Instructions for Proposing Revisions to the Scope 2 Standard

About this document

The purpose of this document is to provide a framework for proposed Phase 1 revisions to the scope 2 standard in a consolidated, organized, and efficient manner. While it includes excerpts from the Scope 2 Guidance, it is not exhaustive. Its contents primarily focus on the purposes and intended uses of each method as described within the Scope 2 Guidance, their respective calculation methodologies, and the associated reporting requirements.

Instructions for TWG members

Step 1: Review this document in its entirety and determine whether any critical text from the Scope 2 Guidance has been omitted. The secretariat has made every effort to consolidate and organize all relevant text from the Scope 2 Guidance that pertains to revision topics within the Phase 1 Scope of Work in the Scope 2 Standard Development Plan (SDP). If any such information from the Scope 2 Guidance has been omitted from this template, please notify the secretariat as soon as possible. In the event there are additions to the text deemed necessary, such updates will be logged in the section 'Change Log' as well as added in its appropriate location(s) within the document.

Step 2: Propose edits to the scope 2 standard using Track Changes feature in Word. This could include adding, deleting, or modifying:

- How the various purpose, use, and objectives of each method are presented
- Methodology
- Reporting requirements and recommendations
- Other sections as applicable
- Terminology or references

All edits proposed must relate to Phase 1 topics identified in the Scope 2 SDP Scope of Work. Proposed edits for any items identified in the Scope 2 SDP as "out-of-scope items addressed elsewhere by GHG Protocol" should be avoided. Phase 2 topics will be considered following public consultation on Phase 1.

Step 3: Develop supporting rationale. In addition to development of specific revisions to the scope 2 standard as described above, TWG members are asked to provide a concise overview of why any proposed revisions to the standard are appropriate and necessary. Supporting rationale could include:

- What combination of options covered within the discussion paper the proposed revisions reflect, i.e.,
  - Required reporting methods (Option A, B, C, and D)
  - Location-based method improvements (Option A, B and C)
  - Market-based method improvements (Option A, B, C, D and E)
- If a new option or iteration of any of the above options is proposed, an assessment must be provided for how the new option aligns with the Decision Making Criteria.
- Supporting evidence or information that address TWG meeting discussion questions(s) that relate to the proposed option(s).

Supporting rationale should be provided as presentation slides.

TWG members are encouraged to work collaboratively to develop joint proposals where practical. As described in the TWG Terms of Reference (ToRs), all members are expected to make recommendations that adhere to the following principles:

i. Consensus-seeking: Attempting to generate as much agreement amongst TWG members as possible through a focus on finding solutions.
ii. Rigor: Attempting to shape decisions that reflect the GHG Protocol decision-making criteria and hierarchy as in the GHG Protocol Governance Overview.
iii. Integrity: Striving for the best possible decisions which uphold the public interest and mission of GHG Protocol, rather than an organizational or personal preference.

Contents

Scope 2 Guidance draft revisions template

Definition of Scope 2

Scope 2 indirect emission definition

Scope 2 is an indirect emission category that includes GHG emissions from the generation of purchased or acquired electricity, steam, heat, or cooling consumed by the reporting company. (Section 5.3, p. 34)

Scope 2 emissions are accounted for when a company obtains its energy from another entity, or when a company sells an energy attribute certificate from owned and consumed generation. (Section 5.4, p. 35)

Location-based method definition:

A method to quantify scope 2 GHG emissions based on average energy generation emission factors for defined geographic locations, including local, subnational, or national boundaries. (Table 4.1, p. 26)

The location-based method is based on statistical emissions information and electricity output aggregated and averaged within a defined geographic boundary and during a defined time period. (Section 4.1.1, p. 25)

This method only looks at the broader energy generation profile for a region, regardless of supplier relationships. (Section 4.1.1, p. 26)

Market-based method definition:

A method to quantify the scope 2 GHG emissions of a reporter based on GHG emissions emitted by the generators from which the reporter contractually purchases electricity bundled with contractual instruments, or contractual instruments on their own. (Table 4.1, p. 26)

Under the market-based method of scope 2 accounting, an energy consumer uses the GHG emission factor associated with the qualifying contractual instruments it owns. (Section 4.1.2, p. 26)

[This allocation method] represents contractual information and claims flow, which may be different from underlying energy flows in the grid. (Section 4.1.2, p. 26)

Emission rate approach of scope 2

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

- They represent emission rates that allocate emissions at generation to end-users. This type of treatment is consistent with corporate inventory approaches across other scopes, particularly with product-specific emission factors or labels. Both methods **should** be applied comprehensively to ensure all energy generation emissions within a defined region have been accounted for. (Section 4.2, p. 28)
- They use generation-only emission factors (e.g. emissions assessed at the point of energy generation), designed to label emissions associated with a quantity of electricity delivered and consumed. The emission factors **do not** include T&D losses or upstream life-cycle emissions associated with the technology or fuel used in generation. Instead, these other categories of upstream emissions **should** be quantified and reported in scope 3, category 3 (emissions from fuel- and energy-related activities not included in scope 1 or scope 2). In the case of supplier-specific emission factors, the emission factor **should** reflect emissions from all delivered energy, not just from generation facilities owned/operated by the utility. (Section 4.2, p. 27)
- This [standard] **does not** support an "avoided emissions" approach for scope 2 accounting due to several important distinctions between corporate accounting and project-level accounting. However, companies **can** report avoided grid emissions from energy generation projects separately from the scopes using a project-level accounting methodology. (Section 4.2, p. 28)

