BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

FILED
03/22/19
04:59 PM

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

OPENING COMMENTS ON TRACK THREE PROPOSALS OF SUNRUN INC.

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March 22, 2019

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Pursuant to Commissioner Randolph's January 29, 2019 *Amended Scoping Memo and Ruling*, Sunrun, Inc. ("Sunrun") hereby submits the following comments on Parties' Track 3 Proposals addressing further refinements to the Resource Adequacy ("RA") program.[1]

Parties' Track 3 proposals and discussions at the March 12 and 13 workshops highlight the need for resolution on the issues Sunrun raised related to behind-the-meter ("BTM") distributed energy resources ("DERs"). The California Energy Commission's ("CEC's") presentation demonstrated the incrementality issue Sunrun raised in its Track 3 Proposal where "autonomously procured" DERs, *i.e.*, those established based on historical adoption and broad market trends, within the CEC's forecast hide any incremental procurement of DERs procured for specific purposes, such as providing local capacity. While Pacific Gas & Electric Company's ("PG&E's") proposal to stop treating DERs as load modifications could address the issue, that proposal suffers from key short-comings and appears to be contradictory in its assumptions regarding the deliverability of distributed resources.

Further, numerous parties have suggested proposals for a Qualifying Capacity ("QC") counting methodology for solar-paired resources, but few, if any, of those proposals address

[1] R.17-09-020, *Amended Scoping Memo and Ruling of Assigned Commissioner*, p. 3 (Jan. 29, 2019).

BTM DERs. Action on such proposals, in coordination with changes to how DERs are treated for load forecasting purposes, and in addition to much-needed clarity on incrementality, is needed to animate the use of BTM DERs to meet RA capacity needs. Such action also would respond to the Commission's policy to more fully integrate BTM DERs into the State's capacity framework. The Joint DR Parties' proposal to allow for RA value for load shifting moves the State forward toward those goals, and Sunrun supports it as one of a number of measures that are needed.

Sunrun also supports Energy Division's proposal to spread the diversity benefit from supply-side storage to supply-side solar for existing resources. However, the Commission should allow developers (or customers) that directly combine solar with storage, whether in front of or behind the meter, to directly benefit from that pairing on a going-forward basis.

I. Load Forecast Proposals

The CEC's load forecast includes modifications attributed to DERs based on two factors: (1) historical adoption trends of DERs, which suggests DERs will be autonomously procured based on past consumer behavior, and (2) typical generation forecasts for basic DERs, *i.e.*, those that rely only on photovoltaic ("PV") panels to produce power. Each issue poses its own short-coming and requires resolution both here in this proceeding and at the CEC.

First, the Commission relies on the CEC's load forecasts to set RA requirements for load-serving entities ("LSEs").[2] However, the CEC forecast only incorporates broad market trends,

[2] Cerutti, M. and Brooks, D., California Public Utilities Commission, *Resource Adequacy 2016 Load Forecast Adjustment Methodology - Revised*, p. 6 (2016) (stating with regard to load forecasting that "[a]fter the coincidence adjustments and plausibility adjustments are applied, CEC staff allocates credit for energy efficiency (EE), demand response (DR), and distributed generation (DG) programs in each of the three IOU service areas. The allocation accounts for the proportion of the load impacts accruing to each LSE due to a portion of the distribution charge paid by their customers. CEC staff allocates the impacts of the programs to LSEs proportionate to their share of load and so the decrease to their loads equals to the sum of the EE, DR, and DG credits. Consistent with the direction in D.05-10-042, impacts

and it makes no forecast of deployment of specific resources separate from those overall trends. It misses, for example, distinct procurement specifically for local capacity purposes because such procurement is set via a contract undertaken by a third-party directly with an LSE. If outside of the market trend the CEC observes, the Commission simply ignores the procurement unless it stems from Proxy Demand Response, which itself waters down the QC by only acknowledging load modifications and ignoring the potential of export capacity. Thus, LSEs have no clear avenue to procure RA from DERs since the "autonomous" adoption in the load forecasts may already account for the incremental procurement.

This avoidable scenario has already arisen. Certain LSEs, such as Southern California Edison and PG&E, are extrapolating the CEC forecast down to local areas for the purposes of excluding DER eligibility during procurement solicitations. Other, more progressive, LSEs are looking to procure DERs specifically for RA value but have no clear means to account for that procurement. For both willing and less-than-willing LSEs, the lack of distinction in the load forecast eliminates the ability for DER customers and providers to demonstrate incremental load reduction benefits from DERs and provide additional value to customers to drive increased DER deployment. The result is the exclusion of local DERs from procurement under the guise of incrementality, even though the CEC's load forecast itself makes no assertion regarding specific DER development in these local areas.

