Southern California Edison Company’s Track 2 Testimony in Rulemaking 17-09-020

Before the

Public Utilities Commission of the State of California

Rosemead, California
July 10, 2018
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Appendix A Witness Qualifications
I. INTRODUCTION AND BACKGROUND

On September 28, 2017, the California Public Utilities Commission (“Commission” or “CPUC”) filed Rulemaking (“R.”) 17-09-020 to Oversee the Resource Adequacy (“RA”) Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years (“RA OIR”). The RA OIR identified a preliminary scope of issues that included “[c]hanges to the RA Program.”¹ The RA OIR explained that “[g]iven the passage of time and the rapid changes occurring in California’s energy markets, it may be worthwhile to re-examine the basic structure and processes of the Commission’s RA program” and informed the parties that they could “identify specific changes they recommend be made to the RA program.”² In response, Southern California Edison Company (“SCE”), Pacific Gas and Electric Company (“PG&E”) and San Diego Gas & Electric Company (“SDG&E”) (together the “joint Investor-Owned Utilities (“IOUs”)) submitted comments on the RA OIR recommending the development of a new RA paradigm and suggested a dedicated track of the OIR to investigate, develop, and implement as necessary potentially significant changes to the RA Program that would, among other things, fulfill the State’s policy goals, provide for an acceptable level of reliability, mitigate market power concerns in capacity procurement and the wholesale energy market, allocate costs appropriately, operate efficiently under an increasing number of load-serving entities (“LSEs”), and simplify the procurement and market operations as much as practical.³

On January 18, 2018, the Commission issued a Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (“Scoping Memo”) dividing the proceeding into

¹ R.17-09-020 at 4.
² Id.
³ Comments of Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas and Electric Company on the Order Instituting Rulemaking to Oversee the Resource Adequacy Program at 2, 4-5.
three separate tracks, of which Track 2 was intended to consider “more complex and slightly less time-sensitive modifications and refinements to the Commission’s RA program[,]” including the adoption of multi-year Local RA requirements if a multi-year procurement framework was adopted in Track 1 and further refinements to the Local RA rules.\(^4\) D.18-06-030 (“Track 1 decision”), issued on June 25, 2018, focused on the resolution of Track 1 issues, and of note adopted a multi-year framework for Local RA\(^5\) and ordered the parties to propose a multi-year Local RA requirement with a three-to-five-year duration and central buyer structures for multi-year Local RA procurement in their Track 2 testimony.\(^6\) The Commission also encouraged the parties to explore other issues in Track 2, including incorporating behind-the-meter PV into the Effective Load Carrying Capacity (“ELCC”) modeling framework.\(^2\)

Thus, pursuant to the Scoping Memo and the Track 1 decision, SCE respectfully submits this testimony on the following issues: (1) multi-year Local RA requirements and central buyer structures; (2) ELCC methodology; (3) the proper System, Local and Flexible RA accounting for resources combining more than one technology type at a single location and presented to the market as a single resource; (4) the gap in timing between the California Independent System Operator’s (“CAISO”) backstop procurement and the CPUC RA process; (5) restriction in load migration change between initial and true-up forecasts; and (6) refinements to the Local RA rules.

\(^4\) Scoping Memo at 7.
\(^5\) D.18-06-030 at 28.
\(^6\) Id. at 54 (Ordering Paragraphs (“OP”) 10 and 11).
\(^2\) Id. at 37-40.
II. MULTI YEAR-AHEAD PROCUREMENT AND A CENTRAL BUYER STRUCTURE

The issues surrounding the implementation of a multi-year forward Local RA requirement are complicated and generally interconnected. Each element must be balanced against the others to strike an appropriate balance of reliability, affordability, resource certainty and cost allocation to all benefiting customers to avoid CAISO backstop procurement.

In addition, there are key considerations that must be made in order to plan, procure, and implement a new Local RA multi-year forward requirement in a manner that is practical. The following sections address the various interconnections and the trade-offs between them.

There is a separate section on centralized procurement to discuss the various elements that must be in place to make such a program successful, as well as how such a program could address the trade-offs (e.g., minimum procurement requirements versus ease of load migration, the simplicity of procurement for large combined local areas versus the need for specific sub-area resources, etc.) described in Section II.B below.

It is worth noting that the future of the electrical grid and the use of resources to meet California’s policy goals is being developed currently as part of a special “California Customer Choice Project” ongoing at the Commission (the Project issued its draft paper, California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (also known as the Green Book)). As such, the RA OIR should consider the potential for centralized procurement as an interim solution as additional policy guidance unfolds through the “California Customer Choice Project” as well as a number of legislative efforts currently in progress. Additionally, the current critical path for resource certainty for a number of resources is to demonstrate compliance with once-through-cooling (“OTC”) regulations by 2020, or to be able be financially viable until the post-OTC compliance window to objectively determine the

8 Senate Bill (“SB”) 237 proposes allowing direct access to all non-residential customers over a three-year period.
need for continued operation of the resource(s). Therefore, an interim process adopted by the
Commission in 2019 with a planning and procurement term of three-years will be sufficient to
cover the period encompassing compliance with California’s OTC compliance schedule.

In addition, any framework for centralized procurement must address the following
fundamental issues in order to be sustainable, even if the framework is only applicable for an
interim period:

- A framework with durable cost recovery such that the procurement entity can
  sustainably provide the ongoing investment to resources for the mandated multi-year
  period;
- A framework with equitable cost allocation and environmental attribution of centrally
  procured resources such that all customers that benefit from the reliability pay their
  fair share and are attributed with the environmental impacts of those resources; and
- The obligation of such procurement must be consistent with the ability of the chosen
  centralized entity to reasonably perform, including adherence to established bidding
  protocols to ensure that centrally procured resources operate for the benefit of all
  customers.

These elements are covered in more detail in Section II.B below.

A. **Multi-Year RA Requirement: Load Migration Challenges**

In the Track 1 decision, the Commission (1) ordered the parties to propose a multi-year
local RA requirement with a three-to-five year duration\(^\text{10}\) and (2) found that a 100% local
requirement for the first year and a 95% requirement for the second year is appropriate, and
requested that the parties propose a reasonable amount of local RA procurement for year three
and beyond, if a longer program is proposed.\(^\text{11}\)

\(^{10}\) D.18-06-030 at 54 (OP 10).

\(^{11}\) *Id.* at 30. It should be noted that, in general, higher requirements place a greater need for either
forward RA forecasting participation, a limitation on load migration consistent with the forward
procurement obligation, or the use of a central procurement entity that can effectively address load
migration with durable and equitable cost allocation.
The duration and minimum procurement requirements of a multi-year RA requirement are inextricably linked to the ability to allow for expected amounts of load migration. Simply put, the longer the duration and the higher the minimum quantities in each year, the larger the issue of load migration becomes. In the Track 1 decision, the Commission adopted a requirement that community choice aggregators (“CCAs”) participate in the annual load forecasting process and take on RA requirements consistent with their expected load service prior to beginning to serve load. This requirement recognizes the importance of having each LSE obtain sufficient resources to fulfill their own RA needs given that procurement for RA must occur, at present, a year in advance for 90% of their System and Flex requirements and for 100% of their Local requirements.

Consideration of a multiple year local RA requirement could potentially push this requirement to having CCAs and Direct Access (“DA”) providers participating in the load forecasting process multiple years prior to their serving of load to address the same concern. There are, however, multiple ways to address this issue as described below.