Purposes

Purposes of scope 2 reporting

Companies **can** use these reported totals to set targets, reduce GHG emissions, track progress, and inform their stakeholders. (Section 1.4, p. 7)

Companies consuming electricity **may** seek to:

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

(Section 2.1, p. 15)

Purpose of dual reporting

The revisions in this guidance [i.e., dual reporting] **should** enhance the relevance, completeness, consistency, transparency, and accuracy of reported scope 2 totals. (Section 1.4, p. 7)

Both methods are useful for different purposes; together, they provide a fuller documentation and assessment of risks, opportunities, and changes to emissions from electricity supply over time. (Section 1.5, p. 7)

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

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

(Section 7.4, p. 62)

This guidance's framework addresses and reduces double counting between scope 2 inventories when using the same accounting method, improving the accuracy of reported results and ensuring clear performance tracking toward goals. (Section 7.4, p. 62)

The dual reporting requirement in this guidance can complicate the understanding of whether double counting is occurring and whether it threatens an inventory's accuracy. (Section 5.5, p. 39)

This is an inherent condition of two methods. Each method's results **shall not** be added or netted. Each method represents a separate way of allocating energy generation emissions, so depending on geographic or market boundaries, each method's scope 2 result can reflect some of the same emissions reflected in the other method. (Section 5.5, p. 40)

Purposes of the location-based method

1. **Estimating and reflecting emissions based on grid data**

   - Providing a method of estimating emissions based on 'statistical emissions information and electricity output aggregated and averaged within a defined geographic area and time period' (Section 4.1.1, p. 25-26)

   - Reflecting the 'GHG intensity of grids where operations occur, regardless of market type' (Section 4.1.1, p. 26)

- 'Consumers can represent that they are served by all the energy resources deployed on their regional grid' (Section 2.5, p. 19)
- Reflecting 'the role of "balancing" resources and their emissions through grid average emission factors. These emission factors include emissions from all local energy generation' (Box 4.1, p. 27)

2. **Risk and opportunity assessment related to grid emissions**
   - Showing risks/opportunities that are better evaluated based on average emissions in a grid (Section 6.4.1, p. 45; Section 2.2, p. 15-17)
   - Reflecting risks related to grid operation and maintenance (e.g., maintaining regional grid reliability). 'Certain overall costs related to grid operation and maintenance could be allocated to all consumers regardless of their individual choice in electricity supplier, electricity product, or tariff. In addition, maintaining regional grid reliability often requires a mix of generation resources. The location-based method incorporates the GHG emissions of this mix into the grid average emissions factor' (Section 2.2, p. 16-17)
   - Highlighting a 'company's exposure to geographic risks, including (a) air pollution such as sulfur dioxide (SO_x) or mercury from coal combustion; (b) the impact of hydropower on local waterways and aquatic life; and (c) the risks from nuclear waste disposal or emergencies' (Section 2.2, p. 17)

3. **Enabling decision-making for consumers and companies**
   - Enabling facility-siting decisions based on carbon intensities of standard grid-delivered electricity in different regions. 'For instance, locating new facilities on a GHG-intensive grid means that in the near term, energy demand will be met with a higher GHG emissions profile, assuming that the energy is consumed locally' (Section 4.3, p. 28)
   - Enabling facility-siting decisions based on natural features of a location. For example 'areas with low-carbon natural resources, or additional benefits such as natural ambient cooling or heat' (Section 4.3, p. 28)
   - Highlighting opportunities for 'reducing energy use' (Section 2.2, p. 17)
   - Reflecting the 'cumulative effect of consumer or supplier choices over time that change the grid-average emission factor' (Section 4.3, p. 31)

4. **Improving comparability**
   - Improving 'comparability across multiple markets over time' (Section 6.4.1, p. 45)
   - Comparing 'the aggregate GHG performance of energy-intensive sectors (e.g., comparing electric train transportation with gasoline or diesel vehicle transit)' (Table 4.1, p. 26)

Purposes of the market-based method

1. **Estimating emissions based on contractual relationships to electricity supply**
   - The market-based method reflects the GHG emissions associated with the choices a consumer makes regarding its electricity supplier or product. (Section 4.1.2, p. 26)
   - Demonstrating the 'individual corporate choices of electricity product or supplier, or the lack of a differentiated choice, which requires the use of a residual mix' (Section 4.3, p. 31)
   - Allocating 'emission attributes based on a company's contractual relationships, or what a company is paying for' (Section 2.5, p. 19)

2. **Influencing electricity suppliers and generation resource supply mix across the grid**
   - Increasing demand for low-carbon energy. 'As demand grows, it will push up the price of these attributes, which in turn can stimulate supply. This theory underlies the basis of market-based accounting in scope 2, as it reflects an allocation of consumer preferences (demand) for the GHG attributes from a given supply of attributes available for those claims' (Section 11.1, p. 89).

