

December 17, 2018

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**Re: Response of the California Energy Storage Alliance to Advice Letter 5435-E of Pacific Gas and Electric Company, Advice Letter 3904-E of Southern California Edison Company, and Advice Letter 3309-E of San Diego Gas and Electric Company**

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Dear Sir or Madam:

Pursuant to the provisions of General Order 96-B, the California Energy Storage Alliance (“CESA”)<sup>1</sup> hereby submits this response to the above-referenced Advice Letter 5435-E of Pacific Gas and Electric Company (“PG&E”), *Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities Pursuant to D.18-02-004* (“PG&E Advice Letter”), submitted on November 28, 2018, to the above referenced Advice Letter 3904-E of Southern California Edison Company (“SCE”), *Southern California Edison Company’s Request for Approval to Launch the Distribution Investment Deferral Framework Solicitation* (“SCE Advice Letter”), submitted on November 28, 2018, and to the above-referenced Advice Letter 3309-E of San Diego Gas and Electric Company (“SDG&E Advice Letter”), submitted on November 28, 2018.

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<sup>1</sup> 174 Power Global, 8minutenergy Renewables, Able Grid Energy Solutions, Advanced Microgrid Solutions, AltaGas Services, Amber Kinetics, American Honda Motor Company, Inc., Avangrid Renewables, Axiom Exergy, Boston Energy Trading & Marketing, Brenmiller Energy, Bright Energy Storage Technologies, Brookfield Renewables, Carbon Solutions Group, Centrica Business Solutions, Clean Energy Associates, Consolidated Edison Development, Inc., Customized Energy Solutions, Dimension Renewable Energy, Doosan GridTech, Eagle Crest Energy Company, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, ElectrIQ Power, eMotorWerks, Inc., Enel X North America, Energport, ENGIE, E.ON Climate & Renewables North America, esVolta, Fluence, Form Energy, GAF, General Electric Company, Greensmith Energy, Ingersoll Rand, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Iteros, Johnson Controls, KeraCel, Lendlease Energy Development, LG Chem Power, Inc., Lockheed Martin Advanced Energy Storage LLC, LS Power Development, LLC, Magnum CAES, Mercedes-Benz Energy, NantEnergy, National Grid, NEC Energy Solutions, Inc., NextEra Energy Resources, NEXTracker, NGK Insulators, Ltd., NRG Energy, Inc., Parker Hannifin Corporation, Pintail Power, Primus Power, Quidnet Energy, Range Energy Storage Systems, Recurrent Energy, Renewable Energy Systems (RES), Sempra Renewables, Sharp Electronics Corporation, SNC Lavalin, Southwest Generation, Sovereign Energy, Stem, STOREME, Inc., Sunrun, Swell Energy, Tenaska, Inc., True North Venture Partners, Viridity Energy, VRB Energy, WattTime, Wellhead Electric, and Younicos. The views expressed in this Response are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies.

## **I. BACKGROUND AND INTRODUCTION.**

In the Distribution Resources Plan (“DRP”) proceeding (R.14-08-013), each of the investor-owned utilities (“IOUs”) worked with the Distribution Planning Advisory Group (“DPAG”) to provide advisory input into their Grid Needs Assessment (“GNA”) and Distribution Deferral Opportunity Report (“DDOR”) as part of the new Distribution Investment Deferral Framework (“DIDF”). As a member of the DPAG, CESA found the meetings to be helpful and provided important insights into distribution planning processes, including around forecasting methodologies and how planned investments are determined. While the time and resources required to participate in the DPAG were intensive and streamlined in future cycles, this look into the distribution planning process was very helpful for stakeholders representing market participants, such as CESA, to similarly provide insights into the capabilities of distributed energy resources (“DERs”) and to identify ‘best-fit’ opportunities for DERs to potentially cost-effectively defer a planned investment.

