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CMUA Response to RFI

Additional submitted attachment is included below.

April 14, 2023

California Energy Commission
Docket Unit, MS-4
Re: Docket No. 21-OIR-01
715 P Street
Sacramento, CA 95814-5512

RE: California Municipal Utilities Association Response to Request for Information, Power Source Disclosure [CEC Docket No. 21-OIR-01]

Dear Commission Staff,

The California Municipal Utilities Association (CMUA) respectfully submits this response to the *Request for Information, Power Source Disclosure* (RFI), issued on March 21, 2023. CMUA thanks the California Energy Commission (Commission) for requesting information on feasibility issues relating to Senate Bill (SB) 1158 (stats. 2022). SB 1158 creates a very complex new reporting requirement that has the potential to have significant impacts on energy markets and procurement decisions, as well as to create a substantial administrative burden for Commission staff and utilities alike. CMUA strongly encourages Commission staff to continue outreach to stakeholders and engage in a robust information gathering effort during the informal stage of this proceeding in order to ensure that its proposed regulations do not lead to unintended consequences or have unfair impacts to the obligated reporting entities.

As the Commission gathers information and begins to develop proposed regulations, CMUA urges the Commission to consider the following recommendations:

- **Balance the Express Purpose and Intended Benefits of SB 1158 Against the Burdens and Costs:** The Legislature clearly acknowledged the challenges that may be associated with the hourly tracking of greenhouse gas emissions (GHGs) associated with the generation used for retail electric customers. This is why SB 1158 expressly grants the Commission the discretion to "delay when retail suppliers shall begin reporting . . . if the Energy Commission determines that it is *infeasible or unreasonably costly for retail suppliers to obtain the necessary data or develop the necessary reporting tools* within the timeframe established in" Public Utilities Code section 398.6(b).[1] Therefore, the CEC should weigh the additional value provided by this hourly GHG reporting (considering

[1] Cal. Pub. Util. Code § 389.6(m).

existing sources of similar information)[2] in comparison to the additional costs and burdens to the reporting entities and, ultimately, to ratepayers. The Commission should be able to clearly articulate to ratepayers how this information will benefit them and how it will be used.

- **Consider Impacts to Existing Contracts:** SB 1158 creates a new attribute that will be associated with any electricity from owned or contracted generating resources: *hourly GHG emission profile*. The existing statutory requirements for renewable procurement and emissions reductions do not place greater or lesser value on generation based on the *hour* of generation. SB 1158 now provides a greater value (for purposes of reporting) for zero carbon generation that occurs during the hours where a utility's retail load is the highest and a lower value for zero carbon generation occurring when a utility's retail load is the lowest. As the Commission develops its regulations, it must consider the impacts on existing contracts, which were executed without consideration of this new hourly GHG emission profile attribute.

    - First, the Commission should minimize the extent to which new reporting or verification requirements will impose costs on generation facility owners. Any new reporting obligations applicable to the seller or any new certification process that the generating resource must comply with will necessarily not have been contemplated at the time of contract execution. Some contracts will address future regulatory uncertainty by including compliance expenditure provisions, which may limit a seller's obligation to meet new compliance requirements. These compliance expenditure provisions may (i) limit the actions that the seller must take, (ii) limit the scope of applicable requirements (*e.g.,* only if changes relate to resource adequacy or renewables portfolio standard (RPS) requirements), and/or (iii) set a dollar amount cap that the seller is obligated to expend towards these new requirements. This means that the seller may have no obligation (or only a limited obligation) to take additional actions to support these new SB 1158 requirements.

    - Second, for projects with multiple buyers, the rights to generation *in specific hours* may not be assigned to individual buyers under the existing contracts. The allocation of the generation may be balanced over a longer period, such as monthly. It is possible these SB 1158 regulations could necessitate amendments to contracts or force the execution of new agreements in order to determine which buyer has rights to the output during specific hours. Having to reopen existing contracts (if doing so is even possible) could have detrimental impacts for utilities that are dependent on current contracts for compliance with other mandates, such as the RPS.

[2] *See, e.g.,* CAISO CO_2 Emissions, Today's Outlook, available at: https://www.caiso.com/TodaysOutlook/Pages/emissions.aspx.