- Motivating 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' (Section 2.3, p. 19)
- Enabling consumers to 'establish contracts, that include certificates, such as PPAs directly with low-carbon generators.' (Section 4.3, p. 30)

3. **Risk and opportunity assessment related to contractual relationships**

- Reflecting reputational risks/opportunities related to a company's energy procurement. 'Prior to this guidance, companies may have reported scope 2 without fulfilling the Scope 2 Quality Criteria for the market-based method, leading to misleading claims and potential double counting between scope 2 inventories. Transparent disclosure about a company's energy procurement and its key attributes in the market-based method can help clarify the company's strategy and rationale.' (Section 2.2, p. 17)
- Conveying legally enforceable rights and claims from contractual instruments. 'Neglecting to report a market-based scope 2 that aligns with those claims can expose companies to legal risks' (Section 2.2, p. 17)
- Reflecting risks related to 'costs associated with premiums for low-carbon energy' and related GHG emissions (Section 2.2, p. 15)
- Reflecting risks related to the 'cost of environmental compliance for the resources owned by their [the customer's] utility, or the energy purchased by their utility' (Section 2.2, p. 16)

4. **Enabling decision-making for consumers and companies**

- Enabling facility-siting decisions based on 'changes in supplier (new utility service area), changes in other types of contractual instruments, or the residual mix used in that location' (Section 4.3, p. 28)
- Highlighting opportunities for reduced energy consumption. 'Reducing electricity demand can minimize the additional costs associated with purchasing contractual instruments at a premium above standard electricity costs' (Section 4.3, p. 30)
- Enabling a 'choice of specific resources' (Section 2.4, p. 19)
- Reflecting the individual consumer or supplier choices (or lack thereof) that over time and in aggregate 'drive supply change' (Section 4.3, p. 31)
- Providing 'transparency in corporate reports to allow internal and external stakeholders to assess performance and how effectively corporate energy procurement achieves broader company goals—including accelerating the growth of new low-carbon energy in a short period of time' (Section 11.3, p. 91)

Methodology

Identifying GHG sources, determining applicable methods, and collecting activity data

Identify GHG emissions sources for scope 2

Scope 2 includes emissions from all purchased/acquired and consumed electricity, heat, steam, or cooling. Companies **can** identify these energy uses on the basis of utility bills or metered energy consumption at facilities within the inventory boundary. (Section 6.1, p. 43)

Determine whether the market-based method applies for any operations

The presence of contractual information in any market where a company has operations triggers the **requirement** to report according to the market-based method. The contractual instruments themselves must be assessed for their conformance with Scope 2 Quality Criteria. If they do not meet the Scope 2 Quality Criteria, then other data (listed in Table 6.3) **shall** be used as an alternative in the market-based method total. (Section 6.2, p. 43)

If a multi-regional company has any operations within the corporate inventory where the market-based method applies, then a market-based method total **shall** be calculated for the entire corporate inventory to ensure completeness and consistency. For any individual operations in the corporate inventory where market-based method data on the hierarchy is not applicable or available, data from the location-based method **should** be used to represent the emissions from the facility (see Table 6.3). For these operations, the calculated scope 2 according to the market-based method will be identical to the location-based. (Section 6.2, p. 43)

If no facilities in the entire organizational boundary of the reporting entity are located in markets with contractual claims systems, or where *no* instruments within those systems meet Scope 2 Quality Criteria required by this document, then only the location-based method **shall** be used to calculate scope 2. (Section 6.2, p. 43)

Required reporting methods for scope 2

In addition to all existing *Corporate Standard* accounting and reporting requirements (see Chapter 9 of the *Corporate Standard*), companies **shall** calculate and report scope 2 in the following ways:

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

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

For companies with any operations in markets providing product or supplier-specific data in the form of contractual instruments:

- Companies **shall** account and report scope 2 emissions in two ways and label each result according to the method: one based on the location-based method, and one based on the market-based method.
- Many companies' GHG inventories will include a mix of operations globally, some where the market-based method applies and some where it does not. Companies **shall** account for and report all operations' scope 2 emissions according to both methods.
- To do so, emissions from any operations in locations that do not support a market-based method approach **shall** be calculated using the location-based method (making such operations' results identical for location-based and market-based methods). Companies **should** note what percentage of their overall electricity consumption reported in the market-based method reflects actual markets with contractual information.

(Section 7.1, p. 59)

Collect activity data

For scope 2 calculation, activity data includes all energy purchased/acquired and consumed from an entity outside of the organization or from owned/operated generation facilities where energy attributes (e.g. certificates) have been sold or transferred. (Section 6.3, p. 44)

To determine activity data, metered electricity consumption or utility bills specifying consumption in MWh or kWh units **can** provide the most precise activity data. (Section 6.3, p. 44)

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). (Section 6.3, p. 44)

Identify distribution scenarios

If energy is produced and consumed by the same entity (with no grid connection or exchanges)

No scope 2 emissions are reported, as any emissions occurring during the power generation are already reported in scope 1. (Section 5.4.1, p. 35)

If the consumed electricity comes from a direct line transfer [e.g. energy production is fed directly and exclusively from company A to company B]

The company with operational or financial control of the energy generation facility would report these emissions in their scope 1, following the operational control approach, while the consumer of the energy reports the emissions in scope 2.

