Methodology Reference	In current working paper. Calculations based on *China Energy Statistical Yearbook (*fuel consumption data, lower heating value of fuels), *China Key Energy Use Reporting System* (lower heating value of fuels), *China NDRC Provincial GHG Inventory Development Guide* (heat-based carbon content of fuels, oxidization rate), *IPCC 2006* (fuel carbon content, CH_4 and N_2O emissions data).						
UK Defra	Electricity production in UK	Annual	Net imports from Ireland and France	CHP excluded, and separate CHP heat/steam factors available	Generation only	Excluded from emission factor	CO_2, CH_4, N_2O
Methodology Reference	2013 Government GHG Conversion Factors for Company Reporting: Methodology Paper for Emission Factors. July 2013. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224437/pb13988-emission-factor-methodology-130719.pdf						

[23] Sub-regions are a subset of the regions defined by the North American Electricity Reliability Council (NERC), and composed of entire power control areas (PCAs) with the exception of PJM Interconnection and New York Independent System Operator PCAs. Also covers some regions of Canada exporting power into the US.

8.3 Decision-making value

The GHG inventory calculated using this the location-based method can inform:

- *Facility siting decisions*: For many companies, the GHG emissions profile from locally-distributed electricity has not factored into decisions about where to locate a facility or office building, due to many factors, including specific business operational needs, location of existing building stock, and the lack of an accounting system to link precise location with GHG emissions. In addition, the proximity to electricity generation facilities is typically fixed. But broadly speaking, this information demonstrates the GHG emission differences from using electricity within a GHG-intensive region vs. a non-intensive region.

- *Electricity demand and consumption decisions:* Advanced smart grid information has been used to time electricity-using equipment to consume at favorable (lower cost and or lower GHG-emissions) time periods, based on other consumer demand patterns. Traditional DSM activities supported by utilities also encourage reduction in energy use by large customers, which may be further informed by more specific distribution information as well as more general "grid average" factors. However, the limited spatial precision combined with temporal delays in data publishing (2-3 year lag), can render an ex-poste grid average figure of limited value in specific corporate demand-side decision-making or risk-assessment. These factors can show overall production intensity, but may not meaningfully inform specific demand-side actions beyond *overall* demand reduction (efficiency can also arguably be pursued with financial gain regardless of the specific emissions associated with electricity consumption).

- *Decisions to influence grid mix of resource technologies:* Market-based 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. Over time, the collective impact of supplier and consumer preferences about technology types may, along with other factors such as economics and environmental regulation, shape the type of generation facilities added to the grid, or removed from operation – thereby altering the GHG emission output of the local power sector.

9. MARKET-BASED METHOD

This chapter describes the market-based method for scope 2 accounting and reporting, including example emission factors and the decision-making value of market-based method results.

9.1 Description of the market-based method

The market-based method seeks to reflect the GHG emissions associated with the choices a consumer makes regarding its electricity supply. These choices (such as choosing a retail electricity supplier, a specific generator, a differentiated product or energy tracking certificates) are reflected in agreements (contractual instruments) between the purchaser and the provider. The contractual instrument must convey generation and environmental attributes, and specifically the right to claim the GHG emissions that originate at the point of energy generation and are applied at the point of consumption. This pathway represents an *information and claims flow* apart from underlying energy flows in the grid. Certificates, for example, are issued after energy has been generated, and do not directly impact the distribution decisions made by the grid operator.

Under the market-based method of scope 2 accounting, an energy consumer can use the GHG emission factor associated with the qualifying contractual instruments it owns. But this method is only applicable where consumers can procure or use contractual instruments that meet the Quality Criteria identified in this Guidance. While only a few countries around the world have established markets for certificates that support this method, large electricity consumers in many other markets around the world may see opportunities to purchase a differentiated product and/or enter into contracts directly with generators, both of which support the disclosure of supplier-specific information.

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. Responsibility to lower scope 2 emissions is analogous to other purchasing decisions, namely to buy a less GHG-intensive product and/or less of it.

9.1.1 "Balancing" emissions

As noted in the location-based method, intermittent resources like wind or solar may require suppliers or grid operators to deploy other dispatchable resources such as coal or gas-fired generation. A market-based method does not necessarily take into consideration the overall needs of the grid or support function that fossil fuel resources often provide – instead, individual consumers can select via contractual instruments the source of their power.

Box 9.1 Summarizing the market-based method

- ✓ **Definition:** A method to quantify scope 2 GHG emissions based on GHG emission factors derived from contractual instruments that convey attribute claims from the point of energy generation to the point of energy use.

- ✓ **Rationale:** With consumer choice comes responsibility and accountability in reporting. Voluntary consumer demand for specific energy sources can influence, in aggregate over time, the mix of generation resources on a given grid. Voluntary demand for low carbon resources can be expressed via contractual instruments that convey physical energy and/or information about that energy (its attributes, including specifically the right to claim the GHG emission factors) from generators to suppliers, and ultimately to consumers. In markets where consumers can either contract directly with electricity generators, or choose

their electricity supplier, a specific electricity product, or tradable energy certificates, this method:
- Reflects the GHG emissions and other attributes associated with the energy products chosen by the company; and
- Transparently documents active procurement choices (for both low and high-carbon generation) as well as default decisions not to buy a specific product.

✓ **Decision-making value**: Companies can reduce their market-based scope 2 emissions by switching to or purchasing from sources of energy with a low-GHG emission rate using the contractual instruments or certificates applicable in the market. To achieve this, companies may:
- Work with electric suppliers to obtain a low-carbon product, substantiated by applicable certificates;
- Switch electric suppliers (where supplier choice exists) to one that offers low-carbon products, also validated by certificates where applicable;
- Establish contracts such as power purchase agreements (PPAs) directly with low-carbon generation facilities, and acquire applicable certificates;
- Purchase certificates separately from energy;
- Install on-site low carbon generation, reducing the consumption of grid-distributed energy, and retain applicable certificates.

9.2 Types of data

Under the market-based method, different contractual instruments become carriers of GHG-emission rate information or emission factors for consumers to use to calculate their GHG emissions. To ensure this, instruments must specify that the GHG emission rate attribute is included (see Quality Criteria section). Each type of instrument has a specific history and use in its market, but they broadly fit into similar classes (as noted in the *Corporate Standard).*

This list does not represent a preferred hierarchy on procurement method (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. It represents a hierarchy of most *precise* (certificates issued in units that match consumption units, e.g. MWh) to least precise (attributes representing all production in a region). See Table 9.1.

Table 9.1. Market-Based Scope 2 Data Hierarchy and Indicative 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 Quality Criteria instruments listed here not guaranteed to meet Quality Criteria, but are indicative of instrument type.

EMISSION FACTORS	INDICATIVE EXAMPLES
Electricity attribute certificates or equivalent instruments (unbundled, bundled with electricity, conveyed in a contract for electricity, or delivered by a utility)	• *Renewable Energy Certificates (US, Australia)* • *Guarantees of Origin (EU)* • *Electricity contracts (e.g. PPAs) with renewable generators that also convey RECs or GOs*

Contracts for electricity, such as power purchase agreements (PPAs) that explicitly include the GHG emission rate attribute (or that are silent on attributes and these have not been otherwise conveyed to another party), and where certificates are not required for an attribute claim	• *In the US, contracts for electricity from specified non-renewable sources like coal in regions other than NEPOOL and PJM*
Supplier/Utility emission rates may be a standard product offer or a different product (e.g. a "green power product" or tariff), and must be disclosed (preferably publicly) according to best available information	• *Default fuel mix and emission rate allocated to retail electricity users and disclosed for any utility, included on a utility bill or otherwise made available* • *Green energy tariffs* • *A supplier using a product label such as Green-e Energy or EKOenergy* • *Voluntary renewable electricity program*
Residual mix (sub-national or national) (to be used where no specific electricity purchase is made)	• *Calculated by EU country under RE-DISS project* [24,25]
Other grid-average emission factors (sub-national or national) – *see location-based data*	• *eGRID total output emission rates (US)*[26]*.* 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 figures[27]

- ***Electricity attribute certificates or equivalent instruments*** (unbundled, bundled with electricity, conveyed in a contract for electricity (e.g. PPA), or delivered by a utility) This type of instrument tracks electricity attribute information on a per-output (MWh) basis, and conveys this to the entity that ultimately claims, redeems, "retires" or cancels the certificate.

- ***Contracts such as power purchase agreements (PPAs)***[28]
  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.

  Contracts may be established in jurisdictions with certificate systems, in which case the certificates themselves should serve as the emission factor for the market-based method. If the certificates are bundled with the contract, the purchaser can claim the

[24] http://www.reliable-disclosure.org/static/media/docs/RE-DISS_2012_Residual_Mix_Results_v1_0.pdf.
[25] 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/ .
[26] http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html
[27] http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=304
[28] 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.

certificates. If the certificates are sold separately, the power recipient cannot claim the attributes of the specific generator.

Where certificates are not issued by a tracking system, a PPA may nevertheless convey generation attributes if, the PPA includes language which confers attribute claims to the power recipient. This more explicitly renders the PPA a GHG attribute-claims carrier. As shown in the Quality Criteria, a statement from a verifier or 3rd party is needed to demonstrate that no other entity is claiming the attributes from this generation.

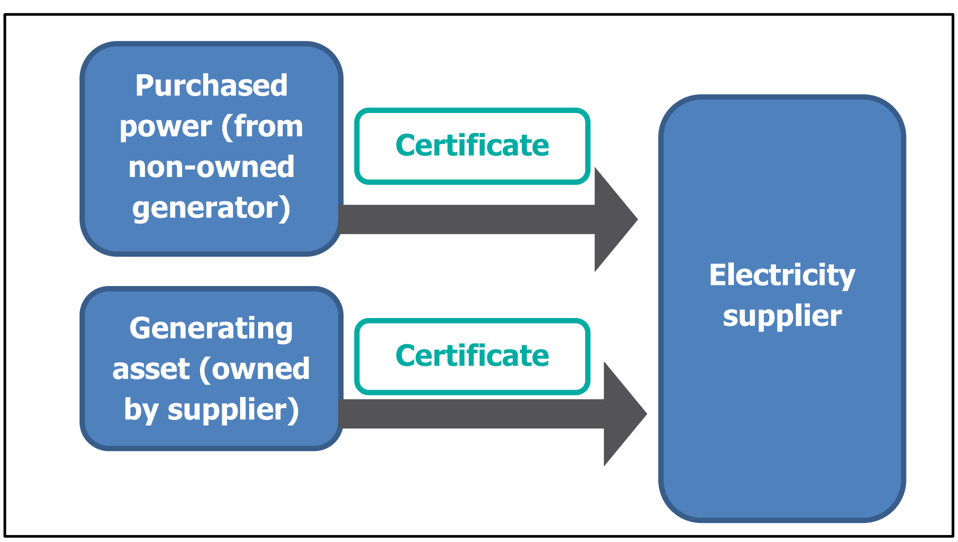
- ***Supplier-specific emission rate***

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 "green power product" or tariff), and must be disclosed preferably publicly according to best available information, and where possible best practice methods, such as The Climate Registry Electric Power Sector Protocol. 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. In particular, if the supplier has a differentiated product (e.g. a "green power product"), the certificates or other contracts used for that product should be used only for that product and not counted in the standard product offer.