CESA generally supports the approval of each of the IOU advice letters as they comply with the requirements of Decision (“D.”) 18-02-004 and thus recommends the timely launch of their 2019 Integrated Distributed Energy Resources (“IDER”) Request for Offers (“RFO”). CESA finds that the IOUs reasonably applied their timing and technical screens and their prioritization criteria. Though the screens and prioritization criteria could be improved upon, CESA believes that is a policy matter that will likely need to be addressed in R.14-08-013, not here in the advice letters. In this response, CESA comments on the selected and eliminated projects but also focuses on the IOUs’ findings on their lessons learned from their prior DER solicitations for distribution deferral.

However, while supportive of the selected projects and the process by which these projects were selected, CESA notes that some concerns around the terms, conditions, and provisions of the *pro forma* contracts used for DERs in this solicitation have been separately identified to advice letters filed on November 21, 2018. These concerns need to be addressed, which are separate from but related to these solicitations.

## **II. IDENTIFIED DISTRIBUTION DEFERRAL OPPORTUNITIES.**

In this section, CESA provides our feedback and recommendations for the candidate projects selected for approval as well as the projects that are not proposed to advance to a solicitation. As noted, CESA supports each of the IOUs’ proposed candidate projects to move toward an IDER RFO.

### **A. CESA supports the advancement of the PG&E’s three Tier 1 projects for the 2019 IDER RFO as well as the exclusion of the Tier 2 and 3 projects**

CESA supports PG&E moving forward with an RFO for DERs for the distribution grid needs identified for the following projects: New Lammers Feeder (1.5 MW); Huron Bank (3.7 MW); and Santa Nella Bank 1 and New Feeder (5.4 MW). The project meets the timing criteria with an in-service date within 3-4 years of the expected deficiency (April 1, 2021, June 1, 2021, and May 1, 2022) and meets the technical criteria of identifying one of four services that DERs can provide in accordance with D.16-12-036.<sup>2</sup> Each of the projects present potential significant cost benefits based on the unit cost and locational net benefits analysis (“LNBA”) assessments and an opportunity to test whether DERs can defer a long-duration (though not baseload) need (*e.g.*, 10 hours).

In particular, CESA appreciates the refinement of the expected performance and operational requirements since these opportunities were presented in the DPAG meetings – *i.e.*, grid need (MW), hours duration, and maximum calls per year are achievable by DERs.<sup>3</sup> CESA also supports how PG&E will encourage and allow participants to submit offers for one or more of the grid needs, thus allowing for the possibility of a portfolio of DERs to meet the deferral need. One area of concern may be the maximum number of calls per year for Requirement 1b of the Huron Bank 1 Project, which appears high given that up to 131 calls could be made out of five delivery months (roughly 150 days), but CESA supports the advancement of this project and believes certain DERs or a portfolio of DERs could achieve these requirements.

CESA supports PG&E’s determination to not include the Tier 2 projects for the 2019 IDER solicitation. As noted by PG&E, though the fact that four independent grid needs needing to be addressed is less of an important barrier for DERs, the Santa Teresa Substation and Dolon Road Bank 1 projects are reasonably flagged and screened out for cost-effectiveness and the baseload nature of the need, respectively.<sup>4</sup> CESA also supports PG&E’s determination to consider the Estrella Substation in future IDER RFOs for forecast certainty reasons. The 2024 forecasted need year provides sufficient time for DERs to be procured later with firmer forecasts. Other than the in-service date, the project is otherwise a strong candidate for deferral by DERs, but it appears the forecasted need year provides sufficient time for DERs to be procured later with firmer forecasts.<sup>5</sup> Finally, CESA supports the elimination of the Tier 3 projects given the challenges of DERs to meet baseload needs.<sup>6</sup> Based on the lessons learned from the PG&E’s DRP Demo C RFO results as well as the DPAG discussions, it seems reasonable to eliminate these Tier 3 projects.

**B. CESA supports the advancement of the SCE’s proposed four Tier 1 projects for the 2019 IDER RFO as well as the exclusion of most of the Tier 1 and 2**

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<sup>2</sup> PG&E Advice Letter, p. 9.

<sup>3</sup> *Ibid*, p. 10.

<sup>4</sup> *Ibid*, pp. 9-10.