Any third-party financing institution that owns but does not operate the energy generation unit would not account for any scope 1, 2, or 3 emissions from energy generation under the operational control approach, since they do not exercise operational control. Only the equipment operator would report these emissions in their scope 1 following an operational control approach. Equipment owners would account for these generation emissions in scope 1 under a financial control or equity share approach, however.

If all the energy generation is purchased and consumed, then Company B's scope 2 emissions will be the same as Company A's scope 1 emissions (minus any transmission and distribution losses, though in most cases of direct transfer there will be no losses). (Section 5.4.2, p. 36)

If the consumed electricity comes from the grid

Electricity generators report any emissions from generation in scope 1, but most renewable or nuclear technology would report "zero" emissions from this generation. (Section 5.4.3, p. 36-37)

If some consumed electricity comes from owned/operated equipment and some is purchased from the grid

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

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

- For accurate scope 2 GHG accounting, companies **shall** use the total—or gross—electricity purchases from the grid rather than grid purchases "net" of generation for the scope 2 calculation. A company's total energy consumption would therefore include self-generated energy (any emissions reflected in scope 1) and total electricity purchased from the grid (electricity). It would exclude generation sold back to the grid.
- If a company cannot distinguish between its gross and net grid purchases, it **should** state and justify this in the inventory.

(Section 5.4.4, p. 37-39)

Selecting emission factors and matching to activity data

Choose emission factors for each method

Companies **should** use the most appropriate, accurate, precise, and highest quality emission factors available for each method. Table 6.2 indicates these preferences for the location-based method, and Table 6.3 for the market-based method. (Section 6.5, p. 45)

Companies using the market-based method **shall** ensure that any contractual instrument from which an emission factor is derived meets the Scope 2 Quality Criteria listed in Chapter 7. Where contractual instruments do not meet the Scope 2 Quality Criteria requirements, and no other market-based method data are available, the location-based data **should** be used. (Section 6.5, p. 46)

Match emission factors to each unit of electricity consumption

Each unit of electricity consumption **should** be matched with an emission factor appropriate for that consuming facility's location or market. (Section 6.6, p. 49)

Companies centrally purchasing energy attribute certificates on behalf of all its operations in a single country or region **should** indicate how they match these purchases to individual site consumption. (Section 6.6, p. 49)

Companies **may** also use certificates conveyed to them by their supplier, separately from the other supplier mix information. This ensures equivalent treatment of certificates regardless of how they are sourced. (Section 6.6, p. 49)

Certificate sale scenarios

The creation of a certificate that conveys an energy generation attribute claim means that the underlying power—sometimes called "null power"—can no longer be considered to contain the energy attributes, including the type of energy (e.g., that it is "renewable") and its GHG emission rate (that it is zero emissions/MWh). By the conveyance of energy attributes or certificates to a third party separate from the electricity, users of the null power electricity **cannot** claim to be buying or using renewable energy in the absence of owning the certificate. (Section 6.4, p. 44)

Instead, companies consuming energy from owned/operated facilities or direct-line transfers where certificates are sold off, **shall** calculate that consumption using other market-based method emission factors such as "replacement" certificates, a supplier-specific emission rate, or residual mix (for the market-based method total) and the grid average emission factor (for the location-based total). (Section 6.4, p. 44)

Companies who are consuming energy directly from a generation facility that has sold certificates (either owned/ operated equipment or a direct line) forfeit not only the right to claim those emissions in the market-based method (requiring the use of some other market-based data source such as other "replacement" certificates, a supplier-specific emission factor, or residual mix) but also the right to claim that emissions profile in the location-based method. Overall, the location-based method is designed to show emissions from the production supporting the local consumption without reference to any contractual relationships. However, the attributes contained in certificates usually carry legally enforceable claims, which **should** take precedence. (Section 6.4.1, p. 44)

Therefore, in the event of certificate sales from owned/operated energy production and consumption, companies **should** still use the location-based emission factor hierarchy (see Table 6.2). (Section 6.4.1, p. 44)

Companies **should** avoid using location-based totals for goal tracking where certificates convey these claims and/or carry legally enforceable claims. (Section 6.4.1, p. 44)

Location-based emission factors

The emission factors necessary to estimate location-based scope 2 emissions include GHG emission intensity factors for energy production in a defined local or national region. Where advanced studies or real-time information is available, companies **may** report scope 2 estimations separately as a comparison to location-based grid average estimation (see Box 6.2, p. 53). Companies should be aware of the following caveats about location-based emission factors:

- The location-based grid average emission factors **should** be distinguished from supplier-specific information, even if the electricity supplier is the sole energy provider in a region and produces a supplier-specific emission factor that closely resembles the overall regional grid average emission factor.
- Grid average emission factors in the location-based method **should not** reflect any adjustments or removals for market-based contractual claims by suppliers or end-users. By contrast, a residual mix in the market-based method **should** represent all unclaimed energy emissions, which is formulated by removing contractual claims data from energy production data (often the same as grid average data).
- Companies **shall not** use marginal emission factors such as those provided by CDM for a location-based scope 2 calculation.

(Section 6.10, p. 53)

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 (Section 6.10.1, p. 53)

- **Spatial boundaries -** The most appropriate spatial boundaries for emission factors serving the location-based method are those that approximate regions of energy distribution and use, such as balancing areas. All generation and emissions data within this boundary **should** be aggregated and any net physical energy imports/ exports and their related emissions should be taken into account.

