BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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.

R.17-09-020
(Filed September 28, 2017)

PREPARED DIRECT TESTIMONY OF WITNESSES LORENZO KRISTOV, RICHARD MCCANN AND SHEHZAD WADALAWALA ON BEHALF OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

TRACK II ISSUES

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July 10, 2018
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# List of Acronyms

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<th>Acronym</th>
<th>Description</th>
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<tr>
<td>CAISO</td>
<td>California Independent System Operator</td>
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<tr>
<td>CAM</td>
<td>Cost Allocation Mechanism</td>
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<td>CCA</td>
<td>Community Choice Aggregator or Community Choice Aggregation</td>
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<td>CPM</td>
<td>Capacity Procurement Mechanism</td>
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<tr>
<td>DA</td>
<td>Direct Access</td>
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<tr>
<td>DER</td>
<td>Distributed Energy Resources</td>
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<tr>
<td>DR</td>
<td>Demand Response</td>
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<td>DRP</td>
<td>Distribution Resources Plan</td>
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<td>EE</td>
<td>Energy Efficiency</td>
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<td>ERR</td>
<td>Essential Reliability Resource</td>
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<td>ESP</td>
<td>Electric Service Provider</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>GAM</td>
<td>Green Allocation Mechanism</td>
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<td>IDER</td>
<td>Integrated Distributed Energy Resources Proceeding</td>
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<td>IEPR</td>
<td>Integrated Energy Policy Report</td>
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<td>Investor Owned Utility</td>
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<td>IRP</td>
<td>Integrated Resource Plan Proceeding</td>
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<td>LCA</td>
<td>Local Capacity Area</td>
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<td>LCR</td>
<td>Local Capacity Requirement</td>
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<td>LSE</td>
<td>Load Serving Entity</td>
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<td>OTC</td>
<td>Once-Through Cooling</td>
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<td>Power Charge Indifference Adjustment</td>
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<td>PPA</td>
<td>Power Purchase Agreement</td>
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<td>PTO</td>
<td>Participating Transmission Owner</td>
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<td>RA</td>
<td>Resource Adequacy</td>
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<tr>
<td>RFO</td>
<td>Request for Offer</td>
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<tr>
<td>RMR</td>
<td>Reliability Must Run</td>
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<td>RPS</td>
<td>Renewables Portfolio Standard</td>
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<tr>
<td>UDC</td>
<td>Utility Distribution Company</td>
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<td>UOG</td>
<td>Utility Owned Generation</td>
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I. INTRODUCTION AND EXECUTIVE SUMMARY

California’s continued leadership in setting and achieving critical targets for reducing greenhouse gas emissions and moving to clean energy is of global importance.

Leadership is also critical to the health and safety of all Californians – both present and future – a point highlighted by the already visible impacts of the changing climate. Local communities have embraced the state’s call for local action by forming community choice aggregators (CCAs) to build on state efforts. Continued success in achieving the state’s emissions reduction and clean energy targets depends on continuing the evolution of California’s regulatory programs and policies, including resource adequacy (RA) program rules and procurement structures.

The need to evolve the RA framework is driven primarily by three key changes.

Fossil-fired and nuclear power plants that have long played a role in grid reliability are retiring, sometimes before alternative clean energy solutions can be implemented. In addition, the growth of diverse distributed energy resources (DER) is making it harder to forecast net demand, set Local RA requirements and to determine how those requirements will be met. Finally, the transition of the Commission-jurisdictional retail
market from a few large investor-owned utilities (IOUs) to an increasing number of
smaller load-serving entities (LSEs) increases the need for the Commission’s
coordination of LSEs’ efforts in meeting RA requirements.

The most recent annual RA compliance cycle for 2018 emphasized the
importance of the greater coordination in meeting Local Capacity Requirements (LCRs).
In the PG&E Transmission Access Charge (TAC) area, there was a 1,071.76 MW total
deficiency due to sub-area constraints while individual LSE deficiencies totaled 72.23
MW.¹ The shortfall required supplemental backstop procurement by the California
Independent System Operator (CAISO), leading to collective overprocurement of Local
RA and unnecessary costs for ratepayers.

The Commission responded to these challenges² in its Track 1 Decision, D.18-06-
030, directing stakeholders to propose multi-year Local RA programs and central buying
for at least some portion of Local RA. The Track I Decision, along with the Scoping
Memo and recent Customer Choice en banc hearing, highlight key objectives and issues
that must be addressed to respond effectively to the evolving RA landscape:

- Ensuring sufficient resource availability to maintain required and expected
  levels of system reliability;
- Avoiding collective overprocurement of Local RA and mitigating unnecessary
  ratepayer costs;

¹ CAISO Evaluation Report of Load Serving Entities’ Compliance with 2018 Local and
² The Commission also responded directly to the CAISO’s backstop procurement for 2018
through Resolution E-4909, issued on January 11, 2018, authorizing PG&E “to hold a
competitive solicitation for energy storage and preferred resources to address two local sub-area
capacity deficiencies and to manage voltage issues in another sub-area.” The Resolution
contemplated that this procurement would result in “lower overall ratepayer costs.” Resolution
E-4909 at 1.
Preserving LSE procurement preferences for local, clean resources to meet RA requirements;

Allocating the cost of meeting LCRs equitably among LSEs;

Mitigating planned and unplanned resource retirement, which has resulted in out-of-market backstop procurement by the CAISO;

Reducing market and regulatory uncertainty, which is leading to stagnation of new preferred resource build-out to replace retiring resources;

Realining scale between buyers and sellers (large existing assets and smaller LSEs);

Increasing the transparency of market information to ensure efficient and economic procurement of needed Local RA resources;

Mitigating market power (total and partial) in local capacity areas (LCAs)

Decarbonizing the electricity sector by addressing California’s goals to eliminate gas-fired generation, reducing the impacts on Disadvantaged Communities (DACs), and leveraging trends in DER growth.

Immediate progress on many of these issues can be made through near-term implementation of a transitional multi-year Local RA program that will ensure local reliability while mitigating impacts on ratepayers. A more comprehensive long-term planning and deployment process is also needed, however, to reduce reliance on fossil-fuel generation and address other broader policy goals.

Based on these considerations, CalCCA proposes a two-phase approach to addressing local reliability needs. The multi-year-forward Transition Program would begin in 2019 for compliance in 2020 and beyond. The Transition Program relies on a rolling three-year forward Local RA procurement requirement for all LSEs, in

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CalCCA understands that some existing fossil-fuel resources may still be needed for system flexibility even after they are no longer needed for local-area reliability. CalCCA anticipates that the long-term strategy proposed here can and will be targeted to obviate these needs as well by facilitating development of flexible preferred resources.
compliance with the Track I Decision, aimed to address the shortcomings identified with
the existing program. In parallel, the proposed Long-Term Strategy coordinates LSE
procurement (consistent with Integrated Resource Plan (IRP) and RA obligations) with
the CAISO transmission planning process (TPP) to deploy preferred resources to address
local constraints. Together, these actions will enable the Commission and stakeholders to
address all key issues and provide an orderly transition from our present capacity fleet to
a carbon-free capacity fleet, thereby ensuring grid reliability, minimizing ratepayer costs
and accelerating achievement of California’s climate goals.

A. Summary of CalCCA’s Proposed Transition Program

CalCCA’s Transition Program envisions (i) a three-year Local RA procurement
obligation for LSEs, (ii) greater transparency of reliability needs in local sub-areas, and
(iii) a centrally procured residual Local RA amount in each LCA. Under the program,
greater sub-area transparency, along with the Commission’s coordination of LSE
procurement and central buying, ensures meeting 100 percent of Local RA requirement
for Year 1 and 95 percent and 80 percent for Years 2 and 3, respectively. These
objectives would be met through assignment to each LSE of its proportionate share of the
net local capacity requirement (Net LCR) for each LCA. Net LCR is the load-forecast-
based Total LCR from the CAISO LCR studies reduced by:

1) The proportionate share of the Total LCR to be procured by Publicly
   Owned Utilities (POUs) within the LCA; and
2) The CPUC Jurisdictional LSEs’ share of expected procurement of
   “Essential Reliability Resources” (ERR) – resources for which there are
   no substitutable resources⁴ – identified by the CAISO as necessary to
   address LCA or sub-area requirements; and

⁴ CalCCA proposes that any pivotal supplier in a sub-area, i.e. a resource some of whose
capacity will be needed even if all other resources in the sub-area are procured for their full
3) The Commission’s allocation to LSEs of resources under the Cost Allocation Mechanism (CAM) and any other allocation of Local RA resources held in the IOUs’ portfolios.

