CESA
CALIFORNIA ENERGY STORAGE ALLIANCE

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Dear Aloke:

Per our discussion from last week, I'm sending you CESA's comments regarding the three topics for the upcoming June 2, 2014 Solicitation Application Workshop.

Topic 1 – Energy Storage Definitions and Eligibility

1. What defines eligible storage technologies? CESA response – please see description of eligible technologies, per statute
2. What was the Commission's intent with respect to 'ownership'.

   CESA's notes that D.13-10-040 provides:". . . [W]e find that the utility ownership of storage projects should not exceed 50 percent of all storage across all three grid domains at this time. In other words, utilities may own no more than half of all of the storage projects they propose to count toward the MW target, regardless of whether it is interconnected at the transmission or distribution level, or on the customer side of the meter." Conclusion of Law Number 30 also provides: "It is premature to allow 100% utility ownership in transmission and distribution-connected storage until it is determined what narrow applications are best suited for utility ownership versus third-party ownership." Conclusion of Law Number 30 also provides: "It is premature to allow 100% utility ownership in transmission and distribution-connected storage until it is determined what narrow applications are best suited for utility ownership versus third-party ownership." If 100% Utility-owned energy storage assets are proposed to be procured outside of the Storage Framework or as authorized in other Commission proceedings, the Utilities should explain why such a procurement is justified on a case-by-case basis without re-litigating the Commission's express asset ownership preference in each instance.

   SCE responds: "CESA suggests that the Commission limit the utility ownership of storage assets to 50% of the storage target in each grid domain – transmission, distribution, and customer. This suggestion is contrary to D.13-10-040, which states that "the utility ownership of assets should not exceed 50% of all storage across all three grid domains." D.13-10-040 indicates that SCE can own no more than 290 megawatts ("MW") of storage total, regardless of where it is connected. Who is right?

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3. What defines commercially viable storage technologies? CESA response – since IOU RD&D projects 'count' toward the procurement target, then similar levels of performance track record/commercial readiness should be extended to any new procurements. Further, perhaps the question regarding commercial viability also introduces a broader questions about how to treat various types of risk –

    1) *identify and characterize* uncertainties and elements of risk
    2) *quantify* the elements of risk
    3) decide what elements of risk and the amount of risk that should be assumed by which stakeholder(s), especially
        - utilities
        - vendors
        - specific electricity end-users
        - ratepayers a group
        - society
    4) identify and develop approaches to mitigate risk
    5) identify and develop approaches to assign unmitigated risk
    6) identify and develop approaches to risk and reward sharing, possibly including one or more of the following:
        - contracts and terms of pay and performance (à la PPAs)
        - prices (locational, time-specific, etc.)
        - performance penalties
        - rent/lease rather than buy/ratebase
        - warranties
        - service contracts
        - "call options" involving "reservation charges" for capacity (a real example is reservation charges for Diesel generators that a utility MAY need on short notice.)

    By the way, addressing risk THAT way goes a long way toward obviating the need to decide what storage types are "acceptable" or "ready" or "good enough" (without regard to specific environment and siting related challenges.)

4. How will EV battery capacity count toward the energy storage procurement targets? CESA has advocated that the portion of EV capacity that provides both charging *and* discharging should count toward the targets. Simply providing grid services through 'charging' is insufficient, as there is no 'return of energy' to the grid.

Topic 2 – Energy Storage Valuation Protocol

Below are a number of questions and comments for the utilities regarding their valuation techniques to ensure that the value of storage is not underestimated relative to other resource options. Further, due consideration should be given to factoring in benefit streams that are occurring simultaneously. (eg. frequency regulation and peak shaving can occur simultaneously).

<u>Capacity Value:</u>

Storage can provide system, local and flexible capacity value. How does each utility calculate these values for storage projects? For example, if a storage project is serving a local capacity need does storage get assigned a higher capacity value compared to base-load facility serving the local area need?

How many dispatch hours at full load are required to get the full capacity value?

Ancillary Services Value:

The price and quantity needed is highly uncertain in the future; however, both price and quantity are likely to increase as more renewables are added. How is the ancillary services value calculated for storage projects?

