**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources. | Rulemaking 14-10-003<br>(Filed October 2, 2014) |

**COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE TO THE E-MAIL RULING INTRODUCING DISTRIBUTED ENERGY RESOURCES TARIFF STAFF PROPOSAL AND DIRECTING COMMENTS AND RESPONSES TO QUESTIONS**

Alex J. Morris
Executive Director

Jin Noh
Senior Policy Manager

**CALIFORNIA ENERGY STORAGE ALLIANCE**
2150 Allston Way, Suite 400
Berkeley, California 94704
Telephone: (510) 665-7811
Email: cesa_regulatory@storagealliance.org

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# COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE TO THE E-MAIL RULING INTRODUCING DISTRIBUTED ENERGY RESOURCES TARIFF STAFF PROPOSAL AND DIRECTING COMMENTS AND RESPONSES TO QUESTIONS

In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") hereby submits these comments to the *E-Mail Ruling Introducing Distributed Energy Resources Tariff Staff Proposal and Directing Comments and Responses to Questions* ("Ruling"), filed by Administrative Law Judge ("ALJ") Kelly A. Hymes on October 6, 2020.

## I. INTRODUCTION.

Since its inception in 2018 and its evolution and lessons learned over the past three years, the Distribution Investment Deferral Framework ("DIDF") represents an important framework to provide transparency into the investor-owned utility ("IOU") distribution planning process through the Distribution Planning Advisory Group ("DPAG") and to identify key opportunities to deliver ratepayer cost savings through the deferral of traditional distribution investments via distributed energy resources ("DERs"). As a regular and active participant in DIDF policy development and in DPAG meetings, CESA appreciates the Commission's commitment to continue to make improvements to the DIDF, including with helpful modifications made to contracting structures, planning processes, and procurement mechanisms over the years. We also extend the appreciation to the IOUs, who have made significant strides in improving the Grid Needs Assessment ("GNA") and Distribution Deferral Opportunity Report ("DDOR") filings, making additional planning/siting information and tools available, and soliciting and considering stakeholder input via the DPAG process. Due to these efforts, DERs have been solicited and has successfully deferred a handful of distribution investment projects. While success is not necessarily measured by having DERs defer all possible or even shortlisted planned investments, CESA believes that DERs as a possible lower-cost alternative should be assessed and/or pursued to the extent possible while ensuring safety and reliability in the interest of ratepayer savings. Without reasonable consideration and solicitation of DER information and market participation, the Commission and the IOUs would be unable to assess whether the planned investment is indeed the most cost-effective solution to the meet the identified distribution need.

To date, the current DIDF Request for Offers ("RFO") sourcing mechanism has been successful in procuring entirely in-front-of-the-meter ("IFOM") energy storage resources to address some of the identified distribution deferral needs with all-at-once, upfront procurement. CESA commends the efforts that led to these types of results, but competitive solicitations may not be best suited for all types of identified distribution deferral needs. For instance, IFOM resources are likely better positioned to participate in competitive solicitations and developers of such resources are generally attracted to high capital cost projects with large capacity needs to achieve economies of scale and spread project development and overhead costs. Meanwhile, behind-the-meter ("BTM") DERs have yet to be successfully procured in the DIDF RFOs and may not be participating as robustly in competitive solicitations due to the challenges of meeting larger capacity needs with an aggregation of smaller resources, particularly under tight timelines. Whereas IFOM resources can more easily identify one or a few project sites to address a deferral need, BTM resource deployment involves multiple sites with their associated customer acquisition, interconnection, and contracting to address the same need.[1]

As a result, CESA believes that alternative sourcing mechanisms are needed to increase the viability of deferral opportunities to succeed, especially as BTM DERs are better positioned to address smaller capacity needs and opportunities where ratable procurement is possible. After more than two years since the Commission discussed and solicited DER tariff proposals, CESA

[1] CESA seeks to correct staff's understanding of IFOM DERs generally facing longer interconnection timelines as compared to BTM DERs, which may not always be the case, or may not be as significant of a gap as suggested. For example, if IFOM energy storage is able to pursue an independent study process for interconnection, timelines can be substantially reduced (*e.g.*, less than one year). When deliverability is required to be able to stack Resource Adequacy ("RA") value to the distribution service, timelines can be substantially increased to 2-3 years to proceed through the cluster study process, with an additional 2-6 years depending on the upgrades needed and IOU construction timelines to get the DER fully deployed. *See* Staff Proposal at 17 and 21.

thus appreciates the introduction of Energy Division's *Distributed Energy Resources Tariff Staff Proposal* ("Staff Proposal") that seeks to streamline and scale up procurement of DERs for distribution deferral purposes (including via tariff-based sourcing mechanisms), reduce transactional costs, and clarify incrementality policy for DERs sourced for deferral. CESA wholly agrees with the issues and solutions discussed in the Staff Proposal where ratable procurement approaches can mitigate uncertainty in terms of cost and need for distribution investments as well as over- and under-procurement risks.[2] As the Staff Proposal correctly notes, tariffs have certain advantages in reducing the time and resources required of DER service providers through bottom-up participation for discrete grid services, and in allowing for incremental procurement to potentially 'right-size' distribution grid needs as they change or grow.

To this end, CESA is strongly supportive of the Staff Proposal and looks forward to working with staff and other stakeholders to refine the concepts and pilot proposals such that they can be tested in the 2021-2022 DIDF cycle. Regarding the proposed Clean Energy Customer Incentive ("CECI"), CESA supports the adoption of the Incentive Pilot 1 for the 2021-2022 DIDF for implementation in August 2021 and offers the following comments and recommendations to support its refinement:

- CESA generally supports the proposed guiding principles but recommends modifications to clarify that comparisons are made between DER payments and the deferral value and remove the principle that DER alternatives must be reasonably expected to reduce greenhouse gas ("GHG") emissions.

- CESA is not opposed to implementing a prescreening process but it should focus on some minimum viability criteria, be implemented in a streamlined fashion at the state level, and without reapplication unless necessary – all in an effort to ensure the process is not be market-limiting, overly burdensome, or duplicative of other processes.

- CESA strongly supports the use of ratable procurement and believes that this approach can best address steady load growth projects and possibly even known load growth projects upon further examination.

- The subscription period and contingency date of the tariff is likely project dependent, but an assessment of the in-service need date could inform how long to set the subscription period and when to close the tariff to pursue contingency solutions.

[2] Staff Proposal at 16-17.

- CESA generally supports the Staff Proposal to set the tariff budget based on the cost of the planned investment, but the Commission should fix the tariff budget upon launching the tariff to provide market certainty, seek to identify best-fit projects that yield tariff prices that spur market interest, and set the tariff budget at 100% of the planned investment cost for the purposes of piloting a new idea.

- In concept, CESA does not oppose the use of customer attestations, so long as the process does not prove to be burdensome, but the Commission should consider whether the upfront contracting approach should be incorporated in the tariff.

- The tariff should take advantage of the ratable procurement concept to establish multiple subscription period and multiple acceptance triggers, as appropriate.

- CESA supports the marketing and outreach proposal, modified to consider the role of partners as well as opportunities to synergize with existing activities and channels.

- CESA generally supports the Staff Proposal to use a single-price method for the tariff, but many details will likely need to be worked out, including price differentiation by time period and guardrails to ensure service quality in a first-come first-served model.