<sup>5</sup> *Ibid*, p. 10.

<sup>6</sup> *Ibid*, p. 10.

**projects not selected by SCE for solicitation, but the MacArthur and Crater projects should be added to the procurement list**

CESA supports SCE moving forward with an RFO for DERs for the distribution grid needs identified for the following projects: Nogales 66/12 (1.83 MW) Substation, Sun City 115/12 Substation (12.87 MW), Mira Loma 66/12 Substation (5.2 MW), and Newhall 66/12 Substation (4 MW). The project meets the timing criteria with an in-service date within 3-4 years of the expected deficiency (between 2021 and 2022) and meets the technical criteria of identifying one of four services that DERs can provide in accordance with D.16-12-036.<sup>7</sup> Each of the projects present potential significant cost benefits based on the unit cost and LNBA assessments and have grid needs that are achievable by DER solutions. For the Mira Loma 66/12 Substation, it will be important to structure the long-duration need to allow for both short- and long-duration DER solutions.

In particular, CESA appreciates that SCE decided to include the Newhall 66/16 Substation Project in the 2019 IDER RFO in response to DPAG feedback.<sup>8</sup> As noted in the DPAG meetings, CESA found the limited duration and manageable capacity need of deferring the planned investment as making it viable for DER deferral solutions and believes that DERs can provide the voltage support needed in an n-1 contingency so long as contractual provisions are defined such that, during HE15 to HE17, DERs may be needed and dispatched for outage or extreme heat conditions.

CESA supports SCE's determination to not include the identified Tier 1 and 2 projects for solicitation. CESA supports SCE's determination to not advance the two Elizabeth Lake 66/16 (D) Substation projects, the Mariposa 66/12 Substation project, the Moorpark A 220/66 Substation project, and the Crater 66/16 project to an RFO due to the very large or baseload-like needs and/or low forecast certainty from insufficient progress of development of expected new load.<sup>9</sup> For the projects that are not prioritized due to forecast uncertainty (e.g., MacArthur 66/12 project), CESA agrees with the recommendation from the IE report that the MacArthur 66/12 project be added to the procurement list, with close monitoring of the forecast certainty from firmer commitments from the developers of new expected load.<sup>10</sup>

The Lockheed 66/16 Substation project, which originally rated as a Tier 1 project due to many of the same traits as the Nogales project, was ultimately not selected due the forecast uncertainty of a single 'customer' driver.<sup>11</sup> The reasons cited seem reasonable and this project should be considered in future DIDF cycles as more concrete plans are conveyed by the single residential developer.

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<sup>7</sup> *Ibid*, p. 9.

<sup>8</sup> SCE's Advice Letter, pp. 9-10.

<sup>9</sup> *Ibid*, pp. 11-12.

<sup>10</sup> *Ibid*, Attachment A, pp. 28-29, pp. 34-35.

<sup>11</sup> *Ibid*, p. 11.

During the DPAG meetings, CESA recommended that SCE consider advancing the Saugus C 220/66 Substation project to an RFO. While the 20 MW capacity need under n-1 scenario is an extremely large need that may be difficult to meet from the largely residential customer base, CESA expressed that this deferral need could be effectively met by a combination of in-front-of-the-meter (“IFOM”) energy storage at scale and smaller DERs like PV-paired storage system, whose expected generation profiles appeared to align well with the load profile in non-contingency situations. However, CESA finds it reasonable to not advance this project forward after receiving clarification from SCE that the load has not yet been ‘graded’, leading to some forecast uncertainty.<sup>12</sup>

CESA also recommended the Crater 66/16 Substation project to an RFO given that the load shape and duration and the small need above the criteria made this need well-positioned for DER solutions. DERs should be able to materialize to fully meet the identified need. CESA also argued for the advancement of this project to an RFO because DERs could provide significant value given the unit cost of traditional mitigation (over \$10 million), among the highest of the candidate projects. Finally, SCE discussed how the cost of siting DERs in this area would be prohibitively expensive, but CESA is unclear on how this cost of development would be materially different from developing traditional mitigation solutions at this location. However, the IE Report explains that the project cannot be deferred by DERs on a capacity service basis but would require DERs to develop microgrid capability. Given this explanation, CESA believes the infeasibility of advancing the Crater project forward to an RFO is limited more by the structure of grid services being sought as opposed to an inherent limitation of DERs, which are capable of providing islanding and microgrid services. CESA continues to recommend the advancement of the Crater project to an RFO, though we recognize that the current RFO structure and *pro forma* contracts may not have been designed to solicit such services.