- **Harmonize with Existing Reporting Requirements:** To the greatest extent possible, the Commission should utilize the data already being reported and the verification systems already in place. POUs already report a significant amount of related information to the California Air Resources Board ("ARB") through the Mandatory Greenhouse Gas Reporting Regulation (MRR) and to the Commission through the existing Power Source Disclosure Report (PSDR), RPS, Integrated Energy Policy Report (IEPR), and Integrated Resource Plan (IRP) requirements. Data already provided to the Commission and other state agencies should be utilized before imposing any new requirements.

- **Consider Key Fundamental Questions Early:** CMUA agrees with the Commission's approach of requesting information on the feasibility of providing and gathering the key data necessary for these reporting requirements. However, some answers to RFI questions are necessarily tied to how the Commission will interpret certain core aspects of SB 1158. This includes:

    - *Calculation of Avoided GHG Emissions*: The Commission should clarify how it intends to calculate Avoided GHG Emissions. Specifically, the Commission should clarify that Avoided GHG Emissions are not only accrued during hours where a utility's total zero carbon generation ***exceeds*** its total retail load during that hour. Instead, Avoided GHG Emissions should be the zero carbon attributes of ***any*** generation that are not otherwise counted towards retail load during any hour. Understanding the Commission's interpretation of this element of SB 1158 is essential to providing input on the appropriate stacking order for counting resources.

    - *Resource Adequacy-Only Contracts*: The Commission should clarify that a utility is only obligated to report emissions associated with electricity that it actually takes title to under the terms of the associated contract. If, for example, a POU has a contract with an energy storage facility where the POU is only purchasing the resource adequacy attributes, then the POU should not be obligated to report the GHG emissions data associated with the charging and discharging of that energy.

    - *Emissions Factor for Unspecified Purchases*: The Commission should seek input on how the emissions intensity factor for unspecified resources will be calculated and how/if that factor will differ across different balancing authority areas (BAAs). This should also include clarifying how system sales from one POU to another will be treated. Further, any default emissions factors for unspecified power may not be an accurate reflection of emissions on a particular system at a given time.

    - *Reporting on Loss-Adjusted Load*: The Commission should expressly clarify that POUs must only report, and the Commission will only publish, information related to electricity sources serving hourly loss-adjusted load in aggregate. Requiring POUs to report information for each retail product would pose significant practical challenges and would not be supported by the plain language of the statute.

I. RESPONSE TO RFI QUESTIONS

A. Questions for Electricity Sellers from Generation or Storage Facilities

> ***1.*** *Discuss the feasibility and financial impact of providing each purchaser from your generation facility with the purchaser's hourly share of electricity that is scheduled into a California balancing authority.*

CMUA Response: It is CMUA's understanding that hourly generation data should typically be available to the resource owners and that the purchasers should have access to that data as well. In some cases, however, POUs make sales from their *system* that are not contractually tied to any specific resource. It is not clear if this should be treated as a system sale from the POU's BAA or if POU resources that ran during the relevant interval should be allocated to these types of purchasers. As described above, a challenge that the POUs face is that the underlying contracts may not give any guidance here.

If the Commission requires the use of a new accounting or certification system or requires the matching of e-Tags, this may present challenges that need to be explored further. In addition, as noted above, purchases and sales of generation can come from a specific BAA's system. These sales' e-Tags will not contain generator specific information, leaving it unclear how the seller and purchaser will view the GHG allocation for Commission reporting purposes. Additionally, different BAA's will have differing system power GHG emission intensities.

> ***2.*** *Discuss the feasibility and financial impact of providing each purchaser with its hourly share of exported electricity from your energy storage facility and the hourly electricity consumed by your facility in prior hours necessary to export that electricity after taking into account round-trip storage losses.*

CMUA Response: As the Commission develops the GHG accounting rules for energy storage facilities, it should ensure that the rules are reasonable and feasible for all anticipated configurations. For example, utility-scale energy storage facilities are often integrated into renewable generation projects. In these hybrid projects, it may be possible for the energy storage facility to be charged by either the integrated renewable resource or from the grid. The Commission's regulations should ensure that the purchasers of the output from a hybrid system that allows grid charging does not incorrectly or unfairly allocate hourly GHG emissions to the purchasers or otherwise discourage operating structures that provide the greatest reliability support to the grid and the greatest cost savings to customers.

B. Questions for Retail Electricity Suppliers

> 1. *Discuss* the feasibility and financial impact of obtaining hourly delivery data for each specified procurement for each hour of the year, organizing that hourly data into an Excel template provided by the Commission, and reporting that data to the Commission annually.