In addition, suppliers may be required by regulation to calculate and disclose their fuel mix using a specific methodology, which may or may not include a GHG emission rate disclosure or recognition of "differentiated" products offered to specific consumer classes. 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.

In general a supplier calculates its GHG emission-rate based on how it supplies and delivers power: from owned generation assets, from power contractually purchased

Figure 9.2 Electricity supplier purchasing and disclosure



from other generators or on the spot-market, or a combination of the two (see Figure 9.2). Suppliers may also source energy tracking certificates on behalf of its customers, and disclose this GHG emission rate to those participating consumers.

Some suppliers may disclose only emissions from owned generation units (the supplier's scope 1 emissions). This type of emission rate does not constitute a complete picture of the GHG emissions delivered to grid customers and therefore are not as accurate for scope 2 accounting.

- ***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 un-tracked 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 did not purchase certificates or a specified product, do not have a contract with a specified source, or do not have supplier-specific information. In the EU system, this has been called a residual mix[29] developed based on generation data ("grid average" mixes at a country or regional level) adjusted so that claimed attributes are removed. Currently, this residual mix has not been explicitly designated as fully appropriate for consumer GHG calculation.[30] See Appendix D for guidance on how the residual mix has currently been calculated in the EU.

  There are two[31] regional tracking systems in the US that issue certificates for attributes for all types of generation technology (not just renewable generation.) These take the total of all certificates and subtract any and all certificates claimed by load serving entities for their environmental disclosure labels. Certificates purchased by voluntary customers are also retired and removed from circulation. The remainder, what has not been claimed by load-serving entities or voluntary purchasers, constitutes the "residual mix." This mix can then be assigned to the remaining MWh used to serve retail load but that have no matching certificates. These all-generation tracking systems therefore provide a residual mix calculation that can be used for GHG accounting purposes.

  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 US overall, the adjusted mix estimation does not differ significantly from the location-based grid average data. In fact, according to a paper by the Environmental Tracking Network

[29] For further background see RE-DISS (http://www.reliable-disclosure.org/) and the E-Track Project (http://www.e-track-project.org/docs.php)

[30] *"Note that these figures are destined for electricity disclosure purposes only. This does not imply any recommendation by the RE-DISS project team of these figures to be used in corporate or product carbon foot-printing. This is due to unresolved data inconsistencies and open issues regarding carbon footprint methodologies."* European Residual Mixes 2012, version 1.0. Reliable Disclosure Systems for Europe (Phase II), http://www.reliable-disclosure.org/static/media/docs/RE-DISS_2012_Residual_Mix_Results_v1_0.pdf. p. 1.

[31] PJM-GATS and NENePOOL GIS; New York is also planning this type of system.

of North America (ETNNA), *Intersection between Carbon, RECs, and Tracking* (2010), the difference is currently less than one half of one percent.[32]

In places where a residual mix is not available, other unadjusted grid average emission factors such as those used in the location-based method may be used.

To avoid double counting, companies making claims based on contracts (as opposed to certificates issued by tracking systems) 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.

9.3 Quality Criteria

The market-based method of calculating scope 2 emissions depends on ensuring that contractual instruments can reliably and uniquely convey GHG emission rate claims to consumers. Without this, a resulting market-based scope 2 inventory 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 Quality 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. See Table 8.3 for a list of these Quality Criteria and additional explanation below.

Where contractual instruments do not meet the Quality Criteria requirements in Table 8.3 cannot be used for the market-based method, location-based data should be used in its place to calculate the market-based method total.

- **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 national certification standard) define RECs as conveying "all environmental attributes" associated with the MWh of energy generation. This type of claim is considered "fully integrated," meaning that no other instrument can be generated from that MWh which conveys consumer claims regarding any of the environmental attributes of the energy. The tracking systems themselves support only fully integrated certificates. However, some have questioned the specificity or enforceability of inclusive "environmental attribute"[33] language. 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

[32] Environmental Tracking Network of North America (ETNNA). February 2010. *The Intersection between Carbon,RECs, and Tracking: Accounting and Tracking the Carbon Attributes of Renewable Energy*. pg. 14. http://etnna.org/images/PDFs/Intersection%20btwn%20Carbon%20RECs%20and%20Tracking.pdf.

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

certificates, but requires that only one instrument 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.

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 is separately from the scopes

- *Other attribute claims*

For the purposes of scope 2 accounting, the GHG emission rate is the critical energy attribute that certificates must convey. But several other attributes about the underlying energy may also be conveyed, including a description of the energy source itself. This would allow a company in possession of a certificate to claim that its purchased energy came from a specified source such as wind, solar, hydropower, etc. This has been used in renewable energy labeling and purchase schemes such as WindMade.
While it is theoretically possible to disaggregate attributes for the purpose of consumer claims, this has generally not been done in the programs surveyed here. In the US, 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 US tracking systems do not support separating individual attributes. This "all attributes" approach would effectively prevent the same MWH being used to create multiple attribute claims from renewable energy projects in the US.

The "renewable" attribute of energy

The precise definition of what qualifies as renewable energy can vary depending on program and goal, but it is generally linked to the source of the fuel or generation and how quickly it regenerates. This quality is present regardless of the emissions rate at the point of generation. While most renewable energy sources such as solar, wind and hydro have zero emissions at generation, others such as biomass still produce emissions when combusted (these are reported outside of the scopes). In turn, non-renewable resources such as nuclear may also produce zero emissions. It is possible to be renewable without being zero GHG emissions, and vice versa. However, from a policy point of view renewables are valued in large part because of their zero emission rate for GHG's and other pollutants.

- **Criteria 2. Unique claims.** To avoid double-counting, it is important that these attributes be excluded from the generation and environmental attributes reported for the market as a whole. This requirement also helps ensure that the instrument that conveys a claim (see above) is also the *only* instrument that does. In some cases, this may require arbitration regarding the validity and enforceability of a claim where multiple instruments exist and remain unclear on attribute claims.

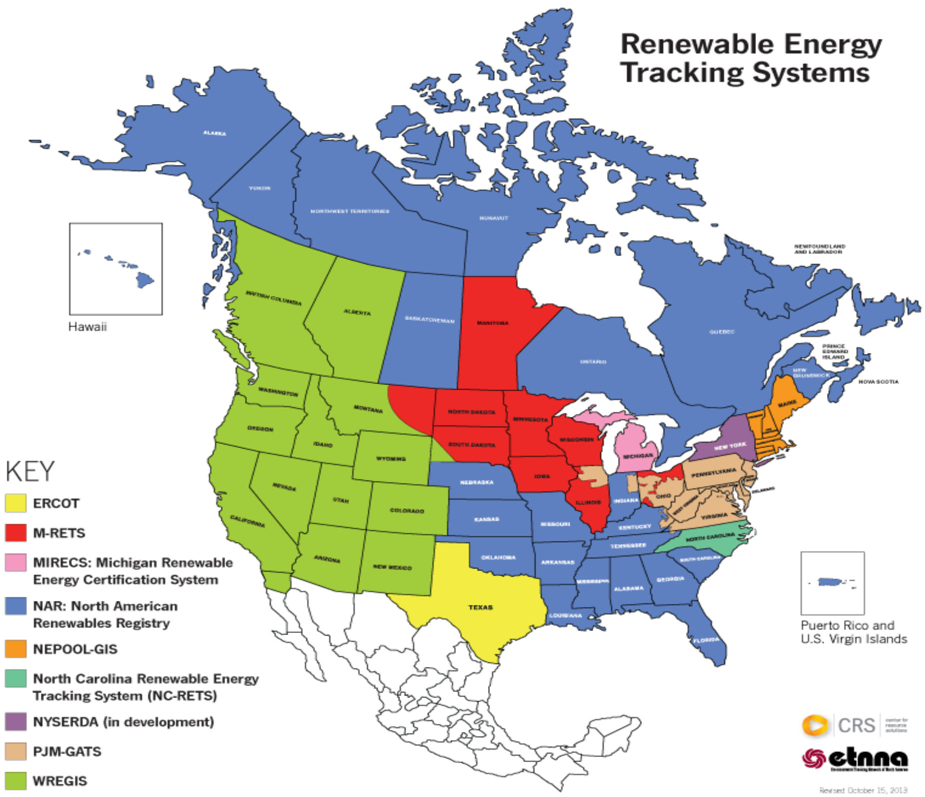
In addition, the creation of a certificate that conveys an energy generation attribute claim should in turn render the underlying energy "null power." This means that the power can no longer be considered to contain the energy attributes, including both the type of energy (e.g., that it's "renewable") 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 "green power" in the absence of owning the certificate.

However, null power is still consumed– by individual facilities consuming energy from on-site energy projects which have sold off certificates, or indirectly as part of the mix consumed by users on a grid. Many of these other consumers do not procure other certificates or instruments that convey attribute claims to "cover" their quantity of null power consumption. A clear set of other energy attributes is needed to characterize this null power. To avoid double-counting of certificate attributes and to provide an attribute profile for null power, a residual mix should be calculated for a market region and used to calculate emissions from null power.

- **Criteria 3. Retirement/Cancelation.** Certificate issuance and residual mix calculation is often managed through a certificate tracking system. A certificate tracking system, also referred to as a certificate registry, is a database that is used to track the ownership of certificates and therefore the right to claim attributes of the electricity generation for which the certificates are issued. A tracking system 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 must be redeemed or retired when they are used or claims are made based on their attributes or characteristics. 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 must ensure that no other entity is issuing certificates (or emission reduction 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.[34]

[34] Additional external documents describing tracking systems can be found here:
- EPA website: http://www.epa.gov/greenpower/gpmarket/tracking.htm
- Design Guide for Renewable Energy Tracking Systems: http://www.nationalwind.org/assets/past_workgroups/Design_Guide_for_REC_Tracking_System_-_July_2004.pdf
- Association of Issuing Bodies: See European Energy Certificate System (EECS) Rules at http://www.aib-net.org/portal/page/portal/AIB_HOME/EECS

Figure 9.1 Illustration of renewable energy tracking systems in the US



From ETNNA and CRS: **http://www.etnna.org/images/ETNNA-Tracking-System-Map.gif**.