**C. CESA supports the advancement of the SDG&E’s one proposed project for the 2019 IDER RFO but has concerns about the lack of transparency and detail in the advice letter**

CESA supports SDG&E moving forward with an RFO for DERs for the distribution grid needs identified. The project meets the timing criteria with an in-service date within 3 years of the expected deficiency (June 1, 2022) and meets the technical criteria of identifying one of four services that DERs can provide in accordance with D.16-12-036. While SDG&E appropriately applied the timing and technical criteria, CESA has several areas of feedback to improve the solicitation to ensure viability for DERs to meet the distribution deferral need. CESA does not have an issue with the project selected but rather how the RFO will be structured, which CESA has commented on previously in

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<sup>12</sup> *Ibid*, p. 12.



DPAG meetings, in comments to SDG&E's 2018 IDER RFO evaluation,<sup>13</sup> and in protests to SDG&E's technology-neutral *pro forma* contract<sup>14</sup> – all issues that CESA does not aim to repeat extensively in detail in this response. As noted in those filings, CESA does not find any compelling need to couple thermal capacity services with back-tie services from the same DER solutions,<sup>15</sup> which will create disproportionate financial and contract risk for DER providers in participating in the RFO. More justification from SDG&E is needed before requiring back-tie services from DERs that provide peak capacity requirements. CESA also notes that the IE Report touched upon this issue by saying that the separation of the two services should be explored<sup>16</sup> and how the need for back-tie services should be done on a case-by-case basis, not as a general rule.<sup>17</sup>

Importantly, CESA has broad concerns around the lack of information provided around the identified project. Whereas the other IOUs provided certain locational and MW capacity need information publicly, SDG&E redacted this information in its advice letter based on its request for confidentiality (Attachment A). CESA does not find a compelling reason in its narrative justification that would give SDG&E unique treatment of this information that is not granted or requested by PG&E and SCE. The confidentiality issue is a broader issue in R.14-08-013, but these broad redactions make it difficult for parties to review this advice letter in detail. Even as a member of SDG&E's DPAG meetings, CESA is unable to specifically comment here on some of the concerns raised in the DPAG meetings and to assess whether feedback has been incorporated or rejected. For example, CESA provided feedback on the timing and duration of the service provision need and how those needs will be addressed through the solicitation and contracting process but is unable to comment out of concerns about violating confidentiality or due to the lack of transparency in the advice letter.

Furthermore, even though only one project reasonably met the timing and technical screening criteria, CESA sought to understand the details around SDG&E's market prioritization criteria, which was presented as just color coding rather than through specific numbers or ranges. According to the attached IE Report, it does not appear that this specificity is provided, which will be helpful in evaluating potential deferrable projects in future DIFD cycles. This information should be provided to inform prioritization going forward.

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<sup>13</sup> *Comments of the California Energy Storage Alliance on the Report of San Diego Gas and Electric Company (U 902 E) Concerning Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism Pilot*, filed on November 19, 2018. See link [here](#).

<sup>14</sup> *Protest of the California Energy Storage Alliance to Advice Letter 3308-E of San Diego Gas and Electric Company*, submitted on December 11, 2018. See link [here](#).

<sup>15</sup> SDG&E's Advice Letter, Attachment D, p. 11.

<sup>16</sup> *Ibid*, p. 29.

<sup>17</sup> *Ibid*, p. A-3.