LSEs in Years 1 and 2 of the three-year RA cycle must procure 90 percent of their shares of the Net LCR for each LCA with the remainder procured by a Central Buyer. For Year 3 LSEs must procure 80 percent of their Net LCR shares.

capacity, is necessarily an ERR. Further, if a resource is determined to be pivotal supplier in Year 2 or Year 3 but not preceding years (most likely due to planned plant retirements in the sub-area), it should also be designated as an ERR in all preceding years to ensure it does not retire prematurely.
To ensure proper incentives for LSEs to invest in new carbon-free resources to meet their requirements and relieve constraints, the LSE’s Year 2 and 3 obligations can be met with newly contracted resources under certain conditions, as discussed in Section III. Section III explains how LSE procurement and Central Buyer procurement together achieve the Local RA needs on a rolling annual basis. It also describes all the steps of the Transition Program. Appendix A provides a detailed time line.

CalCCA proposes that the Central Buyer bear ultimate responsibility to procure the ERRs, with an opportunity in advance of this procurement for LSEs to meet or beat the CAISO’s Capacity Procurement Mechanism (CPM) Soft Offer Cap (SOC). The Central Buyer would also be responsible to procure the Residual Need, defined as 10% of the Net LCR for Year 1 and 5% of the Net LCR for Year 2.

CalCCA recommends that the CAISO serve as Central Buyer for the ERRs and the Residual Need, as defined in this testimony. By leveraging the existing procurement mechanisms authorized to the CAISO by the Federal Energy Regulatory Commission (FERC), specifically the CPM and Reliability Must Run (RMR), with certain refinements explained later herein, the Transition Program is best positioned for success.

Designating the CAISO as residual Central Buyer:

- Minimizes wholesale market jurisdictional conflicts between the Commission and FERC, preventing potentially more sweeping market reform by FERC;

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Examples of potential jurisdictional conflicts include FERC-directed capacity market design, as FERC’s rejection of the PJM ISO capacity market proposal (FERC, “Order Rejecting Proposed Tariff Revisions, Granting In Part And Denying In Part Complaint, And Instituting Proceeding Under Section 206 Of The Federal Power Act,” Docket Nos. EL16-49-000 et al, June 29, 2018), and Complaint of CXA La Paloma, LLC to FERC, submitted June 20, 2018, asking for creation of a central buying authority for the CAISO to resolve its issues.
• Leverages the CAISO’s existing tools, which would not be available to
any other Central Buyer, to mitigate local market power of FERC-
jurisdictional wholesale generators;

• Permits the use of the CAISO’s cost allocation tools to ensure that all
LSEs – including POUs and other LSEs outside the scope of Commission
authority – pay for needed LCA resources;

• Avoids exacerbating the growing mismatch between the IOUs’ supply
portfolios and their bundled demand; and

• Avoids the need to create yet another complex regulatory structure within
California’s electricity market.

Only the CAISO as Central Buyer can meet these objectives.

Two additional issues require consideration. First, as the Commission
contemplated in the Scoping Memo, transparency into sub-area requirements will better
enable all procuring parties to achieve program objectives. Three-year forward forecasts
regarding ERR requirements and CAM resources are a critical foundation to
transparency. Transparency of other information will also be important to enable LSEs to
understand sub-area dynamics such as resource effectiveness and the performance
requirements for potential substitute preferred resources. Second, the Transition Program
must be coordinated with market sales of excess Local RA in the IOUs’ portfolios, such
as those under consideration in R.17-06-026, to enable LSEs collectively to achieve cost-
effective compliance.

B. Summary of CalCCA’s Proposed Long-Term Strategy

CalCCA’s Long-Term Strategy proposal, described in detail in Section III of this
testimony, is designed to complement the Transition Program proposal by substantially
reducing or eliminating LCA sub-area issues and Local RA needs. This will be achieved

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6 Citation to relevant section
primarily through LSE procurement of local preferred resources, thus reducing the need for substantial CAISO procurement of fossil-fuel ERRs. To achieve this desired end state, CalCCA proposes that the Commission adopt its stated goal, and provide a structure and incentives for all LSEs (including CCAs), the IOUs (as PTOs and distribution utilities as well as LSEs), developers of clean energy resources and other stakeholders to collaborate in developing cost-effective alternatives to transmission solutions identified in the TPP for reducing local grid constraints.  

The TPP uses the CEC IEPR demand forecast as a crucial input. This allows a full accounting for California’s evolving demand for electricity and how it will be affected by the projected growth of load modifiers (including energy efficiency, electric vehicle and rooftop solar adoption). The TPP planning assumptions also reflect scheduled power plant retirements (e.g., once-through-cooling plants and Diablo Canyon) and scheduled in-service dates of approved transmission upgrades. Thus, the TPP would be the process, as it is today, for describing local reliability needs in sufficient detail to inform design of effective solutions, identifying transmission solutions to meet the needs, and evaluating proposed alternatives to determine the preferred solution. 

The Long-Term Strategy builds on two ongoing trends and processes. First, the ongoing growth of DERs is already reducing the need for reliability transmission upgrades, as evidenced by the recent cancellation or downsizing of transmission upgrades.

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that were previously approved based on expected future reliability needs. The proposed
strategy would build on this growth by targeting additional preferred resource
procurement by LSEs to offset LCRs, coordinated with the IRP process. Second, in April
2018 the CAISO announced a transmission study plan for the current 2018-19 planning
cycle aimed to reduce or eliminate Local RA needs in certain LCAs with fossil resources.
The CalCCA proposal would strengthen the impact of this effort by fostering
opportunities for stakeholders to propose non-wires alternatives (NWA) or alternative
transmission solutions (ATS), focused first on alternatives to eliminate fossil-fuel
generation located in DACs.

The Commission must play a coordinating role in the Long-Term Strategy to
ensure that IOUs’ distribution resource plans (DRP) consider the full value of DERs,
including load management measures, and that the needed preferred resource
development is integrated across the DRP, IRP, IDER, the CEC IEPR and the CAISO’s
transmission plan. It must also resolve critical policy issues needed to ensure fair and
accurate compensation to local resources.

The success of CalCCA’s proposed Transition Program and Long-Term Strategy
depend on collaboration and coordination among all LSEs, the Commission, the CAISO,

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9  An NWA is an electrical asset or set of assets that substitute for a transmission solution but are not themselves considered transmission assets. They are typically resources procured for energy and RA capacity by an LSE, and may be interconnected at either distribution or transmission level. A related but distinct concept is an ATS, which is an electrical asset or set of assets that substitute for a transmission solution and are compensated as transmission assets, owned by a PTO and operated as part of the CAISO controlled grid. The attractiveness of the ATS is its ability to earn all or part of its cost recovery as a rate-base grid asset. A solution to meet local reliability needs without a transmission upgrade could involve an NWA or an ATS or a combination of the two, but currently only the NWA construct is open to DERs.
the Energy Commission and the participating transmission owners. The Commission is in a pivotal position to ensure this success through its administration of the Transition Program and coordination of the Long-Term Strategy through the IRP, IDER, DRP and other planning processes.

II. THE EVOLVING CHALLENGES OF ENSURING LOCAL AREA RELIABILITY

Conditions for ensuring local grid reliability are changing, and changes are required in the mechanisms used to meet this objective. The key drivers of these changes include (1) the growth in DER resources, (2) the increasing number of LSEs in the market and (3) the impending retirement of fossil-fuel resources. Even without these new challenges, Local RA procurement has occurred under challenging conditions: (1) the complexity of local grid topology and operations, which creates locationally granular resource needs, and (2) local market power on the part of certain resources within the local areas for which there are no current alternatives (i.e., no competition). Under these conditions, some backstop procurement may be needed even when all LSEs fully meet their Local RA procurement requirements – a problem that arose for the 2018 RA compliance year. Any proposed Local RA solution must thus directly address these conditions.

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Because the transmission constraints that drive local capacity needs pre-date the formation of wholesale power markets in California, the market power of essential local resources has been an issue since the start-up of the CAISO in 1998. The reliability must-run (RMR) mechanism has been the FERC-approved means to procure such resources at mitigated cost-of-service prices since the beginning of California’s electricity market reform.
A. Changing Market Dynamics

In the context of Resource Adequacy, a Local Capacity Area (LCA) is a portion of the CAISO-controlled transmission grid characterized by a need for supply resources located within the area to meet the demand within the area. The need for local supply resources arises due to one or more transmission grid constraints into or within the LCA that prevent the area from fully relying on importing power from elsewhere in the grid to meet demand. These conditions are most prevalent where there are high levels of in-area demand and when contingency events take some grid facilities out of service. Thus, in principle, needs for local-area resources could be eliminated by upgrading the transmission grid in those areas. Until recently, however, existing local resources have met the needs and local transmission upgrades have not been deemed to be needed or cost-effective. The Local RA requirements have ensured that LSEs procure the needed local resources, on an annual basis prior to each compliance year, at reasonable cost under most circumstances, with rare need for backstop procurement by the CAISO.