Second, the existing "stereotypical" generation forecasts the CEC uses for DERs are becoming less relevant as technology evolves. BTM storage load modifications follow a myriad of different adjustments depending on whether customer-specific objectives exist or whether the storage is incorporated in an aggregation to meet other grid service needs. Electricity usage and

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are either allocated to each LSE based on its share of total load or to only the IOUs depending on whether all customers or only bundled customers participate in the program.").

certain DER behavior can be forecast, but, within residential time-of-use ("TOU") windows, battery storage (and by extension electric vehicle charging) has no inherent predictable load shape. Further, the CEC's forecasts are unlikely to take into account smart inverter functions that may result in the curtailment of BTM resources for the purpose of providing grid services. The result is that, while the incrementality of particular battery charge / discharge patterns is of key importance for determining whether batteries are valued for RA, no particular assumed battery operating pattern can be said to be a single rational baseline against which incremental battery operation should be measured. The CEC is planning to revise its approach to DERs to address batteries this year, but it remains far from clear the approach will be accurate or rational for the numerous different types of configurations that can be expected, including those from aggregated DERs providing grid services.

Sunrun recently made the attached comments at the CEC to begin to address the problem. The comments relate to parts of Sunrun's Track 3 Proposal and include suggestions that the CEC:

1. Omit any assumed modification to the aggregate load profile from batteries or similarly flexible DERs unless specific procurement has been verified by an LSE;

2. Establish a reasonable "baseline" forecast for DER adoption, with verified procurement beyond that forecast considered incremental; and

3. Prescribe a reporting protocol for LSEs to reflect DERs procured beyond forecasted adoption rates.

This approach will provide an avenue for LSEs to reflect the value of DERs procured within their load forecasts, while avoiding the potential for errors stemming from application of generic profiles to battery-paired resources that are unlikely to have such profiles.

However, the Commission must still address the issue, as well. D.15-10-042 clarified that if "DG" adoption were to substantially increase, its approach could be revisited and more sophisticated methodologies employed.[3] As noted in Sunrun's Track 3 Proposal, that time has arrived.[4] While both agencies appear open to change, as discussions with CEC staff at the recent workshops demonstrated, the situation should be avoided where both agencies believe the issue should be addressed at the other, and nothing changes.

Beyond Sunrun, only PG&E included a proposal that could potentially address the incrementality issue with how DERs currently are included in load forecasts. PG&E proposes to use end-use consumption—rather than traditional metered load (bulk energy system energy)—for RA program requirements.[5] Under that approach BTM PV resources would be accounted for, as follows: [6]

1. Commission-jurisdictional LSEs report BTM PV resources and sales;
2. The LSEs would then "impute" the self-supply of BTM PV via an undisclosed methodology;
3. The sales would be added to the "imputed self-supply" resulting in a total end-use consumption calculation;
4. The Total System RA Requirement would equal the following: (Total consumption minus the QC of BTM PV) + 15% Reserve Margin; and
5. Each LSE's System RA Requirements would equal the following: LSE's share of end-use consumption less the QC of BTM PV.

Under PG&E's approach, an Effective Load Carry Capacity ("ELCC") methodology would apply for both BTM and front-of-the-meter solar,[7] and BTM DERs would no longer be treated as load-modifying resources. While not specified in the proposal, Sunrun assumes the

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[3] D.05-10-042 at 41.
[4] Sunrun Track 3 Proposal at 16-20.
[5] PG&E Track 3 Proposal at 3.
[6] *Id.* at 3.
[7] *Id.* at 2.

same approach would be afforded to battery-paired resources once a QC methodology is developed for those resources. Further, PG&E's approach would appear to take out the "autonomous DER procurement" from the load forecasts to a limited extent by having Commission-jurisdictional LSEs "report BTM resources and sales," although it is not completely clear whether PG&E is proposing a practice distinct from current practices.[8]

PG&E's suggested approach also suffers from a number of short-comings. First, it would overcorrect for the incrementality problem Sunrun has identified. LSEs should benefit from the level of historical or contracted adoption or load adjustment where assignment of those benefits has been clearly established by the Commission. For that reason, Sunrun has suggested a reasonable baseline be established for DER procurement, with procurement beyond that point being incremental. Second, it is unclear how self-supply would be "imputed" since there is insufficient detail in PG&E's proposal on this aspect. Third, there is no QC counting methodology currently for BTM or paired resources (discussed in the following section), meaning it is unclear how PG&E's proposal would be applied to BTM resources that are paired, or unpaired, with batteries.