  For multi-country regions with frequent and significant exchanges of energy throughout a year (as measured by percent of that country's total generation), a multi-country regional grid average **may** be a better estimate than a production-only national emission factor without energy imports/exports adjustments. In turn, in a country with multiple distribution or balancing areas, these subnational regions would be a more precise spatial boundary for grid average emissions.

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

  (Section 6.10.1, p. 54)

Location-based method emission factor hierarchy

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

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

Notes:

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

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

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

(Table 6.2, p. 47)

Market-based emission factors

Under the market-based method, different contractual instruments become carriers of GHG-emission rate information that function as emission factors for consumers to use to calculate their GHG emissions. To ensure this, instruments **shall** include the GHG emission rate attribute. (Section 6.11, p. 54)

Any type of energy or energy attribute purchase via a contractual instrument **shall** be treated in scope 2 like all other product information— an emission rate in tons GHG/unit of output (here, kWh) rather than an avoided emissions estimation and deduction. Companies then apply the emission factor derived from the contractual instrument to a quantity of energy consumption (activity data), consistent with the usage boundaries of that instrument. (Table 1.1, p. 11)

A range of contractual instruments may be used to convey these attributes directly or indirectly to consumers, including energy attribute certificates, direct contracts such as PPAs, and supplier-specific emission rates. Of all of these, energy attribute certificates underlie most transactions and attribute claims. They can be used alone or can be bundled with PPAs, contracts, and supplier labels. Once attributes are codified and conveyed in a certificate, the underlying energy generation technically becomes "null power," or without attribute identity. Users of the null power electricity **cannot** claim to be buying or using renewable energy in the absence of owning the certificate. Instead, null power should be assigned residual mix emissions for the purpose of delivery and/or use claims in the market-based method. (Section 10.1.1, p. 79-80)

If companies have access to multiple market-based emission factors for each energy-consuming operation, they **should** use the most precise for each operation based on the list in Table 6.3. (Section 6.11, p. 54)

If an electricity supplier purchases offsets on behalf of their customers, the reporting customers **should** report the offsets separately from the scopes. The supplier-specific emission rate used for scope 2 **should** reflect supply only, and not purchased offsets. (Section 6.11.3, p. 56)

Residual Mix

To prevent double counting of GHG emission rate claims tracked through contractual instruments, the market-based method **requires** an emission factor that characterizes the emission rate of untracked or unclaimed energy. This [residual mix] emission factor creates a complete data set under the market-based method, and represents the regional emissions data that consumers should use if they operate in a market with choice for consumers, differentiated products, and supplier specific data, but did not purchase certificates or a specified product, do not have a contract with a specified source, or do not have supplier-specific information. (Section 6.11.4, p. 56)

Companies **should not** attempt to calculate their own residual mix. If a residual mix is not available, other unadjusted grid average emission factors such as those used in the location-based method **may** be used. (Section 6.11.4, p. 56)

Companies **shall** document in the inventory that a residual mix was not available. (Section 6.11.4, p. 56)

Market-based scope 2 data hierarchy examples

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

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

production data and factors out voluntary purchases		Lower
Other grid-average emission factors (subnational or national) – see location-based data	• eGRID total output emission rates (U.S.).[d] In many regions this approximates a consumption-boundary, as eGRID regions are drawn to minimize imports/exports • Defra annual grid average emission factor (UK) • IEA national electricity emission factors[e]	

Notes:

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

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

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

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

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

(Table 6.3, p. 48)

Quality Criteria for market-based method emission factors

Companies **shall** ensure that any contractual instruments used in the market-based method total meet the Scope 2 Quality Criteria specified in Table 7.1. If instruments do not meet the Criteria, then other data (listed in Table 6.3) **shall** be used as an alternative in the market-based method total.

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

(Section 7.1, p. 60)

Scope 2 Quality Criteria

All contractual instruments used in the market-based method for scope 2 accounting **shall:**
1. Convey the direct GHG emission rate attribute associated with the unit of electricity produced. 2. Be the only instruments that carry the GHG emission rate attribute claim associated with that quantity of electricity generation. 3. Be tracked and redeemed, retired, or canceled by or on behalf of the reporting entity. 4. Be issued and redeemed as close as possible to the period of energy consumption to which the instrument is applied. 5. Be sourced from the same market in which the reporting entity's electricity-consuming operations are located and to which the instrument is applied.
In addition, utility-specific emission factors **shall:**
6. Be calculated based on delivered electricity, incorporating certificates sourced and retired on behalf of its customers. Electricity from renewable facilities for which the attributes have been sold off (via contracts or certificates) **shall** be characterized as having the GHG attributes of the residual mix in the utility or supplier-specific emission factor

In addition, companies purchasing electricity directly from generators or consuming on-site generation **shall:**
7. Ensure all contractual instruments conveying emissions claims be transferred to the reporting entity only. No other instruments that convey this claim to another end user **shall** be issued for the contracted electricity. The electricity from the facility **shall not** carry the GHG emission rate claim for use by a utility, for example, for the purpose of delivery and use claims
Finally, to use any contractual instrument in the market-based method **requires** that:
8. An adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly shared electricity shall be made available for consumer scope 2 calculations, or its absence shall be disclosed by the reporting entity

(Table 7.1, p. 60)

Additional Guidance on Scope 2 Quality Criteria

This guidance identifies a set of minimum criteria that relate to the integrity of the contractual instruments as reliable conveyers of GHG emissions rate information and claims, as well as the prevention of double counting. They represent the minimum features necessary to implement a market-based method of scope 2 GHG accounting. *Programs or jurisdictions may have additional requirements that reporting entities **should** consult and follow.* (Section 7.5, p. 63)

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 specific cases of multipliers or issuance of multiple instruments from the same MWh, then all instruments **shall** be retired for a full claim on that MWh. Tracking systems themselves support only fully aggregated certificates.