Figure CCA-2, below, illustrates the amount of CPM capacity procured by the CAISO from 2009 to 2017. Even with the substantial increase in 2017 (largely due to issuing one-year agreements instead of one to two months which had been standard previously), this amounts to about 1,050 MW on average each month compared to a system wide peak of 50,116 MW.
Figure CCA-2

Going forward, any local reliability mechanism must meet the challenges presented by fossil resource retirement, DER growth and the increasing number of LSEs serving the retail market. Existing fossil-fuel generators have traditionally met a major share of the local-area needs. The desire to rely on these resources, however, is declining due to the state’s focus on decarbonization and the elimination of once-through cooling (OTC) generation. While transitioning towards a carbon free fleet, economic trends challenge the financial viability of resources that are needed in the interim. In addition to power plant retirement, DER growth complicates planning any local reliability solution. While DER development initially accelerated through deployment of rooftop solar photovoltaic (PV) resources, DER potential is more diverse due to the success of California’s programs promoting storage, electric vehicle charging, dispatchable demand
and more. These resources add complexity in demand forecasting and quantifying LCR. DER also presents jurisdictional issues – with the local area transmission constraint arising under one jurisdiction (FERC) and potential DER solutions under another (CPUC). Finally, the complications presented by plant retirement and DERs are heightened by the growing number of CCAs. While CCAs present the potential for more effective identification and deployment of local solutions, their growth also highlights the need for area-wide coordination in Local RA procurement to ensure collective procurement sufficiency.

B. Local Sub-Area Market Power

Local market power arises when an ERR holds market power in an LCA or sub-area because there is no other combination of resources that can meet the local reliability need. Competitive procurement is not a near-term option; given the lack of competitive alternatives, only new resources can effectively mitigate market power, and these resources take time to deploy. Even where there is only partial market power, resources can command a higher price than other Local RA resources knowing that they will likely be procured through the CAISO’s Capacity Procurement Mechanism at or near the Soft Offer Cap. Consequently, an individual LSE may be reluctant to procure the essential resource because to do so would subsidize other LSEs who meet their shares of the LCR with less costly, non-essential resources. For this reason, and due to a lack of

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11 The Direct Access ESPs are also LSEs with Local RA requirements, but because their share of system demand has been limited by statute and has remained relatively stable in recent years they have been less of a factor in the recent changes to the Local RA landscape.  
12 And prior to the development of distributed energy resources, physical constraints on building new utility-scale generation or sufficiently large transmission interconnections were often an effective barrier to increasing competition. In addition, the pecuniary impact from market entry that would tend to drive down the price in the local area so that the new entrant may not gain sufficient economic rents to recover its investment.
transparency, these resources may not be procured by LSEs. These factors thus motivate
the role of the Central Buyer, as the CAISO has had to step in for the 2018 RA year to
procure these essential sub-area resources needed to ensure local reliability.

Not surprisingly, the higher value of these resources due to their position in the
market has resulted in them receiving higher prices. The CAISO has paid prices through
the Capacity Procurement Mechanism (CPM) and Reliability Must Run (RMR) contracts
that are higher than the short-term prices reported by the Commission’s Energy Division
for other Local RA.13

C. CAISO RMR and CPM Procurement

An understanding of the circumstances under which CAISO RMR or CPM14
backstop has been required will help create reasonable expectations for a multi-year
program and central buyer structure.

Two circumstances in which the CAISO engages in backstop procurement
through the CPM are particularly relevant in this proceeding. The CAISO procures Local
RA resources through this mechanism to address (1) deficiencies in collective LSE Local
RA procurement, including deficiencies that may arise due to sub-area constraints despite
compliance by all LSEs, and (2) “capacity at risk of retirement within the RA
Compliance Year that will be needed for reliability by the end of the calendar year
following the current RA Compliance Year.”15 In some cases, these resources may have
partial market power as pivotal suppliers or by virtue of their higher effectiveness at
meeting granular local reliability needs than other potentially substitutable resources.

14 2018 was the first year that the CAISO used its CPM authority in the year-ahead
timeframe to address a collective deficiency for any IOU service territory.
15 Id. §43A.2.
While these resources may face some degree of competition in their sub-area, in both cases the value of the resource is likely to be relatively high.

As part of the RA process, the CAISO engages in backstop procurement only after issuing a Market Notice identifying the needed resource and providing LSEs the opportunity to procure the resource. If no LSE cures the deficiency, the CAISO procures the needed resources, typically at the Soft Offer Cap (currently $6.31/kW-month). If the specific generator whose capacity is needed is unwilling to contract at or below the Soft Offer Cap, the parties may seek authority for an RMR-like COS rate from FERC.

Under the CPM, cost recovery includes the generator’s variable costs, net of market revenues, and some amount of capital maintenance expense to ensure cost coverage and some degree of profit. The CPM is based on the going forward costs for an ongoing operation but does not consider recovery of capitalized maintenance costs.

When possible, the CAISO procures Local RA capacity voluntarily through its Competitive Solicitation Procedure (CSP) under its Tariff Section 43.A. A review of CPM transactions for 2009 to 2017, shown in Table CalCCA-1, reveals all but a handful of transactions were priced at the SOC.

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Id. §43A.4.1.1.

The initial soft cap was set in 2009 based on the going forward fixed costs for a combustion turbine estimated from siting case submittals in California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, CEC-200-2007-011-SF, December 2007. The cap was revised updated for the survey results from 20 combined cycle plants reported in California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, CEC-200-2009-07-SF, January 2010. (Dr. McCann was the lead consultant author on both reports.) The soft cap has been revised several times subsequently as described in CPUC, *The 2016 Resource Adequacy Report*, Energy Division, June 2017, p. 32.

CAISO Fifth Replacement Electric Tariff, §43A.4.1.1.1.
### Table CCA-1

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<td>Humbolt Mobile #2</td>
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<td>6/20 - 6/30</td>
<td>$4.28</td>
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<td>Humbolt</td>
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<td>8/2 - 8/31</td>
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<td>$3,892</td>
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<td>2</td>
<td>8/2 - 8/31</td>
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<td>Year</td>
<td>Resource</td>
<td>CPM designation (MW)</td>
<td>CPM designation dates (Mo./Day)</td>
<td>Price $/kW-Mo.</td>
<td>Estimated cost</td>
<td>Local capacity area</td>
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<tr>
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<td>6.31</td>
<td>252,526</td>
<td>SCE TAC</td>
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<td>820,300</td>
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<tr>
<td>2016</td>
<td>Pio Pico Unit 1</td>
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<td>11/9 -12/9</td>
<td>6.31</td>
<td>647,848</td>
<td>System</td>
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<td>2016</td>
<td>Pio Pico Unit 2</td>
<td>102.67</td>
<td>11/9 -12/9</td>
<td>6.31</td>
<td>647,848</td>
<td>System</td>
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<tr>
<td>2016</td>
<td>Pio Pico Unit 3</td>
<td>102.67</td>
<td>11/9 -12/9</td>
<td>6.31</td>
<td>647,848</td>
<td>System</td>
</tr>
<tr>
<td>2016</td>
<td>Sentinel Unit 1</td>
<td>1</td>
<td>11/9 -12/9</td>
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<td>System</td>
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<td>Sentinel Unit 2</td>
<td>1</td>
<td>11/9 -12/9</td>
<td>6.31</td>
<td>6,310</td>
<td>System</td>
</tr>
<tr>
<td>2016</td>
<td>Sentinel Unit 3</td>
<td>1</td>
<td>11/9 -12/9</td>
<td>6.31</td>
<td>6,310</td>
<td>System</td>
</tr>
<tr>
<td>2016</td>
<td>Sentinel Unit 6</td>
<td>1</td>
<td>11/9 -12/9</td>
<td>6.31</td>
<td>6,310</td>
<td>System</td>
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<td>2016</td>
<td>DELTA ENERGY CENTER AGGREGATE</td>
<td>114</td>
<td>12/14 - 2/11</td>
<td>6.31</td>
<td>1,438,680</td>
<td>PG&amp;E TAC</td>
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## CAISO CPM Transactions - 2009-2017