1. **Requiring Multi Year Forward Participation in RA Forecasting Process**

   **Prior to Load Service**

   Assuming the forward requirements are set at sufficiently high targets, for this option, a retail provider would need to participate in the load forecasting process for each of the forward requirement years prior to serving load. For example, for a five-year requirement, an entity participating in the 2029 forecast for years 2030 through 2034 would be able to begin serving load in 2034 since forward procurement by other LSEs accounting for the load of the customers anticipated to migrate would have been performed for 2028 and prior years resulting in RA resources being procured to meet a forward-year obligation from an LSE that ultimately

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12 Id. at 18.
13 As currently discussed in the Track 1 decision, the minimum Local procurement requirements are 100% in year one and 95% in year two. D.18-06-030 at 30. This example assumes that the procurement in the following years remains at a similarly high minimum procurement level.
will not serve that load. This forward participation process prior to serving load, while lengthy, is a fair and equitable way to ensure that the LSE ultimately responsible for serving the load is responsible for the procurement and associated cost and that system reliability is maintained in the process.

If the process of participating in load forecasting for RA purposes multiple years in advance is seen as inhibiting retail choice, then it is possible to consider reducing the length of forward procurement requirements. Doing so would not by itself allow a new LSE to serve load within a single RA forecasting process year, but would reduce the length of time after participating in the load forecasting process. Using the example above and shortening the forward requirement from five to three years, the entity participating in the 2029 forecast for years 2030 through 2032 would be able to begin serving load in 2032 as the entity would have then been required to procure local RA for 2032 consistent with the expected load served by that LSE.

2. **Capping Load Migration Based on Forward Minimum Procurement Requirements**

As a general matter, the higher the forward requirements in each year of a multi-year forward obligation, the higher the potential for load migration changes to impact procurement responsibility and equitable cost allocation. A potential solution to this is for the Commission to establish load migration limitations consistent with the minimum requirements established in this proceeding. For example, if a three-year requirement was established at 100% in year one, 95% in year two, and 70% in year three, the Commission could limit load migration from bundled service to retail choice in an amount consistent with these requirements. That is, for a 10,000 megawatt (“MW”) load LSE, there could be no load migration in year one, 500 MW of load migration in year two, and 3,000 MW of load migration in year three. Such a process would allow for an orderly transition to retail choice while allowing for adjustments in a portfolio that would not place undue burdens on an entity serving bundled load to procure for load that it may not serve in the future. Such a method would also place less stress on
mechanisms such as the Power Charge Indifference Adjustment (“PCIA”) to effectively allocate reliability costs upon load migration. The trade-off of such a proposal is that the farther away from a 100% requirement, the less certainty there is for generators, placing pressure on the risk of retirement and potential backstop procurement mechanisms.

3. Implementing a Central Buyer Structure

Implementation of a central buyer structure mitigates the challenges of load migration and its impacts on procurement responsibility and equitable cost allocation. A properly designed central buyer structure allows for procurement and operation of needed reliability resources with costs following the customers, regardless of which LSE is serving them. The central buyer concept is presented in more detail below.

B. Central Buyer Structures

In the Track 1 decision, the Commission ordered the parties to propose central buyer structures for multi-year local RA procurement with a single central buyer or a single central buyer per Transmission Access Charge (“TAC”) area, while addressing the ability to procure all available resource attributes, not just Local RA, and also balance economic procurement criteria with other essential state policies.¹⁴

The Energy Division¹⁵ and PG&E¹⁶ put forth proposals to procure Local RA needs through a centralized entity. The proposals point to the benefits of a single entity’s ability to procure the sub-area resource needs more effectively than depending upon a potentially large number of differently sized and positioned LSEs procuring the necessary set of (potentially limited) resources. These proposals have led to consideration of refinements to the Local RA program, including topics such as the disaggregation of local areas into their sub-areas and revisions to RA penalty provisions and the waiver process.

¹⁴ D.18-06-030 at 54 (OP 11), 32-33.
¹⁵ The Energy Division proposed two frameworks, where Framework 1 consists of a Central Buyer model, and Framework 2 consists of a model without a central buyer. Id. at 30.
¹⁶ Track 1 Proposals of PG&E, dated February 16, 2018, at 7-8.
These issues can be largely mitigated, if not made completely moot, by centralized procurement if the centralized procurement is the only Local RA procurement performed (i.e., when the central buyer procures full Local RA requirements on behalf of all LSEs). However, electing to have a single central buyer procure all Local RA requirements will give rise to other issues that must be resolved. A key issue that would need to be addressed is how LSEs’ existing Local RA procurement should be treated. If a solution to this issue is a buyout process, to ensure equitable cost treatment, such a buyout process may need to determine an appropriate price for the buyout, which can be challenging given that the market condition and procurement decisions may be quite different since the resources were procured, and the market value of Local RA is dependent upon the location of each resource and other attributes that the resources can provide. This issue must be addressed thoughtfully and equitably to avoid after-the-fact cost shifting between LSEs and going forward cost shifts between bundled service and departing customers. However, the issue of existing procurement can be addressed by implementing a central buyer for residual needs only (i.e., the Local area resource need remaining after a point in time in which all LSEs have been provided an opportunity to show/identify their forward procurement of Local area resources).

If the centralized local procurement is performed as a residual need (i.e., allow LSEs the first chance to procure their prescribed requirement, and any remaining deficiencies are addressed by the centralized entity), then it becomes important to make sure that all LSEs face the same obligations to procure resources within not only the Local area, but the sub-areas as well, and/or to adjust waiver processes as necessary to avoid inappropriate allocations of costs. That is, without a sub-area requirement and without modification to the waiver process, LSEs will have an incentive to sign the least expensive Local area resources without regard to effectiveness at meeting the sub-area needs. To solve this problem, the Commission can either...
specify sub-area requirements and/or allow waivers recognizing that the central entity will
procure the premium sub-area resources and allocate costs to all LSEs.17

It is also possible that the process can begin with a residual central buyer design, which
then can gradually transition to a full central buyer structure. The central buyer on a transitional
or interim basis may not be the same entity that should serve on a longer-term or permanent
basis. SCE recommends that the issues and options surrounding central buyer structures be
addressed in a Track 2 workshop. Other important issues that should be addressed in the
workshop include how to best achieve least-cost procurement for all customers under centralized
procurement, how to count LSEs’ existing procurement in deriving a residual need
(i.e., consideration of effectiveness of procured resources meeting a local or sub-area need and
cost allocation that follows), and what are appropriate procurement rules for the central buyer to
abide by and wholesale market bidding requirements for centrally procured resources.18

Once the central buyer has procured a resource, the efficient dispatch of that resource is
equally important. If the contract type conveys the right to dispatch the resource (e.g., a tolling
agreement), then to ensure desired outcomes, the Commission’s existing Standard of Conduct 4
(referred to as “Least Cost Dispatch”) for IOU resource dispatch should be considered to be
applicable to the dispatch of the resource procured by the central buyer. For resources procured
under a RA contract, the CAISO must offer obligation rules should apply.

Regardless of the actual structure and processes, interim or permanent, cost recovery and
cost allocation are critical elements for any central buyer construct.

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17 This assumes that the central entity allocates costs on a load ratio basis. If costs are allocated on the
basis of procurement within the sub-area, then the use of a central procurement entity would still
require the allocation of Local requirements to LSEs by sub-area.