CMUA Response: While POUs will typically have access to hourly load and generation data, as well as emissions factors, matching and compiling this data has the potential to create a significant administrative burden. As described above, the Commission should develop regulations that limit the burden and cost of any required data gathering and verification requirements because resource owners may not be obligated to support these efforts under the existing contracts. Further, duplicative reporting requirements may divert limited POU staff resources from other important activities. To the greatest extent possible, the Commission should utilize data that is already gathered through the MRR and the California Independent System Operator (CAISO), which requires retail electricity suppliers to stack, report, and independently verify emissions to serve retail customers.

One important aspect of this feasibility question is how the various tasks will be distributed. Will the electric utilities only be obligated to provide the actual hourly data so that Commission staff can match generation to load and apply the stacking methodology, or will the utility need to process the data before it is reported? The answer to this question will have different impacts on different utilities. The Commission should gather input during this initial stage of the regulatory process on the most cost-effective way to allocate these responsibilities.

Finally, as described above, the right to generation during specific hours may not be allocated in the existing agreements. It would be valuable for the Commission to consider reporting structures that can avoid the need for contract amendments or new agreements.

> 2. *Discuss* the feasibility and financial impact of obtaining and reporting hourly settlement data from your retailer's balancing authority.

CMUA Response: The Commission should be able to meet its obligations under SB 1158 through the use of revenue quality meter data alone. This data should be readily available, provide the necessary accuracy, and be verifiable. It is unclear what additional benefit that the Commission would obtain by having access to the balancing authority settlement data. For the CAISO, there are multiple settlements within each hour and this data would be very complex for purposes of SB 1158 verification. For the California balancing authorities other than the CAISO, the balancing authority may not have the necessary settlement data for all participants within its BAA. Additionally, the settlement data would likely be market sensitive and contain financial data not relevant to the GHG reporting purpose of SB 1158. Finally, a focus on settlement data would raise concerns that procured generation from a facility located outside of the electric utility's BAA, but within a California BAA, would not be fully counted or considered for these purposes.

C. General Questions

> ***1.*** *Under an hourly load matching framework, what should be the load order for determining which resources are matched to load first? In other words, which resource types should be deemed to be overprocured/overdelivered during hours in which a retailer's specified procurements exceed its hourly loss-adjusted load?*

CMUA Response: This question raises one of the most fundamental issues that the Commission will need to address in this rulemaking, and CMUA encourages careful deliberation. The Commission must balance the intent of SB 1158 to quantify GHG emissions on an hourly basis against any unintended consequences or unreasonable outcomes for the obligated utilities. There should also not be a conflict between reporting for SB 1158 and reporting for other uses (*e.g.* RPS, PSDR, and GHG compliance). For example, the "over-procurement" of renewable generation during low load hours should not render the emissions intensity of the over-procurement stranded and applied to some other entity's retail load. The retail seller that procures the electricity and associated environmental attributes and that pays the premium for that product should get the full benefit.

Each utility will have its own approach to procuring and scheduling sufficient resources to meet its load. Unique circumstances (particularly for POUs in non-CAISO BAAs) may dictate specific scheduling structures that cannot be accommodated by a single approach. To address this, the Commission should consider a structure where the regulations specify a default resource stacking methodology, but where a utility may utilize an alternate methodology.

CMUA recommends that following assumptions be used for the default methodology:

> **Assumption 1:** <u>First, count all hydroelectric generation towards load</u>. The release of water through hydroelectric facilities is generally dictated by factors outside the control of the electric utility. This includes maintaining minimum flows, flood control, irrigation demand, and water conservation. This means that SB 1158's requirements will not be capable of incentivizing any change in behavior by utilities for the dispatch of hydroelectric generation. The Commission's regulations should not penalize or devalue this essential resource for reasons outside the control of the affected utilities. Further, certain allocations from federal hydroelectric projects require that the generation be used to serve load. If the Commission's regulations deem this generation to be surplus generation that is sold to the market, the Commission could threaten the ability of these utilities to continue to receive these federal allocations.
>
> **Assumption 2:** <u>Second, count all generation from renewable resources (any resource technology listed in Public Resources Code § 25741(a)(1), or in Public Utilities Code §§ 399.12, 399.12.5, or 399.12.6)</u>. Renewable resources are generally needed for RPS compliance purposes and are bid into the market in a way that generally ensures they will be run. Further, the utility will hold contractual title to the electricity and the renewable attributes, including the renewable energy credits (RECs). Further, when a utility sells (or resells) renewable generation to another utility, there is an associated contract and transfer of RECs. The entity holding the REC and title to the generation has paid the

premium for this generation and should get the benefit. This supports a default assumption that these resources are always used to meet the purchasing utility's retail load before other resources.