- **Criteria 4. Vintage.** This criteria seeks to ensure that the certificate issuance and cancelation/retirement/usage occurs within a reasonable time period to the energy consumption to which it is applied. This should be distinguished from the age of the facility or when the facility was constructed.

- **Criteria 5. Market boundaries.** Energy may be purchased from any grid connected to that which serves the consumer, but attribute tracking certificates have been made available across markets that extend beyond local energy grids. For GHG accounting, energy certificates should be acquired from within the same market appropriate for a usage claim.

  Markets for trading certificates have historically been country-based or regional, including areas where the laws and regulatory framework governing the electricity sector are consistent (though not necessarily identical) between the areas of production and consumption. For example, the US, despite differences in state law and local regulatory policy and variation in physical interconnection within these regions, operates under overarching federal laws and regulations, and therefore constitutes a single market for use of contractual instruments. In these cases, that country's consumers can only use certificates generated within that country. In other cases, a "market" may encompass several countries that recognize each other's certificates as fungible and available to any consumers located therein. The EU represents this type of 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, retiring and calculating a residual mix must be established in order to prevent double counting of GHG emission rates.

- **Criteria 6. Residual Mix.** See the description of the residual mix in the list of data for the market-based method.

Table 9.3. Quality Criteria checklist

CRITERIA REQUIRED FOR ALL MARKET-BASED METHOD DATA
1. **Conveying GHG emission rate claims:** The contractual instrument must convey with it the direct GHG emission rate attribute associated with the unit of electricity produced. In the absence of direct language on attributes, attestations from each owner in the chain of custody may also ensure this criterion is met.[35]
2. **Unique Claims:** The contractual instrument must be the only instrument that carries the GHG emission rate attribute claim associated with that quantity of generation. If other instruments exist that can be used by end-users, it must be ensured that the one being used for a GHG emission rate claim is the only and sole one which does so. The underlying electricity (or megawatt-hour) minus the instrument, sometimes called "null power," must also not reflect the same GHG emission rate, but should be assigned residual mix or average grid emissions for the purpose of delivery and/or use claims in the market-based method.
3. **Retirement/Cancelation:** The contractual instrument must be tracked and redeemed, retired or canceled by or on behalf of the reporting entity in order to support a claim in a GHG inventory. This can be done through a tracking system, an audit of contracts, or third-party certification.
4. **Vintage:** Vintage reflects the date of energy generation from which the contractual instrument is derived. Instrument vintage must be reasonably close to the inventory year of the energy consumption to which the instrument is applied, consistent with existing standards for the market where the contractual instruments exist.
5. **Used within appropriate market boundaries:** The contractual instrument must be sourced from within the same market as the reporting facility to which it is applied. The regulatory authorities and/or certification/issuing bodies responsible for certificates may specify the boundaries in which certificates may be traded and redeemed, retired or canceled. Companies must adhere to these boundaries for the purpose of GHG accounting and reporting. Contractual instruments in which electricity is sold bundled with the energy attributes or certificates are usually within a regional transmission organization, power pool or balancing area, but exports and imports may broaden these markets. Markets for unbundled certificates are less constrained and are typically national in scope unless other countries or portions of countries are interconnected electrically or are included in a common economic market. Voluntary electricity labels or GHG reporting programs may restrict the boundary of certificate sourcing further, e.g. to a sub-national entity or an interconnected electricity region.
6. **Residual mix**: An adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly-shared electricity, based on combining national or sub-national energy and emissions production data with contractual instrument claims, must be made available for consumer scope 2 calculations. If a residual mix is not currently available, a procedure or threshold by which a residual mix emissions rate will be calculated should be identified by regulatory authorities,

[35] Although it might be perceived as a bit burdensome, it is a practical solution that has worked in the US, not just for emissions attributes but also for double claims, regulatory additionality, and keeping all attributes together in a "whole" REC. Green-e has some examples on its website at http://green-e.org/verif_docs.html.

	issuing/certification bodies or other recognized data providers. If a residual mix is not currently available, all reporters using a market-based method should provide a footnote: *"No adjustment to the grid average emissions factor has been made to account for voluntary purchases. An adjusted emissions factor is not available or has not been estimated. This may result in double-counting."* 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.
ADDITIONAL CRITERIA FOR REPORTERS USING SUPPLIER- OR UTILITY-SPECIFIC EMISSION FACTORS	
7.	The utility or supplier-specific emission factor must reflect delivered electricity based on certificates and other contracts for electricity either owned or retired by the utility/supplier on behalf of its customers or retired and claimed for the public benefit, such as with the US state RPS programs. 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. Electricity from renewable facilities for which the attributes have been sold off (via contracts or certificates) or are otherwise not owned by the utility or supplier must be characterized as having the GHG attributes of the residual mix in the utility or supplier-specific emission factor. The utility or supplier-specific emission factor may be a standard product offer or a different product (e.g. a "green power product" or tariff), and must be disclosed (preferably publicly) according to best available information, and where possible best practice methods, such as The Climate Registry Electric Power Sector Protocol. In this case, the certificates or other contracts used for those products should only be used once for that product and not mixed into other product offers.
ADDITIONAL CRITERIA FOR REPORTERS PURCHASING ELECTRICITY DIRECTLY FROM A RENEWABLE ELECTRICITY GENERATOR OR USING ON-SITE RENEWABLE ELECTRICITY GENERATION	
8.	All instruments conveying emissions claims must be included in the contracts and transferred to the reporting entity only. It must be true that no other instruments that convey this claim to another end user have been issued for the contracted electricity. The contract and claim associated with it should be verified by a third party to convey unique or sole ownership right to claim GHG emission rate. The electricity from the facility must not also carry the GHG emission rate claim for use by a utility, for example, for the purpose of delivery and use claims.

Demonstrating conformance with Quality Criteria

Reporting entities must ensure that contractual instruments meet these Quality Criteria, signified by a third-party statement, via the certification program issuing the certificates. A disclosure statement on the regulatory relationship is also required. This Guidance recommends that other generation features relating to programmatic eligibility be disclosed. See chapter 11 for a full list of reporting requirements and recommendations.

Comparing Quality Criteria to program-specific eligibility criteria

The market-based method is designed to reflect all types of contractual claims, not just specific green power programs. Therefore, these Quality Criteria do not make "eligibility" requirements regarding the type of energy generation underlying the contractual instrument (i.e., specific technologies, when the project came online, what type of funding it received, etc.). As noted in chapter 6, these eligibility criteria relate to programmatic and policy preferences rather than how to execute the overall *method* of allocating generation attributes to end-users.

9.4 Relationship between voluntary certificates and compliance instruments

As noted in chapter 6, markets have defined the relationship between compliance instruments and voluntary contractual instruments, particularly instruments, in different and often distinct ways. Voluntary contractual instruments used in the market-based method **should** achieve of regulatory surplus, based on consumer expectations and for the assurance of a minimum level of market impact. But some markets' compliance instruments have not conveyed energy attribute claims (e.g. the UK) and have instead structured multiple instruments or certificates to fulfill different purposes. Therefore, to ensure transparency and clear understanding, companies using voluntary contractual instruments **shall** disclose the type of relationship between that contractual instrument and regulatory compliance instruments, if they exist. Table 9.4 describes three types of relationships that can be documented.

Table 9.4 Relationships between voluntary certificates and regulatory/ compliance instruments

Type of relationship	Description	Example	Optional disclosure explanation
Voluntary instrument is above and beyond compliance quotas	Voluntary contractual instrument represents all the generation and environmental attributes of a MWh of electricity generation, and there are no other instruments or claims representing the same MWh for regulatory compliance.	Voluntary RECs in US and Australia	*"Organization X acquires instruments that solely represent the application, use or claim on a MWh of electricity generation. To the best of its knowledge, no other party can make a claim against this MWh for the purpose of meeting a regulatory mandate or other public policy objective."*
Voluntary instrument combined with retired compliance instrument	Voluntary contractual instrument is unique in conveying the emissions attribute claim (see Quality Criteria), but other instruments are created for the same MWh, or other claims may be made against the same MWh, including to meet regulatory mandates or other policy objectives. A reporting entity may strengthen its regulatory surplus claim by acquiring an equal number of such other instruments or rights to make claims against that MWh, such that their action eliminates any double claims against that MWh.	Acquiring and retiring an ElCert along with a GO in Norway[36]	*"Organization X acquires multiple instruments for each MWh of electricity generation, including rights that could otherwise be used to satisfy a regulatory mandate or other public policy objective. To the best of its knowledge, no other party can make a claim against this MWh for the purpose of meeting a regulatory mandate or other public policy objective."*

[36] Illustrative example, not currently common practice

Voluntary instrument not surplus to compliance instruments	Voluntary instruments are unique in conveying the GHG emission rate and use claim, but other instruments created for the same MWh are used to satisfy a quota or other policy objective without environmental attributes	UK REGO acquired and retired, but the ROC and LEC are acquired and retired by different claimants[37]	*"Organization X acquires instruments that convey the emissions factor for electricity generation, but other instruments may be created for the same MWh and used by other parties for other purposes, including to meet regulatory mandates or other public policy objectives."*

9.4.1 Supplier-specific emission rates where supplier quotas apply

For utilities under a supplier quota requirement (such as an RPS in the US), structuring a 100% green power product may introduce double counting or "surplus" energy attribute certificates depending on how the product is structured. For example, if a utility is under a 20% renewable energy sourcing requirement, then voluntary contractual instruments would be required to account for the remaining 80% of the delivered energy. However, if voluntary contractual instruments are used to cover 100% of the delivered energy, then the 20% represented in the RPS would be double counted. In cases where a compliance quota is included in a supplier-specific emission rate that is not combined with voluntary instruments, the reporter can indicate **"inclusive of supplier quota instruments."**

As noted in the Quality Criteria, utilities should be transparent regarding the composition of their product.