<table>
<thead>
<tr>
<th>Year</th>
<th>Resource</th>
<th>CPM designation (MW)</th>
<th>CPM designation dates (Mo./Day)</th>
<th>Price $/kW-Mo.</th>
<th>Estimated cost</th>
<th>Local capacity area</th>
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<tr>
<td>2016</td>
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<td>89.79</td>
<td>12/14 - 2/11</td>
<td>$6.31</td>
<td>$1,133,150</td>
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<td>2016</td>
<td>MOSS LANDING POWER BLOCK 1</td>
<td>141.04</td>
<td>12/18 - 1/17</td>
<td>$6.31</td>
<td>$1,779,925</td>
<td>System</td>
</tr>
<tr>
<td>2016</td>
<td>Mountainview Gen Sta. Unit 3</td>
<td>36.37</td>
<td>12/19 - 2/16</td>
<td>$1.90</td>
<td>$138,206</td>
<td>SCE TAC</td>
</tr>
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<td>510</td>
<td>Annual</td>
<td>$6.19</td>
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<td>Annual</td>
<td>$6.31</td>
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<td>SDG&amp;E</td>
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<td>2017</td>
<td>ENCINA UNIT 5</td>
<td>273</td>
<td>Annual</td>
<td>$6.31</td>
<td>$20,671,560</td>
<td>SDG&amp;E</td>
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</table>
Unlike the CPM, RMR contracts have been part of the CAISO grid management tools since the initiation of the restructured market in March 1998. RMR resources are defined as:

Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes: i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.¹⁹

As described in the Commission’s 2016 Resource Adequacy Report, RMR contracts are annual agreements that are reviewed and renewed as needed. RMR contracts typically have been provided to resources for which there are no substitute resources. The contracts typically have a one-year term that can be renewed annually under the same terms and conditions, with compensation set at a price based on the generator’s cost-of-service (COS). COS prices are necessary because these resources are local monopoly resources and thus could charge exorbitant rates if procured at “market-based” prices.

In their most recent incarnation, RMR contracts are offered to units that did not bid or accept a voluntary CPM offer, but are still needed for local reliability and stability purposes. Units designated as RMR may receive cost-based remuneration above the CPM SOC with approval of the FERC. However, these prices are not completely comparable “apples to apples” with CPM because CPM recipients retain all wholesale market revenues while for these RMR Condition 2 contracts (which are must-offer bidders), the wholesale revenues are to be returned to the CAISO, hence the “potential” cost

¹⁹ CAISO Fifth Replacement Electric Tariff, March 16, 2018, Appendix A Master Definition Supplement.
description. Table CalCCA-2 lists the most recent additions to the RMR designations for 2018, and the contracted price in $/kW-month.

<table>
<thead>
<tr>
<th>RMR Unit Designation for 2018</th>
<th>NQC MW (Aug.)</th>
<th>Potential Cost ($/kW-Month)</th>
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<td>Metcalf</td>
<td>580</td>
<td>$10.41</td>
</tr>
<tr>
<td>Yuba City</td>
<td>47.6</td>
<td>$7.81</td>
</tr>
<tr>
<td>Feather River</td>
<td>47.6</td>
<td>$7.76</td>
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</table>

The higher value of these critical resources is also confirmed by the prices paid by the IOUs for utility-owned generation (UOG) providing Local RA in their service territories. Southern California Edison (SCE) paid $435,219,778 in 2017 for 2,534.3 MW of CAM reliability capacity at an average price of $14.31/kW-month according to SCE’s 2017 FERC Form 1 filing. Pacific Gas and Electric Company’s (PG&E’s) FERC Form 1 reveals a cost of $203,474,897 for 1,637.3 MW of CAM resources, at an average price of $10.36/kW-month. For PG&E’s PCIA-eligible fossil RA generation PPAs, the total cost was $478,244,526 for 2,486.4 MW at an average cost of $16.03/kW-month.

The key lesson from these observations is that expecting resources with partial or complete market power to negotiate “competitive” rates that resemble the short-term price for Local RA is unrealistic. These resources, as rational market actors, will logically seek to recover as much as they can from buyers, whether the CAISO, IOUs, other LSEs or a new Central Buyer. Until local sub-area constraints are eliminated, these resources can demand higher prices and their market power is only limited by the CAISO authority to require acceptance of an RMR contract that is tied to their cost of service. Only the imposition of a FERC-authorized mechanism can limit those prices to either a defined cost basis under a voluntary transaction or an approved cost of service basis for
must-offer resources. A Central Buyer will need this same authority to compel generator participation. Nevertheless, a Central Buyer is only needed to procure from these pivotal suppliers for the period when those resources can exert market power. With the successful implementation of the Long-Term Strategy, that role should diminish as local sub-are constraints continue to be removed. Once market power is addressed, LCRs can be defined at sufficient granularity to align with the CAISO’s actual grid needs, CalCCA does not dismiss the possibility of achieving prices below the Soft Offer Cap for these resources with more transparent information and an expanded procurement timeline. In the near term, the most viable way of achieving lower prices— as the Commission has fully recognized – is to offer the generator multi-year contracts.

III. CALCCA’S PROPOSED TRANSITION PROGRAM

The economic interests of all LSEs are naturally aligned to ensure local area reliability while reducing overprocurement of Local RA and ratepayer costs. Pending physical solutions to address underlying local area constraints, and consistent with the Commission’s directives, CalCCA’s Transition Program will achieve these objectives through (1) a three-year compliance obligation, (2) greater transparency in local sub-areas, and (3) a centrally-procured residual Local RA amount in each local capacity area (LCA). Added transparency into local area and sub-area requirements will also

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20 For example, when the restructured market was initiated in March 1998, the vast majority of power plants in the Los Angeles Basin had at least one unit on a RMR agreement. Today, almost all of those plants have been removed from the RMR designation contracts and a few show up on the CPM procurement list.

21 In the development of the LCR framework, the Commission chose to aggregate six of the local capacity areas in PG&E’s TAC area, to mitigate local market power concerns (See Energy Division Proposal, p. 12.)
incentivize and maximize opportunities for LSEs, separately or collectively, to procure effective Local RA capacity and reduce the need for central buying.

Recognizing that some degree of central buying may be necessary in the near term – particularly for resources with market power – CalCCA proposes to rely on the CAISO as the Central Buyer for the residual Local RA needs, using existing mechanisms modified as described below to meet current needs. The CAISO appears to be the ideal entity, with the tools and legal authority to spread costs across both IOU and POU service territories based on cost-of-service rates (if and when negotiation with the essential resources fail) until local constraints can be relieved. The CAISO is also well positioned to compensate LSEs who step forward to procure sub-area resources to the benefit of all LSEs with modifications to the existing CPM cost allocation.

A. Transition Program Mechanics

CalCCA has identified six key steps in a rolling, annual, three-year-forward RA program. The six steps would occur over a 15-month period leading up to the start of each three-year RA compliance cycle. In conjunction with the proposed six-step structure, CalCCA recommends the RA compliance year be re-defined on an April 1 to March 31 basis rather than the calendar year, as discussed further below. Thus, the timeline for the six steps would occur from January 1, 2019 through March 31, 2020 for the April 2020-March 2023 RA cycle.

The six steps, with illustrative timings for each of them, are as follows:

Step 1: CAISO performs LCR studies to determine Total LCR values for each year of the upcoming three-year RA cycle and for each LCA, and identifies Essential Reliability Resources (ERR), if any (January 1 – May 31, 2019)
Step 2: Utilities provide CAM forecasts to the CPUC for each year of the upcoming RA cycle (by May 31, 2019)

Step 3: CPUC calculates annual Net LCR = (Total LCR – POU share – CPUC Jurisdictional LSE share of ERR– CAM) for each LCA and allocates shares to LSEs (by June 30, 2019)

Step 4: LSEs procure required percentages of their shares of Net LCR for each of the three years, as specified in the table below (July 1 – September 30, 2019), a process that must be coordinated with any IOU sales of RA to other market participants.

Step 5: LSE provide showings of their System, Flexible and Local RA procurement for April 2020 through March 2023 to CPUC and CAISO (by October 1, 2019)

Step 6: For each LCA CAISO calculates Residual needs, including needs driven by sub-LCA constraints. The Central Buyer then procures the Residual Need and any ERR capacity not already procured by LSEs (by December 1, 2019 – four months ahead of the start of the next RA compliance year).

Each step is discussed in detail below, and Appendix A provides a process overview and timeline.