Finally, there is an inherent contradiction in PG&E's suggested approach. PG&E appears to suggest that the Commission should use a kind of "supply-side" approach to count DERs for the purposes of modifying load forecasts and the resulting RA requirements. However, the utilities have argued in other contexts that DERs must interconnect under their Wholesale Distribution Access Tariffs, and participate as wholesale resources, in order to provide "supply-side" RA. Sunrun does not believe it makes sense to require BTM resources to prove their deliverability to loads with which they are collocated or loads they neighbor. If an approach

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[8] *Id.* at 3.

similar to PG&E's is adopted, the resources should be assumed to be deliverable in *both* the context of establishing RA requirements and the context of determining net qualifying capacity.

As noted in Sunrun's Track 3 Proposal,[9] the Commission needs to establish appropriate ways for DER providers and LSEs to apply capacity values for subsequent, incremental contribution from BTM solar and battery storage combinations that are procured by LSEs to either modify their specific RA obligations or to provide RA supply. A reasonable approach towards this end may be to allow BTM DERs to earn capacity value on the demand side by default unless they are put on the supply side by the asset owner, via an express choice to participate in a certain program or solicitation, with deliverability assumed in both cases. Such an approach would allow DER providers to be able to seek compensation from an LSE for either providing beneficial load modification above a reasonable "baseline" forecast, or for providing a supply-side RA resource that an LSE can procure to meet its RA obligations. It will also ensure double-counting of resources is prevented so that the market truly benefits from incremental contribution of capacity and that capacity is not unreasonably withheld from the market based on overly conservative or opportunistic disqualification.

II. QC Counting Methodology Proposals

Sunrun supports the calls from numerous parties for the Commission to put in place a QC counting methodology for battery-paired resources.[10] However, parties' efforts toward that end have largely ignored BTM resources to date. Apart from PG&E's brief and rather vague discussion in its load-forecasting proposal,[11] none of the parties' Track 3 Proposals has put forward a proposal specific to calculating a QC for BTM DERs. CESA calls "for record-

9 Sunrun Track 3 Proposal at 21-22.

10 CESA Track 3 Proposal at 3-5; PG&E Track 3 Proposal at 2-3; SCE Track 3 Proposal at 4-8; Joint DR Parties at 5-6; and CalCCA Track 3 Proposal at 9-10.

11 PG&E Track 3 Proposal at 2-4.

building and a determination of how to provide market access from this resource class" and "workshops to establish RA counts for DERs and to explore any related performance, participation or 'offer' obligations for these resources."[12] Sunrun agrees with CESA's procedural approach and believes SCE's proposals[13] for front-of-the-meter paired resources may be a good starting point for discussions on BTM resources.

Energy Division's proposal and analysis continue to show a synergistic benefit from introducing storage into a solar-heavy resource mix. However, staff still suggests spreading the extra benefit of storage only to "supply side solar," regardless of whether those specific solar resources had paired storage with their solar generation.[14] As Sunrun noted in its Track 3 Proposals, the Commission should ensure that ELCC modeling allows developers (or customers) that directly combine solar with storage, whether in front of or behind the meter, to directly benefit from that pairing and not dilute the benefit of storage pairing by socializing the benefits across all solar resources. Staff's approach may be fine for immediate ELCC valuations for existing solar due to existing storage, but it should not be adopted on a going-forward basis.

III. Joint DR Parties' Proposal for RA Value for Load Shifting Demand Response

Sunrun supports the Joint DR Parties' proposal for including RA value for load-shifting demand response. The Joint DR Parties' proposal notes that the Load-Shift Working Group has "recognized that shifting load from the net load peak to the middle of the day should receive RA recognition by reducing the amount of capacity required to meet the net load ramp, and by reducing the midday trough."[15] Sunrun agrees with the Joint DR Parties that "the RA value of

12 CESA Track 3 Proposal at 6.
13 SCE Track 3 Proposal at 6.
14 Energy Division, *Revised Staff Proposal*, Slides 10, 14 and 17 (Feb. 13, 2019).
15 Joint DR Parties Track 3 Proposal at 6.

load shifting should be included and considered in Track 3."[16] Consideration of load-shifting capacity would likely need to build off of existing DR QC counting protocols with consideration for the export capacity potential within the daytime excess energy and evening peaking period time domains.