Is the full range from charging to discharging used to estimate the reg-up and reg-down value for battery storage?

Energy value

The volatility and spread between low price hours and high price hours are expected to increase in the future. How is this pricing effect included in the evaluation of storage projects? What is the basis for estimating these future price changes that will greatly influence the value of storage?

Locational adjustments

Certain locations will be attractive for storage development versus other locations which could increase system transmission costs. Are the utilities going to give guidance before RFOs on the more attractive locations to site projects?

Energy and GHG benefits

Storage facilities allow much better optimization of the system resources. A marginal analysis of storage charging and dispatch does not capture the improvement is system dispatch optimization. How are the utilities going to ensure that the energy savings and GHG reductions from better system optimization is captured in the economic evaluations? Will production simulation modeling be done? Can production simulation modeling being performed in other rulemakings be used as a proxy?

Distribution Level Storage Projects

What are the specific changes in the evaluations that the utilities will use in comparing these storage projects to transmission level interconnected storage projects?

Note that the utilities appear to prefer ownership of distribution level facilities. Since they have a financial incentive regarding ownership versus contracting, it is important to ensure that they are creating a fair comparison between distribution level storage and transmission level storage offers.

Water Usage

Given California's extreme drought conditions, how will water usage be factored into overall benefits of energy storage versus status quo solutions?

Topic 3 – Procurement and RFO Requirements

Storage Project Size Limitations
SDG&E's proposed size limit of 10MW would potentially eliminate some forms of energy storage from bidding, such as small scale (<50MW pumped hydro storage) and aggregated larger scale projects >10MW that maybe very cost effective due to their larger size. While this may make sense for SDG&E in the very near term because their targets are so low and they've already made substantial progress toward these targets, an arbitrary limit may inadvertently stymie innovation and prevent very cost effective solutions from emerging.

Further, CESA respectfully requests that the CPUC clarify that the specific pumped hydro limit of 50MW limit be defined as 'what is delivered at the generator interconnection point to provide full value to the electric grid". This clarification would account for losses a pumped storage hydro facilitate would incur, as it would have to be sized slightly larger than 50MW to deliver a full 50MW to the grid.

Contract Term Limits
PG&E's proposed contract term limit of 10 years does not allow storage technologies with longer useful life spans to offer competitive pricing that reflects amortization of capital costs over a term that matches the lifespan of these projects which is 20+ years, potentially placing technologies with very long life spans at a distinct disadvantage. CESA recommends that the contract term limit proposed in PG&E's application be eliminated and all three IOU applications conform to SCE's proposal such that projects have the option to bid for 20 years or for longer than 20 years.

Customer Sited Pilot
CESA recommends that the CPUC encourage the IOUs to engage in a pilot to procure energy storage services from behind the meter third party and customer owned assets as early as this fall. This pilot would be focusing on piloting creating contracting mechanisms for IOUS to procure service from behind the meter energy storage resources, and will also help further the customer sited target requirement.

Energy Storage Pro Forma Agreement
CESA recommends that the CPUC assist with addressing problematic portions of the proposed pro forma agreements to ensure consistency across all IOU procurements. This will greatly reduce transaction costs from energy storage procurements going forward. Below are some issues with the SCE pro forma:

1. Article Ten. Adjustments to Monthly Capacity Payment. The pro forma contract is structured so as to penalize a Project twice for any reduction in available capacity. Pursuant to Section 10.01, any reduction in Net Qualifying Capacity would reduce the SU Contract Capacity, resulting in lower capacity payments. Further, any reduction in Available Storage Capacity would further result in a payment reduction, pursuant to Section 10.01(c). This would result in a Project potentially being penalized twice for a capacity reduction, if a Project's NQC was reduced as a result of that reduction in Available Storage Capacity.