CalCCA’s six-step Transition Program does not depend on the proposed change in the compliance-year time period from January 1 through December 31 to April 1 through March 31, and could be implemented without the change. A change in the compliance period may be desirable, however, as certain existing processes would need to be moved forward to preserve the four-month lead time between Step 6 and the beginning of the compliance period. 22 First, the change allows for greater certainty in the results of the CAISO multi-year forecasts (Step 1). The CEC’s Integrated Energy

22 CalCCA proposes this four-month period based on the understanding that generating resources that may need to be procured by the Central Buyer need this much advance notice of procurement.
Policy Report (IEPR) demand forecast is critical to the CAISO’s study process. The CEC typically adopts the forecast in January, suggesting that the CAISO cannot begin the study process before February 1. Second, the change in timeline will allow the LSEs and Central Buyer to complete all procurement, including contracts with ERRs that have local market power, at least four months prior to the start of the compliance period (Step 6). This schedule gives more certainty to generators which CalCCA expects will lead to better maintenance planning, increased reliability and lower costs for ratepayers.

**STEP 1: CAISO Performs LCR Studies and Identifies Essential Reliability Resources**

The Commission observed in the Scoping Memo and D.18-06-30 that greater transparency of resource requirements in local areas and sub-areas may be one means of reducing out-of-market Local RA procurement. Step 1 of CalCCA’s Transition Program thus starts with the CAISO LCR study process and concludes by May 31, when the CAISO provides the LCR and identifies ERRs for each local area and each year of the multi-year compliance period. In addition to ERRs, the CAISO LCR report identifies available resources within an LCA and indicates their different effectiveness on critical sub-area constraints. While this information will be useful to the CAISO as Central Buyer, it will also be useful to LSEs as they conduct their Local RA procurement and attempt to reduce the need for central buying. Lastly, the CAISO will identify what share of the LCR in each LCA will be met by POU procurement.

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23 Scoping Memo at 4.
24 D.18-06-030 at 44.
STEP 2: Utilities Provide Multi-Year CAM Forecasts

The allocation of Local RA capacity by the IOUs requires a clear understanding of anticipated allocation of Local RA capacity by the IOUs under the Cost Allocation Mechanism (CAM). Today, CAM allocations are provided by the CPUC in late July and then trued up on a quarter-ahead basis during the compliance period. To support a multi-year program, the IOUs must provide to the Commission their then-current three-year forecasts of CAM resources for each LCA at the same time the CAISO provides its LCR study results at the end of Step 1. The CPUC will use the CAM forecasts in Step 3 to determine Net LCR amounts and allocate them to LSEs.\(^{25}\) LSE specific CAM allocations for Year 2 and Year 3 would be revised annually based on updated information and the Year 1 allocations would be revised quarterly as is done today.

In addition to CAM Local RA resources, the IOUs currently hold Local RA resources in their Power Charge Indifference Adjustment (PCIA) eligible portfolios. While future disposition of these resources is under consideration in R.17-06-026,\(^{26}\) the CPUC must at a minimum receive this information from the IOUs by LCA and year and include it in calculating the Net LCR allocations in Step 3.

STEP 3: CPUC Allocation of Net LCR Requirements to LSEs

Using the information from Steps 1 and 2 above and the CPUC Jurisdictional LSE share of the Total LCRs, the Commission calculates Net LCR for each LCA and

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\(^{25}\) For the CPUC to allocate the Net LCRs for the three-year period to LSEs, it will need a three-year forecast from each LSE; CalCCA recommends that the current annual load forecast that is submitted in April be a three-year load forecast.

\(^{26}\) Proposals for disposition of this Local RA capacity include long-term resource or product sales (CalCCA) and quarterly allocation of Local RA attributes associated with hydro resources among LSEs (Joint Utilities) and periodic sales of Local RA attributes from other IOU resources (Joint Utilities).
compliance year. The Net LCR is calculated as (CPUC Jurisdictional LSE Share of Total LCR – CPUC Share of ERR - CAM). The Commission then allocates shares of Net LCR among jurisdictional LSEs. The CalCCA timetable calls for the Commission’s provision of Net LCR allocations to LSEs by July 1.

5 **STEP 4: LSE Procurement of Net LCR**

Once the Commission has provided the Net LCR allocations, the LSEs have three months (July – September) to secure 90 percent of their Net LCR shares for Years 1 and 2, and 80 percent for Year 3. LSEs would also have opportunities to procure prior to the July 1 allocation but would have less information to rely upon before further Local RA procurement. Setting LSE procurement requirements below 100 percent of the Net LCR still results in procuring the required 100 percent of Net LCR for Year 1 and 95 percent for Year 2 when combined with the Central Buyer procurement.\(^{27}\) At the same time, these LSE procurement levels provide headroom that the Central Buyer can use to address remaining sub-area needs with reduced risk of over-procurement by the end of Step 6. Table CCA-3 below shows CalCCA’s proposal for the LSE and Central Buyer procurement shares of the Net LCR for each compliance year, and illustrating the rolling three-year RA compliance cycle.

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\(^{27}\) The Central Buyer will not procure an ERR for Year 2/3 unless it is still not procured when it is needed for Year 1; this is necessary to avoid undermining ERR incentives to sign multi-year contracts with LSEs.
The LSE procurement efforts should focus not only on Local RA generally, but on ERRs and other resources that are most effective in addressing sub-area constraints. An LSE’s obligation may be met by new non-fossil resources. These resources can be counted for Year 1 under existing guidance. Under the Transition Program, for Years 2 and 3, these resources can be counted towards an LSEs requirement under three conditions: (1) the LSE has executed a contract for purchase or development; (2) the project is already in the utility’s or the CAISO’s interconnection queue and (3) the scheduled commercial operation date falls on or before the first date of the compliance month in which the LSE wishes to count the resources towards its obligation.

Table CCA-3: Procurement of Net LCR by LSEs and Central Buyer

<table>
<thead>
<tr>
<th></th>
<th>2020-22 RA Cycle</th>
<th>2021-23 RA Cycle</th>
<th>2022-24 RA Cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Year 1</td>
<td>Year 2</td>
<td>Year 3</td>
</tr>
<tr>
<td>Net LCR achieved</td>
<td>100%</td>
<td>95%</td>
<td>80%</td>
</tr>
<tr>
<td>LSEs procurement</td>
<td>90%</td>
<td>90%</td>
<td>80%</td>
</tr>
<tr>
<td>Central Buyer</td>
<td>10% (5% more)</td>
<td>5%</td>
<td>0</td>
</tr>
</tbody>
</table>

1 The LSE procurement efforts should focus not only on Local RA generally, but on ERRs and other resources that are most effective in addressing sub-area constraints.
2 An LSE’s obligation may be met by new non-fossil resources. These resources can be counted for Year 1 under existing guidance. Under the Transition Program, for Years 2 and 3, these resources can be counted towards an LSEs requirement under three conditions: (1) the LSE has executed a contract for purchase or development; (2) the project is already in the utility’s or the CAISO’s interconnection queue and (3) the scheduled commercial operation date falls on or before the first date of the compliance month in which the LSE wishes to count the resources towards its obligation.
One additional factor must be considered. Several parties contemplated in R.17-06-026 that the IOUs will sell some portion of their existing RA resources or, at a minimum, RA products. It is critical that any IOU sales with Local RA value be timed in a way that optimizes the potential for use by other LSEs and maximizes revenues for ratepayers.

**STEP 5: LRA Compliance Showing**

LSEs would make their annual three-year showings on October 1. For Year 1, this would also include the annual System and Flexible RA Showing. To the extent an LSE falls short of its required Net LCR procurement share, that shortfall will be included in the Central Buyer procurement in Step 6 with a corresponding adjustment to the LSE’s share of the Central Buyer’s procurement costs. This is consistent with how the CAISO handles individual LSE deficiencies in local capacity procurement today.

To the extent an LSE has met its Net LCR compliance target and has procured excess Local RA in an LCA, no compensation would be provided to the LSE (e.g., in the form of a reduced share of the Central Buyer procurement costs). This is consistent with the practice today when an LSE showing includes Local RA in excess of its obligation but the CAISO determines there is a collective deficiency. The reasoning is that self-provision of Local RA beyond the Net LCR target does not necessarily offset needs for the Central Buyer to procure highly-effective local resources on sub-LCA constraints. In contrast, to the extent an LSE has procured ERRs, the procurement would offset its share of the ERR costs 1:1 up to its proportional share of those costs because it would directly offset the need for Central Buyer procurement. Further, the CAISO could also credit the LSE for any excess ERRs procured beyond the LSE’s load-ratio share at the CPM Soft.
Offer Cap. The credited costs will be recovered by the CAISO from all other LSEs, including IOUs, POUs, CCAs and ESPs, in proportion to their unmet shares of these critical resources. This outcome fairly allocates these costs to all entities that benefit and incentivizes LSEs to procure from ERRs if they can obtain a price better than the CPM Soft Offer Cap.