- CESA is generally supportive of a tiered payment structure believes that there may be too many tiers, which could dilute the incentive for any component and should thus be consolidated around tiers related to deployment and capacity reservation.

- CESA supports the incrementality rules in the Staff Proposal where simple rules should be developed to increase accessibility, with expanded guidance related to DER solutions funded through Transportation Electrification ("TE") program deployment incentives.

- The tariff should not be contingent on IOU Distributed Energy Resources Management System ("DERMS") functionality or requirement to be integrated with their DERMS since third-party aggregators already have and can deliver similar functionality.

Despite the potential benefits of the CECI pilot concept being applied to broader areas rather than specific projects, CESA agrees that more discussion and refinement is needed such that 2021-2022 DIDF cycle implementation is less likely, but the Commission should target the 2022-2023 DIDF cycle for piloting this concept that affords sufficient time to flush out the details of Incentive Pilots 2 and 3.

Regarding the RFO changes to streamline the process, CESA is cautiously supportive of the Staff Proposal to allow projects to proceed directly to the RFO stage but recommends the following to support the streamlining objective while also supporting continued improvements:

- Stakeholder discussions and input should be solicited to review lessons learned from previous RFO processes and identify any key changes that should be adopted and implemented for the next cycle.

Regarding the Standard Offer Contract ("SOC") pilot, CESA views the SOC as being worthwhile to pilot to measure whether such benefits come to fruition, especially as the SOC does not appear to be excessively different from the current status quo, but provides the following comments and recommendations to clarify and refine the pilot idea:

- Rather than waiting for the full five-year pilot period to consider additional uses of the SOC in future DIDF cycles, it should be considered in all future DIDF cycles following the first pilot, even though adoption of a formal program is delayed until a more comprehensive evaluation can take place.

- To make the SOC work, standard product definitions and operational requirements may be needed to enable simple auction pricing, where the quantity of DER capacity procured is in essence commoditized similar to what has been done by Pacific Gas and Electric Company ("PG&E").

- The existing technology-neutral *pro forma* ("TNPF") contract used for competitive solicitations would need to be simplified for the purposes of the SOC pilot, such as by having the contract be structured to buy distribution capacity only.

- How resources that seek marketing and outreach support should be reflected in the auction pricing should be clarified to ensure a level playing field.

To advance the concepts and pilot proposals, CESA also responds to the aforementioned questions in the Ruling with examples of projects shared in the DPAG meetings during the 2020-2021 DIDF cycle to help highlight how the details in the Staff Proposal could be structured and implemented, as well as to show how certain project opportunities may be better fits for the proposed tariff pilots.

While no questions are posed on the Emergency Reliability Dispatch Program or the planning area pilots, CESA strongly supports these in concept and recommends that they be explored further in the coming months.

## II. RESPONSES TO QUESTIONS ON THE STAFF PROPOSAL.

**Question 1: Are the proposed guiding principles for the Staff Proposal, including the proposed new principles, appropriate and complete? If not, what revisions and/or additions should be made.**

CESA generally supports the proposed guiding principles[3] and appreciates staff's addition of the new proposed guiding principles that support the proposed CECI, as well as the changes to the first principle to ensure a level playing field, the third principle to incentivize the reduction, rather than the minimization, of overall costs including operations and maintenance, and the fifth principle to focus on DER deployment and utilization. Together, these changes should better reflect the opportunities for deferral by both existing and new DER deployments.

However, CESA notes that the first new principle to "maintain tech neutrality among DER types while recognizing that some DERs will be better able to meet certain needs than others"[4] may be superfluous, as the proposed CECI does not recognize these different abilities. Furthermore, the second new principle states, "the cost of DERs must cost less than the deferral value cost cap."[5] CESA recommends this principle be modified to clarify that it is the *payment to the DER,* rather than the cost of the DER itself, that must be under the cost cap. For example, the principle could read: "cost of ~~DERs~~ ***the IOU's payment to the DER*** must cost less than the deferral value cost cap." As proposed, the CECI budget is tied to the unit cost of the traditional investment, not the cost of DER equipment, software, installation, or related costs, and CESA recommends the principles be revised to reflect as such. Thirdly, in alignment with the modified fifth principle and affirmed incrementality rules, CESA recommends that the second new proposed principle be revised to "leverage private investment in *new and existing* DERs" to allow for the utilization of existing DER deployments for incremental grid services.

Consistent with our February 15, 2019 and May 24, 2019 comments, CESA proposes modifications to the second existing principle to ensure that the underlying standard for current and future iterations of the proposed DER tariff concepts are reasonable and advance the key goals of the DIDF, which is to ensure grid reliability while reducing ratepayer costs. CESA recommends the Commission consider the implementation challenges of "providing an incentive for energy usage and market behavior that is reasonably expected to reduce greenhouse gas emissions and other air pollutants."[6] To CESA's knowledge, GHG emissions reduction is not a standard for wires solutions, and the Commission has not adopted a method to set a baseline against which non-wires

[3] Staff Proposal at 19.

[4] *Ibid.*

[5] *Ibid*.

[6] *Ibid.*

solutions can improve the GHG emissions profile of a wires investment.[7] While reducing GHG emissions is an important state policy goal, it is not the primary objective of or the standard of review for traditional distribution investments. In line with the principle that the traditional wires solution or the DER is not inherently favored, this principle should be modified accordingly.

Additionally, this principle may also preclude the ability to meet a broader range of deferral needs, such as the ones that have been identified in the DDOR filings and discussed at the DPAG meetings as having longer-duration capacity needs or baseload-like attributes. In such instances, for example, it may increase the viability of DER alternatives by pairing energy storage and/or renewable resources with fuel cells that may have some emissions associated with the fuel cell's operations but deliver successful and cost-effective distribution deferral benefits that energy storage and/or renewables could not achieve on their own. To this end, a GHG-related principle could be established to give preference to cleaner DER alternatives (such as for renewables or resources without point-source emissions like storage) over other DERs but not to establish this principle based on how it may impact GHG emissions as compared to the traditional wires solution.

Instead, DER alternatives should be assessed and selected based on their ability to provide distribution grid services and their relative costs to the traditional solution, and efforts to reduce GHG emissions from DER alternatives should be pursued through rate design and/or via DER participation in programs aligned with GHG emissions (*e.g.*, GHG signal from the Self-Generation Incentive Program ["SGIP"]). CESA is concerned that this GHG-related principle may present challenges, such as developing methods to assess GHG emissions of traditional wires solutions, that slow down implementation of the proposed DER tariff concepts and, in turn, the enablement of deferral capabilities. Having to demonstrate GHG emissions reduction to be eligible for deferral services or be approved for tariffs or contracts would also slow down DER deployment.

<u>**Question 2**</u>**: For each of the following elements of the proposed Clean Energy Customer Incentive, explain what modifications, if any, should be made:**

[7] For example, while the baseline for "procuring" existing DERs is clearer (*i.e.*, GHG emissions associated with current operations and behavior) regardless of the planned distribution investment, the baseline is unclear for new DER procurement. Do we measure GHG emissions reduction of new DER procurement to the planned investments, which would likely require a broader system perspective of the impact of the wires investment? Even if this was the case, the GHG emissions analysis may be overly complex and slow down tariff or contract approval processes as well as deployment timelines – factors that have been identified throughout the DIDF process as being limited and critical in nature.