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

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

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

(Section 7.5, p. 63-65)

Criteria 2. Unique claims

If other instruments exist that can be used for attribute claims by other electricity consumers, companies **must** ensure that the one being used by the reporting entity for a GHG emission rate claim is the only and sole one that does so.

Companies **should** check with their electricity supplier or relevant policy-making bodies to ensure that the certificates are claimed, paired, or retired in compliance with applicable jurisdictional or program requirements.

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

(Section 7.5, p. 63-65)

Criteria 3. Retirement for claims

Ensuring that instruments are retired, redeemed, or claimed to support a consumer claim **can** be done through a tracking system, an audit of contracts, third-party certification, or **may** be handled automatically through other disclosure registries, systems, or mechanisms.

(Section 7.5, p. 63-65)

Criteria 4. Vintage

Vintage reflects the date of energy generation from which the contractual instrument is derived. This is different from the age of the facility.

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

(Section 7.5, p. 63-65)

Criteria 5. Market boundaries

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

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

If the market boundary is not specified or not clear: Markets for certificates are typically determined by political or regulatory boundaries rather than just physical grid interconnection. This means market boundaries **can** be limited to a single country or group of countries that recognize each other's certificates as fungible and available to any consumers located therein.

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

Additional geographic sourcing considerations: In addition, if not already specified by regulation or program, contractual instruments **should** be sourced from regions reasonably linked to the reporting entity's electricity consumption.

(Section 7.5, p. 63-65)

Criteria 6. Supplier or utility-specific emission factors.

As part of the calculation, the utility or supplier **should** disclose whether and how certificates are used in the emission factor calculation, unless there is third-party certification of the utility product.

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

(Section 7.5, p. 63-65)

Criteria 7. Direct contracts or purchasing.

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

(Section 7.5, p. 63-65)

Criteria 8. Residual mix.

To ensure unique claims by all electricity users, an adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly shared electricity **is necessary**.

This residual mix **should** be based on combining national or subnational energy and emissions production data with contractual instrument claims.

If a residual mix is not currently available, companies **shall** disclose that an adjusted emissions factor is not available or has not been estimated to account for voluntary purchases and this may result in double counting between electricity consumers.

Reporters **may** provide other information about the magnitude of this error, where it is available and where it puts the scale of the residual mix adjustment into a context of other sources of error in grid emission factor calculation.

(Section 7.5, p. 63-65)

Treatment of biogenic emissions

Based on the Corporate Standard, any CH_4 or N_2O emissions from biogenic energy sources use **shall** be reported in scope 2, while the CO_2 portion of the biofuel combustion **shall** be reported outside the scopes. In practice, this means that any market-based method data that includes biofuels should report the CO_2 portion of the biofuel combustion separately from the scopes. (Section 6.12, p. 57)

For the location-based approach, most commonly used grid average emission factor—including those issued by EPA eGRID (U.S.), Defra (U.K.), and the International Energy Agency (for all countries worldwide)—do not note the percentage of biomass in the emission factor and do not separately report the biogenic CO_2, effectively treating it as "zero" emissions. Companies **should** document this omission in any grid average emission factors used. (Section 6.12, p. 57)

Calculate emissions

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

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

(Section 6.7, p. 49)

Gross/net reporting

The two method totals (location-based and market-based) **should not** be viewed as "gross/net," since a net calculation typically implies that external reductions such as offsets have been applied to the inventory.

While many contractual instruments in the market-based method represent a zero-emission rate from renewable energy and generally serve to lower the GHG intensity of the reporter's electricity use, the market-based method **should** also include other contractual instruments representing fossil fuel or mixed-resource emission factors as well.

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

(Section 7.4.2, p. 63)

Roll up GHG emissions data to corporate level

For more guidance on this process, see Chapter 6 of the Corporate Standard. (Section 6.8, p. 52)

Reporting Requirements and Recommendations

Required disclosures

Methodology disclosure

Companies **shall** disclose methods used for scope 2 accounting. For the market-based method, companies **shall** disclose the category or categories of instruments from which the emission factors were derived, where possible specifying the energy generation technologies. (Section 7.1, p. 61)

Base-year information

Companies **shall** disclose the year chosen as the base year; the method used to calculate the base year's scope 2 emissions; whether historic location-based data is used as a proxy for a market-based method; and the context for any significant emission changes that trigger base-year emissions recalculation (acquisitions/ divestitures, outsourcing/insourcing, changes in reporting boundaries or calculation methodologies, etc.) (Section 7.1, p. 61)