9.5 Program eligibility and product features

Markets currently differ as to what types of generation facilities are currently producing instruments that are recognized in the market-based method corporate GHG inventories. As illustrated in chapter 6, different program purposes and goals result in different *eligibility criteria* that determine what energy generation facilities are recognized in the program, produce a certificate, or are used for consumer claims purposes. This variation can make it difficult to compare and understand the different procurement choices a company has made in different markets. Companies **should** voluntarily disclose features about the programs or underlying energy generation represented in their contractual instruments. This can help companies make their procurement more transparent and allow for clearer comparison of market-based scope 2 totals across organizations.

These features should include, but are not limited to, those listed in Table 9.5. Disclosure of these features should be clearly linked to the contractual instruments.

[37] Ibid.

Table 9.5 Product features and other information

Reported features should include, but are not limited to:
• **Certification or label name (if applicable)**
• **Energy resource type**—What energy resource was used to generate the claimed energy?
• **Facility location** —Where were the electricity generation facility(ies) where the instrument was generated located (state, nation, grid region for emission calculations)?
• **Facility age**—In what year was the generation facility that created the certificate/contract first operational or substantially repowered?
• **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 in relation to on behalf of your voluntary purchase of instruments from this facility? (Y/N)
• **Funding**–Did the facility receive public subsidy? (If that subsidy resulted in the subsidy provider acquiring the certificates and GHG emissions rate claims, then claims must follow certificates, and the energy becomes "null power").
• **Offsets**—Is the facility producing offset credits from the same MWh reflected in the contractual instrument? (Not applicable to contractual instruments in the US, Australia, EU.)

- **Certification or label name:** This can include certification such as Green-e in the US, or labels such as EKOenergy in the EU. This can help stakeholders identify further information on the eligibility criteria and other policies. The certification or label name should also specify what is being certified, e.g. in the U.S. Green-e certifies against a set of requirements descried in their National Standard, including that certificate is of proper vintage, generated by proper technology, etc.

- **Energy resource type:** 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." Certificates or PPAs should clearly identify the resource reflected in the instrument.

- **Facility location:** Depending on the information available from the certificate, supplier or contract, the generation facility location could be identified at a national or sub-national level (either geopolitical such as a US state, and/or a 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. If this information is not made available on the certificate, consumers can ask the certification program, tracking system, or supplier for further information. Lacking other information, a company may disclose a range identified by the certificate program (e.g. last 15 years for Green-e US RECs).

- **Cap and Trade:** Allowance set-aside programs can help demonstrate that voluntary certificate purchases are reducing the number of allowances available for energy emitters. It also provides context for other GHG reduction policies affecting the power sector.

- **Funding:** Almost all energy generation facilities have received some kind of government or public subsidy, directly or indirectly. The funding disclosed here can highlight recent funding or subsidy policies directly and substantially affecting the generation facility.

- **Offsets.** Disclosing whether the supplier-specific emission rate or PPA originates from a generation facility also producing offsets can be critical in helping stakeholders understand the context of that project in the local grid. In the US, the Green-e certification rules state that a given RE project can either produce RECs or an offset credit (if certain criteria such as additionality are met), but could not produce both. See more on the relationship between offsets and certificates in Appendix B.

9.5.1 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. An illustrative example of this is provided in Table 9.6. 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 9.6 Example of checklist disclosure for market-based method

Quantity of contractual instrument type	Features					
	Certification or label name	Project location	Facility age	Cap and Trade	Offsets	Funding
100 MWhs RECs	Green-e certified	Colorado (US)	Built in 2005	No	No	Production Tax Credit
100 MWh with supplier-specific factor	n/a	PJM service territory (mix of resources)	Mix of generation facilities	PJM includes RGGI (cap and trade) states, but consumption occurring in Pennsylvania (not in RGGI)	No	Mix of generation facilities – in some cases yes
100 MWh *unspecified* - eGRID sub-region (*No adjustment to the grid average emissions factor has been made to account for voluntary purchases. An adjusted emissions factor is not available or has not been estimated. This may result in double-counting.*)	n/a	n/a mix of resources RFCW (Reliability First Corporation West (eGRID subregion))	n/a mix of resources	n/a	No	Mix of generation facilities

9.6 Decision-making value

Where market-based contractual claims are possible, an inventory calculated using this method could inform:

- *Facility siting decisions:* Faced with the possibility of using a market-based calculation method, a company may prefer (all other things being equal) to locate in a *market region* where market choices are enabled and contractual instruments are supported.

- *Electricity demand and consumption decisions:* Reducing electricity demand can prove financially beneficial both broadly in terms of minimizing electricity costs but more specifically in terms of minimizing *additional* costs associated with purchasing contractual instruments at a premium above standard electricity costs. However, there may be a risk that a "zero emissions" figure in a market-based scope 2 calculation would reduce perceived need to continue efforts on efficiency.

- *Decisions to influence mix of resource technologies:* This method prioritizes market choice by companies to claim attributes and instruments from low-carbon generation, based on aggregate demand influencing supply (generation stock) over time. Without these claims systems, the emissions associated with a consumer's individual choice of supplier, product or contract would have no direct visibility in GHG accounting. Many contractual systems today only reflect tracking of renewable generation, generally as an incentive to reward "green" buyers, but complete, all-generation tracking would facilitate the disclosure of emission claims related to *all* contractual instruments, including non-renewable resources. The method provides for an opportunity to express and aggregate demand for specific types of generation, but 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, and other factors See chapter 6 for further background.

10. 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
- Determine whether the market-based approach applies
- Collect activity data and choose emission factors for each method
- Perform calculations
- 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.*

10.1 Identify GHG emissions sources for scope 2

Scope 2 includes emissions from all purchased 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.

10.2 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 contractual instruments listed in chapter 8 are available in a given market and meet the Quality Criteria.

If a company has any operations within the corporate inventory where the market-based method applies, then a market-based method total must be calculated for the entire corporate inventory. For operations in the corporate inventory where the market-based method does not apply, data from the location-based method should be used to represent the emissions from the facility. In some cases where the market-based method applies, the calculated scope 2 total will be identical to the location-based if a residual mix is not available.

If no facilities in the entire inventory are located in markets with contractual claims systems, or where <u>no</u> instruments within those systems meet Quality Criteria, then only the location-based method is used to calculate scope 2.

10.3 Collect activity data and choose emission factors for each method

Activity data includes information on the total quantity of purchased and consumed electricity, heat, steam and cooling provided. Metered electricity consumption or utility bills specifying consumption in MWh or KWh 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)[38].

[38] See chapter 14 of The Climate Registry's General Reporting Protocol

Each operation's activity data is then multiplied by the emission factors specified for each calculation method. A summary of these emission factors for each method is listed in chapter 8 and 9. Companies should use the most appropriate and highest-quality emission factors available for each method.

10.3.1 Emissions from biofuels

Biofuel is increasingly used as a resource for energy generation on-site and on the grid. While biofuels can produce fewer GHG emissions than fossil fuels and may be grown and used on a shorter time horizon, they still produce GHG emissions and should not be treated with a "zero" emission factor. Based on the *Corporate Standard,* the CO_2 portion of the biofuel combustion should be reported outside the scopes. Any CH_4 or N_2O emissions should still be reported in scope 2. Today, most grid average emission factors used in the location-based method do not separately note the percentage of biofuel portion of the emission factor.

10.3.2 Assessing data quality

Assessing data quality of the emission factors for both methods can provide a sense of the overall data quality of the report, and help prioritize where and how to improve data in the future, particularly when requesting data from suppliers. Companies should provide an assessment of emission factor data quality in their inventory report.

The *Scope 3 Standard* identified five commonly used data quality criteria[39] that are also applicable to Scope 2 data, describing both the representativeness of data (in terms of technology, time, and geography) and the quality of data measurements (i.e., completeness and reliability of data). These criteria are articulated in tables 10.2 and 10.3 with example assessments of emission factor data for reference.

Table 10.2. Examples of location-based electricity emission factor evaluation based on data quality indicators

Indicator (representativeness to the activity in terms of:)	Description	Examples of scoring emission factor data on different quality indicators
Technological representativeness	The degree to which the data set reflects the actual technology(ies) used for electricity generation in a region	*High quality*: Accurate emissions information from all technologies generating electricity on the grid *Poor quality:* lack of accurate information on technologies, so proxy data or assumptions from neighboring countries used
Temporal representativeness	The degree to which the data set reflects the actual time (e.g. day, month, year) or age of the activity	*High quality*: real-time dispatch information on daily basis, capable of being aggregated over annual period for inventory *Good quality:* publication of yearly average grid emissions for defined region soon enough after year-end for the emission factors to be used in calculating the corporate inventory for that year. *Poor quality:* data with several years difference between inventory year to which it is applied

[39] *Corporate Value Chain (Scope 3) Accounting and Reporting Standard*, p. 76

Geographical representativeness	The degree to which the data set reflects the actual geographic location of the activity (e.g. country or site)	*High quality*: power flow tracing from actual generation dispatched to consumer demand location Good quality: spatial boundaries specific to the dispatch region to reflect the emissions from generation sources supporting local consumption *Fair quality*: production information from broader geographic boundaries such as national borders *Poor quality*: Data from an area without a grid emission factor (i.e., using the factor of a neighboring country)
Completeness	The degree to which the data is statistically representative of the relevant activity. Completeness includes the percentage of locations for which data is available and used out of the total number that relate to a specific activity. Completeness also addresses seasonal and other normal fluctuations in data	*The activity is consuming electricity so the emission factor should represent a consumption-based boundary. But all generation produced and consumed within a region should be accounted for.* *High quality:* All GHG emissions from all electricity generation dispatched within a defined spatial region to meet consumer´s local demand, with methodology applied consistently across the regions where electricity is imported/exported (national or even trans-national) *Poor quality*: Only CO_2 emissions from selected electricity generation facilities (i.e., systematically excluding certain facilities or types of resources)
Reliability	The degree to which the sources, data collection methods and verification procedures used to obtain the data are dependable	*High quality*: Third-party verified data based on quality control checks using consistent methods, whether published by government, academic association, or data companies *Low quality*: Data not verified by third-party and no clear indication of quality control checks used

Because the market-based method for scope 2 relies on deriving emission factors from contractual instruments with a financial value (vs. a statistical set of emission factors used in the location-based method), consumers have demanded that contractual instruments demonstrate a minimum level of reliability and quality in order to be accepted as a valid emission factor in the market-based method. But additional data quality improvements beyond the Quality Criteria can be sought according to the table below.

