# Stakeholder Comments Template

## Energy Storage and Distributed Energy Resources (ESDER) Phase 4

This template has been created for submission of stakeholder comments on the Straw Proposal Working Group Meeting for ESDER Phase 4 that was held on August 21, 2019. The paper, stakeholder meeting presentation, and all information related to this initiative is located on the initiative webpage.

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business **September 4, 2019.**

| Submitted by | Organization | Date Submitted |
|---|---|---|
| *Mike Pezone*<br>*(415) 973-6093* | *Pacific Gas & Electric* | *9/4/2019* |

**Please provide your organization's general comments on the following issues and answers to specific requests.**

1. **Discussion on non-24x7 settlement of BTM Resources**

   *Which areas will require the local regulatory authority to change its rules or provide clarification to load serving entities?*

   PG&E opposes moving forward with this topic at all in its current form, absent broader participation by the California Public Utilities Commission and instead use an enhanced demand response model. Using the non-generator resource (NGR) model behind-the-meter (BTM) with a non-24 x 7 requirement poses numerous challenges specific to local regulatory authority (LRA) rules This change would impact retail bills, retail meters, and would also necessitate investment in new infrastructure and IT systems to manage and coordinate DERs, which are all topics under CPUC's jurisdiction. Without guidance from the CPUC, this effort at the CAISO will lead to a regulatory gap whereby the utility is not able to distinguish wholesale from retail, resulting in the potential for resources with distributed energy resources (DERs) to bypass retail rates – as well as, a potential for reliability issues to the distribution and transmission systems by not having the proper coordination procedures in place between the various actors (i.e. CAISO, Utility Distribution Company (UDC), Load Serving Entity (LSE), and DER).[1]

In response to the CAISO's question on what rules a Local Regulatory Authority (LRA) will need to change or provide clarification to LSEs, PG&E reiterates its position that BTM resources continue to use the Proxy Demand Response (PDR) model as the rules have been established. However, if redundant efforts were undertaken to explore how BTM storage might be able to participate in the CAISO's market as NGR, the CPUC should refer to the next steps outlined in the Multiple Use Application (MUA) Compliance Report[2] for storage.[3] For non 24 x 7 NGR to be feasible, the following changes would be needed:

1. Rules & Standards
    - UDCs and LSEs[4] need jurisdictional clarity (e.g., what meters are required, what billing rate to apply, rules to separate wholesale vs. retail, what program participation is or is not allowed) if a CPUC-jurisdictional BTM resource participates as an exporting resource in the CAISO market.[5]

2. Support Systems
    - Separate metering to differentiate wholesale versus retail transactions.[6]
        - This impacts both billing and an LSE's load forecast. To the load forecasting piece, either separate metering or a provided schedule to the LSE will be needed to determine what is wholesale or retail. For example, a BTM non-24 x 7 resource would be scheduled by a non-LSE aggregator which raises the risk of scheduling the load twice if the LSE also schedules this load as a result of a perceived increase in retail load without notification of the wholesale transaction.
    - An accounting methodology for estimating retail versus wholesale in cases where the sub-meter is behind a retail meter and the resource provides different services in different intervals.

[1] Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid. June 2017. Prepared by Staff of CAISO, PG&E, SCE, SDG&E with Support from More Than Smart (now Gridworks). https://www.caiso.com/Documents/MoreThanSmartReport-CoordinatingTransmission_DistributionGridOperations.pdf

[2] Compliance Report of Southern California Edison Company (U338-E), Pacific Gas and Electric Company (U 39 E) and San Diego Gas & Electric Company (U 902 – E) on Behalf of the Multiple Use Application Working Group. Appendix A. Multiple-Use Applications for Energy Storage: Final Working Group Report. August 9, 2018. http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/0EF9A015334951F8882582E4007ACC53/$FILE/R1503011-SCE%20MUA%20Working%20Group%20Report.pdf

[3] PG&E notes this effort was limited to energy storage as the MUA report was a part of the Energy Storage OIR, Track 2. This rulemaking would need to change if it were to expand to all DERs. Additionally, as the CPUC's Energy Storage proceeding is closed, a new proceeding would need to be opened to address these various issues.