Assumption 3: Third, count any remaining zero carbon generation, such as nuclear generation. Nuclear power plants run at constant load and do not ramp up and down based on market signals. As with hydroelectric generation, the Commission's rules should not punish a resource that does not have the ability to respond to incentives.

Assumption 4: Fourth, count any fossil generation from resources scheduled by the utility. If the utility serves as the Scheduling Coordinator (SC) or has an SC contracted to act on their behalf, the default assumption should be that the generation is being used to serve load after the resources identified above.

Assumption 5: Fifth, count all other fossil generation that is contracted for, but not scheduled by the utility. Any remaining generation where the electric utility has procured the generation directly through a contract, but where the seller serves as the SC, should be counted next.

Assumption 6: Finally, assume that any unmatched load is met with system power. If the hourly total of generation from the resources listed above is less than the utility's load during the applicable hour, then the remaining gap should be filled using the methodology for determining a GHG emissions intensity for unspecified power.

In addition to the assumptions listed above, the Commission will also need to determine if/how emissions associated with the Energy Imbalance Market (EIM) and the Extended Day Ahead Market (EDAM) are allocated to individual electric utilities or otherwise accounted for. SB 1158 reporting requirements should not discourage participation in expanded wholesale markets such as EIM and EDAM.

2. *How will hourly load matching affect grid reliability in the state, particularly during emergency events?*

CMUA Response: The Commission should ensure that its regulations do not create incentives that discourage or penalize generation that is necessary for meeting reliability needs. While this is only a reporting requirement, how the Commission implements these regulations may inform subsequent discussions on how California will achieve its long-term zero carbon goals. Therefore, the Commission should carefully weigh its decisions with these long-term impacts in mind. Price formation pressures that incentivize lower emission resources over higher emission resources already exist. There should be no conflict between the regulations for SB 1158 implementation and market price formation or reliability needs. Consider, for example, that a retail seller inside the CAISO has "overprocured" for wind during low load hours. That retail seller must not be incentivized to curtail that generation simply because it is more generation than the utility needs to serve their retail load. There are other entities that may need that power for reliability purposes or at minimum can back down higher GHG emitting resources. Creating a disincentive to generate zero carbon generation would be counter to a broad array of state programs and policies. For example, the purpose of the EIM was to capture the benefits of these periods where California's zero carbon generation exceeds the state's needs.

3. *How should in-state and out-of-state line losses be calculated for determining loss-adjusted load?*

CMUA Response: The issue of line losses is very complex and has been challenging in other regulatory contexts, such as ARB's MRR. This is due in part to the fact that there several ways that utilities account for line losses in their contracts and procurement. This makes it impossible to develop a single approach, such as a default factor applied to all purchases. Further, there may not be sufficient data to determine actual line losses depending on where the resources are located. Additionally, the process of collecting the necessary data and calculating actual or assumed line losses can be very administratively burdensome. The Commission should determine what level of precision is necessary to meet the statutory requirement for determining "loss-adjusted load," and the relative value of actual data as compared to the use of assumptions. The Commission's regulations should utilize readily available data, be sufficiently simple to apply, and allow for individual electric utilities to use alternative methodologies.

As part of this structure, the Commission will need to determine what the losses are applied to. For example, if a utility has a contract to purchase electricity that is to be delivered to a Trading Hub (*e.g.,* NP-15), will losses only be calculated to the delivery, or will additional losses be calculated or assumed from the contractual delivery point to the utility's actual service territory? CMUA's assumption is that line losses should only be calculated to the contractual delivery point and not to a purchaser's actual service territory. Losses that occur downstream of the delivery point are part of the energy it takes to serve load, and GHG emissions for those losses are accounted for in the utility's overall energy supply (*i.e.,* generate more electricity to compensate for the line losses).

II. CONCLUSION

CMUA appreciates the opportunity to provide this response to the Commission. Thank you for your time and attention to these comments.