18 Depending on the type of contract utilized for the central procurement of Local RA resources, the
buyer may have the responsibility to bid such resources into the CAISO’s energy and ancillary
services market. Under such a situation, the central procurement entity would need to have rules
placed upon them to ensure that the resource is appropriately bid into the CAISO markets for the
benefit of all customers, and not be allowed to potentially exercise locational market power.
1. **Cost Recovery and Cost Allocation Are Critical Elements for Any Central Buyer**

Durable cost recovery and allocation by any central procurement entity is critical for two distinct reasons. First, durable cost recovery ensures the central buyer remains financially viable. In turn, this allows contracting and sufficient revenues to secure and operate resources needed for reliability. Proper cost allocation ensures that all parties benefiting from reliability pay their equitable share without cost-shifting. Second, it provides readily available cures for the trade-offs listed in Section 2.A above (e.g., the trade-off between very high minimum procurement requirements and their impact on ease of load migration). Finally, the type of procurement arrangement made will have impacts on the method for allocating costs and benefits and will need to be considered in developing the acceptable procurement arrangements that a central buyer may enter into.

a) **Security of the Central Procurement Entity via Durable Cost Recovery and Allocation**

The primary options proposed for the centralized procurement entity include the CAISO, the IOUs, or another entity that would have to be created or selected. Regardless of the entity chosen, the ability to recover costs from and allocate costs to those that cause the cost to be incurred is a necessary step to ensure that the central entity remains viable and that all customers are treated equitably. In the case of the IOUs performing central procurement for the benefit of all customers, historically, such procurement has been performed under the Cost Allocation Mechanism (“CAM”), primarily to bring new resources online to satisfy the reliability needs of all customers. In this case, the procurement is not necessarily for new resource needs, but is more focused on procurement of existing resources in local areas needed for grid reliability. Regardless, CAM provides for the recovery and allocation of costs and distribution of benefits. Public Utilities Code §365.1(c)(2)(A-B) and prior Commission
decisions\textsuperscript{10} provide for an equitable allocation of costs of procurement by IOUs for reliability purposes. If, for the interim process, the central buyer is the IOU, the CAM process is well established to provide for appropriate cost allocation of the resources that would be procured for local reliability. If a non-IOU is the central buyer, then a similar cost allocation mechanism is necessary to ensure that the cost of such procurement is not disproportionately shared among customers. To ensure that the no entity is unduly burdened, each LSE (or its customers) should be allocated costs and receive benefits consistent with their contribution to the need for the centralized procurement. Even if the central entity is not the IOU, the ability to fully recover and allocate costs such that no customer group is unfairly burdened is a critical element to ensure that the adopted construct is viable and equitable.

Within the context of cost allocation, consideration of the type of contracts that a central buyer will procure is necessary. At the two extremes are: the procurement of an RA capacity only product versus a full tolling or dispatchable arrangement. Depending on the type of contract structure chosen, the calculation of the costs to be allocated will differ. Fundamentally, both contract types will allocate the full cost of the contract to the LSEs (or their customers) that benefit from the resource. In the case of an RA capacity only contract, the cost of the contract is the only consideration. In the case of a tolling or dispatchable agreement, the resource will be under the dispatch of the buyer with additional costs for energy operation as well as offsetting revenues for CAISO market awards and other potential transactions. In such a case, similar to CAM, the market revenues net of operating costs should be credited against the contract price to ensure that the final allocation of costs is net of the market rents received for the resource. If a different form of agreement is reached than those described above, the costs, revenues and benefits (e.g., additional compliance attributes such as RPS or GHG) from such an

\textsuperscript{10} D.04-12-048, D.06-07-026, D.07-09-044, D.08-09-012, and D.13-02-015 all address the cost allocation mechanism.
arrangement will need to be considered to ensure that the costs and benefits are equitably allocated to all benefiting customers.

b) Cost Allocation Can Address Many of the Requirement Driven Trade-Offs

As noted in Section 2.A, the manner in which requirements are applied (i.e., LSE-specific or central procurement performed on a residual basis) has impacts on load migration, sufficiency of procurement, and the ability to procure the necessary resources to maintain reliable operations. However, the allocation of cost responsibility is greatly simplified if the central buyer is required to procure all needed reliability resources on a multi-year forward basis, as the allocation of costs will be performed based on actual load share. Such a program would simply require a transparent process to determine multi-year forward procurement requirements and identify local constraints and environmental policy objectives which will shape the Local RA procurement.

Similarly, the duration of requirements and the minimum procurement requirements are made moot as the central entity will allocate costs as load service is realized rather than having procurement requirements switch between entities due to load migration. In such a case, the issues are reduced to the length of term necessary to sufficiently address reliability needs tempered by the ability to accurately forecast load and local transmission constraints into the future. For example, it could prove costly to procure 100% of forecast Local area requirements five years forward if unpredicted changes in consumption or changes to the transmission grid obviated the original need in subsequent years. This issue can be addressed by “layering in” procurement annually, such that 100% procurement does not occur sooner than two years forward, to mitigate the risk of such occurrence. Regardless, the risk of load migration is removed from both the duration and minimum procurement quantities through centralized procurement with cost allocation on a realized (i.e., metered) load share basis.

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20 If the central buyer only procures the residual local need, elements such as the disaggregation of local sub-areas with individual LSE procurement obligations would continue to be necessary to ensure that all LSEs are appropriately allocated central procurement costs.
c) **Environmental Attribution of Centrally Procured Resources**

As LSEs seek to comply with or exceed state mandates for renewable resources, it is important that resources procured in order to meet reliability needs are allocated not only for their net costs, but also for the environmental attributes they are associated with. As discussed above, some of the existing resources procured by a central entity for local reliability needs are likely to have an emissions profile if they are procured as tolling or fully dispatchable contracts. Such energy profiles then must be accurately depicted in the various portfolio content and emissions reports submitted by LSEs to ensure that the environmental profile of the energy dispatch associated with these reliability resources is reflected appropriately by all LSEs. For example, the Power Source Disclosure / Power Content Label process will need to be revised to ensure that the energy output from tolling or fully dispatchable resources procured by a central procurement entity are attributed to all customers that benefit from the reliability resource. In addition, each LSE reports GHG emissions associated with the load that they have served. In the case of centrally procured tolling or dispatchable reliability resources, the emissions associated with these facilities should be allocated on the same basis as the cost allocation to all LSEs. Finally, Assembly Bill 1110 requires retail providers to report to the California Energy Commission (“CEC”) energy procured from resources by generator type or from unspecified resources such as CAISO market purchases. This reporting should likewise reflect the attribution of energy dispatched from Local RA resources procured using either a tolling or dispatchable contract structure in order to meet reliability needs to all retail providers (i.e., LSE) that receive the reliability benefit. Failing to make such adjustments will inappropriately attribute the characteristics of a given resource solely to the designated central buyer. In an environment with retail choice, the accuracy of not only price data but also of the characteristics of the product being received is of similar importance.