IV. Conclusion

Sunrun appreciates the Commission's consideration of these comments and looks forward to continuing to work with Staff and other parties on the issues addressed herein.

Respectfully submitted,

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Dated: March 22, 2019

[16] *Id*.

March 18, 2019

California Energy Commission
Dockets Office, MS-4
Re: Docket No. 19-IEPR-03
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Comments in Response to the 2019 Integrated Energy Policy Report (2019 IEPR) Workshop on Data Inputs and Assumptions for 2019 IEPR Modeling and Forecasting Activities, 19-IEPR-03

Sunrun Inc. ("Sunrun") appreciates the opportunity to provide comments on the California Energy Commission's ("CEC") workshop on the 2019 IEPR workshop held on March 4, 2019. The purpose of these comments is to request the CEC:

- Acknowledge the link between the treatment of distributed energy resources ("DERs") in Comission's 2019 Integrated Energy Policy Report ("IEPR") forecast and the limitations that treatment creates in using DERs to meet the State's reliability needs;

- Affirm that DERs procured for local capacity purposes are incremental to any behind-the-meter ("BTM") solar that is forecasted in the IEPR in order to clarify the deployment of specific resources separate from overall market trends;

- Include local areas in the IEPR's future Energy Demand Forecasts, with the methodology used to apply the statewide forecast to local areas made publicly available and transparent to external stakeholders;

- Recognize the complexity in forecasting battery-paired DERs;

- Omit any assumed modification to the aggregate load profile from batteries or similarly flexible DERs unless specific procurement has been verified by an LSE;

- Establish a reasonable "baseline" forecast for DER adoption, with verified procurement beyond that forecast considered incremental; and

- Prescribe a reporting protocol for LSEs to reflect DERs procured beyond forecasted adoption rates.

I. About Sunrun

Sunrun (Nasdaq:RUN) is the nation's largest residential solar, storage and energy services company. With a mission to create a planet run by the sun, Sunrun has led the industry since 2007 with its solar-as-a-service model, which provides clean energy to households with little to no upfront cost and at a saving compared to traditional electricity. The company designs, installs, finances, insures, monitors and maintains the systems, while families receive predictable pricing for 20 years or more. The company also offers a home solar battery service, Sunrun Brightbox, which manages household solar energy, storage and utility power with smart inverter technology. For more information, please visit: www.sunrun.com.

II. Discussion

A. The CEC's Use of "Typical" Generation Profiles to Modify Load Forecasts in the IEPR Unintentionally Limits the Ability of DERs to Meet the State's Reliability Needs.

Distributed clean energy resources are uniquely suited to serve local capacity needs. They can be sited directly where local capacity is required and can be scaled in subsequent years in relation to changing demand. For example, in transmission constrained areas, solar and battery-paired DERs can provide renewable energy and peak load reduction, thereby alleviating the need for peaking generation capacity or new transmission lines, as well as provide ongoing local generation in the event of a transmission contingency.

The IEPR plays a key role in energy planning in California that impacts the ability of DERs to provide these distribution, transmission and generation capacity services. The IEPR demand forecast informs the State's load-serving entities' ("LSEs'") integrated resource planning, as well as the California Independent System Operator's ("CAISO's") Transmission Planning Process. The IEPR is critically important to setting LSEs' Resource Adequacy ("RA") requirements at the California Public Utilities Commission ("CPUC"), where the CEC is largely responsible for collecting and validating LSE load forecasts that the CPUC adopts for the purpose of setting LSEs' RA responsibility.

To set the load forecasts within the IEPR, the CEC uses data from utility distribution companies to establish historical installation data for photovoltaic ("PV") DERs.[1] While the CEC plans to update that forecast in the 2019 IEPR, and include storage technologies and methodological

[1] S. Konala, *Distributed Generation Forecast Input and Modeling Updates*, Workshop Slides 7-12 (Mar. 4, 2019) ("Workshop Slides").

changes related to incorporating tilt and azimuth,[2] for example, there are overarching problems with accounting for DERs in this manner.