For some indicator categories, a "low quality" example (e.g., poor temporal representativeness for a certificate generated several years prior used several years later) would not satisfy the criterion.

Table 10.3 Examples of market-based emission factor evaluation based on data quality indicators

Indicator (representativeness to the activity in terms of)	Description	Examples of scoring emission factor data on different quality indicators
Technological representativeness	The degree to which the data set reflects the actual technology(ies) used	*High quality:* The measured or calculated GHG emission rate associated with the energy production is clearly listed *Fair quality*: The technology and fuel is known (e.g. biomass combustion), but the emission rate associated with fuel combustion is not identified on the certificate

Temporal representativeness	The degree to which the data set reflects the actual time (e.g. year) or age of the activity	*High quality*: Generation occurred in the year for which the attributes are claimed or reported *Poor quality*: Generation occurred several years prior to the year for which the attributes are claimed or reported *(not allowed in Quality Criteria)*
Geographical representativeness	The degree to which the data set reflects the actual geographic location of the activity (e.g. country or site)	*High quality*: Purchase or claim of electricity attributes generated from within a country or market in which the entity claims the attributes *Poor quality*: Purchase or claim of electricity attributes generated outside the country or market within which the entity claims the attributes *(not allowed in Quality Criteria)*
Completeness	The degree to which the data is statistically representative of the relevant activity. Completeness includes the percentage of locations for which data is available and used out of the total number that relate to a specific activity. Completeness also addresses seasonal and other normal fluctuations in data.	*High quality:* All GHG emissions from all electricity generation within in defined market region are accounted for by contractual instruments, consistent supplier emission rate disclosure and residual mix, without double counting *Fair quality*: Residual mix is not available, allowing double counting and incomplete tracking of emissions in a market-based method
Reliability	The degree to which the sources, data collection methods and verification procedures used to obtain the data are dependable.	*High quality*: A certificate system uses 3rd party verification of data, tracks information in a registry, and provides for certificate retirement once a claim is made. *High quality:* Electricity suppliers use a consistent, publicly-available methodology to calculate the emission rate of their supply mix *Fair quality:* A PPA in a system without certificate tracking is assured or assessed by inventory verifiers, but information not tracked in a registry. *Low quality*: Data not verified, no indication of quality control checks used, no registry

10.4 Perform calculations

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

- 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.

- Multiply Global Warming Potential (GWP) values by the GHG totals to determine total in CO_2equivalent (CO_2e).

- Report final scope 2 by each method in metric tons of each GHG and in CO_2e

Box 10.1 Basic calculation formula for calculating GHG emissions

Activity data	x	Emission Factor for Each GHG	=	Total emissions by metric tons by Gas	X	GWP	=	Total emissions in metric tons in CO_2e

Example calculations are provided for the location-based method and market-based method in Table 10.4 and 10.5, respectively.

Table 10.4 Example calculation for location-based method

Activity data			**Emission factors**					**Calculated Emissions**			
Facility	Location	Quantity of energy	CO_2 emission rate	CH_4 emission rate	N_2O emission rate	CO_2e emission rate	*GHG emission factor source*	CO_2 (mt)	CH_4 (kg)	N_2O (kg)	CO_2e (mt)
US facilities	eGRID subregion NYUP	2,500 MWh	497.92 lb/MWh	15.94 lb/GWh	6.77 lb/GWh	500.35 lbs/MWh	*eGRID* year 2009	564.63	18.07	7.67	567.39
	eGRID subregion RFCE	2,500 MWh	947.42 lbs/MWh	26.84 lb/GWh	14.96 lb/GWh	952.63 lbs/MWh	*eGRID* year 2009	1074.36	30.43	16.97	1080.26
EU facilities	Denmark	3,000 MWh	0.303 mtCO2	---	---	0.303 mtCO2e	*IEA Denmark, 2011*	908.25	---	---	908.25
	Belgium	2,000 MWh	0.218 mtCO2	---	---	0.218 mtCO2e	*IEA Belgium, 2011*	435.79	---	---	435.79
Total consumption		**10,000 MWh**									
Total scope 2 emissions in market-based method								**2983.02**	**48.51**	**24.64**	**2,991.68**

Table 10.5 Example calculation for market-based method

Activity data				**Emission factors**	**Calculated Emissions**	**Quality Criteria and disclosure**		
Facility	Total energy consumpt-ion	Contractual instrument type	Quantity of energy	CO_2e emission rate	CO_2e (mt)	Quality Criteria met?	Regulatory relationship	Other product features
US operations	5,000 MWh	PPA with REC retention	2,500 MWh	0 mt CO2e / MWh	0 mtCO2e	Yes, Green-e certified	Regulatory surplus	See disclosure statement
		REC purchase	2,500 MWh	0 mt CO2e / MWh	0 mtCO2e	Yes, Green-e certified	Regulatory surplus	
EU operations	5,000 MWh	Supplier program	3,000 MWh	0.25 mtCO2e	750 mtCO2e		Inclusive of quota	
		Residual mix	2,000 MWh	0.5 mtCO2e	1,000 mtCO2e	x	n/a	
Total energy consumption			**10,000 MWh**					
Total scope 2 emissions in market-based method					**1,750 mtCO2e**			

10.5 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.*

11. Reporting Requirements

A credible GHG emissions inventory presents relevant information that is complete, consistent, accurate and transparent, following the *Corporate Standard.* For scope 2, this includes the following requirements:

11.1 Required Information for scope 2

A public scope 2 GHG emissions report that is in accordance with the *GHG Protocol Corporate Standard* and Scope 2 Guidance **shall** include the following information:

11.1.1 Description of the company and inventory boundary

- An outline of the organizational boundaries chosen, including the chosen consolidation approach.
- The reporting period covered
- Any specific exclusions of sources, facilities and/or operations

11.1.2 Information on emissions

For all companies

- Emissions data for all 7 GHGs separately (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, NF_3) in metric tonnes and in tonnes of CO_2 equivalent. For electricity generation, only CO_2, CH_4 and N_2O are generally emitted.

- Emissions data for direct CO_2, emissions from biologically sequestered carbon (e.g., CO_2 from burning biomass/biofuels), reported separately from the scopes. Any CH4 and N2O emissions from biomass/biofuel combustion should be included in scope 2.

- **Methodology disclosure**: Methodology used to calculate scope 2 emissions according to each method, providing a reference or link to any calculation tools used. For the market-based method, companies shall disclose the category of instruments from which emission factors were derived.

- **Base year information:** Year chosen as base year and method used, and appropriate context for any significant emission changes that trigger base year emissions recalculation (acquisitions/divestitures, outsourcing/insourcing, changes in reporting boundaries or calculation methodologies, etc.)

For companies with operations in markets *without* choice in electricity product or supplier

- Only one scope 2 figure **shall** be reported, based on the location-based method. For most companies using the *Corporate Standard,* this represents no change in methodology or reporting.

For companies with operations in markets *with* choice in electricity product or supplier: (see chapter 6, 9)

- Companies **shall** report scope 2 in two ways: one total based on the location-based method, and one total based on the market-based method where applicable and Quality Criteria are met.

- Many companies' inventories will include a mix of operations globally, some where the market-based method applies and some where it does not. Emissions from any operations in locations that do not support a market-based method approach **shall** be calculated using the location-based method.

- **Quality Criteria:** If reporting a market-based scope 2 figure, a statement from a 3rd party **shall** be made that the instruments used met the Quality Criteria in this Guidance, or reference given to the certificate's certification program which has verified conformance with the Quality Criteria.
  - If a residual mix is not currently available, reporters should footnote: *"No adjustment to the grid average emissions factor has been made to account for voluntary purchases. An adjusted emissions factor is not available or has not been estimated. This may result in double-counting."*

- **Compliance instrument relationship disclosure**: If reporting a market-based scope 2 total, it **shall** be stated whether the certificate used is:

  - *Above and beyond compliance quotas*
  - *Combined with a retired compliance instrument*
  - *Not surplus to compliance instruments*

  If a supplier-specific emission rate includes a compliance quota, the reporting entity should document "inclusive of supplier quota." Additional optional language explaining the relationship can be provided (see chapter 9).

- **Disclose basis for Goal setting**: If a reporting entity sets a scope 2 reduction goal, the entity **shall** clarify whether based on the location- based method total or market-based method total (a market-inclusive figure may be more appropriate for demonstrating company procurement actions).

- **Disclose basis for Scope 3 data uses:** The reporting entity **shall** identify which method total is provided to other entities to calculate their scope 3, product life-cycle analysis inventories, or other GHG inventory uses (if applicable).

11.2 Recommended information disclosure

- Electricity consumption: Disclose in KWh or MWh, separately from the scope totals. This can enhance understanding of energy efficiency or conservation efforts undertaken.

- Product features: If reporting a market-based method total, the product generation features and market context information as indicated in Ch. 9 **should** be disclosed for added transparency about the procurement choices in different markets

- Data quality: Reporting entities **should** report an assessment of data quality (both activity data and emission factors) based on data quality indicators.

- Any offsets or allowances (in metric tons) retired on behalf of the contractual energy purchase.

11.3 Optional information

- Scope 2 totals disaggregated by country (see example)

Country	Market-based Method Total in metric tonnes CO_2e	Location-based Method Total in metric tonnes CO_2e
USA	0	1,000
Japan	400	600
Denmark	0	300
Mozambique	300 (*No market choice)*	300
Total Scope 2	**700**	**1,200**

- Percent of electricity consumption in markets with choice: To improve transparency, companies **may** note what percentage of their overall electricity consumption reported in the market-based method reflects markets with choice.

- Avoided emissions estimation: Consistent with chapter 8 of the *Corporate Standard,* this Guidance will describe how companies **may** separately report an estimation of GHG emissions avoided from a project or action. This quantification should be based on project-level accounting, with methodologies and assumptions documented (including to what the reduction is being compared).

- Disclose purchases that did not meet Quality Criteria: If a reporting entity's energy purchases did not meet Quality Criteria, the entity **can** note this separately. (Location-based method data will be used for scope 2 quantification if market-based method data does not meet Quality Criteria).

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

To communicate the value of both scope 2 method totals, see chapter 7.

12. 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.

12.1 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 choose to track scope 2 performance or set a scope 2 reduction target, companies **shall** choose a scope 2 base year and 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. 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).

Companies who 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.

Once a base year is selected, a reporting entity must 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.

12.2 Recalculating base year emissions

The *Corporate Standard* notes that recalculation may be necessary 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 location-based figure has been used as a proxy since a market-based figure 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 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.