For each of the sub-topics to this question, CESA references potential deferral opportunities identified in the IOUs' DDOR filings to inform how the proposed tariff details could be structured.

**a: Prescreening process;**

CESA is not opposed to implementing a prescreening process. However, several details need to be worked out to ensure that the proposed process is not market-limiting (*i.e.*, inclusive of different and new technologies) and is not overly burdensome for IOUs, DER providers, and customers.

First, the prescreening criteria should focus on some minimum viability criteria to assess whether the company of the DER provider, or key staff members of the company, who have a proven track record to develop commercial projects. To this point, a broader focus on experienced and proven staff, not just at the company level, would function to *not* preclude new market entrants. Meanwhile, technology-specific or equipment-related criteria should not be included in the prescreening process since such equipment will need to be certified to key safety and reliability standards as part of separate interconnection and permitting processes, such that a viability check for these criteria in the prescreening process would be potentially duplicative and only serve to slow down the process.

Second, the requirement to reapply for prescreening every two years seems arbitrary and potentially onerous/unnecessary.[8] DER providers who have already proven their ability to meet grid needs under the proposed DER tariff concepts, or even as part of another IOU program or rate, should not be required to reapply to be screened again. For the purposes of streamlining, there may be other prescreening processes already in place as well that could be leveraged in order to deem certain DER providers as eligible. In these cases, CESA believes that real-world experience may offer stronger evaluation criteria than a prescreening application. Instead, the tariff could establish criteria that would necessitate reapplication through the prescreening process, such as for poor performance.

Third, CESA recommends that any adopted prescreening process be streamlined to the degree possible. For example, this prescreening process could be streamlined by requiring interested DER market participants to apply and be preapproved once at the state-

[8] Staff Proposal at 25.

level for all IOU tariffs, rather than requiring this be done for each IOU and/or each deferral opportunity. While specific grid needs and grid architecture are different for each IOU and opportunity, the minimum viability of DER providers should not vary in this regard. Consequently, with a single statewide process, the administrative burden for DER providers would be reduced; meanwhile, the IOUs would have collectively lower overhead costs and would be able to better focus on the tariff management and marketing/outreach activities.

**b: Use of ratable procurement;**

CESA strongly supports this element of the CECI as a valuable strategy to mitigate the risk to ratepayers because it provides option value. During the previous workshop discussions, some stakeholders expressed concerns with this approach as creating a constant cycle of assess the same distribution grid needs in multiple cycles, rather than addressing the issue "once and for all" for the lifetime of the traditional wires investment (*e.g.*, 20+ years), but such concerns ignore the benefits of right-sizing to the need over time. Though ratable procurement would require distribution grid needs to be monitored and addressed over time, it has the potential to minimize stranded, oversized investment risks. CESA acknowledges that staff's proposed tiered payment structure provides an upfront payment to DERs before they are leveraged for deferral capabilities, thus not completely eliminating stranded investment risks if the need does not materialize, but the tariff, similar to what has been proposed by staff, could be structured to mitigate these risks by capping the upfront payment at some percentage of the cost cap or tariff budget (*e.g.*, 20%)[9] and by only making these payments when the DER market response indicates the ability to meet the need with a reasonable level of certainty.

CESA also request clarification on the proposed 120% procurement margin and whether they would apply only to the original "procurement" or subscription need or for each subsequent period, especially in cases where load growth over time increases or changes. For example, in Year 0, if an IOU identifies a 10-MW distribution capacity need in Year 3, the proposed tariff would seek subscriptions up to 12 MW using the 120% procurement margin; however, if the need increases by another 2 MW, it is unclear at this

[9] Staff Proposal at 25.

time whether the procurement margin would allow for up to 14.4 MW tariff subscription by applying the margin to the new, revised need, as opposed to drawing from the original procurement margin (or 12 MW). CESA believes that the procurement margin should be updated to account for revised upward needs as the margin is intended to protect against attrition or failure of DER deployments and/or with respect to DER underperformance and thus to ensure the planned investment for the need is indeed deferred. Assuming the procurement need and 120% margin is intended to be fulfilled within the cost-capped tariff budget, there should be little concern of cost-effectiveness, though the cost of the traditional capital investment may need to be updated.

Moreover, whether ratable procurement fits for all distribution need types should be explored. CESA generally agrees with staff's belief that the proposed tariff, with its ratable procurement approach, does work well with steady load growth scenarios to address long-term needs,[10] which allows for sufficiently long subscription windows and enables DERs to push out deferral needs further out in time. At the same time, CESA believes that the ratable procurement approach can also work well with certain known load growth projects that may be "lumpy" in nature. For example, as learned through the DPAG process, while specific electric vehicle ("EV") load applications may not always be known in advance and with granularity, investor owned utilities ("IOUs") should have visibility into a significant share of EV charger siting through their make-ready infrastructure plans, which identify best-fit corridors for EV chargers, and in other cases, may involve working with pre-approved EV charging station vendors to site projects. This visibility, along with greater coordination with EV service providers ("EVSPs"), could allow DERs to be sited in advance to make locations ready for siting EV chargers.

Beyond just working with EVSPs to get their long-term plans for deployment, the Commission should broadly consider reforms to the EV service connection process to initiate an automatic sourcing process via a tariff, such as the one contemplated in the Staff Proposal, to solicit DERs to defer primary system upgrades. Though the interim policy to ratebase all utility side of the meter secondary infrastructure upgrades has been extended through the DRIVE OIR and has been deemed a permanent policy through the passage of

[10] Staff Proposal at 22.

Assembly Bill ("AB") 841, there are opportunities to pursue DER deferrals in an expeditious fashion outside of the DPAG process by immediately and automatically launching a DER tariff upon a determination that an EV service interconnection application requires primary distribution upgrades. Depending on the EV service connection application, the tariff could be an effective means to manage distribution upgrade investments and address some of the timing and certainty issues around incremental EV load forecasts and being tied to a prescriptive DPAG schedule.

Along the same lines, even if a large residential housing developer is seeking load service for all the housing complexes in its proposed development,[11] there should be an evaluation on whether such projects indeed require DERs to be procured in lump sum upfront to support the IOUs' go or no-go decision on the traditional capital investment. On its face, such projects appear to be more suitable to competitive solicitations, but as CESA understands it, such known load projects may not need for DERs to be procured all at once upfront since the IOUs have visibility and some indication of certainty of whether such projects will move forward, and since the actual housing development may be phased over time. It seems unlikely that such development projects would involve the simultaneous or near-simultaneous construction of housing complexes such that ratable procurement approaches would not be feasible. In addition to exploring the nature and feasibility of known load projects for ratable procurement approaches, the ratio of upfront versus ongoing incentive payments can also balance the interests of deploying DERs to be deferral-ready for the known load project deferral while mitigating stranded investment costs in the form of upfront incentive payments.

**c: Subscription period and contingency date;**

The subscription period and contingency date of the tariff is likely project dependent, but an assessment of the in-service need date could inform how long to set the subscription period and when to close the tariff to pursue contingency solutions. In doing so, the Commission should identify projects with long enough lead time to set sufficient subscription periods, especially if the tariff is structured to support bottom-up customer

[11] Similar issues seem to have been raised related to large cultivation projects or large commercial property developments, so this consideration could apply and be assessed for other example use cases.

subscriptions (*e.g.*, via customer affidavits) instead of upfront contracting (*e.g.*, similar to LCR contracts with aggregators), as discussed further below.