STEP 6: CAISO Calculation of Residual Need and Central Buying

Based on the October 1 LSE showings, the CAISO will assess residual or unmet Local RA needs for each LCA and each year of the three-year RA cycle, including any needs driven by sub-LCA constraints. The Residual Need will equal (Net LCR — CPUC Jurisdictional LSE showings). Under CalCCA’s proposal that LSEs procure 90 percent of their shares of Net LCR for Year 1, and assuming all LSEs meet that target, the Residual for Year 1 will equal (10%*Net LCR), and may include other specific resources needed to address sub-LCA constraints. The CAISO as Central Buyer will then procure some or all of the remaining Net LCR amounts, as specified in Table 1 above, plus the ERR capacity identified in Step 1 that has not been procured by an LSE for Year 1. Thus, for Year 1, the process obtains at least 100 percent of the Net LCR by summing the procurement of the Net LCR as specified in the table (e.g., for compliance year 1 90% met by LSE and 10% met by Central Buyer), and if necessary any additional resource procurement by the

28 The LSE procuring excess ERR or sub-area resources would not be exempt from the costs actually incurred for the net procurement of the Central Buyer. Today, the CAISO tariff section 43.2.2.1 provides a “proportional credit,” meaning the procuring LSE is subsidizing other LSEs by paying for the RA while all LSEs will benefit by proportionally reduced CPM costs. This is a weakness in the current structure that we address in our transition proposal by offering a 1:1 credit instead of a proportionate credit (and limited to the ERRs) to create the proper incentives. Section 43.2.2.1 provides: “Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any CPM procurement costs under Section 43.8.3 reduced on a proportionate basis.”

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CalCCA - Direct Testimony of L. Kristov, R. McCann and S. Wadalawala
Central Buyer to resolve sub-LCA constraints. When combined with POU procurement, ERR procurement and CAM resources, at least 100% of the Total LCR is achieved.

Because the CAISO will have detailed knowledge of any sub-area needs and the different effectiveness values of different resources, the Central Buyer step should result in more efficient procurement of the Local Capacity than if LSEs were to procure 100% of their Net LCRs as is done today. This should reduce the risk of overprocurement and the likelihood of need for further CAISO backstop procurement for collective deficiency.

Costs of Central Buyer procurement would be allocated equitably among all responsible LSEs, including IOUs, POUs, CCAs and ESPs.

B. Effectiveness of CalCCA’s Proposed Transition Program

CalCCA’s proposed Transition Program effectively addresses many of the key goals identified in Section I above. The program:

- Abates collective overprocurement of Local RA and mitigates unnecessary ratepayer costs by (i) providing early identification of ERR and other highly-effective local resources, (ii) providing an opportunity for an LSE or group of LSEs to procure the resources at a price lower than CAISO CPM Soft Offer Cap, and (iii) providing an opportunity for the CAISO to act as a Central Buyer to secure the residual remaining local resources that it deems necessary for reliability as informed by individual LSE’s procurement;

- Ensures LSEs can act on their preferences for local resources, by providing transparency on what resources are needed, with time to procure those resources, while also narrowly defining the role of Central Buyer.

- Allocates costs equitably across LSEs by avoiding cross-subsidies between POUs and Commission-jurisdictional LSEs while also compensating individual LSEs for procurement that benefits all LSEs;

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29 RMR costs are recovered through the transmission charges collected from utility distribution companies (UDCs), including POUs, served by the CAISO transmission grid. The UDCs then recover these costs from ratepayers through their retail transmission charges. CPM costs due to the collective deficiency are allocated pro rata on a load-share basis to each LSE serving load in the TAC area in which the deficient LCA was located. The LSEs then recover these costs from ratepayers through their retail generation rates.
Mitigates the impacts of planned and unplanned resource retirements and reduces market uncertainty by encouraging LSEs to procure multi-year RA contracts;

Aligns scale between buyers and sellers, by leaving an opportunity for group procurement of larger resources and providing credit for LSEs that procure ERR beyond their own needs; and

Reduces CAISO backstop procurement through transparency of sub-area information, greater opportunity for LSEs to act on that information and alignment of LSE economic interests to reduce overprocurement and ratepayer costs.

Pending progress through the Long-Term Strategy, LSEs can individually focus on decarbonization and DAC solutions in their local communities.

C. Other Related Issues

The success of the Transition Program hinges not only on Commission action, but on coordination of existing processes in progress at the Commission, CAISO and CEC and changes to CAISO tariffs. For example, the CAISO’s Flexible Resource Adequacy Criteria Must Offer Obligation process (FRACMOO-2), will include a must offer obligation for RMR so that flexible and system capacity attributes of RMR resources are not lost. Specific reforms to the CPM and RMR processes also will be required, including (1) adopting a definition of “Essential Reliability Resource,” (2) establishing a process for a three-year ERR forecast, which will need to be coordinated with these solutions, (3) coordinating central buying with the Commission’s multi-year program and (4) facilitating payment to LSEs who purchase certain resources to the benefit of all LSEs. In addition, coordination of Local RA and Flexible RA programs must be ensured. All of these activities will drive the success of the Transition Program and should be considered in another phase of this proceeding, in coordination with the CAISO.
In addition, any central buying program, including the Transition Program, should be reviewed on a regular basis to ensure it is achieving the desired goals. CalCCA recommends that the first review take place 18 months after the commencement of the central buying program, with annual updates thereafter.

IV. LONG-TERM LOCAL RA STRATEGY

The Track I Decision, following the Scoping Memo, appropriately focused on reducing out-of-market procurement, using a multi-year Local RA program and increased transparency to LRA needs. While this objective is important in the near term, solutions should not end with improvements in the way Local RA is procured under local area constraints. As long as these constraints exist, they will confer market power on certain generators, preventing “competitive” procurement, and support continued reliance on fossil fuel generation. The Commission and stakeholders must complement their efforts to develop a multi-year program with a structured process toward the ultimate objective: reducing or eliminating the local area constraints that cause out-of-market procurement in ways that promote decarbonization and benefit DACs. CalCCA’s Long-Term Strategy offers a practical approach to begin this discussion, relying on existing regulatory mechanisms.

Distributed energy resources (DER) hold particular promise in relieving constraints and thus play a central, although not exclusive, role in the Long-Term Strategy. LCAs are typically densely populated areas, and most are currently experiencing high rates of DER adoption, which over time changes the shape and size of local-area demand and local-reliability needs. The latest indication of the potential for DER is in the 2017-18 comprehensive transmission plan, which identifies $2.6 billion
savings from eliminating or downsizing previously-approved transmission upgrades.

These reductions were for reliability upgrades to support constrained areas of the grid.

The Oakland Clean Energy Initiative, recently approved in the 2017-18 comprehensive transmission plan, offers an example of the successful elimination of a fossil generating plant that was needed for local reliability by a combination of grid assets and preferred DERs. CalCCA’s proposed Long-Term Strategy builds on state policies and trends by advancing the growth of preferred resources, including DER, as a solution for local area constraints.

The Long-Term Strategy focuses on two necessary areas of activity, which together can accelerate elimination of market power in LCAs and replacement of fossil-fuel generation with DER. At a policy level, the Commission must resolve open questions that currently present barriers to deploying DERs. If these questions are resolved, then cost-effective DER-based solutions can reasonably be evaluated and adopted through the CAISO transmission planning process as non-wires alternatives (NWA).

Movement toward the ultimate goal will take time, requiring reliance in the interim on a multi-year program like CalCCA’s Transition Program. Recognizing the demands of time, CalCCA recommends adopting a process and general goals in its decision in this Track to initiate longer-term strategies. CalCCA proposes adoption of its Long-Term Strategy to provide such a framework.

A. Removing Existing DER Barriers

Two challenging areas must be addressed to facilitate the desired long-term transition of California’s grid reliability needs through DER deployment. One is the matter of resource valuation and appropriate cost recovery, which requires regulatory
resolution by the Commission; the other has to do with operation of DERs as grid assets, which will involve coordination between the CAISO and the relevant distribution utility to support DER provision of transmission services.

DER deployed to offset local grid constraints have unique value that can be compensated in different ways. In concept, if the DER deployment is fully intended for offsetting the need for further transmission build-out, then such DER deployment could be treated as a cost-based ATS (i.e., a transmission asset), thereby having its costs recovered through transmission rates. One complication with the ATS path, however, is that transmission assets become part of the CAISO controlled grid and as such are subject to CAISO operational control. But to integrate DER as transmission assets will require rules and procedures for coordination between the CAISO, the distribution utility and the DER operator to ensure that the DER is able to deliver the needed transmission services over the distribution system. To date such coordination procedures have not yet been developed; developing such procedures will require collaboration between the CAISO, the distribution utilities, and DER providers, with Commission review of any implementation needs of the IOUs. Another complication to the ATS path for DER is the need to establish methodology under the locational net benefits analysis (LNBA) element of the DRP framework to quantify the transmission benefits of DERs. Policy resolution by the Commission is important to ensure that DERs are fully compensated for the value they provide.