2. Article Nine. Contract Capacity, Associated Energy and Ancillary Services; Energy Adjustment Payment. The Energy Adjustment Payment is calculated in part by using the LMP at the pNode for the storage Storage Unit. However, that LMP is capped at the SCE Tariff Rate Schedule TOU-8 Time-of-Use-General Service-Large for "Service Metered and Delivered at Voltages above 50kV," when the Energy Adjustment Payment is owed to Seller, while not similarly capped when owed to SCE. Section 9.6 (e). Not only is the disparate treatment inappropriate, as SCE also has the right to dispatch the Storage Unit, and thus has control over whether the Unit is dispatched during a period when the LMP is greater than the TOU-8 rate. The cap should be removed, or should be applied uniformly.

3. Deviations between SCE's Pro Forma RPS Agreement and the Pro Forma Energy Storage Agreement. A side-by-side comparison of this form agreement to SCE's form power purchase agreement shows that numerous changes were made throughout the document in sections that are not specific to either energy generation or energy storage. Almost universally these changes are harshly unfavorable to Seller, and usually unnecessarily so. Examples include shortened cure periods (and exclusion of standard cure extension language), changing bilateral requirements to unilateral requirements, removing expense reimbursements, inserting SCE discretionary approvals at various stages of project development, shortening the delivery timeframe for letters of credit, and reducing the permissible timing window for project completion to exactly one day. These changes are frequently to language that is fairly standard, not just within SCE power purchase agreements, but within industry practice or contracting as a whole. The combined effect of these non-storage-related changes is significant, and could present a hurdle to financing. SCE should be encouraged to more closely track standard contracting, or at least their own PPA.

Other Important Issues that Have Not Come up Yet That Will Dramatically Impact Valuation of Storage Projects (Maybe for Interconnection or Storage OIR #2?)

Interconnection Study Assumptions

The discharging and discharging of energy storage assets is currently subject to different study processes. Discharging is subject to the CAISO's or utility's generator interconnection study processes. Generator interconnection studies are generally done as cluster studies[1] that assume all generation in the cluster shares responsibility and cost for network upgrades. Charging, however, is being studied separately through the utilities' load interconnection processes. These usually look at the 'load' independent from any other resources applying to interconnect in the area. Because the assumptions are different, the results of the studies are also likely to be different even though the impacts may be the same[2].

In addition, generator interconnection tariffs have different treatment for how upgrades are paid for than load interconnection tariffs. If a network upgrade is needed to address both the charging and

[1] Unless a project qualifies for the independent or fast track study processes

[2] See CESA's comments on the CAISO's Storage Interconnection Initiative (http://www.caiso.com/Documents/CESAComments-EnergyStorageInterconnection-Apr72014Discussion.pdf)

discharging of a storage asset, conflicting cost responsibility rules would currently apply. In order for this issue to be resolved, CESA recommends that the CPUC more clearly define what applications of storage facilities constitute "load" under its load interconnection tariffs. For example, the CPUC could define station power as "load," because it is an end use, while charging would be excluded from the definition of "load" because it is done with the intent of reselling the power (in effect, charging would be considered "negative generation"). This would substantially streamline interconnection processes and remove conflicting rules for how to study projects and address cost responsibilities.

Cost of Charging Energy Storage Assets and Clarifying what is 'Station Power'

Similar to tariff treatment for interconnection processes, the charging of energy storage is subject to different rate treatment than discharging depending on where it is sited (customer sited, co-located with a generator etc.). Energy storage systems selling into wholesale energy markets use electricity as their fuel source for generation. If fuel for charging was considered end use "load" by the utilities and priced at retail rates, then the value proposition for storage assets will be distorted and decimated[3]. However, some energy that is used at an energy storage facility can legitimately be counted as 'station power'. For example, would electric load from air conditioning or pumping at a flow battery facility be considered station power, or would that 'load' be simply part of the cost of 'charging'? As with interconnection study assumptions, it would be helpful if the CPUC can more clearly define what constitutes "load" for energy storage (e.g. station power) versus what is not considered to be load (e.g. charging, which could be considered "fuel" or "negative generation"), in order to optimize the use of energy storage assets on the grid for all ratepayers?

[3] In addition, the load serving entities' tariffs define their load customers as those that consume and do not resell power.