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### **III. LESSONS LEARNED.**

Over the course of multiple working group meetings in the IDER proceeding as well as the Distribution Planning Advisory Group (“DPAG”), CESA has provided many specific redlines and feedback on the TNPF contracts and is appreciative to see that many changes were made or clarifications were provided, as recommended by CESA and other parties, including around:

In addition to these points, CESA requests that the independent evaluator (“IE”) to the working group also provide its assessment and recommendations, having facilitated the working group. CESA reads the IE report included as attachments as being more of a summary of discussions of the working group rather than an assessment of the negotiations and feedback on the TNPF contract that eventually lead to some key takeaways, conclusions, and recommendations. With this added assessment, CESA believes that the IE report will provide actionable advice and assistance to the Commission in assessing and potentially directing modifications of the proposed TNPF contract.

#### **A. CESA agrees with the IOUs on the importance of prioritization but also seeks to ensure that these efforts do not excessively screen out viable opportunities**

Overall, CESA believes it is prudent to balance having more candidate deferral projects to create a large market opportunity for DER providers and test whether the DER marketplace could potentially cost-competitively address distribution capacity needs in lieu traditional capital investments, with focusing the DER marketplace on a more focused list of candidate deferral projects that better ensure the success of the shortlist of projects that will be subject to a competitive solicitation.

A key purpose of the shortlisting process should be to identify viable deferrable opportunities where DERs may sufficiently materialize in a competitive solicitation to avoid having DER providers who targeted their bids at those projects to have ‘wasted’ their efforts. Sometimes, this may require a DER provider to depend on other DER providers who combine to meet the overcapacity need. Given the binary nature of traditional capital investments, a portfolio of DER projects may be needed to spread risk and operational requirements and address the full need. Developers put up financial capital (*e.g.*, development, project securities) and may need to ‘pick and choose’ which deferral opportunities to pursue given limited resources, so rather than imprudently use up the IOUs’ and developers’ time and resources in conducting and participating in such solicitations, a narrower (but still somewhat broad) list of viable candidate deferral projects should be pursued. These solicitation participation costs were highlighted in the IE Report,<sup>18</sup> but it should also not the opportunity costs of targeting non-viable or unlikely deferral projects.

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<sup>18</sup> PG&E’s Advice Letter, Attachment C, p. 21 and SCE’s Advice Letter, Attachment A, p. 25.

Following the 2019 IDER RFO, it may be prudent to reassess the technical screening and market prioritization criteria. Each IOU takes a varied approach but it may be reasonable to identify the ‘best practices’ among the different approaches, as many of the criteria could become standardized.

**B. Options to install capacity over time and other solutions may hedge against forecast uncertainty**

CESA agrees with concerns about forecast uncertainty for certain deferral needs. The importance of firmer load forecasts was highlighted in the DPAG meetings in prioritizing different projects, as well as in discussions of past experiences.<sup>19</sup> CESA supports the need for prioritization in terms of forecast certainty as it would be imprudent to waste IOU and DER developer time on projects that do not materialize. At the same time, CESA agrees with PG&E’s point that there should be flexibility in distribution planning, though CESA recommends that flexibility also be incorporated into the contracting and deployment processes as well, such as by installing DER capacity over time, as done by SCE in its 2018 IDER RFO<sup>20</sup> and as SCE proposes to do in its 2019 IDER RFO.<sup>21</sup> Unlike wires solutions, DERs can be ‘right sized’ and incrementally built to the overcapacity need or other distribution grid service need over time, thus mitigating forecast uncertainty, managing the risks of overbuilding capacity that could occur with a wires investment, and supporting developers in meeting incremental development and construction milestones. This appears to be a best practice that could be shared across all IOUs.

**C. Long-duration needs can be challenging deferral projects but these opportunities should not be automatically screened out for being “unviable”**

CESA agrees that DERs will face challenges meeting baseload needs, especially if there is no baseload generation available or insufficient time for charging energy storage resources.<sup>22</sup> However, short of baseload needs, there are DER technologies that are commercially available that can address long-duration needs, such as flow batteries that are capable of 6 to 18 hours of load shifting. As done with PG&E’s and SCE’s proposed RFOs, the service requirements can also be divided to address the need in more manageable portions that may invite greater market participation and better enable multiple-use applications. This would require a portfolio-based approach and creates some contracting challenges,<sup>23</sup> but CESA believes these challenges are addressable with

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<sup>19</sup> PG&E’s Advice Letter, p. 3.