Using Tier 1 projects of Southern California Edison Company ("SCE") in its 2020 DDOR filing, CESA offers a couple of examples of how the subscription period and contingency date could be structured to illustrate a few points:

| **Project** | **El Casco** | **Newcomb** |
|---|---|---|
| Capacity need (maximum 10-year) | 2.8 MW | 5.7 MW |
| Tariff launch | January 1, 2021 | January 1, 2021 |
| Tariff subscription close date | June 1, 2021 | June 1, 2022 |
| Deployment timeline | 12 months | 12 months |
| Contingency solution initiation date | June 1, 2022 | June 1, 2023 |
| Operating date | June 1, 2023 | June 1, 2024 |

In the above example, CESA works backward from the operating date and assumes a one-year lead time is needed to allow the IOUs sufficient time to deploy the contingency wires solution. In addition, considering that the identification of the best-fit projects for a tariff will likely involve the DPAG, CESA assumes that the tariff could also launch on the same current timeline as that for the DIDF RFO. Finally, CESA conservatively assumes that BTM DER projects, specifically energy storage, can take around 12 months on average to proceed through the interconnection process to reach permission to operate ("PTO"), with smaller residential projects likely taking less time due to the fast-track processes in place while larger commercial projects may take between 9-18 months, depending on the complexity of the configuration (*e.g.*, whether microgrid islanding capabilities are incorporated). Using these assumptions, the El Casco project could feasibly allow the tariff subscription period to be opened for 6 months (or "close" earlier if an acceptance trigger is hit) whereas the Newcomb project could be open for as long as 18 months before contingency solutions must initiated if DER alternatives fail to materialize or deploy.

Taking into account the above, on its face, the Newcomb project appears to be a better fit for a tariff given the lengthier subscription period, in contrast to the El Casco project, where six months may not provide sufficient time to even get marketing and outreach activities launched and underway. However, the nature of the project-specific needs, such as the capacity needed and growth of that need, must come into play in assessing best-fit opportunities as well as in setting subscription periods and/or multiple subscription periods under a ratable procurement approach. With 50% lower relative capacity needs, for example, the El Casco may still be feasible under a tariff model despite having one-third of the available subscription period before contingency solutions are required. When looking at these needs over time, the needs may actually be lower by the estimated June 1, 2021 tariff subscription close date, such that multiple periods could be established. More is discussed on the ratable concept in the sections below.

**d: Cost cap and forecast;**

CESA generally supports the Staff Proposal to set the tariff budget based on the cost of the planned investment,[12] but it is important to affirm the Commission's previous Ruling on DIDF reforms and fix the tariff budget upon launching the tariff to provide market certainty. Since the tariff budget represents the "pie" from which the upfront incentive and ongoing performance payment amounts are apportioned, this amount must not be changed over the course of the tariff being available; otherwise, if changed due to revisions to the planned investment cost, the various compensation rates in each of the payment tiers will be affected – an approach that is unworkable for BTM DERs to be financed and deployed.

The DIDF process will also need to identify planned investment projects that are generally higher cost with lower capacity and energy needs to provide a sufficient cost cap, resulting in a higher and more attractive tariff prices across the different payment tiers. While not a prescreening process, CESA recommends an early process to determine the attractiveness of a tariff price structure. Some of this will be done through the DPAG, but this subset of stakeholder interests may not capture the broad market interest and potential of establishing a new tariff for a particular wires investment. To inform whether DER providers and aggregators will even participate in the tariff and to ensure the most efficient use of IOU and stakeholder time and resources, it may be worthwhile to establish a notice-of-intent procedure to gauge whether there will be tariff participation once tariff prices are set and published for the different payment tiers. If the tariff incentives and prices are not

[12] Staff Proposal at 27.

attractive, some DER providers and aggregators may not even find it worthwhile to submit a prescreening application. Such tariffs may not be worthwhile to run.

Finally, for the purposes of a pilot, CESA recommends that the cost cap should be set at 100% of the planned investment cost, with the intent that it can be lowered in the future (*e.g.*, to 85% as proposed by staff). This would account for the growing pains of such an innovative, ground-breaking program and better align with the first guiding principle to "not inherently favor traditional infrastructure over DERs or vice versa."[13] An 85% cost cap likely favors the traditional solution by offering a lower price to the DER alternative. Additionally, the fact that the CECI provides ratable capacity gives it an added benefit over traditional solutions. Though a tariff budget set at 85% of the cost cap would guarantee cost savings and deliver more benefits to ratepayers, this proposed tariff is currently in the pilot stage, where there may be other lessons learned related to subscription, contracting, deployment, and performance by increasing the viability that the tariff will succeed with a more relaxed but still principally consistent cost cap and tariff budget. An outcome that should be avoided is that we do not even get to draw lessons learned related to those other important aspects of the tariff proposal due to the tariff budget not sufficiently supporting the financial viability of DER projects.

**e: Offer reservation, offer acceptance and procurement;**

In concept, CESA does not oppose the use of customer attestations, so long as the process does not prove to be burdensome, turning the tariff program into one filled with significant paperwork and frequent actions required by the customer to attest to or approve multiple items.

However, in reviewing the Staff Proposal, CESA has a fundamental question regarding what constitutes a tariff versus a contract. Typically, a tariff is different from a contract in that the former outlines generalizable terms, conditions, and requirements whereas a contract involves legal obligations, performance incentives, and penalties (*e.g.*, default provisions) that hold the counterparty accountable to deliver on the contracted services. CESA raises this question because it could inform how offer reservations are made and enforced. According to the Staff Proposal, customers' affidavits of interest are

[13] Staff Proposal at 18.

needed from the provider, with whom the IOU would execute a contract upon the acceptance trigger being met.[14] In this way, the customers must be acquired to some degree (as demonstrated via affidavits) prior to executing a contract that would include the aforementioned provisions to ensure the delivery of contracted services. On the other hand, under a typical contracting model, such as done for BTM Local Capacity Requirement ("LCR") contracts, DER aggregators secure contracts based on their competitive bids or offers prior to acquiring customers, with the contract providing the legal enforcement mechanism and subjecting them to penalties (*e.g.*, reduced payments, default) if they are unable to fulfill the contract, such as in not acquiring a sufficient portfolio of customers to deliver on the contracted services. Under this approach, upfront customer affidavits are not needed to "claim" the available capacity on the proposed tariff.

Considering the above, CESA seeks clarification and discussion with other stakeholders on whether the upfront contracting approach should be incorporated in the tariff. This would increase the viability of the tariff, but it would also involve potentially different contract structures as compared to the one where customer affidavits are required to demonstrate tariff subscriptions up to and beyond the acceptance trigger prior to executing contracts. If the contract proposed in the Staff Proposal serves many of the same purposes as upfront contracts to set deployment milestones, include penalties and default provisions, etc., then upfront contracting should potentially be considered.[15]

**f: Acceptance trigger and contingency planning;**

An "acceptance trigger" is set at 90% of the capacity need before determining that the tariff can move forward with contract execution and make upfront payments, according to the Staff Proposal.[16] However, as described in our response on the subscription periods

[14] Staff Proposal at 27-28.