[4] PG&E notes CCAs with DERP resources could develop different LRA rules.

[5] Stakeholders are expecting a rulemaking from the CPUC on Multiple Use Application implementation. It is unclear if this will be limited to energy storage or extend to all technologies.

[6] As SCE mentioned in the August 21st Working Group Meeting, while this issue is more straightforward when there is a full charge and discharge at wholesale or a full charge and discharge at retail—the issue is extremely complex with "partials" – or mixing wholesale and retail charge and discharge patterns in different intervals.

  - As SCE mentioned in the August 21st Working Group Meeting, while this issue is more straightforward when there is a full charge and discharge at wholesale or a full charge and discharge at retail—the issue is extremely complex with "partials" – or mixing wholesale and retail charge and discharge patterns in different intervals.
- IT systems and billing system

3. Operations and Communication
   - Communication protocols or standards for:
     - DER providers to inform LSEs of their operating/MUA configuration for a given day/season to inform the LSE's load forecast.
     - Other non-LRA jurisdictional operational and communication protocols will need so that the CAISO, UDC, LSE, and DER can all effectively communicate.

Considering the categories documented above that would be necessary to enable non-24 x 7 participation and export, PG&E views a preferred path for BTM resources that wish to provide multiple services to be an enhanced demand response (DR) model. Using the DR model solves many of the jurisdictional issues, has rules to prevent double compensation, and prevents duplicating investments that have already been made for a similar purpose. Additionally, DR is evolving to accommodate the changing physical and operational characteristics of DER aggregations. New models of DR are being developed to respond to this diversity in capabilities with CPUC proposals[7] and CAISO products for bi-directional products (e.g., storage backed DR providing load shift) as well as new baselines to enable more frequent dispatch. New DR models also address the core concern that seems to be driving the non-24 x 7 request.

2. **Market Power Mitigation for energy storage resources**

*The two options proposed in the calculation of cycling costs.*

In general, PG&E is concerned that the default energy bid (DEB) proposals offered in CAISO's most recent workshop presentation extend beyond the scope of addressing market power mitigation and now represent a proposal for fundamental change to the NGR model. PG&E believes that if any DEB calculation is to be in scope for ESDER Phase 4, it should not be based on requiring enhancements to the existing NGR model. PG&E appreciates the CAISO's efforts to explain the two options for calculation of cycling costs, but believes a full explanation of how these calculations would be used was not completed during the workshop due to time constraints.

With that caveat, PG&E believes the first cost option associates a cost with scheduling a non-generator resource (NGR) resource when its state-of-charge (SOC) is far from the maximum SOC; all else being equal, to minimize this cost the

---

[7] See Final Report of the CPUC Working Group on Load Shift. https://gridworks.org/wp-content/uploads/2019/02/LoadShiftWorkingGroup_report.pdf

NGR would be scheduled as close to maximum state of charge as possible (depending on the relative values of energy and the cycle depth cost). This option does not appear to address cycle depth per se, and might lead to inappropriately keeping NGR resources near maximum SOC when a lower SOC level would realize more benefits in terms of flexibility services.

PG&E believes the second cost option associates a cost with change in state-of-charge, which does seem to directly set a cost on depth of discharge (or charge) in the optimization. However, it isn't clear whether this cost option would actually distinguish between multiple relatively shallow cycles and a single deep cycle if the number of integer variables used to represent SOC were small (e.g., two); and if the number of integer variables were large (e.g., five or more), PG&E believes CAISO would be incorrect in assuming the computational burden of the additional integer variables would necessarily be manageable in the CAISO market software.