<sup>20</sup> *Submission of Contracts for Procurement of Energy Storage Resulting From the Integrated Distributed Energy Resources Incentive Pilot Solicitation*, SCE Advice Letter 3874-E, submitted on October 5, 2018, Appendix D, p. 15.

<sup>21</sup> SCE’s Advice Letter, p. 13.

<sup>22</sup> PG&E’s Advice Letter, pp. 4-5, Attachment C, p. 23.

<sup>23</sup> *Ibid*, pp. 4-5.



innovative contracting structures and grid operational frameworks. In sum, CESA cautions against automatically screening out long-duration needs in general.

#### **D. Detailed locational guidance will be needed in the RFO documents**

CESA recommends that the IOUs provide clarifications and guidance on the siting of DERs. As noted from experience from SCE in their 2018 IDER RFO<sup>24</sup> and from SCE in their proposed solicitation,<sup>25</sup> locational guidance on whether DERs are needed at the substation or closer to load on specific circuits made a major difference on the conformance and technical viability of DER projects. Explicit clarifications would be helpful to DER bidders to most effectively support their siting decisions.

#### **E. Incrementality issues will likely need to be resolved in R.14-10-003 or some other policymaking proceeding**

The IOUs discuss how they will employ approved methodologies from D.16-12-036 to assess incrementality of DERs to avoid double compensation and double counting.<sup>26</sup> The details for how incrementality is assessed according to these approved methodologies is important to provide clarity and certainty to DER bidders in how their bids will be assessed incremental value. Incrementality issues must be resolved. BTM developers are discouraged from participating in the IDER RFOs if incrementality methodologies prohibit their resource from providing additional distribution services. These methodologies are within the purview of the IDER proceeding at this time, but engaging BTM developers will be important to the success of any IDER solicitation.

In the meantime, CESA recommends that each of the IOUs report in detail on how they have assessed for incrementality in their upcoming RFOs to guide policymaking in R.14-10-003 or some other proceeding. Without this assessment and an understanding of the status quo, the Commission and stakeholders will face challenges in terms of how to potentially improve upon existing approved methodologies. Many existing or new DERs that are ‘sourced’ through existing programs, tariffs, or other solicitations could potentially provide additional value-added distribution grid services, if not for the incrementality methodologies, which may be overly conservative in assessing what their incremental value is to the utility. However, CESA agrees with SCE that such complex policy issues should not be addressed in these advice letters or as part of the RFOs.<sup>27</sup>

#### **F. Detailed LNBA ranges and unit cost of traditional mitigation information provides some benchmark for developers to price bids**

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<sup>24</sup> *Submission of Contracts for Procurement of Energy Storage Resulting From the Integrated Distributed Energy Resources Incentive Pilot Solicitation*, SCE Advice Letter 3874-E, submitted on October 5, 2018, p. 13.

<sup>25</sup> SCE’s Advice Letter, p. 13.

<sup>26</sup> PG&E’s Advice Letter, p. 15, SCE’s Advice Letter, pp. 18-19 and SDG&E’s Advice Letter, p. 5.

<sup>27</sup> SCE’s Advice Letter, pp. 13-14.