Alternatively, the same DER may also help defer the need for distribution grid build-out, therefore it may be appropriate to recover some of the build-out costs through distribution rates. In this scenario the same DER would be engaged in “multi-use
applications” (MUA), i.e., providing services to and receiving compensation from two different entities: the CAISO with regard to the provision of transmission services, and the distribution utility with regard to provision of distribution services. This is an attractive scenario because the ability to “stack” services and revenue sources would increase the financial viability of the DER. However, it raises other unresolved MUA issues, including priorities among service obligations when needs of the CAISO and distribution utility may be in conflict, and measurement of the resource’s performance so as to ensure that both the CAISO and the distribution utility compensate the resource accurately for services received.

There are other cost allocation issues related to MUA that must also be addressed. For example, if a storage resource procured by an IOU serves both generation needs and distribution system functions, there is the potential for costs of generation services that benefit the IOU’s bundled customers to be characterized as distribution costs and thereby shifted to other LSEs’ customers. The specific matter of appropriate cost recovery for energy storage MUA is currently under consideration in consolidated A.17-12-002 and A.17-12-003 but may also require consideration for other resources.

The CAISO is presently exploring one type of MUA through its “Storage as a Transmission Asset” stakeholder initiative. The scenario being considered is one where the storage asset provides transmission services to the CAISO for part of its cost recovery and participates in the CAISO market for the rest. This is an important first step toward operationalizing MUA by allowing dual cost recovery mechanisms for the same facility.

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30 For details on rules adopted to date and open issues regarding MUA of storage resources see the Commission’s January 17, 2018 decision in Track 2 of the Energy Storage Proceeding, R15-03-011, in particular section 4.2 on open issues assigned to continuing working groups.
one through transmission rates and another through market revenues. But the scope is limited to transmission-connected resources at this time, out of necessity to set aside the matter of operational coordination with the distribution utility that a DER would require. Consequently, there is still a need to develop a coordination framework to enable CAISO operational control of a DER-based ATS.

Up to now, DER deployment has been compensated primarily through services the DER provides to end-use customers (i.e., typically installed behind the meter) and to LSEs as energy and RA capacity resources, rather than as grid assets obtaining cost recovery through distribution or transmission rates. Thus, for the next few years the NWA path, which treats the DER solutions as resources rather than grid assets, will be the most accessible path for DER to address local reliability needs without building new transmission. The challenge here, though, is that even though DER in this scenario offset the need for a transmission upgrade, they do not receive any compensation reflective of the avoided cost of that upgrade and must rely entirely on contracts with LSEs and revenues from the CAISO spot markets. An important open policy question is whether and how DERs targeted to offset transmission upgrades for local reliability can receive the avoided-cost value they provide, without shifting costs between bundled customers and the customers of other LSEs.

As the Commission and various stakeholders consider and work through the DER-related challenges of valuation, compensation, and operations, the Commission could explore the merits of establishing incentives to further state policies through preferred resource solutions to local reliability needs. One possibility could be for the Commission to explore the merits of using Greenhouse Gas (GHG) allowance revenues
or other revenue sources as funding pathways for incentives to prioritize the build-out of local preferred resources alternatives within DACs. Another opportunity could be the potential for the CPUC and the CEC to coordinate and partner to structure incentives and pilots of new DER technologies and control systems that would further reduce Local RA needs.

The valuation and compensation questions surrounding DER, which the Commission began to tackle in the IDER and DER proceedings, are complex and have yet to be solved. CalCCA recommends that the Commission rededicate its efforts toward a multi-agency approach, including the CAISO and CEC in a process aimed to resolve the issue over the next year to support preferred resource solutions by late 2019.

B. Implementing DER Solutions to Transmission Constraints

The CAISO Transmission Planning Process (TPP) identifies transmission upgrades that most cost effectively eliminate or substantially reduce LCA constraints, including sub-area constraints. The Commission and the CEC inform the TPP by providing a range of information, including scheduled power plant retirements, the IEPR demand forecast and forecasts of load modifiers (energy efficiency, electric vehicle and rooftop solar adoption), necessary to support the development of an accurate transmission plan. For the current 2018-19 planning cycle the CAISO has already committed to perform such studies for some of the LCAs, with a particular focus on eliminating fossil-fuel generation and improving air quality in disadvantaged communities, and will provide the results in fourth quarter this year. A coordinated initiative between the Commission and the CAISO, addressing three key areas, could further enhance the TPP and enable increased integration of DER solutions.
First, unless there is a driving reliability need for transmission upgrades, a transmission upgrade to relieve LCA needs must be evaluated as an economic project. This requires that the proposed transmission solution must provide net economic benefits compared to the status quo. The CAISO evaluates economic transmission alternatives using its Transmission Economic Assessment Methodology (TEAM). This methodology considers a range of benefits in evaluating transmission alternatives, including economically driven transmission evaluation criteria and other benefits (e.g., limited “public policy benefit”). Further coordination with the CAISO to ensure the methodology fully considers the benefits and values represented by state policy goals would improve the success of DER solutions.

Second, the TPP today does not provide sufficiently detailed information to allow LSEs and developers to evaluate and propose suitable solutions. CalCCA’s Long-Term Strategy contemplates that the CAISO would specify performance requirements that an NWA or ATS must meet to avoid the transmission upgrade. Once the CAISO provides this information in the course of its TPP, parties could propose an NWA or ATS to meet the same need with local preferred resources. CalCCA proposes initially targeting areas where central buying is required (due to market power concerns) and where local reliability requires fossil-fuel resources that may not yet be scheduled to retire, with the aim of ultimately removing the need for this procurement. LSEs could propose, perhaps in partnership with DER developers or distribution grid operators, effective solutions that help to enhance the affordability of clean energy resources in DACs.31

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31 The 2016 EPIC grants for “Advanced Energy Communities” administered by the CEC offer examples of innovative clean energy and resilience project funding targeted to DACs and other communities. This program did not, however, specifically target reduction of Local RA
Third, timing considerations warrant exploration. A goal should be to ensure that CAISO solicitations in the TPP process for NWAs and ATS are well timed and designed to solicit preferred resource DER project solutions. Consideration must be given the timing and interplay of the TPP and the IRP to maximize the development of alternatives and accelerate implementation. Furthermore, any refinements to Commission-based policies regarding DER valuation and compensation, discussed above, must be reached expeditiously and implemented in sync with the TPP and IRP processes.

C. **Long-Term Strategy Benefits**

The Long-Term Strategy may be perceived as a formalized, natural extension of current trends and the existing relationship between the Commission, CAISO and other stakeholders. Looking closer, however, it changes the local reliability landscape in two key ways, (1) more directly targeting preferred resource development to address local reliability needs and (2) providing all stakeholders with the same information on reliability requirements in a transparent and coordinated manner.

Currently the adoption of DER has not been targeted to offset local capacity or transmission needs; the $2.6 billion in reduced transmission needs has been a positive but unintentional side effect of rapid DER growth through customer adoption. In contrast, the Long-Term Strategy would build on presently unstructured DER adoption by explicitly targeting preferred resource development, including additional DER adoption, to offset LCRs. Importantly, however, the Long-Term Strategy would enable all LSEs (or groups of LSEs) – not only IOUs -- to participate in developing solutions.

needs, which ought to be a consideration in designing future community-focused grant programs. For a summary of the awards see: https://www.lgc.org/epic-approach-advanced-energy-communities/
The Commission’s Resolution E-4909 issued earlier this year is a useful example of targeted procurement of preferred resources to meet local reliability needs. The Resolution authorized PG&E “to hold competitive solicitations for energy storage and/or preferred resources, to meet specific local area needs in three specified subareas.”

Resolution E-4909’s implicit rationale for directing PG&E to procure the desired local resources to the exclusion of other LSEs was apparently one of urgency: “Resources procured pursuant to this solicitation must be on-line and operational by a date sufficient to ensure that the RMR contracts for the three plants – Metcalf Energy Center, Feather River Energy Center, and Yuba City Energy Center – will not be renewed for 2019.”