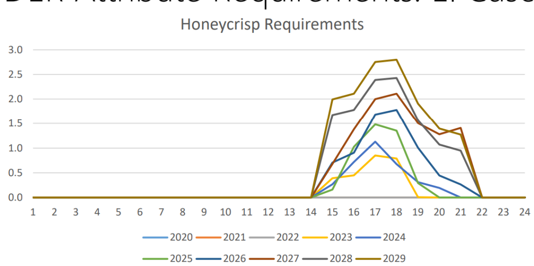
[15] Alternatively, the upfront contracting approach seems to be a better fit for competitive solicitations or the SOC pilot also recommended by staff. Or, the Commission may wish to modify the tariff proposal to be more like a typical tariff that does not include usual contract provisions. All in all, the Commission should consider whether the upfront contracting model could serve certain benefits, where aggregators can manage their portfolio of customer sites to manage an overall need (*e.g.*, relying on some customers more than others at different times), such that a single customer does not bear the responsibility to deliver on the distribution grid need. Under a tariff approach focused only on single-customer responses, it may require a keen focus on the fit of the distribution need and deferral opportunity.

[16] Staff Proposal at 28-29.

and consistent with staff's support for the ratable procurement concept, CESA believes that the 90% acceptance trigger does not reflect project-specific factors and would deter some market participation by having DER participants who have already subscribed to a portion of the tariff capacity to wait for the remaining capacity to be fully subscribed up to the acceptance trigger. By holding up contract execution and upfront payment in this way, irrespective of the project-specific factors, precious time to begin project interconnection and other development activities may be lost.

Instead, as discussed in the Staff Proposal, the tariff should take advantage of the ratable procurement concept to establish multiple subscription period and multiple acceptance triggers, as appropriate. Where load growth and distribution capacity needs are expected to grow over time, such an approach is feasible and leads to a more effective tariff model. For example, in using the El Casco example as done above in our response to the questions for subscription periods, the 2.8 MW capacity need is actually the maximum required over a 10-year period, but in looking at the nature of the need on a year-by-year basis, the need by June 1, 2023 is actually just 0.9 MW.

DER Attribute Requirements: El Casco 115/12kV – Honeycrisp 12kV




| Capacity (MW) | Energy Need (MWh) | Season | Monthly Frequency | Yearly Frequency | Year |
|---|---|---|---|---|---|
| 0.0 | 0.0 | Summer | 0 | 0 | 2020 |
| 0.0 | 0.0 | Summer | 0 | 0 | 2021 |
| 0.0 | 0.0 | Summer | 0 | 0 | 2022 |
| 0.9 | 2.5 | Summer | 5 | 15 | 2023 |
| 1.1 | 3.3 | Summer | 5 | 15 | 2024 |
| 1.5 | 4.3 | Summer | 5 | 15 | 2025 |
| 1.8 | 6.8 | Summer | 5 | 15 | 2026 |
| 2.1 | 10.4 | Summer | 9 | 25 | 2027 |
| 2.4 | 11.9 | Summer | 7 | 25 | 2028 |
| 2.8 | 14.2 | Summer | 10 | 30 | 2029 |

With this project-specific need in mind, it seems unnecessary to set an across-the-board 90% acceptance trigger for all projects, which would require tariff subscriptions exceeding 2.52 MW before moving forward with the tariff-sourced solution – an amount of need that is not forecasted until 2028. While such an approach may be suitable for lumpy load growth projects, it is unnecessary for steady load growth projects such as El Casco. Rather, CESA recommends setting a custom project-specific acceptance trigger that recognizes year-by-year needs that could allow for early projects to get moving and extend the overall subscription period to support DER deployment, customer acquisition, and marketing/outreach activities. The subscription windows and acceptance triggers could be phased as such:

| **Project** | **El Casco** |
|---|---|
| Capacity need (maximum 10-year) | 2.8 MW |
| Tariff launch | January 1, 2021 |
| Tariff Phase 1 acceptance trigger | 0.9 MW |
| Tariff Phase 1 close date | June 1, 2021 |
| Tariff Phase 2 acceptance trigger (cumulative) | 1.1 MW |
| Tariff subscription Phase 1 close date | June 1, 2022 |
| … | … |
| Operating date | June 1 every year through 2029 |

The above approach offers flexibility and sets an acceptance trigger (32%) aligned with the project-specific needs that minimally defers the resource for another year. Most likely, it will not take the full 10 years to fully defer the 2.8 MW need given the general pace and expectation of DER development and deployment timelines.

**g: Marketing and Outreach;**

Yes, CESA supports the marketing and outreach proposal, which could play a helpful role in increasing subscriptions to the tariff.[17] To further support this component of the proposal, the pilot should consider the full universe of partners, such as community-based organizations and community choice aggregators ("CCAs"), who have local expertise and customer relationships.

One question related to this component of the proposal is that the marketing and outreach expenditures would come out of the tariff budget, thereby reducing the compensation available to support DER deployment and/or performance. Given this added component, it will be important to assess potential deferral opportunities where the tariff budget, net of the marketing and outreach expenditures, would lead to an attractive tariff price, as the economics of DER projects will ultimately drive their deployment and operations. To minimize expenditures and make greater levels of the tariff budget available for deployment and performance, the Commission should consider whether the marketing

[17] Staff Proposal at 29.

and outreach efforts in various existing customer programs (*e.g.*, SGIP, SOMAH, TE programs, building decarbonization programs) and already-established channels could incorporate the information related to the available deferral tariff opportunities. Since the tariff is available on a project-specific basis and is available on a time-sensitive on a one-off basis (instead of as a broadly applicable, long-lasting tariff), synergizing with existing channels may be preferable and more nimble and yield better outcomes.

**h: Pricing Methods;**

CESA generally supports the Staff Proposal to use a single-price method for the tariff,[18] but many details will likely need to be worked out to set the price differentiated by month and, in cases where distribution capacity needs must be partitioned across multiple periods (*e.g.*, 3-6pm and 6-9pm versus 3-9pm). It is unclear how the tariff budget would be apportioned across different time periods of the need, for instance.

Under the proposed tariff structure, having a single price available on a first-come first-served basis seems fair and reasonable, with approaches to assess too much further sliding into the tariff becoming a competitive solicitation. While administrative simple and efficient, the tariff should also ensure guardrails against oversubscription of low-quality projects, especially in cases where a good-fit deferral opportunity is identified and a strong "market signal" is structured to entice market participation. A stampede to reserve distribution capacity can result, sacrificing project and service quality at the expense of speed to apply. This may likely be mitigated by the prescreening process, but these details should be worked out and discussed further.

**i: Tiered Payment Structure;**

CESA is generally supportive of a tiered payment structure[19] that incentives DER deployment and operations at every stage to better ensure a successful deferral. In particular, CESA supports the 20% upfront incentive upon reaching the appropriate acceptance trigger, though the specific percentage of the tariff budget dedicated to this payment tier should be customized to the specific deferral opportunity. Any concerns that some or many DERs would be paid for services not provided if the need changes, does not

[18] Staff Proposal at 30-31.