3. **Variable Output Demand Response resources**

The Variable Output Demand Response (VODR) topic is both a planning and operational issue, and CAISO addresses the problem from a planning perspective in proposing a new methodology to determine the resource adequacy (RA) value of DR. PG&E appreciates the discussion on using the effective load carrying capability (ELCC) for DR, but recommends that the CAISO and the CPUC align first on the purpose of DR. Should DR be a product used for reliability on peak days, as reflected in the RA value determination in the CPUC's Load Impact Protocols (LIP)—or as an economic product used frequently as reflected in DMM's analysis of DR's performance[8] and embedded in the recommendation to use the ELCC? If CAISO intends to move to the ELCC, PG&E urges CAISO to provide stakeholders a few examples associated with determining the ELCC for DR. Below PG&E provides additional feedback to the CAISO's proposal.

PG&E supports the CAISO's two key principles concerning variable output DR, welcoming its recognition that DR is a variable output resource. However, it is important to emphasize that the daily operating conditions that the CAISO focuses on are not necessarily equal to the CPUC's RA planning scenario for DR, which uses the monthly peak day, as opposed to the average day in the month. It seems that the CAISO is expecting DR to provide as much capacity on the average day as on the monthly peak day. Since DR is a variable output resource, it is not realistic to expect DR to deliver the same capacity for both the average day and the peak day. This leads to the policy question, "What do we plan to use DR for?" Is it to be used as a reliability product and we should assume peak day conditions (as reflected in the LIP) or as a daily operating product as reflected in the recommendations from CAISO? Simply changing the estimation method to use

---

[8] Integrated Resource Plan. Reply Comments of the Department of Market Monitoring of the California Independent System Operator Corporation. August 12, 2019. Pp 8- 11. http://www.caiso.com/Documents/CPUC-DMMReplyCommentsonRulingInitiatingProcurementTrackandSeekingCommentonPotentialReliabilityIssues-Aug122019.pdf

the ELCC would not improve the forecast accuracy of DR, if the policy question is not first addressed at the CPUC.

In addition, ELCC has its inherent weakness when applied to DR, since it must take a nameplate capacity value, or a maximum capacity value, as an input. Strictly speaking, the total capacity of a DR resource is not the qualifying capacity DR provides to RA. DR's qualified capacity (QC) is the expected (average) load impacts under normal weather conditions on the monthly peak day. Assuming the QC to be the total capacity and then derating the QC using ELCC would likely lead to undervaluing DR resources. Should ELCC be applied to DR, the total capacity needs to be properly defined.

Lastly, the CASIO also proposed that DR, like VERs, provide bid forecasts every 5 minutes on a rolling basis. From PG&E's perspective, this real-time requirement would be onerous and yet adds no incremental value to the forecast accuracy. Since for PG&E's programs the customer count is known for the month and the weather forecast rarely changes significantly in one day, PG&E's DR bid forecasts from the day before will still be valid and the proposed VER forecast would not change or improve the forecast. The real-time update would hardly offer more accurate data than the day-ahead forecast does, but the cadence would create an unnecessary burden on the SCs. If the CAISO allows SCs to submit weather-dependent and time-variable forecasts day-ahead (as opposed to one single QC value for all hours in the month), PG&E believes the current day-ahead forecasts for PG&E's DR programs are sufficient.

4. **Additional comments**

Please offer any other feedback your organization would like to provide from the topics discussed during the working group meeting.

<u>State of Charge Management/Bid Parameters Should Be a Primary Focus of ESDER 4 Implementation</u>

CAISO's most recent presentation did not include new information on the topic of SOC parameters and their use in the market processes. PG&E encourages CAISO to keep SOC management/bid parameters as a primary focus of ESDER Phase 4 due to both its immediate importance and the need for stakeholder participation in resolving open issues. In particular, PG&E reiterates its previous request that BCR rules and implications be carefully and completely described in future revisions of this element of ESDER 4, allowing for better stakeholder review of any proposal.

<u>Battery Charging Costs</u>

PG&E appreciates CAISO's efforts to fully model all real costs seen by NGR market participants in its proposal for calculation of NGR default energy bids. The

CAISO's discussion on the importance of the incremental costs of deep cycling (versus previous assertions, often found in vendor warranties, about the incremental costs of throughput as such) have raised issues that should be considered by market participants in their optimization and bidding processes.