12.3 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 (see chapter 2). Based on this Guidance, companies should specify which method's results are being used to set a reduction target over time. Two targets, one for each method's results, is possible and can help prioritize projects which will reduce both totals' emissions. Certain actions will reduce emissions in both totals, while other actions are more clearly reflected in only one of the methods. These are described below.

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)
- **Target level.** The numerical value of the reduction target

The activities that reduce sector-wide emissions over time are described in chapter 7, 8 and 9. The actions that help achieve a reduction target for each method are described below.

12.3.1 Targets for market-based scope 2 total

To achieve reductions in the market-based method, a company can reduce energy consumption, change supply to on-site rather than grid-distributed (any emissions from on-site generation may become scope 1 depending on consolidation approach), and change its energy procurement choices depending on the options available. In some markets, legally-enforceable claims associated with the acquisition of energy tracking certificates make this a more appropriate goal for external-facing messaging.

12.3.2 Targets for location-based scope 2

To achieve reductions in the location-based method, a company can reduce energy consumption, change time of day of consumption (if time-based emission factors are available), change supply to on-site rather than grid-distributed (any emissions from on-site generation may become scope 1 depending on consolidation approach). The location-based method grid average emission factor can decrease due to supply changes prompted by local/regional policies or economic conditions. New low-carbon projects' funded by other consumers would also reduce the grid-average factor. However, a noticeable difference in grid emission factors would require significant aggregate action by consumers.

- The location-based method results are not reflective of market-based claims, which may be legally-enforceable in some areas. Caution should be exercised in creating marketing claims based on the location-based method total. For example, see US Federal Trade Commission Green Guide for consumer-facing environmental claims.

12.3.3 Reducing scope 2 in both totals

Reducing grid-supplied energy consumption can help achieve both market-based and location-based scope 2 targets, whether through efficiency/conservation efforts or through changing to on-site energy production. When it comes to grid-supply procurement decisions, contractual transactions that help support new, local low-carbon projects can count towards market-based emission factors as well as help reduce the GHG intensity of the location-based emission factor over time.

12.4 Holistic energy goals

Some companies and industry groups have emphasized a holistic approach to energy and GHG emissions management, emphasizing the primacy of consumption changes. Other related goals include:

- **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 the overall energy performance of operations.

- **Renewable energy procurement goals**– Some companies have set the goal to be powered or supplied by 100% 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 RE 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.

APPENDIX A. SURVEY OF CURRENT ENERGY ATTRIBUTE TRACKING CERTIFICATES BY COUNTRY AND REGION

This summary of certificate tracking systems is intended to provide general information about the availability of such systems around the world. Tracking systems do not themselves the boundaries for energy attribute markets; rather, they are a tool to help execute energy attribute certificate issuance and cancelation/retirement/claims. They are registries whose function is to verify generation and energy attributes, to support ownership claims and to prevent double counting. They are typically tied to geopolitical or grid operational boundaries, but they do not define the market boundaries for voluntary claims made on these certificates. 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.

REGION **COUNTRY** **Subregion**	**Instrument issuer and associated tracking system**
USA & Canada	
Michigan	Michigan Renewable Energy Certification System (MIRECS) www.mirecs.org Government-owned
Mid-Atlantic	PJM-Generation Attribute Tracking System (GATS) www.pjm-eis.com/ Grid-operator-owned private subsidiary
New England	NEPOOL Generation Information System (GIS) http://www.nepoolgis.com/ Power pool-owned
New York	New York Generation Attribute Tracking System (NYGATS) (under development) http://www.nyserda.ny.gov/Energy-and-the-Environment/New-York-Generation-Attribute-Tracking-System.aspx Government-owned
North Carolina	North Carolina Renewable Energy Tracking System (NC-RETS) http://www.ncrets.org/ Government-owned
Rest of USA & Canada	North American Renewables Registry (NAR) www.narecs.com Privately owned
Texas	Texas Renewable Energy Certificate Program – Electricity Reliability Council of Texas (ERCOT) https://www.texasrenewables.com/ Grid operator-owned
Upper Midwest	Midwest Renewable Energy Tracking Systems (M-RETS) www.mrets.org Private, non-profit owned
West	Western Renewable Energy Generation Information System (WREGIS) www.wregis.org Non-profit electricity reliability organization
Europe (including EU/EEA)	
Austria	European Energy Certificate System Guarantee of Origin (EECS-GO) issued by E-Control www.e-control.at
Belgium	EECS-GO issued by Brugel (Brussels), VREG (Flanders) or CWaPE (Wallonia). http://www.brugel.be/ http://www.vreg.be/ http://www.cwape.be/
Croatia	HROTE has made formal application to issue EECS-GO, and is expected to commence in summer 2014. http://www.hrote.hr
Cyprus	TSO-CY has made formal application to issue EECS-GO, and is expected to commence in summer 2014. http://www.dsm.org.cy
Czech Republic	EECS-GO Issued by OTE http://www.ote-cr.cz/
Denmark	EECS-GO issued by Energinet http://www.energinet.dk
Estonia	Elering has made formal application to issue EECS-GO, and is expected to commence in spring 2014. http://www.elering.ee

REGION COUNTRY Subregion	Instrument issuer and associated tracking system
Finland	EECS-GO – issued by Grexel http://www.grexel.com/
France	EECS-GO – issued by Powernext http://www.powernext.com/
Germany	EECS-GO – issued by Umweltbundesamt http://www.umweltbundesamt.de/
Iceland	EECS-GO – issued by Landsnet http://www.landsnet.is/
Italy	EECS-GO – issued by GSE http://www.gse.it
Luxembourg	EECS-GO – issued by ILR http://www.ilr.public.lu/
Netherlands	EECS-GO – issued by CertiQ http://www.certiq.nl/
Norway	EECS-GO – issued by Statnett http://www.statnett.no/
Slovenia	EECS-GO – issued by Javna agencija RS za energijo http://www.agen-rs.si
Sweden	EECS-GO – GOs are issued by http://www.energimyndigheten.se/ imports and exports of EECS-GOs done by Grexel http://www.grexel.com/
Switzerland	EECS-GO – issued by http://www.swissgrid.ch/
Other EU/EEA countries not mentioned	National GOs often exist although they are not electronically standardized.
Asia	
Turkey	Turkish I-REC Certificate – issuer information can be found at http://www.internationalrec.org
Taiwan	Taiwanese I-REC Certificate – issuer information can be found at http://www.internationalrec.org
South Africa	zaREC - Issued by http://www.zarecs.co.za/. Standardization agreement with I-REC .

Appendix B. Comparing Offset Credits with Energy Attribute Certificates

Offsets from renewable energy facilities

Renewable energy projects remain a popular type of GHG reduction project under offset schemes such as the Clean Development Mechanism (CDM) as well as voluntary standards. Offset schemes are designed to provide a revenue stream that enables a project to be built which, in the absence of the offset sales, would be unfeasible. The offset represents a quantity of GHG emissions reduced or avoided by the project compared to a baseline scenario of what would have occurred in the absence of the offset-funded project. See Appendix C for more information on avoided emissions calculation and methodology.

Offsets have primarily been issued from renewable energy generation facilities in emerging economies where energy attribute certificates are not available. However, in grids where generation projects are established, the energy output from the generation facility is supplied to the local grid and consumed by local end-users. Like all energy generation, the energy output is subject to contracts between generators and suppliers. This means that the zero emission rate from the generation facility will likely be reflected in several emission factors:

- Grid average emission factors
- Supplier-specific emission factors
- Any PPAs between the generator and consumer of the energy.

For scope 2 accounting, these contractual information sources may still qualify as a conveyer of energy generation emission rates under the market-based method. Therefore, the zero emission rate from the project will likely be reflected in both the location-based and market-based method for scope 2. Companies **should** disclose whether their contractual instrument (such as a supplier-specific emission rate or PPA) is associated with or includes a facility that also produces GHG offsets. This is an evolving space where local regulation or restrictions on how the emissions information from offset-generating facilities is treated will continue to develop.

Distinguishing avoided emissions from scope 2 accounting

It may appear that the GHG emissions benefit of the offset is "double counted" with the scope 2 allocation procedures for the project's grid. But there are subtle differences between the GHG emissions information contained in an offset as compared with a contractual instrument in scope 2. An offset does <u>not</u> convey information about energy emissions occurring at the point of production, like a contractual instrument does. Instead, an offset conveys emissions avoided from the rest of the grid compared to a BAU scenario. Its claim concerns an impact relative to the rest of the grid. By example, a natural gas facility newly established in a largely coal-based grid will avoid operating margin emissions as coal plants with a higher GHG emission rate are backed down. But the natural gas plant still emits at a fixed rate (emissions/MWh). See Appendix C for further distinction between avoided emissions and emission-rate calculation.

The company purchasing and claiming the offset can make a claim in their inventory outside of the scopes about tons of avoided emissions represented in the offset. The consumer using a contractual instrument conveying the generation attributes of the underlying power can make a claim about using zero emissions power in a market-based scope 2 report.

Other claims from offsets

Offsets are designed to be fungible globally, derivable from a variety of project types (forestry, renewable energy, etc.) and should only convey metric tonnes of avoided GHG emissions to the purchaser. To date, offset credits 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 indeed designed to also provide a variety of social and sustainable development benefits, these have not been quantified and conveyed directly with the offset credit. Those social benefits are designed to "stay" within the community, even as the carbon is sold globally. It would not be supported to infer from the offset a variety of unquantified, unverified and unspecified other claims about the project.

Other offset accounting issues

Companies may encounter offsets while calculating a corporate inventory, including when:

- *Offsets are included in a purchased electricity product (e.g. provided by supplier to "reduce" emissions globally)* Offsets are accounted for separately; they are not an electricity instrument conveying attributes about the energy purchase. Any offsets obtained by the supplier for the consumer should be reported separately.

- *Reporter owns a renewable energy project that produces offset credits sold on the global market.* The company owning the renewable energy facility shall separately report any offsets produced from the generation, outside of the scopes.

APPENDIX C. METHODS FOR EVALUATING REDUCTIONS IN THE GRID-DISTRIBUTED ENERGY SECTOR

To reduce and avert the worst impacts of climate change, significant reductions across all GHG producing sectors, including electricity, are necessary. But for a shared energy distribution system with multiple possible production points, evaluating whether and how emissions have been reduced based on specific actions can vary depending on the type and boundaries of the analysis. Emission reductions can be evaluated using different boundaries, including:

- Project level (looking at the generation method that may be backed down as a result of the action or how the action impacts which generating methods are built)

- Sector level (treating energy as a single system whose boundaries are defined geopolitically or by grid physics), or

- Corporate or consumer level (under both a location-based and market-based method). The GHG Protocol also is currently developing standards for evaluating the impacts of climate policies and actions taken by national actors, including policies affecting the electricity sector.