[19] Staff Proposal at 32.

arise, or is unmet is understandable, but such risks are mitigated by limiting the upfront incentive. While there may be some payments paid for services not rendered or needed, DERs in aggregate may still prove to be more cost-effective and deliver in accordance with the need, where the procurement margin can mitigate any such delivery risks. In effect, upfront payments for DERs could support deployment but also compensate for the hedging value for flexibility to respond to dynamic distribution grid needs. Structuring this cost-effectiveness assessment will be vital to pilot development and execution.

On the other hand, CESA believes that there may be too many tiers, which could dilute the incentive for any component – *e.g.*, deployment, test, reservation, and performance – since the tariff budget is fixed as a percentage of the cost cap. With diluted incentives, we may end up where the deployment incentive is not high enough to spur new DER deployment, or performance payments are not high enough to incentivize certain operations. In the interest of consolidating tiers and sharpening, CESA recommends that the tiered payment structure be consolidated into tiers related to deployment and capacity reservation. First, the test payment is not needed since the capability/dispatch requirements are already covered in the tariff and contract and are already typically required in commissioning projects. In some cases, the preliminary test dispatch is used to verify capabilities and set the upfront payment amount. Second, the capacity reservation and performance can be interrelated similar to what is done within the Demand Response Auction Mechanism ("DRAM"), where actual performance and deliveries affect the RA capacity payment.[20] A history of underperformance when called upon will reduce eligible capacity payments. Similar constructs will sharpen resource incentives while ensuring ongoing performance in accordance with the contract.

In addition to consolidating payment tiers, several other clarifications or refinements are needed. Importantly, CESA underscores a key nuance related to DER deployment in the form of new installations versus new capabilities. The upfront deployment incentive should also support the enrollment of DERs, not just upfront installation incentives. Additionally, how payments are structured across the deferral period will need to be addressed. For reference, New York's new Dynamic Load

[20] The DRAM makes these distinctions by attributing resources with a qualifying capacity ("QC") value and a demonstrated capacity ("DC") value.

Management, designed to compensate assets over a multi-year period to stimulate more participation and investments in load management solutions, will implement a payment structure that provides compensation equally spread out over the term of the contract.[21] CESA believes this evenly spread payment structure represents a best practice for DER compensation and therefore supports staff's proposed tiered pricing structure.

**j: Payment Structure to allow for non-dispatchable distributed energy resources;**

CESA has no comment at this time.

**k: Incrementality; and**

CESA supports the incrementality rules in the Staff Proposal.[22] Some may argue that projects supported by technology incentives, such as SGIP or through TE programs, should not be eligible for the upfront incentives contemplated in the proposed tariff. Consistent with the rules that the DIDF is a framework designed to pay for distribution grid services, DERs already supported by upfront incentives from other programs should thus only be eligible for the other payment tiers. While valid in principle, CESA believes that there are additional "upfront" costs that are needed for aggregators to acquire customers with existing DERs and potentially install incremental equipment (*e.g.*, automated demand response controls, load management technologies) to make them controllable and remotely dispatchable. Moreover, many technology incentive programs such as SGIP will not be funded in perpetuity, and the need to determine which projects and which incremental equipment can be funded through the CECI upfront incentive could become complicated and slow down the process for tariff subscription, counteracting objectives in the DIDF to streamline processes. Taken together, it may be more efficient and accessible for the tariff to allow both existing and new DERs to be eligible for the CECI upfront incentive.[23]

The incrementality rules should also be expanded to consider DER solutions funded through TE program deployment incentives. Managed charging is already eligible as a

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[21] *See Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Requirements and Associated Cost-Recovery*, State of New York Public Service Commission, September 17, 2020 at 31.

[22] Staff Proposal at 33-34.

[23] Alternatively, two simple tiers of upfront incentives could be established to account

demand response ("DR") solution, but recent decisions by the Commission in R.17-07-007 have cleared the pathway for vehicle-to-grid ("V2G") solutions to interconnect on the grid[24] and soon be available as an eligible DER solution in the various DIDF opportunities. Some components of the overall V2G solution will be funded through TE programs, but like the case of SGIP projects, these are technology deployment incentives that are *not* a payment for grid services. Similar incrementality rules for SGIP-funded systems should be therefore extended to DER solutions funded through TE programs.

At a greater level, CESA believes that this incrementality issue is a policy matter that should be addressed in a broader policymaking proceeding, such as a new cross-cutting Multiple-Use Application ("MUA") rulemaking. Although CESA has welcomed and commends the Commission for the improvements and refinements to the incrementality rules in the DIDF context, these rules have not been incorporated in other planning processes, such as R.19-11-009 for Resource Adequacy ("RA").[25] Consistency is needed across all planning processes.

**l: The proposed tariff name, Clean Energy Customer Incentive.**

CESA recommends that the proposed tariff be renamed to something along the lines of the Reserved Distribution Capacity Tariff ("REDCAT"). Though seemingly minor as a matter of semantics, CESA believes it is important to frame the CECI concept as a payment for grid services as opposed to an incentive.

**Question 3: What level of utility Distributed Energy Resources Management System (DERMS) functionality is necessary for distributed energy resources to defer Distribution Deferral Opportunity Report planned investments through the proposed Clean Energy Customer Incentive? Could aggregators perform the DERMS function for the utilities?**

CESA does not believe that IOU Distributed Energy Resources Management System ("DERMS") functionality is absolutely necessary to facilitate aggregated DER response, which

[24] *See* D.20-09-035 at 107-117 and Ordering Paragraphs 37-44.

[25] *See* D.20-06-031 at 32: "The Commission agrees with parties and the Working Group that numerous issues must be addressed before considering treating BTM resources similarly to IFM resources, including…(5) changes such that net energy metering (NEM) and self-generation incentive program (SGIP) resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value."

can be executed through third-party aggregators who meet the applicable requirements (*e.g.*, smart inverter Phase 2 communication and cybersecurity requirements). DERMS can be helpful to increase the pool of customer participants who can subscribe to the tariff to have direct dispatch capability in response to IOU signals but are not integrated in the portfolio of a third-party aggregator, but it should not be the only option. Third-party aggregations for RA, such as through the Demand Auction Response Mechanism ("DRAM") and for BTM LCR contracts, are already active and operating today, where such pathways should also be offered as an option for tariff subscribers. Both IOU and third-party aggregations should be allowed. Such optionality is preferrable because there are questions as to at what point DERMS will be fully deployed in terms of functionality and scale.

**Question 4: Staff proposes testing the Clean Energy Customer Incentive and its elements through three separate pilots, but we focus only on the pilot proposed to begin in August 2021 (Pilot 1). What, if any, modifications to the proposed Incentive Pilot 1 should be made?**

CESA supports the testing of the three separate pilots, starting with Incentive Pilot 1 in August 2021 because of how this first pilot concept more readily fits within the current DIDF, which assesses individual project-specific needs. Our suggested modifications to proposed Incentive Pilot 1 are discussed in our responses above.