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21 The costs of emissions compliance, however, should remain with the designated central buyer and be reflected in the net cost calculation for allocation to all customers to reduce administrative complexity.
d) **Burden on Central Buyer**

Multiple central buyer models have been put forth. Key among them is the number of entities and the scope of their procurement responsibility. A single central buyer for all local resources for the entire state is a significant undertaking that reduces the number of candidate entities, including probably the IOUs. The ability of an IOU to collect costs from customers it does not serve within its TAC area may be challenged. Additionally, there are considerable costs associated with debt equivalence of large amounts of state-wide procurement. If a single IOU were to procure for all Local area reliability needs for the state, the impact on the balance sheet of the one utility could be very large and lead to significant debt equivalence issues. Debt equivalence is addressed in each IOU’s Cost of Capital proceeding and the costs of such debt equivalence are paid for by the customers of the IOU performing the procurement. Procuring for areas in which the IOU does not have customers would result in the incurrence of cost that the IOU presently cannot allocate to those that caused the cost to be incurred. As such, in order to mitigate this impact, a single IOU should only be required to procure for Local area reliability within its own TAC area. Additionally, this allows the IOU to consider trade-offs between resource procurement and other mitigations, such as transmission upgrades and/or customer programs to reduce/modify demand.

e) **Centralized Capacity Market**

A number of commenters have suggested that the Commission consider a centralized capacity market to address the needs of RA procurement. While SCE is not proposing such a mechanism here, it is worth noting that a centralized capacity market is an efficient means to procuring reliability resources for the benefit of all customers and can effectively address a large number of the issues raised in this proceeding and within the Commission’s “California Customer Choice Project” or “Green Book” initiative. In particular, the ability to obtain Local sub-area resources as well as address significant quantities of load migration are inherently simpler with a centralized capacity market. In addition, a centralized capacity market provides the appropriate signals and incentives to generators to allow for
rational decisions about resource investment or retirement to occur. SCE believes that the ability to continue to support carbon-free resource development, and even have renewable and energy storage resources serve as reliability resources, can be compatible with a centralized capacity market structure.

f) **Testimony and White Paper of Dr. Susan Tierney**

SCE, PG&E and SDG&E have co-funded and contributed to the development of the white paper served in this proceeding by Dr. Susan Tierney of Analysis Group. SCE along with PG&E and SDG&E have engaged in discussions of the relevant policies addressed by Dr. Tierney. SCE largely agrees with the issues identified by Dr. Tierney’s white paper. SCE believes that the white paper is beneficial to this proceeding in that it identifies the inter-play between reliability, policy and market issues, and the trade-offs of the variety of mechanisms that could be employed to address those issues.

2. **Central Residual Procurement Proposal**

To address the issues identified in this testimony, SCE recommends a mechanism that attempts to resolve many of the trade-offs in an effective manner. Given that the Commission’s “California Customer Choice Project”/“Green Book” process is intended to recommend comprehensive policy recommendations around a number of these issues, SCE recommends that any central buyer construct adopted in this proceeding be considered an interim mechanism in recognition of the need for further evolution as California’s energy policies are prioritized and implemented. As a result, the procurement term for multi-year forward Local RA procurement should be limited to three years to avoid potential procurement policy changes having an adverse impact on forward commitments required to be made by market participants and/or a central buyer. However, given the need to ensure certainty of resources required for Local area reliability, SCE supports requiring a central buyer to procure on a residual basis up to

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22 In addition as noted in the beginning of Section II, a three-year term will encompass the schedule for OTC compliance for CAISO interconnected resources.
100% of forecast requirements for the entire three-year period. Concerns about over-
procurement in Years 2 and 3 are largely addressed by the ability to use any excess procurement
(of which there would likely be little given the relatively static nature of the physical grid and
load demands) to also meet all LSEs’ System and/or Flexible RA requirements. Because all
procurement performed by the central buyer is being done for the benefit of all customers, any
forward Local RA procurement that is subsequently determined to not be needed for Local area
need will still offset the associated System and Flexible RA requirements of all LSEs, and is
therefore not stranded.

The residual central local procurement would work as follows:

First, no LSE would have a specific Local RA requirement. Instead, LSEs would
continue to procure RA to meet their System and Flexible requirements on a year-ahead and
month-ahead basis. In doing so, LSEs will have the opportunity to procure the least cost
resources to meet their RA needs. If the least cost resource is a Local area resource, that Local
area resource will reduce the quantity of Local RA that the central procurement entity needs to
procure to meet the residual need provided the LSE procured the resource at least three years in
advance of the RA compliance year.

Since the System and Flexible RA showings are performed on an annual basis
(with a month-ahead showing for residual System RA), any LSE showing a Local area resource
will need to indicate the number of years for which they have the resource under contract and
will need to voluntarily agree to show the resource in each subsequent annual and monthly
showing for the period of time that the resource is under contract. Doing so will enable the
central buyer to not procure that resource and will reduce the need to procure other Local area
resources. If the resource is not under contract for the full three-year forward period, then the
central buyer will need to procure resources for the years not under contract.

By following this methodology, currently signed contracts will not lose their
System and/or Flexible RA value, and no complicated rules will need to be established for the
central buyer to procure the resource from the LSE that has it under contract. In addition, LSEs
will have an opportunity to continue to procure the least cost resources to meet their System and
Flexible RA requirements, and if those resources meet a Local area need, that will reduce the
need for central procurement which will reduce the costs allocated to LSEs. This process will
also eliminate the need to allocate more detailed Local sub-area requirements to individual LSEs
as well as address load migration concerns as entities will procure voluntarily for Local area
resources, and likely only to the extent that it is the least cost resource to meet their System
and/or Flexible RA requirements.

Once the annual showing has been made, the CAISO and the central buyer will
work together to identify the resources that need to be residually procured to meet the Local area
reliability needs. The central buyer will then make efforts to negotiate a contract with those
resources, and if procured, allocate net costs to all LSEs on a realized load ratio share in each
operational month (or directly to customers through a non-bypassable charge if the procurement
is performed by an IOU through the CAM).

Provided that the conditions of Section II.B.1 are met (i.e., durable cost recovery,
equitable cost allocation, limited to TAC-area procurement, and environmental attribution of
centrally procured Local area reliability resources to all LSEs), SCE does not object to
performing the procurement described in Section II.B.2 as the IOU of its TAC on an interim
basis while a more comprehensive solution is developed through the Commission’s “California
Customer Choice Project”/“Green Book” process, and/or other CPUC processes, or through
legislative activity.
III.

EFFECTIVE LOAD CARRYING CAPACITY

A. Treatment of Behind-the-Meter Solar

The development of behind-the-meter (“BTM”) solar is a significant portion of California’s solar generation portfolio. BTM solar has the same impact on RA as the impact of central station solar, and increasing implementation of BTM solar contributes to the shift of the net load peak in the same way as central station solar. When BTM solar is not considered appropriately within the effective load carrying capacity (“ELCC”) calculation consistent with other solar resources (e.g., Renewable Portfolio Standard (“RPS”) or in-front-of-the-meter solar), the ELCC values for solar resources are biased upward. This bias is further evidenced by the inconsistency in how BTM solar is treated in the Commission’s RA process and the CEC load forecasting process in determining ELCC values. The Commission recognized these implications. However, the Commission decided to delay addressing these implications to avoid abrupt and significant changes in RA values, particularly of solar resources, as described in D.17-06-027.

Energy Division notes that moving from the current exceedance method to ELCC results in a “…notable decrease in RA capacity credit given to solar generators…,” and accordingly Energy Division’s second proposal seeks to ease that transition. (Energy Division February 24, 2017, Proposal at 16.) Because the relatively low ELCC value for solar can be partially ascribed to the addition of behind-the-meter solar to the grid (even though behind-the-meter solar does not receive RA credit), Energy Division’s second proposal is designed to back out the effect of behind-the-meter solar from the ELCC calculation. (Id.)

PG&E recommends going to an ELCC approach, but with a two year transition period in order to soften the change, and to allow LSE’s to adjust to “the anticipated decrease in RA capacity from wind and solar resources during the peak months.” (PG&E February 24, 2017, Proposal at 4.)