As the CAISO has acknowledged in the default energy bid discussion, other costs have previously been identified by market participants as contributing to the cost of incremental discharge. Wholesale market costs of charging may include not only the costs to charge forecast at the time of bidding, but also a risk component associated with the possibility that the CAISO markets may yield a schedule in which charge is not awarded to support discharge, resulting in high imbalance charges due to inability to discharge per schedule. Throughput costs may not be reducible to a static daily opportunity cost-based value but may require updating based on forecasts of conditions beyond the horizon of the CAISO markets. The energy-related opportunity costs associated with regulation awards (and potentially, imbalance reserve awards if implemented in the Day Ahead Market Enhancements initiative) may also vary and be very hard to forecast except in terms of maximum risk. All of these opportunity costs may or may not be large relative to the opportunity cost which has been the focus of the CAISO's analysis to date; PG&E suggests that market experience should be used to inform the effort of calculating a DEB based on these cost components, and that therefore it may be more appropriate (and ultimately more beneficial to both the CAISO and market participants) to delay formulation of a DEB until some extended experience of a year or more can be shared with all stakeholders.

The CAISO Should Avoid Mitigation of Bids Intended to Mitigate Risk or Avoid Unintended Market Outcomes

PG&E would also like to point out that in many stakeholder settings, the CAISO has advocated for the use of bids as the primary tool to be used by market participants to accurately schedule the charging and discharging of energy storage resources. Such bids may be set at very high levels not to exploit market power, but to avoid excessive dispatches under unusual system conditions (usually, conditions not anticipated by either market participants nor the CAISO, such as major forced outages). PG&E is concerned about the tension between this approach, recommended by the CAISO for management of constraints not directly captured in the market, versus the need for local market power mitigation. On reliability grounds, the CAISO should avoid mitigation calculations that result in excessive and inappropriate dispatches in the markets. PG&E suggests that either bid prices cannot be used for the purpose advised by the CAISO, or that some additional parameters or attributes may be required to identify and distinguish this form of uneconomic bidding from bidding that must be mitigated to avoid unjust and unreasonable prices.

Spread Bidding and Market Power Mitigation

The CAISO commented in the most recent workshop that it believed a “spread bid” model for battery storage did not require additional development; in essence it claimed, without clarification, that the capability already existed in the existing NGR model. PG&E believes the CAISO is correct if the market solves to the true optimal solution, because in such case the most cost-effective use of battery energy bids will be based on the arbitrage between discharge costs and charging costs, without regard for the absolute levels of bids. It is clear, however, that in practice the market does not arrive at the optimal arbitrage solution, whether because the market does not normally solve to full optimality or for other reasons: PG&E has observed that its charge and discharge market awards are normally consistent with its absolute bid levels rather than with the arbitrage implied by the bid set.

If the arbitrage model for battery storage were implemented (considering only the Integrated Forward Market (IFM) for purposes of this argument), PG&E believes it might not be possible to mitigate battery bids in the current LMPM construct, because LMPM is based on mitigation of the absolute level of bids in mitigated periods, and such mitigation would instead have the effect of modifying (reducing) the battery’s desired arbitrage.

<u>Market Power Mitigation of Charging Bids</u>

Finally, PG&E would like to request a clearer example of why the CAISO and the Department of Market Monitoring (DMM) believe it might be appropriate to mitigate charge as well as discharge bids on an NGR. PG&E believes the scenarios that have been described to date, in which pivotal supply can take advantage of charging demand that increases price at a location, would certainly result in mitigation of the supply in the first place, and that such mitigation would be sufficient to eliminate any benefits of using market power to increase demand on a bid to charge an energy storage resource.

PG&E recognizes that even without explicit LMPM performed on charging bids, it may be necessary to mitigate the charging portion of an NGR’s energy bid due to the requirements of monotonicity, if the discharge portion of the bid were mitigated. In this case, PG&E recommends that the same option provided to NGR resources in the EIM, of having the option to limit charging when the energy bid curve is mitigated, should also be available to CAISO NGR market participants if this is not already the case (PG&E is not aware of this capability or option being made available to resources internal to CAISO).