The issues stem from the CEC process establishing what might be called "autonomously procured" DERs. These are DERs that the CEC accounts for based on historical adoption trends, and then adjusts for factors such as weather sensitivity. The CPUC then takes the CEC's results and follows an approach to account for DERs established *in 2005* which, given the limited penetration of DG at that time ("a few hundred megawatts"), simply relies on CEC's modification of the load forecasts based on "stereotypical" generation forecasts:

> After the coincidence adjustments and plausibility adjustments are applied, CEC staff allocates credit for energy efficiency (EE), demand response (DR), and distributed generation (DG) programs in each of the three IOU service areas. The allocation accounts for the proportion of the load impacts accruing to each LSE due to a portion of the distribution charge paid by their customers. CEC staff allocates the impacts of the programs to LSEs proportionate to their share of load and so the decrease to their loads equals to the sum of the EE, DR, and DG credits. Consistent with the direction in D.05-10-042, impacts are either allocated to each LSE based on its share of total load or to only the IOUs depending on whether all customers or only bundled customers participate in the program.[3]

As the current load forecast templates demonstrate, this informal and undocumented approach is still in effect, whereby only the IOUs provide forecasted monthly MW peak impacts of adoption for DERs. [4]

The problem is the IEPR incorporates broad market trends but makes no forecast of deployment of specific resources separate from overall market trends. The IEPR does not take into account specific programs unique to local areas, such as programs to add value to DERs that drives increased deployment. The procurement of BTM DERs for local capacity purposes, for example, is distinct and not forecasted by the IEPR because it is a contract undertaken by a third party directly with an LSE. Thus, LSEs' use of battery-paried DERs as an RA asset has been hindered because it is unclear the degree to which the IEPR is already predicting solar capacity growth in local areas.

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[2] *Id.*
[3] Cerutti, M. and Brooks, D., California Public Utilities Commission, *Resource Adequacy 2016 Load Forecast Adjustment Methodology - Revised*, p. 6 (2016).
[4] *Id.* at 6.

Even though the IEPR historically has not been a locally-derived forecast, certain LSEs are extrapolating it down to local areas for the purposes of determining resource eligibility during procurement solicitations, with little to no action in response from the CPUC. As a result, local DERs are being excluded as non-incremental to the IEPR, even though the IEPR itself makes no assertion regarding specific DER development in these local areas.

Without establishing clarity in load forecasts between RA needs and "autonomously procured" DERs in the CEC's forecast, it becomes difficult to procure RA from DERs of *any* type whose "autonomous" adoption is in the load forecasts that determine RA needs. Stated another way, the lack of distinction in the load forecast eliminates the ability for DER customers and providers to demonstrate incremental load reduction benefits from DERs. Therefore, in addition, to the more specific changes outlined below, Sunrun initially requests the CEC affirm that BTM DERs procured for local capacity purposes are incremental to DERs forecasted in the IEPR.

The CPUC's 2005 decision clarified that if "DG" adoption were to substantially increase, its approach could be revisited and more sophisticated methodologies employed.[5] Sunrun recently submitted the attached proposals to address this issue at the CPUC, noting that not only has "DG" adoption substantially increased, it has evolved technologically, and the scale introduction of flexible battery storage within DER systems calls into question the methodology and design of load forecasts inclusive of DERs. While both agencies appear open to change, as discussions with CEC staff at a recent CPUC workshop demonstrate, the situation should be avoided where both agencies believe the issue should be addressed at the other, and nothing changes.

B. Forecasting Battery-Paired DERs is Much More Complex than PV-only DERs.

More practical problems exist in addition to the overarching problems of forecasting DER impacts discussed above. First, it is important the CEC use more granular data in its IEPR Energy Demand Forecast so that DERs can better provide solutions to help optimize the grid and help the State meet its long-term greenhouse gas reduction goals. Sunrun was pleased to hear that the CEC is working with the National Renewable Energy Laboratory ("NREL") on adapting NREL's Distributed Generation Market Demand Model. To further promote the procurement of distributed energy resources for local capacity purposes, Sunrun proposes the IEPR include local areas in future Energy Demand Forecasts, with the methodology used to apply the statewide forecast to local areas made publicly available and transparent to external stakeholders.

Second, there should be transparency on the forecasted quantity of adoption and the forecasted aggregate profile adjustments that are attributed to the most common BTM DER technologies.

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[5] D.05-10-042 at 41.

While there is considerable variation in different solar technologies and azimuth orientations, standardized aggregate profiles are likely acceptable as long as the assumptions and sources are transparent, and Sunrun is encouraged to see the CEC's continuing evolution on these issues.

Third, electricity usage and certain DER behavior can be forecast, but, within residential time-of-use ("TOU") windows, battery storage (and by extension electric vehicle ("EV") charging) has no inherent predictable load shape. A wide range of battery discharge patterns can be equally economically rational within a TOU pricing period.