We agree with PG&E and other parties that moving to an ELCC approach such as Calpine’s proposal or Energy Division’s first proposal could result in an overly abrupt and significant change in RA values, particularly of solar resources, and would be unnecessarily disruptive. Both Energy Division’s second proposal and PG&E’s approach address this issue, but we believe that Energy Division’s second proposal, which seeks to remove the influence of behind-the-meter solar, has a stronger analytical basis, and is less of a stopgap measure than PG&E’s proposal. Accordingly, we adopt Energy Division’s second proposal, and the numbers resulting from that proposal are the approved values for 2018, as set forth in Appendix A. Going forward, the process used to calculate monthly ELCC values will be subject to changes, improvements and refinements as needed.24

Clearly, the Commission believed that the 2018 compliance year is a part of the two-year transition period to fully adopt the proposals that would address this issue. Since the Track 1 decision did not adopt such a proposal, the two-year transition period has been met. Any further delay will result in continued incorrect investment signals, plus the potential for a negative impact on reliability.25 Given the broad support by stakeholders on this issue, the Commission should act now to adopt a proposal that will address the issue.

As described in D.17-06-027, two proposals gained significant support among the parties, Energy Division’s proposal and a proposal from Calpine.26 While SCE does not have a preference on which of the two proposals should be used, the Commission should address and resolve this issue in Track 2 of this proceeding so that ELCC estimates accurately reflect the impact of BTM solar. Therefore, SCE recommends reviewing the proposals from Energy Division and Calpine in Track 2 and adopting one of them to address the disparate treatment of solar resources in demonstrating resource adequacy.

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24 D.17-06-027 at 20-21.
25 The lack of recognition of the impact of BTM solar on the ELCC value for solar along with a need to re-evaluate forecasting of load have significantly contributed to speculation that the planning reserve margin for RA should increase and/or a more conservative load forecast should be utilized. Prior to taking such actions, the Commission should ensure that resources are accounted for appropriately to avoid unnecessary and potentially inaccurate responses such as an increased planning reserve margin and/or a more conservative load forecast basis (i.e., 1 in 10 versus 1 in 2 as currently adopted).
26 See D.17-06-027 at 20. Energy Division updated its original proposal to ease potential significant lower RA credit to solar generators. D.17-06-027 adopted Energy Division’s second proposal, which is designed to back out the effect of BTM solar from the ELCC calculation, in approving the ELCC values for 2018. The decision did not conclude which proposal/model will be used for future ELCC determinations.
B. **Locational and Technology Difference**

Currently, the ELCC values for solar and wind are calculated on an aggregate level without any distinction for location or technology. That is, there is a single ELCC value for all solar resources and similarly a single ELCC value for all wind resources. Such an approach does not provide an efficient investment signal, nor does it recognize differences in the contribution of those resources to reliability. As an example, a wind plant in an area with low wind production has the same ELCC value as a wind resource in an area with high wind production; and similarly, a fixed tilt solar resource has the same ELCC value as a tracking solar resource which has the same ELCC value as solar thermal even though they could have significantly different production during hours that have the largest reliability impacts. It is important to align the RA value a resource receives with the actual reliability value the resource provides to the system.

1. **To Ease Integration, Locational Differences Can Be Addressed First,**

Followed by Technological Differences

SCE proposes that ELCC values be differentiated based on location and technology and that modeling parties provide details on the level of distinction that is possible within their models. Rather than delay addressing the issue, a phased approach should be considered, which can better balance the need and any potential modeling complexity. In particular, while recognizing that in general, a more granular assessment (*i.e.*, the consideration of locational and technology distinctions) will provide a better indication of the value of the resource, if it is too resource-intensive for the Commission to address locational and technological differences simultaneously at this stage, locational differences should be addressed before technological differences. Further, to simplify, the ELCC methodology can consider several large zones that may be needed for LSEs and resources alike to accurately reflect the value of wind and solar resources for grid reliability.
2. **Potential Solutions Should Be Explored to Expedite Integrating Technological Differences into the ELCC Methodology**

Presumably, it may take more effort to integrate individual resources’ technological differences into the ELCC methodology compared to the integration of locational differences. To expedite this process, potential solutions should be explored in Track 2. For instance, one approach can be to categorize all solar and wind resources into different technology classes\(^ {27}\) and develop a simplified yet realistic formula that derives an ELCC value for each technology class. Such an approach can be built upon a regression analysis of historical performance of the output of the resources in each class. To ensure acceptable accuracy, any formula that tries to simplify the modeling would be benchmarked against more rigorous ELCC analysis. Such an approach can serve as an interim solution before a full evaluation based on the ELCC model is feasible.

SCE proposes the development and evaluation of ELCC values to assess the differences in technology type and location. If such granular assessment is feasible and is shown to provide a better assessment of the resources’ RA contribution, Track 2 should adopt both locational and technology categories to further refine the RA value provided by renewable resources. Such a distinction will help provide the correct incentives in the procurement of renewable resources that would recognize not only the RPS and GHG value that the resources bring, but also their relative contribution to grid reliability.

C. **Marginal ELCC**

ELCC is highly dependent on the conditions on the grid at a given point in time. Over a time horizon, the level of and relative ratio of wind to solar as well as anticipated load conditions can change the calculated ELCC value. This changing value can potentially lead to concerns with regard to procurement that must be addressed.

\(^{27}\) E.g., wind above 70 meters, wind below 70 meters, solar thermal, solar photovoltaic with fixed tilt and solar photovoltaic with tracking. Other categorization may also be possible.
1. **Issues Resulting from the Changing Value of ELCC**

There are two issues that result from the changing value of ELCC: (1) the consistent treatment of ELCC within different proceedings at the Commission; and (2) the potential to create contractual risk associated with a varying ELCC value over the life of a contract.

a) **Consistent Treatment of ELCC**

The first issue resulting from the changing value of ELCC is the consistent treatment of ELCC within different proceedings at the Commission. For example, the RPS and Integrated Resource Planning (“IRP”) proceedings will utilize ELCC to evaluate renewable resources for procurement and planning purposes. In addition, the RA OIR uses ELCC to determine the Qualifying Capacity (“QC”) of renewable resources that are counted towards meeting a LSE’s System and Local RA requirements, subject to deliverability constraints. It is imperative that these processes utilize the same methodology to avoid providing conflicting procurement/planning guidance. In addition, conflicting rules in this area could create an unlevel competitive environment if the incentives among CPUC jurisdictional entities and non-CPUC jurisdictional entities vary. Take for example a situation in which the CPUC determines that for RPS purposes CPUC jurisdictional entities\(^{28}\) are to evaluate renewable resources based upon a marginal ELCC methodology. Non-CPUC jurisdictional entities would not be obligated to value such resources for RPS procurement purposes in the same manner. In addition, suppose that the RA program adopted an average ELCC approach. Since both the CPUC and the CAISO develop the RA Net QC (“NQC”) for all resources, the use of average ELCC will apply to all LSEs. In this case, if the average ELCC is above the marginal ELCC value, a non-CPUC jurisdictional entity would have a clear incentive to value renewable RA resources at the average ELCC value as this is what will ultimately count toward meeting their RA obligation. CPUC jurisdictional

\(^{28}\) It is not clear at this point whether the CPUC could and would assert jurisdiction over CCA and DA providers with respect to how they evaluate and procure RPS resources. Even if the CPUC did assert such jurisdiction, Municipalities would still be subject to this disparate treatment.
entities on the other hand would be obligated to value the renewable resources in accordance
with the RPS standard of marginal ELCC and would have a tendency to undervalue the resource
compared to the resource’s actual RA value. Further, this issue could impact the relative value
of wind and solar resources leading to the same undesirable outcome.