At the same time, each of the other two pilots have significant merit that moves the CECI to more of a traditionally-known tariff structure that is broadly available with standardized service and operational requirements. By structuring a tariff that looks at the pool of planned investments on a Distribution Planning Area ("DPA") basis, DERs could offer flexibility to the IOU to deploy DERs across any area in which they are needed. In aggregate, a DER tariff or program promoting distribution upgrade deferral via a mix of upfront and performance payments may be less expensive than the category or subset of capital investments, making the program or tariff cost-effective. This pool of funds would be less than the approved capital expenditures to ensure cost savings. Alternatively, on a pilot basis, a separate pool of funds could be established to specifically support DER deployments committed to distribution needs and then to assess on a portfolio-wide basis on whether the DPA experienced aggregate savings by supporting DERs, where less than the approved capital expenditures was utilized. This may be a specific area where further discussion is needed on investment approval and rate recovery approaches used by the utilities and assessed by the regulators. Despite the potential benefits of the CECI pilot concept being applied to broader areas rather than specific projects, CESA agrees that more discussion and refinement is needed such that 2021-2022 DIDF cycle implementation is less likely, but the Commission should target the 2022-2023 DIDF cycle for piloting this concept that affords sufficient time to flush out the details of Incentive Pilots 2 and 3.

**Question 5: Explain why the Commission should or should not adopt the Clean Energy Customer Incentive and implement Incentive Pilot 1 in August of 2021, either as proposed or with modifications?**

With the modifications and considerations from our responses above, CESA supports the adoption of the CECI for the 2021-2022 DIDF cycle for implementation in August 2021. As laid out in the new proposed principle, the Commission should seek to learn by doing through these pilots and test out new tariff mechanisms.

**Question 6: Explain whether the Commission should or should not adopt the proposed changes to the Requests for Offers process in order to streamline the process, including the allotted time for contract execution?**

CESA is cautiously supportive of the Staff Proposal to allow projects to proceed directly to the RFO stage without DPAG review and without a Tier 2 advice letter submittal.[26] These proposed changes would provide added lead time (*i.e.*, 5 months) for DER participants to submit bids, negotiate contracts, and most importantly, interconnect and deploy DERs under compressed one- to three-year timelines. Although the DPAG meetings are open to market participants to get advanced knowledge of potential opportunities, the likelihood of DER participants taking action to develop projects prior to finalization of the candidate projects and Commission approval of the solicitation may be low. With earlier timelines to launch solicitations, the time at which executed contracts are submitted for approval should be accelerated as well, which can be helpful to get earlier Commission approval of the contracts and afford additional time for project deployment with regulatory certainty. Especially as the IOUs have improved their GNA/DDOR filings and their screening criteria and prioritization processes,[27] CESA feels generally comfortable with this proposed process.

[26] Staff Proposal at 51.

[27] Particularly, Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") have made major strides in the DIDF, whereas the DIDF process for San Diego Gas and Electric

However, CESA has some concerns with the lack of input that could be provided by market participants such as CESA as well as other stakeholder groups through the DPAG process. Even though staff is only proposing that identified Tier 1 opportunities would be eligible for such a streamlined process, DPAG stakeholders could previously review and provide input/feedback on the operational requirements for the distribution grid need. In our view, upfront input and feedback prior to solicitation launch has allowed stakeholders to shape these requirements to better reflect DER capabilities, solicit additional technical information (*e.g.*, grid charging constraints), and shape operational requirements and eligibility rules (*e.g.*, incrementality) – all in an opportunity to structure the RFO to have a higher probability of succeeding. Such opportunities may be lost through this proposed streamlined process. Some of this could be addressed in the bidder's webinar or conference, where market participants ask and seek this clarifying information, but these bidder's events may not be able to accommodate these changes – *i.e.*, other than clarifications, bidders must take the solicitation requirements as is. Somewhat relatedly, in line with the proposed tariff and other alternative sourcing mechanisms, CESA also has some concerns that certain deferral opportunities may be pursued via one mechanism (*e.g.*, RFO) over another (*e.g.*, tariff) without stakeholder input, even though one approach may be more advantageous for any given project.

To support the streamlining objective while also supporting continued improvements, CESA recommends that a regular working group meeting be convened (*e.g.*, within the current DPAG structure) to discuss lessons learned from previous RFO processes and identify any key changes that should be adopted and implemented for the next cycle. By soliciting and incorporating stakeholder input prior to RFO launch, both efficiency gains and improvements in the DIDF process can be achieved.

**<u>Question 7</u>: The Staff Proposal recommends a pilot of the Standard Offer Contract. For each of the following elements of the proposed Standard Offer Contract pilot, explain what modifications, if any, should be made:**

CESA supports the proposed SOC pilot that would leverage a prescreening process and price sheet instead of allowing for negotiation and potential modification of the base TNPF

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Company ("SDG&E") is still untested, where CESA believes such "straight-to-RFO" processes may be premature in their case.

contract, whereby bidders would indicate the quantity of DER services they are willing to provide at pre-determined prices as a percentage of the cost cap.[28] In contrast to the competitive solicitation, the transaction costs of negotiating contracts would be reduced, though not entirely eliminated according to PG&E's proposal that would allow for some limited modifications.[29] As a result, this sourcing mechanism could potentially deliver some incremental efficiency benefits in the sourcing process that would increase the viability of deferral and invite additional market participation. In the below sub-sections, we discuss some recommendations for modifications or considerations in advancing the SOC to a pilot.

**a: Pilot period;**

CESA does not support the proposed 5-year pilot period for two key reasons. First, if the deferral period for a planned investment spans seven years, it is unclear why the contract should be shortened arbitrarily for the purposes of limiting the scope of a pilot. Particularly for DERs requiring significant capital investments, a longer-term deferral contract, where appropriate for the planned investment, supports the financeability of DER projects. Second, the 5-year pilot period suggests that the Commission will not evaluate whether to pursue additional opportunities to utilize an SOC or to adopt the SOC as part of a formal program until the end of the pilot period. CESA does not believe that it is necessary to wait until the end of the pilot period to make this determination or to withhold on future additional opportunities to use an SOC until the pilot has completed and has been evaluated, which would be in 2026. Earlier determinations should be and has previously been made. As reference, the Commission adopted the DIDF as an ongoing annual process just more than one year after the Integrated Distributed Energy Resources ("IDER") Incentives Pilot was implemented and lessons learned were gathered and assessed.[30] In the same vein, CESA sees no reason to unnecessarily extend the timeline in which a determination could be made on the SOC and whether the SOC could be used in subsequent DIDF cycles even though a full evaluation is needed to make this a formal program.

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[28] Staff Proposal at 52-53.

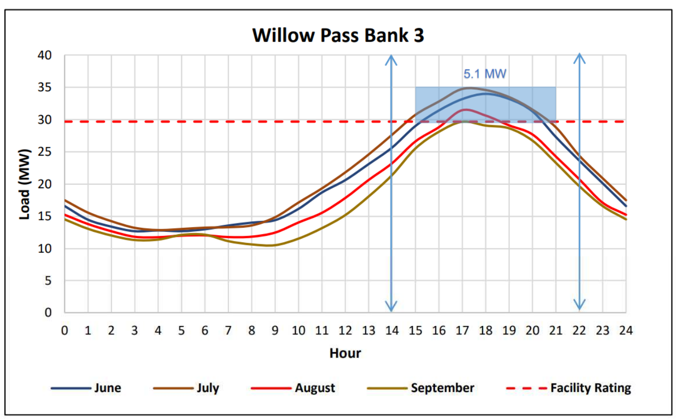
[29] *Pacific Gas and Electric Company Attachments: PG&E Comments and Proposals on DER Tariffs Pursuant to Administrative Law Judge's November 16, 2018 Ruling* filed on February 15, 2019 in R.14-10-003 at 14.

[30] *See* D.18-02-004 at 26.