That is, storage load modifications follow a myriad of different adjustments depending on the customer-specific objectives and whether the storage is incorporated in an aggregation to meet other grid service needs. As an owner and operator of a BTM storage fleet, it is unclear to Sunrun how a load forecast *could* be done fairly for battery storage except if extrapolated on an empirical basis under an agreed-upon methodology. Even in this case, the result would be from arbitrary battery settings for existing customers and might not be appropriate on which to gauge the behavior of future customers. A net energy metering ("NEM") battery with export ability can discharge in any number of patterns that are equally economically rational during TOU peak periods lasting several hours. While the incrementality of particular battery charge / discharge patterns is of key importance for determining whether batteries are valued for RA, *no particular* battery operating pattern can be said to be a single rational baseline against which incremental battery operation should be measured.

C. The CEC Should Modify its Approach to DERs to Minimize Reliance on Historical Trends Resulting in "Autonomously Procured DERs."

The previous two sections show how an IEPR forecast that to date has not accounted for battery behavior—and arguably will be unable to do so accurately—is being used as the basis for incrementality determinations for battery-paired DERs for local capacity procurements. To resolve this issue, and address the complexity of modeling BTM batteries, Sunrun believes it would be most appropriate when setting the IEPR forecast to omit any assumed modification from batteries or similarly flexible DERs to the aggregate load profile until after specific procurement has been verified by an LSE. If this is not done, an LSE that seeks to avoid crediting BTM storage could simply suggest that battery discharge done specifically for RA from an individual battery is already assumed in the aggregate load forecast, thereby completely ignoring the incremental value the addition of batteries provides, with no way for an aggregator to disprove the assertion.

In addition, perhaps even more fundamental than providing an accurate *prediction* of load modifying impacts of flexible DERs, the CEC should clearly establish guidelines for what baseline level of adoption and load modification should be reflected in various LSEs' load forecasts. Without transparent and fair guidelines, LSEs may be precluded from valuing RA at the system or local level delivered by DERs because there is no established methodology for how such capacity would relate with the load forecast. That is, the forecast used to determine the Local RA requirement, for example, includes *some* DERs from the IEPR process, but it is not clear *which* DERs. This means it is impossible to determine if a given contracted procurement of BTM DERs is the "same" DERs expected to be "autonomously" adopted in the forecast, and it precludes the procurement of a resource that may be ideally suited to deliver Local RA need.

At the same time, LSEs should benefit from the level of historical or contracted adoption or load adjustment where assignment of those benefits has been clearly established by the Commission. For simplicity, the CEC should consider an approach where DER adoption supported by an explicit agreement between an LSE and DER providers is considered incremental to forecasted DERs. This approach will allow a DER provider to commit to providing its product, on a contractual basis, in exchange for RA value, rather than precluding such commitment for performance by deferring to a forecast that cannot precisely predict how, when or where a DER resource will show up on the system. Stated another way, the CEC should assist in enabling DERs to provide beneficial load modification to LSEs beyond a reasonable "baseline" forecast.

D. A Reporting Protocol for LSEs Will Enable More Accurate Forecasts that Appropriately Reflect DERs' Value in Ensuring Reliability.

These important reforms require a means to report DER procurement upon which the CEC can rely. Therefore, a need exists to create a process where LSEs can show procurement of battery-paired DERs, or more basic DERs procured beyond a baseline forecast, and have that procurement directly reduce load forecasts establishing RA capacity requirements. It is Sunrun's understanding that protocols exist for some LSEs to report procurement and participation to the CEC regarding Demand Response programs, and consideration should be given to whether those protocols are appropriate for the load-modification products Sunrun and more progressive LSEs envision. The development of a methodology to account for incremental CCA and IOU procurement of paired DERs as load modifiers in advance of establishing a forecast will avoid the need to rely on historical data to demonstrate and appropriately count the impacts of these resources. That is, an "upfront" means to establish incremental load modification allows for the creation of immediate value, which is important for contracting for the benefits of these resources.

III. Conclusion

By incorporating the modifications discussed above, the IEPR can increase its effectiveness in promoting cost-effective grid planning and clean energy deployment, as well as help address evolving reliability needs for local capacity with the most efficient and beneficial resources.

Sunrun appreciates the opportunity to provide comments and looks forward to continued participation in the IEPR process.

Sincerely,

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Attachment: Sunrun Track 3 Proposals in R.17-09-020 at the California Public Utilities Commission