b) **Risk Associated with a Varying ELCC Value Over the Life of a Contract**

The second issue resulting from the changing value of ELCC is the
potential to create contractual risk associated with a varying ELCC value over the life of the
contract. If an average ELCC value is chosen, the amount of RA capacity available from the
resource is only known for the compliance year. With many RPS contracts having delivery
terms of up to 20 years, this creates uncertainty in the value of the RA from that contract over
time. This is an issue in SCE’s current Moorpark Sub-Area Local Capacity Requirements/Goleta
Resiliency Request for Proposals (“LCR RFP”). In the LCR RFP, SCE is seeking resources to
meet LCR need but in doing so the resources must also qualify for RA. In the RFP incremental
Preferred Resources, including renewable resources, are preferred to meet the local needs. As
such, procurement duration is likely to be longer including up to twenty years. Attempting to
place value on an RA resource 20 years in the future with great uncertainty to its value if an
average ELCC methodology is used has many consequences in the procurement process. Where
actual values are higher or lower, it is possible that the selection process will result in the
selection of the wrong technology and will not provide the best value to customers. If a marginal
ELCC is utilized, the RA value of the resource over the 20-year life of the contract will not
change and the additional certainty in the procurement process will enable the LSE to select the
product of the highest value for the given costs.

One way to solve this issue is to adopt a marginal ELCC value that would
then establish the RA value for the resource that would be retained for the life of the resource.
Not only does this solve the contractual uncertainty, but it also places the correct incentives
regarding which type of renewable resource to build at any point in time. That is, if the build out
of *solar* resources has pushed the marginal RA value very low, it is likely then that the marginal
value of wind will be higher, and vice versa. This will then provide the appropriate signal to procure and develop a balanced portfolio of renewable resources. Even if the RA value of both wind and solar were to become very low, LSEs would still need to meet their RPS requirements and would still procure renewable resources even if they did not count significantly towards meeting RA capacity requirements. Therefore, a marginal ELCC value will not reduce the amount of renewable resources procured necessarily but will provide the correct signals to procure one type of renewable resource over another in support of system reliability.

2. Changes to a Facility Over Time and the Impact on ELCC Value

In workshops prior to D.17-06-027, parties identified a concern that SCE had not addressed in its proposed marginal ELCC treatment. Those questions surrounded changes to a facility over time and the potential to game the ELCC value by shutting down a resource and then introducing the same resource if the marginal ELCC value is higher at that time than it was when it first began operation. In order to address these concerns, SCE proposes the following:

For additional plant capacity under the same interconnection and resource ID, the new facilities would receive the current marginal ELCC. For example, suppose a solar developer built a 50 MW facility at a time when the marginal ELCC was 30%. This would provide a QC value of 15 MW. Suppose further, the same facility later added an additional 10 MW of capacity at a point where the marginal ELCC had fallen to 20%. In this case, the resource should receive an additional 2 MW of QC for a total of 17 MW of RA counting capacity. Each successive addition of capacity would be assessed for RA value at the time that the additional capacity reaches commercial operation.

For plant retirements, the simplest method would have the total RA QC of the facility reduced pro-rata to the reduction in capacity retired. If we continue with our example above, which after the addition is a 60 MW installed capacity facility with RA QC of 17 MW, the retirement of each MW of installed capacity would reduce the QC quantity by 0.28 MW (1/60 * 17 = 0.28).
Parties had expressed concern that a facility installed under a given marginal ELCC could “shut down” and re-open under a higher ELCC to obtain the higher value. This can be addressed in several ways. First, this should be addressed by incentives in the interconnection process. That is, the facility should not be allowed to simulate a shut down. Rather, the facility should have to surrender its interconnection, and if the facility is to re-open with the same ELCC technology it would need to re-enter the interconnection queue and address any system upgrades necessary to provide full deliverability. In addition, the resource owner should have to notify the CAISO of its retirement and follow all procedures within the CAISO tariff to shut-down the resource as well as bring the “new” resource back on line. Finally, Energy Division should be able to evaluate whether the facility is truly new capacity or is a restart of an old facility and assign ELCC consistent with its value. These checks and balances would be effective at prohibiting the gaming that parties have identified.

Similarly, parties in the workshops asked what would happen if a facility were to perform upgrades that while utilizing the same base technology improved the RA value provided. An example, is a fixed solar facility that converted to tracking solar. As discussed above, SCE recommends that the Commission develop more granular technology based and location based ELCC values. If this is done, then the example in this case would change the technology from fixed to tracking and would receive the ELCC associated with the solar tracking technology when the facility reaches commercial operation with the new technology. SCE notes that if there is no technology differentiation, then the upgrade would not change the ELCC value; thus mooting the issue of the original ELCC value when the plant was first placed into operation and the ELCC when the upgrade went into place since the technological ELCC only recognizes the general category of solar.

3. **Green Allocation Mechanism and Marginal ELCC**

Finally, under the Green Allocation Mechanism (“GAM”), the adoption of marginal ELCC would not create any disadvantage to either bundled or departing customers, as the RA credits at the marginal ELCC associated with existing renewable resources that were
procured would be allocated to all customers on a pro rata basis. After the contract for a
resource expires, the resource would carry its ELCC value with it and be available to all LSEs
for procurement thereafter. Thus, if the ELCC value of a resource is declining over time, it will
not be the case that the retail choice customer only has available to it the low ELCC value
resources as the GAM will transfer a pro-rata share of the previously ELCC-valued resources to
accompany the migrating load.

In D.17-06-027, the Commission adopted an ELCC calculation that is neither an
average nor a marginal process. Rather it was a value calculated at a point in time. Therefore, if
this calculation methodology were to be used for future years, since the resulting ELCC values
will not be truly marginal, it will either overstate or understate the RA contribution of future
deployment of wind and solar resources. A decision needs to be made on which methodology
should be chosen to avoid this outcome. While the Track 1 decision noted SCE’s proposal and
its support from multiple parties, it did not adopt the proposal but directed further evaluation of
the proposal and surrounding issues.

As with the issues of the treatment of BTM solar and the consideration of
locational and technological values above, adopting a marginal ELCC methodology will provide
an appropriate signal for investment and contract valuation. For all of the reasons discussed
above, SCE continues to propose that the Commission adopt a marginal ELCC methodology. In
addition, SCE recommends that the Commission adopt a consistent ELCC methodology in the
RA OIR and any other proceeding utilizing ELCC (e.g., RPS and IRP) so that the planning
processes and RA processes place the same capacity value on the resource.
IV.

**NQC COUNTING FOR VARIOUS RESOURCES**

The Track 1 decision removed the prohibition on combined storage and demand response (“DR”) resources being eligible for RA, and going forward in the RA OIR, parties should consider combined storage and DR resources to be eligible for System, Local and Flexible RA. This issue raises the question of what is the proper System and Local NQC and Effective Flexible Capacity (“EFC”) RA accounting for resources combining more than one technology type at a single location and presented to the market as a single resource. The following section addresses the three most likely combinations of such resources and proposes rules for the accounting of NQC and EFC for each. The combinations are the pairing of a battery with a dispatchable generating resource, a demand response resource, and a non-dispatchable renewable resource.