Scope 2 reductions recorded in a corporate inventory do not necessarily correspond to absolute reductions, but instead should be thought about in terms of contributing to aggregate reductions in GHG emissions throughout the sector. However, companies can estimate avoided emissions from projects or actions using project-level methodology in the *GHG Protocol Guidelines for Grid-Connected Electricity Projects,* 2007*.*

Understanding the difference the emission reduction evaluation methods can help to understand the action a company has undertaken and how the effect is described. While this Guidance is designed for corporate level scope 2 accounting, historic sector-level analysis within a national boundary can provide the overall emission trends that inform national-level reduction commitments and policies. These are compared in Table C.

- **Project level reductions**
  Any new grid-connected electricity generation facility (or anew "project") or energy efficiency project, will have an impact on when other energy generation facilities provide electricity, and how much. As noted in chapter 6, these dynamics are influenced by the choices of the grid operator or utility. In the case of low-carbon generation projects, evaluating the emission reduction impact of the project can be necessary for earning offset credits (where applicable) or generally describing the benefits of the project. The emissions impact of new electricity projects can be assessed in terms of operating margin (what other energy generation facilities within the defined grid region are likely "backed down" due to the operation of the new project) and the build margin (how the emissions rate of the new project compares to what would likely have been built otherwise). A combination of the operating margin and build margin constitute the emissions reference case (baseline) against which the project's impact is evaluated. This enables the project to claim that the project creates reductions occurring at other generation facilities throughout the gird, compared to what would have occurred in the absence of the project.

  This type of impact analysis could theoretically be conducted for any type of new energy generation project (or in the case of the operating margin, an existing one: that is, what other generation facilities operating at the margin are impacted when this facility operates?) However, offset projects require proof that the project was built due to the ability to sell offset credits – and that without the intervention of the offset, the project would not have been constructed. If a new energy generation project would likely have been built due to support by other local financial incentives, or generally favorable market conditions, then the offset credit cannot claim to have spurred "additional" reductions. This is not to say that emissions have not been reduced at a sector level in aggregate; instead, it means that the offset has not been the cause of those reductions and therefore loses the right to convey that claim through the offset.

Table C. Comparing different boundaries and methods for assessing reductions in the grid-distributed energy sector

Type of analysis	Type of comparison	Boundary of analysis	Example
Project Level			
• Avoided emissions	**Hypothetical reference case**	Grid distribution area	A renewable energy offset project reduced emissions at 100 metric tons/year compared to what would have occurred in the absence of the offset incentive
Sector Level			
• Absolute emissions	**Historic**	Geopolitical or grid distribution area	Emissions from energy generation in X- state have decreased in absolute terms from 6,000 metric tons CO2e in year 1990 to 5,000 metric tons CO_2e in year 2000
• Emissions intensity	**Historic**	Geopolitical or grid distribution area	The GHG-intensity of energy production in grid service region Y have decreased from 0.5 kg/KWh in 2005 to 0.4 kg/KWh in 2006
Corporate or Consumer Level			
• Location based method	Relative to past corporate scope 2 inventories	Emission factors calculated at grid distribution area, or sub-national or national level	Reported emissions have decreased from 400 metric tons CO_2e in 2010 to 370 metric tons CO_2e in year 2011. This is due to combination of consumption decrease and emission factor decrease
• Market-based method	Relative to past corporate scope 2 inventories	Market-boundary where attribute claims traded.	Reported emissions have decreased from 400 metric tons CO2e in 2010 to 0 metric tons CO_2e in year 2011. This is due to consumption decrease and purchasing low-GHG emission contractual instruments for 100% of consumption

- **Reductions reported in corporate scope 2 inventories**

Emission reductions in corporate scope 2 accounting are defined as actual, historic reduction within a defined boundary – and the calculation method simply implies different methods and boundaries in which that change should be tracked. 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 activity of the reporting company and the resulting GHG emissions.[40] 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.[41]

- For the location-based method, reductions are recorded based on a combination of decreases in the reporting entity's consumption and decreases in the grid-average emission factor. A decrease in emissions intensity of the grid average emission factor may not necessarily correspond to absolute reductions in emissions over time. Likewise, absolute emissions at the sector level may decrease while the emission rate stays the same.

- For the market-based method, reductions are recorded based on a combination of decreases in the reporting entity's consumption and contractual instruments claimed. Chapter 6 and 9 describe how market-based methods can lead to overall emission reductions in the sector over time. Residual mixes represent the adjusted mix of "unclaimed" emissions. Therefore, one effect of implementing a contractual claims system for scope 2 could mean that other reporters using a residual emission rate for scope 2 could see their emission rate *increase* compared to previous years*.* Again, technically this rate increase does not necessarily indicate that more emissions are occurring on the grid compared to years past – it simply reflects different allocations of emissions to consumers on the grid.

Avoided emissions calculations in the US

This emissions calculations approach stems from an historic treatment of contractual instruments in US programs[42], which were treated as a type of "offset" in a scope 2 corporate GHG inventory instead of an emission rate allocating generator emissions to grid consumers. Under this "avoided emissions" estimation, a user would first calculate a gross scope 2 figure according to a grid average emission factor (called the location-based method in this Guidance). Then, it would multiply the MWh of represented by purchased renewable electricity by the *marginal emission rate* or *non-baseload* rate in the grid where the renewable electricity was generated[43]. This rate represents an estimate of the emissions (per MWh) of sources that are operating on the margin, and which would therefore most likely be displaced by a new renewable energy source. The

[40] 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.

[41] *Corporate Standard,* p. 59 and 60

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

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

reporting entity then *deducted* the estimated "avoided emissions" from the renewable electricity purchase from their calculated gross scope 2.

This approach is a simplified version of renewable energy offset project accounting, as described in the *Guidelines for Grid-Connected Electricity Projects.* Renewable energy offsets are designed to quantify and represent absolute emission reduction occurring at other fossil fuel generators elsewhere on the grid.

- **Definition**: Corporate GHG accounting tracks emissions associated with a quantity of energy consumed, rather than estimates emissions avoided due to a specific intervention.
- **Boundaries:** In project-level accounting, a baseline comparison serves as the reference point for assessing the emissions avoided. This is a fundamentally different boundary than the historic year-on-year corporate inventory tracking historical emissions over time.
- **Instrument differences:** Most certificates do not undergo the quality criteria evaluation that offset projects do to ensure additionality, ownership, etc. This limits the extent to which certificates can reasonably be stated to *avoid emissions.*

Project level accounting for corporate energy projects or purchases

Many companies have sought a means to calculate how changes to their own operations result in GHG emissions changes at sources not included in their own inventory boundary, or not captured by comparing emissions changes over time. This could include:

- *A new renewable energy project either owned by the company or providing energy to a company via a PPA*

- *Substituting fossil fuel with waste-derived fuel that might otherwise be used as landfill or incinerated without energy recovery.*

- *Installing an on-site power generation plant (e.g., a combined heat and power, or CHP, plant) that provides surplus electricity to other companies may increase a company's direct emissions, while displacing the consumption of grid electricity by the companies supplied.*

- *Substituting purchased grid electricity with an on-site power generation plant (e.g., CHP) may increase a company's direct GHG emissions, while reducing the GHG emissions associated with the generation of grid electricity.*

Being able to quantify the GHG impacts of a project outside the inventory boundary, *on the rest of the grid,* can provide several technical and strategic benefits, including:

- Identifying where low-carbon energy projects can have the biggest GHG impact on system, based on the operating margin.

- Demonstrating that grid-connected projects provide a system-wide service in addition to conveying a specific emission rate at the point of production.

This Guidance follows the *Corporate Standard's"*[44] recommendation to report a grid emissions impact evaluation – termed an avoided emissions calculation when the project is low-carbon and avoids grid emissions—separately from its scope totals. This type of disclosure must specify what project-level methodologies were used.

[44] *GHG Protocol Corporate Standard,* p. 61

APPENDIX D. GUIDANCE ON RESIDUAL MIX CALCULATION

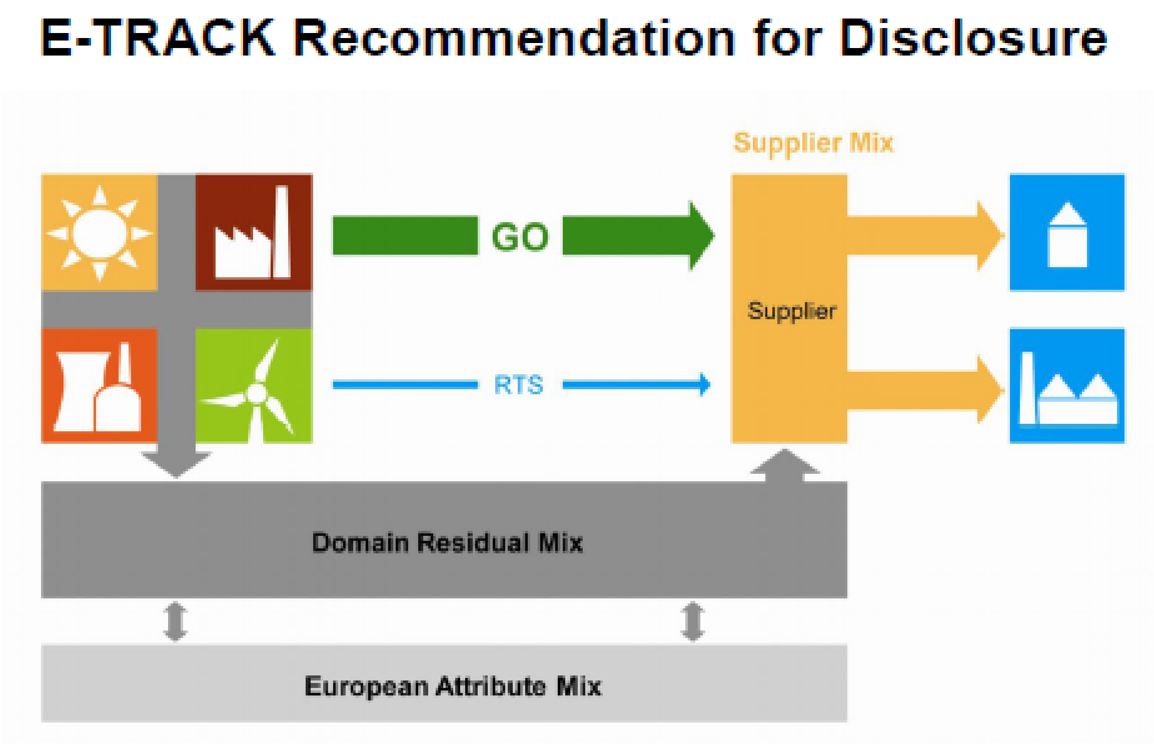
A residual mix serves as a default data source under the market-based method, to be used as an emission factor when no specified energy purchases have been made. For many jurisdictions, a residual mix represents a new type of emission rate data to calculate at the sub-national or national level. Procedures for national regulators or other market data providers to calculate this mix are still emerging, but this Appendix highlights the overall procedures explored in the European market based on research from the E-TRACK project[45] and initial publications of residual mixes through the RE-DISS project.[46]