**b:** **Pricing;**

CESA supports the proposed simple auction pricing for the SOC pilot.[31] However, to make the SOC work, standard product definitions and operational requirements may be needed to enable simple auction pricing, where the quantity of DER capacity procured is in essence commoditized similar to what has been done by PG&E. Each of PG&E's deferral opportunities propose standard distribution capacity being sought in terms of the MW capacity, duration, hours/months of need, and calls per year. At one of the locations for the Willow Pass Bank 1 (DDOR ID: DDOR026), for example, the Bank 3 need has been defined as a day-ahead distribution capacity product where 5.06 MW must be delivered for a six-hour period across certain months and hours of the year, presumably for the entire deferral period.[32]

- Willow Pass Bank 3 – Peak Day, Hourly Load Profile




| Tier | DDOR ID | Candidate Deferral | GNA Facility Name | Distribution Service Required | Real Time (RT) or Day Ahead (DA) | Grid Need | Grid Need Unit | Month | Calls/ Year | Hours | Duration (Hours) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | DDOR026 | Willow Pass Bank 1 | WILLOW PASS BANK 1 | Capacity | DA | 0.26 | MW | 6-8 | 8 | 2PM-8PM | 1 |
| | | | WILLOW PASS BANK 3 | Capacity | DA | 5.06 | MW | 6-9 | 101 | 2PM-10PM | 6 |

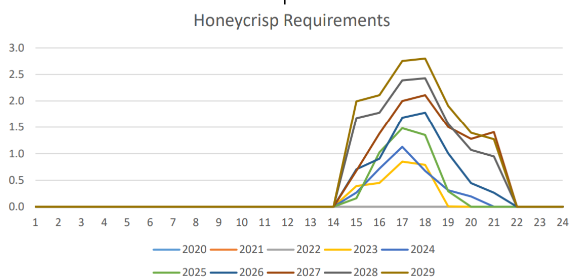
By contrast, SCE defines distribution capacity needs over time across the entire deferral period, which grow in both capacity and energy, as highlighted in the Tier 1 El Casco 115/12kV deferral opportunity identified for the 2020-2021 DIDF cycle. Rather than procuring for the same capacity and energy across the entire deferral period, SCE

31 Staff Proposal at 53.

32 *See* Distribution Planning Advisory Group (DPAG) Meeting presentation on September 16, 2020 at 59.

assesses the changing nature of deferral needs over time and procures DER alternatives in competitive solicitations to phase capacity over time accordingly. This procurement approach is illustrated in SCE's most recent Advice Letter submission for contract approval from their 2020 DIDF RFO. Although the total capacity of the IFOM energy storage resource is 14 MW, the actual amount of deferral capacity procured by SCE is only 2.8 MW in 2023, with the capacity bought eventually increasing to 14 MW by 2028.[33]

DER Attribute Requirements: El Casco 115/12kV – Honeycrisp 12kV




| Capacity (MW) | Energy Need (MWh) | Season | Monthly Frequency | Yearly Frequency | Year |
|---|---|---|---|---|---|
| 0.0 | 0.0 | Summer | 0 | 0 | 2020 |
| 0.0 | 0.0 | Summer | 0 | 0 | 2021 |
| 0.0 | 0.0 | Summer | 0 | 0 | 2022 |
| 0.9 | 2.5 | Summer | 5 | 15 | 2023 |
| 1.1 | 3.3 | Summer | 5 | 15 | 2024 |
| 1.5 | 4.3 | Summer | 5 | 15 | 2025 |
| 1.8 | 6.8 | Summer | 5 | 15 | 2026 |
| 2.1 | 10.4 | Summer | 9 | 25 | 2027 |
| 2.4 | 11.9 | Summer | 7 | 25 | 2028 |
| 2.8 | 14.2 | Summer | 10 | 30 | 2029 |

CESA points to this difference because, while the phased-in approach for distribution capacity may work well within a competitive solicitation framework (particularly for IFOM solutions) and ensures that SCE only buys what it needs at the time (*i.e.*, making the DER solution more cost-effective when assessing every year of the need), it does not seem likely that such an approach would work within an SOC structure. In the above El Casco example, the pricing for a 2.7-hour product in 2023 with relatively small expected frequency of calls in a month and across a year is likely significantly different from a 5.1-hour product in 2029 with double the frequency of expected calls.

**c: Procurement mechanism;**

CESA supports the development of the SOC TNPF[34] that should identify opportunities to simplify, standardize, and streamline the TNPF contract used for competitive solicitation purposes. This development will likely need to occur through a working group process to review and revise the details. One key area to simplify the SOC could be to structure the SOC to only procure for distribution capacity rather than other

[33] SCE Advice 4316-E, *Submission of a Contract for Procurement of Energy Storage Resulting from Southern California Edison Company's 2019-2020 Distribution Resources Plan Distribution Investment Deferral Framework Request for Offers*, submitted on October 20, 2020 at 3.

[34] Staff Proposal at 53.

services such as RA. CESA is strongly supportive of value stacking, but to simplify the existing TNPF contract to form the new SOC, revisions to remove California Independent System Operator ("CAISO") market participation provisions would simplify the "product" being procured in the SOC. Value stacking with RA may be more suitable as a negotiated contract term in the more complex TNPF contract for use in competitive solicitations.

**d: Marketing and outreach; and**

While supportive, CESA seeks clarification regarding the marketing and outreach component for BTM DERs in the SOC pilot[35] – an expenditure that presumably adds to the cost of procuring BTM DERs and is one that IFOM DERs do not need. To ensure a level playing field, this added cost should be reflected in the simple auction pricing for a BTM DER solution. For example, if a BTM DER submits quantities of its resource at 75% of the cost cap in the price sheet, some standard adder (*e.g.*, 5%) should be included to reflect the additional market and outreach required to support its deployment and procurement, such that resources at this price level would actually be represented in the auction at 80% of the cost cap. At the same time, whether a BTM DER bid would be subject to this adder should depend on whether the bidder seeks marketing and outreach assistance. If a bidder finds that it can conduct its own marketing and outreach to acquire customers, they should be able to opt out of this service and not be subject to this adder, making it possible for them to bid quantities of capacity at a lower (and thus more competitive) percentage level of the cost cap.

**e: Allotted time for the contract execution.**

CESA has no comment at this time because it is unclear as to which aspect of the SOC pilot proposal this question is referring to.

**Question 8: Explain why the Commission should or should not adopt the proposed Standard Offer Contract pilot, either as proposed or with modifications.**

CESA views the SOC as being worthwhile to pilot to measure whether such benefits come to fruition, especially as the SOC does not appear to be excessively different from the current status

[35] *Ibid*.

quo. Consequently, the steps needed to refine the details of the SOC pilot may be lesser than that for the tariff, such that it should be entirely feasible to test for the 2021-2022 DIDF cycle. In assessing PG&E's and SCE's 2020 DDOR filings, any of the Tier 1 project opportunities appear to be a good fit for piloting an SOC.

## III. <u>CONCLUSION</u>.

CESA appreciates the opportunity to submit these comments to the Ruling and the Staff Proposal and looks forward to working with the Commission and other stakeholders in this proceeding.

Respectfully submitted,

Alex J. Morris
Executive Director
CALIFORNIA ENERGY STORAGE ALLIANCE

Date: October 30, 2020