**A. Pairing a Battery with a Dispatchable Generating Resource**

This case is likely the easiest to resolve. With the battery and the generating resource fully dispatchable, the NQC and EFC values are the sum of the two parts subject to the interconnection establishing deliverability. For example, a 50 MW peaker with a 20 minute start time, a 10 MW/Min ramp rate and a 10 MW battery with a duration of four hours, could meet an NQC of 60 MW to provide energy to meet Local and/or System RA needs. In addition, this resource could ramp from negative 10 MW to positive 60 MW in a manner to meet the three hour ramping need and as such could have an EFC of 70 MW.

For dispatchable resources, as long as each component can meet the need and the interconnection is sized to allow for deliverability, the NQC and EFC should be determined by the sum of their parts. This is logical since if the resources in the example above were separate resources in separate locations, the NQC of the peaker would be 50 MW while the NQC of the battery would be 10 MW, thus providing between the two resources a total of 60 MW to the grid.

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29 D.18-06-030 at 44, 53 (Conclusion of Law 18).
for NQC. Similarly, the EFC for the peaker would be 50 MW and the EFC for the battery would be 20 MW as separate facilities which would then provide the grid with 70 MW of EFC.

**B. Pairing a Battery with a Non-Dispatchable Renewable Resource**

This case must be broken into two options. In the first, the battery is fully dispatchable by the CAISO through the market. In the second, the battery acts at the discretion of the resource owner presumably to move energy output from periods of low energy prices to periods of higher energy prices.

In the case where the battery is fully dispatchable, the proper NQC is the sum of the ELCC for the renewable resource and the Pmax of the battery under a four-hour discharge. Similar to the assessment where both resources are dispatchable, the interconnection would need to be sized to ensure full deliverability of the battery and the renewable resource at Pmax. This is to ensure that in periods where the renewable resource is scheduling in accordance with RA requirements at its forecast and the forecast is for full output, the interconnection must be sized to allow the incremental capacity from the battery to be delivered at the same time. For EFC, the value should be based upon the flexible capability of the battery.

In the case where the battery is non-dispatchable, an ELCC methodology for renewable resources with a battery should be developed to assess the NQC value for such a facility. Such a method would account for the variable nature of the fuel supply for the renewable resource and the variable nature of the battery output that is not dispatched by the CAISO. In this case, since the resource is not dispatchable it is not bidding into the CAISO but rather self-scheduling its output consistent with its forecast for renewable production plus the net output of the battery.

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30 Assuming each resource is interconnected for full deliverability.

31 This is based on the premise that the renewable resource be non-dispatchable. If the renewable resource has agreed to curtailment in order to provide flexible capacity and qualifies for Flex RA, this amount can then be combined with the flexible capacity of the dispatchable battery. EFC would then be the combined Flex capacity of the two facilities to the extent they are dispatchable to provide ramping service.
Since this resource is not bidding such that it can be dispatched by the CAISO to meet ramping needs, the resource should not be eligible for an EFC value.

C. **Pairing a Battery with Demand Response**

This case is conceptually similar to pairing a battery with a dispatchable generator, and should be treated similarly – allowing for the battery and traditional DR to work in conjunction as long as they are not exporting to the grid. Under the current CAISO rules, interconnection and deliverability studies are not performed for DR resources – as load reduction (down to zero) is by definition deliverable. However, if the load behind the customer meter does not consume all the energy discharged by the storage device, then this combined resource could end up exporting to the grid, which is not allowed under the CAISO tariff. DR resources (including DR paired with storage), registered as Reliability Demand Response Resources (“RDRR”) or Proxy Demand Resources (“PDR”), are not permitted to export energy – they may only provide load reduction. A storage resource that wants to export could qualify for RA, but the storage device would need to interconnect under the Wholesale Distribution Access Tariff (“WDAT”) and have market-based rate authority. Furthermore, it is currently not possible under the CAISO tariff for a DR resource paired with a storage resource (\textit{i.e.}, behind the same customer meter) to be treated as more than one type of RA resource, such as an exporting WDAT and a PDR or RDRR resource – so a WDAT resource would not be a good candidate to combine with DR.

Another challenge is the establishment of a baseline and performance measurement. Combined energy storage and DR can already operate together, and receive credit based on the total load reduction as measured by the available baseline methodologies. To the extent there are proposals to separately measure pieces of a BTM resource, they should be carefully evaluated to ensure that they capture the actual load reduction delivered to the grid (\textit{i.e.}, the sum of all parts should not be greater than the actual load reduction delivered to the grid).

D. **Demand Response Hours**

SCE supports aligning the CAISO’s Availability Assessment Hours (“AAH”) and the Commission’s RA measurement hours to reduce confusion and uncertainty among resource
owners and reduce the potential for double procurement. In implementing this change, as a first step, the IOUs, DR providers, and the Commission should work together to examine the existing DR programs, and if needed and practicable, align program hours with the updated RA measurement hours. Furthermore, the RA counting rules and associated CAISO Must Offer Obligation (“MOO”) should be re-examined to ensure accurate counting of DR resources, and the avoidance of double penalty of the resources. Specifically, resources that cannot fully conform to the AAH would receive a reduced QC through the current Load Impact Protocols and be exposed to RA Availability Incentive Mechanism (“RAAIM”) charges for hours where it was not available to begin with. For example, a 10 MW Supply-Side DR resource that is available for three of the five RA measurement hours, would be given a prorated QC of 6 MW. However it would still be expected to bid 6 MW for the full five hours, or incur CAISO RAAIM charges. The Commission should work with the CAISO and stakeholders to address this issue.

E. Contract Capacity as QC for DRAM Resources

Determination of QC for Demand Response Auction Mechanism (“DRAM”) resources should balance the practicality of determining QC for new and/or short-term resources, with the need to ensure accurate counting for grid reliability purposes. The utility programs undergo annual Load Impact Protocol studies, which are reviewed by Energy Division, that provide a thorough analysis of historical program performance and expected future performance under different weather conditions. While actual performance may differ, the Load Impact Protocols provide robust analysis and are the best available estimate of DR program performance.

SCE believes that a future DRAM program, if adopted by the Commission, should follow a similar process to evaluate historical and future program performance to establish a QC.

If this approach is not practicable, and instead the QC is set at contract capacity, certain DRAM contract provisions, such as performance assurance and development security, would have to change to account for costs and reliability risks that would be incurred by the IOU customers in case these resources do not deliver the contracted capacity. Under the current DRAM Pilot pro-forma contract, several concessions were made recognizing the pilot nature of
the nascent procurement mechanism. If the DRAM is adopted as a program, it will need to have comparable performance guarantees to other reliability resources.
V.

GAP IN THE TIMING OF CAISO BACKSTOP PROCUREMENT AND THE COMMISSION’S RA PROCESS

When identifying deficiencies in meeting local/sub-local needs, in response to retirements of generators that are needed to support grid reliability or due to other reasons, the CAISO can issue backstop procurement in the form of Capacity Procurement Mechanism (“CPM”) and Reliability Must Run (“RMR”) designations.32 The timing of those CPM and RMR designations can be before or after the annual RA procurement has been completed. Currently, SCE understands that where the RMR procurement occurs prior to the annual RA program, the CPUC allocates those resources to each LSE to reduce their RA obligation. This process should continue. When the timing of a CPM or RMR designation is after the annual RA procurement process ends, a procurement under the CPM or RMR can result in overprocurement. SCE encourages the Commission and CAISO to continue to work together to develop timelines for the designation of CPM and RMR such that this issue is avoided to the maximum extent practical.

SCE also notes that a central buyer framework is likely to mitigate this issue as the central buyer would have the capability to procure the right mix of resources needed for grid reliability without the need for CAISO backstop procurement.

VI.

