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

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

Information to Better Reflect Emissions from Electricity Use

(tied to timing and location of buyer consumption)

Information to Measure Decarbonization Impact from Buyer Actions

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

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

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

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

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

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

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

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

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