Disclose basis for goal setting

If a company sets a corporate inventory reduction goal and/or a scope 2-specific reduction goal, the company **shall** clarify whether the goal is based on the location-based method total or market-based method total. (Section 7.1, p. 61)

Inventory totals

For companies adding together scope 1 and scope 2 for a final inventory total, companies **may** either report two corporate inventory totals (one reflecting each scope 2 method), or **may** report a single corporate inventory total reflecting one of the scope 2 methods. (Section 7.1, p. 60)

If reporting a single corporate inventory total, the scope 2 method used **should** be the same as the one used for goal setting. Companies **shall** disclose which method was chosen for this purpose. (Section 7.1, p. 60)

Recommended disclosures

Annual electricity consumption

Companies **should** report total electricity, steam, heat, and cooling per reporting period separately from the scopes totals (in kWh, MWh, BTU, etc.), which **should** include all scope 2 activity data as well as the quantity of energy consumed from owned/operated installations (which may be only reported in scope 1 and not in scope 2.) (Section 7.2, p. 61)

Biogenic emissions

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

- Companies **should** document if any GHG emissions other than CO_2 (particularly CH_4 and N_2O) are not available for, or excluded from, location-based grid average emissions factors or with the market-based method information. (Section 7.2, p. 61)

Other instrument retirement

Companies **should** disclose additional certificate or other instrument retirement performed in conjunction with their voluntary claim, such as with certificate multipliers or any pairing required by regulatory policy. (Section 7.2, p. 61)

Basis for upstream scope 3

The reporting entity **should** identify which methodology has been used to calculate and report scope 3, category 3—upstream energy emissions not recorded in scope 1 and 2, scope 3. (Section 7.2, p. 61)

Instrument features

Where relevant, companies **should** disclose key features associated with their contractual instruments claimed, including any instrument certification labels that entail their own set of eligibility criteria, as well as characteristics of the energy generation facility itself and the policy context of the instrument. (Section 7.2, p. 61)

Role of corporate procurement in driving new projects

Where relevant, companies **should** elaborate in narrative disclosure how any of the contractual instruments claimed in the market-based method reflect a substantive contribution by the company in helping implement new low-carbon projects. (Section 7.2, p. 61)

Optional disclosures

Scope 2 totals disaggregated by country

This can improve transparency on where market-based method totals differ from location-based. (Section 7.3, p. 61)

Advanced grid study estimations

Where advanced studies (or real-time information) are available, companies **may** report scope 2 estimations separately as a comparison to location-based grid average estimations, and companies can document where this data specifically informed efficiency decision making or time-of-day operations. Because these studies or analyses may be more difficult to use widely across facilities or to standardize/aggregate consistently without double counting, companies **should** ensure that any data used for this purpose has addressed data sourcing and boundaries consistent with the location-based method. (Section 7.3, p. 61)

Scope 2 results calculated by other methods

If companies are subject to mandatory corporate reporting requirements for facilities in a particular region/nation that specify methodologies other than the two required for dual reporting, these companies **may** report these results separately from the scopes. (Section 7.3, p. 62)

Disclose purchases that did not meet Scope 2 Quality Criteria

If a reporting entity's energy purchases did not meet all Scope 2 Quality Criteria, the entity **may** note this separately. This note **should** detail which Criteria have been met, with details of why the remaining Criteria have not. This will provide external stakeholders with the information they require, and allow the reporting entity to disclose the efforts made to adhere to the guidance.

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

(Section 7.3, p. 62)

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. Companies required by regulation to use a method other than those listed in this guidance **should** do so for those required reports.

To maintain consistency with the GHG Protocol Corporate Standard and this Scope 2 Guidance, companies **may** additionally and separately report any scope 2 totals calculated for other mandatory reporting rules applying to that region/nation's facilities.

(Section 7.4.1, p. 63)

Reporting Avoided Emissions

Avoided emissions

Consistent with Chapter 8 of the Corporate Standard, companies **may** separately report an estimation of GHG emissions avoided from a project or action (also see Section 6.9). This quantification should be based on project-level accounting, with methodologies and assumptions documented (including to what the reduction is being compared). See the *GHG Project Protocol* and *GHG Protocol Guidelines for Grid-Connected Electricity Projects* for example methodologies. (Section 7.3, p. 61)

Reporting avoided emissions estimations

Companies **can** report the estimated grid emissions avoided by low-carbon energy generation and use, separately from the scopes.

Avoided emissions estimations are not necessarily equivalent to global emissions reductions from additional projects and therefore **should not** be used to reduce a company's footprint. However, quantifying avoided emissions provide several technical and strategic benefits, including:

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

This estimation **should** follow project-level methodology; see GHG Protocol Project Protocol or Guidelines for Grid-Connected Electricity Projects.

However, if the project operates in a jurisdiction with an emissions cap on the power sector, or comes from an energy generation facility also producing verified emission reductions (also termed a GHG offset), the company **should not** make public claims about avoided emissions.