RESTRICTION IN LOAD MIGRATION CHANGE BETWEEN INITIAL AND TRUE-UP FORECASTS

SCE supports the recent order from the Commission that requires all LSEs to participate in the year-ahead RA process, including the load forecasting process, to better align the RA obligation with the expected load serving entity. As the Commission noted in the Track 1 decision:

In order to comply with Public Utilities Code Section 380(f), the Commission established the RA program through a series of decisions that ultimately established (1) an annual process whereby LSEs were required to submit load forecasts for the upcoming year that were used to calculate and allocate RA requirements equitably among LSEs, and (2) a year-ahead process whereby LSEs were required to demonstrate their procurement to meet their RA requirements. The Commission has emphasized the importance of obtaining accurate load forecasts of the “best estimates” of future customers and associated load so that LSEs are not unnecessarily “saddled with excess capacity, or in need of additional capacity, under market conditions where they would not be able to conduct reasonable and appropriate transactions to acquire or dispose of capacity as needed for load migration.”

For the same reason, SCE believes that a restriction should apply to allowable load migration changes between the initial forecast, submitted by LSEs around April prior to the compliance year, and true-up forecast, submitted in August prior to the compliance year. It is imperative that the true-up process not become over-relied upon as its timing is simply too close to the annual RA showing to make significant adjustments to an LSE’s portfolio. In order to recognize the importance of the load forecast and the difficulty of managing large portfolio changes with little time after the true-up forecast, SCE recommends a restriction should apply to allowable load migration change between the April submission and the August submission. This can be achieved by establishing both an upper bound and a lower bound of load migration

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33  D.18-06-030 at 53 (OP 5).
34  Id. at 16.
35  Likely the maximum amount of allowable change needs to be set high enough to allow for flexibility that is needed for normal business operation, such as load forecast error, slight change in implementation date, etc.
change (e.g., ±10% of the initial load forecast) that is allowed by an entity between the initial forecast (i.e., the April submission) and the true-up forecast (i.e., the August submission). This limit should not only consider the amount of the physical MW change of load migration but should also consider the schedule for the change, as both of these elements can have a significant impact on LSE obligations. For any load migration change beyond the allowable maximum amount, the portion should not be allowed to be served by the LSE until a future year when the portion is indeed included in the initial forecast for that year.

Similarly, the Commission should not allow service of load earlier than the original load forecast due in April as there would not be sufficient time for entities to adjust their portfolio having already met such load in the year-ahead filing and likely having completed any residual monthly procurement for the months in question. SCE would have no concern if a departing load serving LSE wanted to extend the date they seek to start service. They would be doing this knowing that they would still be obligated to their year ahead RA requirement to meet the original expected load service date submitted in April.

The proposed upper and lower bounds will address the administrative burden to acquire or dispose of capacity as needed for load migration and will also help ensure the appropriate forward planning of load service for all LSEs. Specifically, a 10% load migration margin is consistent with the delta between the 90% year-ahead system RA requirement and 100% month-ahead system requirement that all LSEs operate under. This approach recognizes the importance of serving load, a responsibility which by no means should be taken lightly, and ensures reliability is maintained at all times. Load service should be viewed as a long-term activity with entities appropriately planning for future load on the grid and sufficient practices with regard to procurement to ensure that near and long-term reliability is maintained.

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36 For example, a change in schedule of the beginning of load service in December according to the original forecast should not be allowed to move to beginning load service earlier than this date in the August update.
VII.

ISSUES ON FURTHER REFINEMENTS TO LOCAL RA RULES

In the Scoping Memo, the Commission included the following items in Track 2:

2. Refinements to Local Area Rules – The Commission may consider the following further refinements to the Local RA program in Track 2, as time permits:

   a. Adjusted or waived LSE procurement obligations for certain local areas with resource deficiencies or near-term procurement difficulties;

   b. Modified treatment of specific local areas or sub-areas (such as San Diego), and associated cost allocation;

   c. Seasonally varying Local Capacity Requirements;

   d. Local penalty waiver requirements; and

   e. Increased transparency for the Commission, and for LSEs procuring RA, regarding which resources are essential for local and sub-area reliability. This transparency may also enable more targeted consideration of potential alternatives to highly polluting plants located in disadvantaged communities.\(^\text{37}\)

As discussed in Section II, there are a great number of trade-offs between LSE-specific procurement and a central buyer framework. This is very much true with regard to items a through e above. As the rules and parties’ proposals are developing, it is important to have clarity around the central buyer framework to address these issues. Solutions to these issues would vary greatly depending on, for example, whether there is going to be a central buyer (or how many and who the central buyers are) and whether the central buyer is procuring all or only residual local requirements, as it is likely most of these issues would be mitigated or no longer exist under a central buyer framework. Therefore, SCE recommends that all the above issues be addressed as more clarity around the central buyer framework and details of multi-year requirements become available.

\(^{37}\) Scoping Memo at 7-8.
Appendix A
Witness Qualifications
QUALIFICATIONS AND PREPARED TESTIMONY

OF ERIC LITTLE

Q. Please state your name and business address for the record.
A. My name is Eric Little, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.
A. I am the Manager of CAISO and GHG Markets within Regulatory Affairs at Southern California Edison. My transition to this position came about through a re-organization of responsibilities on November 3, 2014. Immediately prior to taking my current position, I was the Manager of Procurement and Resource Planning Policy within Regulatory Affairs for Southern California Edison. Within the prior position, I was responsible for developing policy positions associated with the procurement of generating resources to serve both bundled load needs as well as to meet system and local reliability needs. I held this position from January 23, 2012 through November 2, 2014.

Q. Briefly describe your educational and professional background.
A. I hold a Bachelor of Arts in Economics from California State University, Long Beach and a Masters in Economics from the University of California, Santa Barbara. Prior to my current position, I have had a variety of responsibilities associated with Southern California Edison’s Power Procurement organization. These have included development and support of Long-term Procurement Plan Proceedings, Resource Adequacy Proceedings, and development of California Independent System Operator market designs including the Market Redesign and Technology Update. Within these roles, among other responsibilities, I have been responsible for policy development of rules for all Load Serving Entities that provide for equal treatment of all customers. In addition, I have previously provided testimony regarding revisions to the Cost Allocation
Methodology ("CAM") to calculate net costs for battery storage. These changes were necessary to account for both the charging and discharging nature which had not been considered previously as CAM had not been applied to storage resources.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-01, entitled Southern California Edison Company’s Track 2 Testimony in Rulemaking 17-09-020 as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.
Q. Please state your name and business address for the record.
A. My name is Gigio Sakota, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.
A. I am a Sr. Manager of Energy Marketing and Trading, leading the Resource Optimization group within the Energy Procurement and Management (EPM) organization, responsible for optimizing the market value of energy assets managed by SCE. My responsibilities include representing SCE interests in market design and related policy development, as well as management and oversight of the Least Cost Dispatch activities.

Q. Briefly describe your educational and professional background.
A. I have a B.A. degree in Physics from Occidental College, and a M.Sc. degree in Mechanical Engineering from University of California at Los Angeles (UCLA). I have worked at SCE since 2007 in a variety of individual contributor and management roles. I started as an analyst in Market Strategy and Resource Planning, worked as a Project Manager in Bidding Strategy and Asset Optimization, and then in Regulatory Affairs, and most recently as a Sr. Strategic Planning Manager in the Planning division of EPM focusing on policy and strategy regarding Distributed Energy Resources (DER) integration into wholesale markets.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-01, entitled Southern California Edison Company’s Track 2 Testimony in Rulemaking 17-09-020 as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.