Core concepts in residual mix calculation and use include:

- When certificates are exported without associated energy, they are not available to be part of the residual mix calculation. The energy that remains behind is "null power" and will receive residual mix attributes for labeling purposes

- If certificates are imported without associated energy, those attributes should not be part of the calculated residual mix as they are claimed by individual consumers

- The domain must specify whether the mix will use energy production-only data to begin, or use energy consumption (reflect imports/exports of energy)



Step 1. Define the boundary of the market boundary. This is boundary in which trading, and exchange of energy generation attributes, will be occurring.

[45] http://www.e-track-project.org/docs/WP7_E-TRACK-Standard-Revised.pdf
[46] http://www.reliable-disclosure.org/upload/4-RE-DISS_2012_Residual_Mix_Results_v1_0.pdf

- Example: The US constitutes a single market. In addition to production occurring in the United States, this can also include energy imported from border areas in Canada
- Example: EU countries using the Guarantee of Origin instrument. Standardization through the European Energy Certificate System (EECS System) helps the trading process between participating countries

Step 2. Define the domain. This is boundary of the residual mix calculation.

- Example: A single country within a multi-country market, such as Norway

- Example: A sub-national entity or geographic region, such as eGRID sub-regions in the US (regions where energy production data already exists)

Step 3. Identify core information about domain energy production and contractual instrument sales and acquisition

- Identify net electricity generation and related emissions associated with the defined domain

    - Example: country-level energy production and emission publications, such as ENTSO-E or national sources

- Identify total quantity of contractual instruments conveying attribute claims generated within the domain. Identify quantity sold, and quantity cancelled/retired by the domain's issuing body. In the EU, the Association of Issuing Bodies can obtain this information in coordination with electronic tracking infrastructure providers such as Grexel. In the US, volumes of RECs are tracked via regional tracking systems.

Step 4. Perform a preliminary residual mix calculation. This represents an initial adjustment of domain electricity production based on attributes of sold and acquired contractual instruments. To the domain electricity production information:
– Add emission attributes of contractual instruments which have been imported
– Subtract cancelled/retired contractual instruments and their attributes

Step 5. Determine whether initial adjustment yields a surplus or deficit of contractual instrument attributes
This requires determining the volume of contractual instruments available for domain-level disclosure. A deficit occurs when there are insufficient contractual instruments to apply to the electricity consumption occurring within the domain; a surplus occurs when the domain holds more contractual instruments than the electricity it consumes.

Step 6. Exchange with the market-boundary attribute mix
The market's attribute mix is filled from all the preliminary residual mixes of the domains which have a surplus in attributes. Domains in deficit use the market attribute mix to "fill up" the rest of their residual mix.

Step 7. Final residual mix correction for the domain
If the domain had a surplus of attributes, then the final residual mix is the same as the preliminary residual mix, but the volume is reduced according to the final consumption in the domain. If the domain had a deficit in attributes, then the preliminary residual mix and the inflow from the market attribute mix are merged to the final residual mix in the domain.

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 partitioning GHG emissions from a single facility or other system (e.g., vehicle, business unit, corporation) among its various outputs.
Allowance	A commodity giving its holder the right to emit a certain quantity of GHG.
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; USA.
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, e.g. wood, straw and ethanol from plant matter
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).
Biogenic CO2 emissions	CO2 emissions from the combustion or biodegradation of biomass.
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.
Cap and trade	A system that sets an overall emissions limit, allocates emissions allowances to

system	participants, and allows them to trade allowances and emission credits with each other.
Capital Lease	A lease which 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 Financial or Finance Lease. Leases other than Capital/Financial/Finance leases are Operating leases.
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 (CO2e)	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.
Co-generation unit/Combined heat and power (CHP)	A facility producing both electricity and steam/heat using the same fuel supply.
Contractual instrument	Any type of contract between two parties for the purchase of energy or conveyance of attribute claims from that energy. Energy attribute certificates are a type of contractual instrument
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).
Consumer	The end consumer or final user of a product.
Company	The term company is used in this standard as shorthand to refer to the entity developing a scope 3 GHG inventory, which may include any organization or institution, either public or private, such as businesses, corporations, government agencies, non-profit organizations, assurers and verifiers, universities, etc.
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 take ownership of the same emissions or reductions. Some built into corporate framework of direct and indirect, but trouble when same entity same scope
Electric utility	An electric power company whose operations include generation, transmission and distribution of electricity for sale. Generally refers to energy companies in regulated markets.
Eligibility criteria	Features or conditions defined by a policy or program that determine what of energy generation facilities can participate in the program or issue certificates that will fulfill programmatic requirements.
Emission Factor	A factor that converts activity data into GHG emissions data (e.g., kg CO2e

	emitted per liter of fuel consumed, kg CO2e 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 electricity sector to convey information about energy generation to other entities involved in the sale, distribution, consumption or regulation of electricity. This category includes instruments which may go by several different names, including certificates, tags, credits, etc.
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.
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.
Finance Lease	A lease which 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.
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 non-government 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 stand-alone 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 CO2.
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 six gases covered by the UNFCCC: carbon dioxide (CO2); methane (CH4); nitrous oxide (N2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF6), and nitrogen triflouride (NF_3).
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.
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 tonne of cement by 12% between 2000 and 2008.
Intergovernmenta l Panel Climate Change (IPCC)	An International body of climate change scientists. The role of the IPCC is to assess the scientific, technical and socio-economic 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 that are 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 Guidance , jurisdictions are typically countries but may be multi-country regions.
Kyoto Protocol	A protocol to the United Nations Framework Convention on Climate Change (UNFCCC). Once entered into force it will require countries listed in its Annex B (developed nations) to meet reduction targets of GHG emissions relative to their 1990 levels during the period of 2008–12.
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	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, sub-national or national boundaries.
Market-based method for scope 2 accounting	A method to quantify scope 2 GHG emissions based on GHG emission factors derived from contractual instruments that convey attribute claims from the point of energy generation to the point of energy use.
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."
Operating Lease	A lease which 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.
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by the reporting company.
Operational	A consolidation approach whereby a company accounts for 100 percent of the

control	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).
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.
Offset Credit	Offsets are discrete GHG reductions used to compensate for (i.e., offset) GHG emissions 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 of distributed energy generation.
Power	Power is the rate at which energy is transferred from one physical system to another. The standard unit for power is the watt, defined as the transfer of one joule of energy per second. In these guidelines, power indicates the rate at which a power plant transfers energy to the grid.
Power Purchase Agreement	A type of contract that allows a consumer, typically large 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.
Product feature disclosure	A description of specific and contextual features (besides the GHG emission rate) about the energy represented in a contractual instrument that can enable greater transparency about the program or market in which the purchase took place.
Quality Criteria	A set of requirements that contractual instruments must meet in order to be used in the market-based method for scope 2 accounting.
Renewable energy	Energy taken from sources that are inexhaustible, e.g. wind, water, solar, geothermal energy, and biofuels.
Renewable energy certificate	A type of energy attribute certificate, used in the US and Australia. In US, a REC is defined as representing the property rights to the environmental, social, and other nonpower qualities of renewable electricity generation.
Renewable Portfolio Standards (RPS)	A state or federal 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 marketeer depending on the national or sub-national regulation.
Self-generation	On-site generation owned or operated by the entity that consumes the power.
Scope 1 emissions	Emissions from operations that are owned or controlled by the reporting company.

Scope 2 emissions	Emissions from the generation of purchased or acquired electricity, steam, heating or cooling consumed by the reporting company.
Scope 3 emissions	All indirect emissions (not included in scope 2) that occur in the value chain of the
Scope 3 activity	An individual source of emissions included in a scope 3 category.
Scope 3 category	One of the 15 types of scope 3 emissions.
Significance threshold	A qualitative or quantitative criteria used to define a significant structural change. It is the responsibility of the company/ 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).
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) must provide specific emission-rates for each product and ensure they are not double counted with standard power offers.
Supplier quota	Regulations requiring electricity suppliers to source a percentage of their supply from specified sources, e.g. Renewable Portfolio Standards in US states. Regulations generally defined eligibility criteria that energy facilities must fulfill in order to be used to demonstrate compliance.
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.
Target base year	The base year used for defining a GHG target, e.g. to reduce CO_2 emissions 25% below the target base year levels by the target base year 2000 by the year 2010.
Target boundary	The boundary that defines which GHG's, geographic operations, sources and activities are covered by the target.
Target commitment period	The period of time during which emissions performance is actually measured against the target. It ends with the target completion date.
Target completion date	The date that defines the end of the target commitment period and determines whether the target is relatively short- or long-term.
Target double counting policy	A policy that determines how double counting of GHG reductions or other instruments, such as allowances issued by external trading programs, is dealt with under a GHG target. It applies only to companies that engage in trading (sale or purchase) of offsets or whose corporate target boundaries interface with other companies' targets or external programs.
Tracking System	A database or registry that helps execute energy attribute certificate issuance and cancelation/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.
United Nations Framework Convention on Climate Change (UNFCCC)	Signed in 1992 at the Rio Earth Summit, the UNFCCC is a milestone Convention on Climate Change treaty that provides an overall framework for international efforts to (UNFCCC) mitigate climate change. The Kyoto Protocol is a protocol to the UNFCCC.
Utility	See electric utility.
Vintage	The date that electric generation occurs and/or was measured, from which an energy attribute certificate is issued.