Any offsets produced from the project, or any voluntary allowances retired on behalf of the purchase associated with the project, **should** be reported separately. (Section 6.9, p. 52)

Treatment of offsets

Offsets, and their global avoided emissions claim, represent a different instrument and claim from the energy attributes associated with energy production. Offsets convey tons of avoided CO_2 using project-level accounting, but they do not convey information about direct energy generation emissions occurring at the point of production, like contractual instruments do (see Box 4.3). An offset credit does not confer any claims about the use of electricity attributes applicable to scope 2. (Section 8.2.4, p. 71).

Coexistence of offsets and scope 2 accounting

Companies **should** disclose whether their contractual instrument used in a market-based method (such as a supplier-specific emission rate or PPA) is generated from, or includes, the energy output of a facility that also produces GHG offsets. In turn, following the Corporate Standard, companies purchasing and claiming offsets **should** document these purchases outside of the scopes, ensuring that the offset meets offset quality criteria. (Section 8.2.4, p. 72)

Additionality

Role of additionality

This guidance **does not** require that contractual instruments claimed in the market-based method fulfil criteria such as offset "additionality" or prove the overall market impact of individual purchases or supplier programs result in direct and immediate changes in overall supply. (Section 11.3, p. 90)

This guidance lays out the policy-neutral mechanics of a market-based method for scope 2 accounting, so that regardless of what causes the project to be built, the energy attribute certificate still serves as the instrument conveying claims about the attributes of the underlying energy generation for consumers purchasing that generation. (Section 11.3, p. 90)

Offset additionality criteria are not fundamental to, or largely compatible with, the underlying rules for market-based scope 2 accounting and allocation. Offsets represent a different claim (avoided GHG emissions compared to a baseline scenario) than energy generation attributes (X GHG emissions from Y unit of energy generation). Scope 2 reporting is a report of usage and as such is independent of issues associated with additionality. (Section 11.3, p. 90)

While not a part of criteria for market-based scope 2 accounting, suppliers and companies **can** make energy procurement choices that can shift a company's impact from "aggregate" to more directly spurring an increase in new, low-carbon energy generation facilities in a short period of time, consistent with the ambition needed to avoid dangerous climate change. Many of these choices are summarized in box 5.1, highlighting both the policy changes and the individual consumer choices that could, in the case of the U.S., strengthen the impact of voluntary REC products. (Section 11.4, p. 91)

Reporting on voluntary vs. regulatory claims

This guidance **does not** require contractual instruments claimed in scope 2 to be "in addition to," or independent from, regulatory policies such as subsidies, tax exemptions, or supplier quotas.

For transparency, companies **should** disclose the relationships between instruments claimed in scope 2 and regulatory policies, as part of the disclosure of overall instrument features and policy context to improve transparency and stakeholder understanding of the voluntary purchase.

Companies **should** also disclose additional certificates or other instrument retirement performed in conjunction with their voluntary claim. (Elaborated in Table 8.2).

Where relevant, companies **should** state the relationship between the energy claimed in the market-based method and any compliance instruments used for supplier quota regulations.

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

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

(Section 8.2, p. 69-70)

Relationship between voluntary program impact and scope 2 accounting

Consumers who voluntarily claim low-carbon attributes in scope 2 may expect their individual purchase or program participation to result in new generation that lowers system-wide GHG emissions. However, like other markets and products, individual voluntary purchases and consumer programs may or may not result in changes in low-carbon supply, depending on supply and demand dynamics.

Given that voluntary markets for renewable energy aggregate consumer demand in order to affect supply changes, some stakeholders and voluntary programs have incorporated additional specifications or criteria to stimulate growth of low-carbon supply.

Even in the absence of such requirements, the market-based method accurately reflects an allocation of generation attributes among consumers, which is important for reflecting individual actions and purchase decisions as well as for recognizing action to affect demand-side change. In the absence of such requirements, and if there is insufficient demand to drive overall change on the grid, stakeholders may be concerned that the market-based method results only in a reallocation of attributes between those consumers who care about claiming low-carbon energy, and those who are unaware of or uninterested in the opportunity to make these claims. (Section 11.2, p. 90)

Target Setting

GHG targets

If setting a target, companies **shall** specify which method is used in the goal calculation and progress tracking, including the method used for the base-year calculation. (Section 9.3, p. 76)

Where certificates or contractual instruments convey legally enforceable claims, companies setting goals **should** use the market-based method total for goals. (Section 9.3, p. 76)

Two targets, one for each method's results, can help prioritize new low-carbon energy projects that will reduce both totals' emissions over time (if contractual instruments are retained from the project). (Section 9.3, p. 76)

Companies **should** avoid using location-based totals for goal tracking where certificates convey these claims and/or carry legally enforceable claims. (Section 6.4.1, p. 44)

Energy targets

For utilities under a supplier quota requirement (such as an RPS in the U.S.), structuring a green power product that covers 100 percent of a customer's electricity load **may** combine voluntary and compliance instruments up to the level of the quota, provided those compliance instruments convey energy use claims. For example, if a utility is required to procure and deliver renewables for 20 percent of its total retail load, then voluntary contractual instruments would be required to account for the remaining 80 percent of the delivered energy. (Section 9.3, p. 76-77)

Change Log

This section will serve to log a description of additions to the above copied text from the Scope 2 Guidance. If TWG members determine additional relevant text from the Scope 2 Guidance should be included for consideration, those changes will appear here.

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Dec. 16 2024	N/A	N/A - Original Draft Published