CESA appreciates PG&E and SCE providing explicit LNBA ranges and unit cost of traditional mitigation information, which complies with D.16-12-036, was helpful for DPAG members in vetting the candidate projects, and will be helpful to DER bidders during the solicitation to price bids and understand whether they would meet baseline criteria for competitiveness.<sup>28</sup> The LNBA information is provided in ranges, but the IOUs should strive to provide this information in more granular ranges and in terms of actual numbers for DPAG members, as recommended by the IE.<sup>29</sup>

There are certain areas of improvement and consistency that could be made to the LNBA analyses for each of the IOUs. First, the “unique set of assumptions” used in PG&E’s LNBA calculations should also be looked into further,<sup>30</sup> perhaps through the DPAG process. Second, the timeframe in which LNBA values are calculated differ across the IOUs, with PG&E, SCE, and SDG&E looking at 7-year, 10-year, and 5-year values of locational benefits, respectively. Finally, the other IOUs should mirror SCE’s approach to calculating cost-effectiveness for deferral based on a 10-year look ahead, rather than something shorter term. The other IOUs looked at MW or MWh capacity needs at the in-service date, but SCE appropriately takes the approach of looking at deferral needs across a longer time frame that ensures longer-term deferral and allows for DER contracting over a longer period of time, which supports the financeability of DER projects.

Finally, CESA believes the distribution deferral value calculation methodology requires additional evaluation and potential modifications to take into account the potential avoidance value of the planned distribution investment. While each of the IOUs have looked at a short-term window during which deferral value is attributed to the DER solution, CESA recommends that the distribution deferral value incorporate some probability weighted adder of the utility never having to install the capital investment. For example, the net present value (NPV) calculation may include revenue requirements for Years 1-5 (*i.e.*, the deferral period) but should also include the probability of not needing the capital expenditure – *e.g.*, with the probability being, for example, 50% for a five-year deferral and 75% for a 10-year deferral. DER solutions are not only capable of deferring a traditional distribution investment but avoiding those investments altogether, as we have seen with a number of cancelled transmission investment projects in the Transmission Planning Process (TPP) over recent years due to DER growth.

#### **G. Hourly load shapes are needed to support developers in proposing the best solutions to address the identified grid need**

More detailed hour-by-hour load shapes are needed to inform DER providers, similar to what was provided by SCE in their DPAG meetings. This will support DPAG

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<sup>28</sup> PG&E’s Advice Letter, Attachment C, p. 18.

<sup>29</sup> PG&E’s Advice Letter, Attachment C, p. 36, SCE’s Advice Letter, Attachment A, p. 34, and SDG&E’s Advice Letter, Attachment D, p. 22.

<sup>30</sup> PG&E’s Advice Letter, Attachment C, p. 37.

members in vetting the viability of the candidate project and support DER providers in proposing the best solutions to address the identified grid need, helping in their efforts to identify and site DER resources, configure and develop DER projects, etc. While the detailed service requirements are helpful, these detailed load shapes support BTM developers in understanding the market potential of customers in addressing the underlying grid need, similar to how the number of types of customers help DER bidders to understand the market potential for their technology. It may also be helpful to provide load shape information for the distribution grid need under normal operating conditions versus N-1 contingency situations, if materially different.

In addition, to the degree feasible, a similar hourly hosting capacity profile would be helpful to more smartly manage backflow limitations – an approach that is preferable to an outright prohibition of all exports. For certain projects, CESA recommends that exports be allowed to address the underlying grid need while falling within hosting capacity constraints, rather than to broadly prohibit exports due to the lack of general hosting capacity available. Such a granular approach is prudent and reasonable and allows for all viable DER solutions to be smartly deployed and dispatched. The time periods of export limits should be defined, if some level of exports to support the grid need is allowable and beneficial.

#### **H. Future DIDF processes should strive to include voltage support and resiliency projects**

Going forward, in future rounds of the DIDF, CESA recommends the inclusion of voltage support and resiliency projects in the GNA and DDOR. DERs are capable of providing both types of distribution services reliably and in a timely fashion. In addition, while reliability back-tie services were not included in any of the planned investments, CESA requests more information from PG&E on why such projects did not make it through the DDOR. Finally, CESA appreciates that PG&E will include circuit-level needs in the GNA and DDOR in the next round of the DIDF.

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**IV. CONCLUSION.**

CESA appreciates the opportunity to submit this response to the three IOUs' Advice Letters and hopes that our feedback will be taken into consideration. CESA looks forward to collaborating with the Commission and the IOUs ensure a competitive solicitation for identified distribution grid needs.

Respectfully submitted,



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