In fact, however, none of the resources procured by PG&E will be in service on time to meet this requirement of the Resolution. Of the total 567.5 MW of energy storage PG&E proposes to procure, only 10 MW come on-line in October 2019 and the rest only in December 2020, so there will be no impact on local reliability needs until the 2021 RA compliance year. Directing the utility to undertake the desired procurement is unnecessary and unfairly imposes costs on other LSEs and their customers over which they have no input or control. Instead, the Commission should focus its efforts on facilitating a broader opportunity for all LSEs and other stakeholders to procure local preferred resources to offset grid reliability constraints that drive a continued reliance on an aging and polluting fossil-fuel generation fleet. This principle is at the heart of CalCCA’s Long-Term Strategy proposal.

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32 Resolution E-4909 at 1.
33 Id. at 9.
34 PG&E Advice Letter 5322-E page 1.
D. Long-Term Strategy Implementation

The current 2018-19 CAISO transmission planning cycle provides an opportunity to launch the Long-Term Strategy. In April, the CAISO announced a transmission study plan for the current 2018-19 planning cycle aimed at eliminating or reducing as far as possible LCRs in a selected set of LCAs, chosen with the objective of eliminating reliance on local fossil-fuel resources. The CAISO has indicated its intent to identify, by fourth quarter of this year, the economic transmission projects that would be most cost-effective in eliminating the Local RA needs. For those LCAs where the transmission solution would provide net economic benefits, the CAISO would include these projects in its 2018-19 comprehensive plan for Board approval. The current CAISO approach does not, however, explicitly allow an opportunity for parties to propose an NWA or ATS to meet the same needs, other than through the relatively brief stakeholder comment period following the fourth quarter stakeholder meeting.

The CalCCA proposal would extend the window for submission of NWA or ATS by stakeholders to the fourth quarter of the next TPP cycle – to the end of 2019 in this first year iteration. This extension is particularly important for LCAs where existing fossil-fuel resources are not yet scheduled to retire, and the CAISO’s identified transmission upgrade may not meet the economic benefit-cost requirements for approval. Allowing sufficient time to develop cost-effective preferred-resource alternatives could be the pivotal factor in eliminating the need for the local fossil resource.

The Long-Term Strategy anticipates the CAISO’s completion of its current assessment of the selected LCAs this year. Over the following two annual transmission

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planning cycles the CAISO would similarly study all LCAs in the system. Design of
NWA/ATS proposals by stakeholders could begin by the end of 2018 for the LCAs the
CAISO studies this year, with the DER-based NWA/ATS potentially implemented within
the two to three years following CAISO assessment and selection of the preferred
alternatives in the 2019-20 TPP cycle. Thus, the LSEs would use the results of the
CAISO planning studies to participate in developing NWA/ATS to address local
reliability needs, and would include such projects in their IRPs. Any such development
of NWA or ATS would also be included in the LSE’s IRPs. At the Commission level the
combination of all LSE IRPs would then reflect the Long-Term Strategy to implement
local preferred resources to ensure local area reliability while phasing out fossil-fuel
resources that have been needed for this purpose, rather than assuming indefinite
continued reliance on the non-OTC fossil resources to support local reliability.

V. CONCLUSION

Near-term implementation of CalCCA’s multi-year Transition Program promises
to change the way in which Local RA is procured, with the aim of reducing out-of-market
procurement and overprocurement thereby reducing Local RA procurement costs overall.
This approach not only will achieve these initial goals, but will avoid the need for
material structural changes by capitalizing on existing procurement mechanisms and
institutions. The evolution of Local RA procurement should not stop, however, with
improvements in the way Local RA is procured in the short term. As long as local
constraints exist, they will confer market power on certain generators who will be able to
demand sufficient payment to run indefinitely. Expecting resources with partial or
complete market power to negotiate “competitive” rates that resemble the short-term
price for Local RA is unrealistic. The Commission must thus complement the Transition Program with a structured step toward the ultimate objective: reducing or eliminating the local area constraints that cause out-of-market procurement through deployment of resources that promote decarbonization and benefit DACs. CalCCA’s Long-Term Strategy offers a framework to begin this journey. For these reasons, CalCCA recommends the adoption of the Transition Program and the Long-Term Strategy.
APPENDIX A

Local Reliability

Transition Program

Process Overview and Timeline
<table>
<thead>
<tr>
<th>Step</th>
<th>Due Date</th>
<th>CPUC</th>
<th>CAISO</th>
<th>CEC</th>
<th>CPUC LSEs</th>
<th>Munis</th>
<th>Central Buyer</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>1-Feb</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>CEC provides to CAISO peak demand forecasts used for System and Local RA.</td>
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<tr>
<td>1</td>
<td>31-May</td>
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<td>IOUs provide CAM forecasts for each year of the upcoming RA cycle to CPUC.</td>
</tr>
<tr>
<td>2</td>
<td>31-May</td>
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<td></td>
<td></td>
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<td></td>
<td>CAISO completes 3-year forward Local and Flexible Capacity Study and provides the list of ERR resources (years 1 through 3) to CPUC.</td>
</tr>
<tr>
<td>3</td>
<td>30-Jun</td>
<td></td>
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<td></td>
<td></td>
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<td></td>
<td>CPUC allocates net local RA requirements (years 1 through 3) to CPUC-Jurisdictional LSEs, and CAISO allocates net local RA requirements (years 1 through 3) to Munis.</td>
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<td>4</td>
<td>30-Sep</td>
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<td></td>
<td>CPUC-Jurisdictional LSEs and Munis submit RA filings to CPUC and/or CAISO, demonstrating 90% of net LRA requirements for year 1, 90% of net LRA requirements for year 2 and 80% of net LRA requirements for year 3. No LSE cure period will be provided.</td>
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<td>5</td>
<td>1-Oct</td>
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<td></td>
<td>CPUC-Jurisdictional LSEs and Munis submit RA filings to CPUC and/or CAISO, demonstrating 90% of net LRA requirements for year 1, 90% of net LRA requirements for year 2 and 80% of net LRA requirements for year 3. No LSE cure period will be provided.</td>
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<td>6</td>
<td>1-Nov</td>
<td></td>
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<td></td>
<td></td>
<td>CAISO performs local RA Residual needs assessment for year 1 and announces results. Assessment is based on the need to achieve 100% of local RA need for year 1, including addressing any problematic sub-local-area constraints.</td>
</tr>
<tr>
<td>7</td>
<td>1-Dec</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Central Buyer</td>
<td>Central Buyer procures the Residual, including ERR capacity not already procured by LSEs.</td>
</tr>
<tr>
<td>8</td>
<td>21-Dec</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>CAISO performs final Year-Ahead local RA assessment to ensure that all Year 1 Local RA needs have been procured. Notifies LSEs of any deficiencies.</td>
</tr>
<tr>
<td>9</td>
<td>15-Jan</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td>If needed, CAISO uses CPM backstop authority to procure the remaining required Year 1 Local RA resources, and CAISO accordingly allocates RA credits to LSEs and Munis.</td>
</tr>
<tr>
<td>10</td>
<td>15-Jan</td>
<td></td>
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<td></td>
<td></td>
<td>January Year 1 load migration forecasts submitted by CPUC-Jurisdictional LSEs and Munis to CPUC and/or CEC.</td>
</tr>
<tr>
<td>11</td>
<td>15-Feb</td>
<td></td>
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<td>January Year 1 Month Ahead RA filing (T-45). CPUC-Jurisdictional LSEs and Munis submit RA filings to CPUC and/or CAISO.</td>
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CalCCA Proposed Local RA Timeline – April 1 Compliance Year

2/1 CEC provides forecast to CAISO
5/31 IOUs provide CAM forecast to CPUC
5/31 CAISO issues LCR Study
6/30 CPUC Allocates RA to LSEs
9/30 LSEs procure RA
10/1 LSEs submit Local RA filings for 3 years

2/15 LSEs file RA compliance with CPUC
1/15 LSEs submit load migration forecasts
1/15 CAISO procure CPM
12/21 CAISO performs final Local RA Analysis
12/1 Central Buyer procures Residual Local RA
11/1 CAISO performs Local RA analysis for Year 1
WITNESS QUALIFICATIONS

Lorenzo Kristov

Dr. Richard McCann

Shehzad Wadalawala
Résumé

Lorenzo Kristov, PhD
Principal Consultant – Electric System Policy, Structure, Market Design
PO Box 927, Davis, CA 95617, USA; email LKristov@cal.net; mobile +1 916 802-7059

Experience

Independent Consultant (December 2017 to present)

Current focus is on various aspects of power system evolution to high levels of renewable generation and distribution-connected energy resources (DER). Areas of expertise include: wholesale market design; market participation by DERs and DER aggregations; multi-use applications of DERs; coordination of transmission and distribution operations, markets and planning; distribution system operator (DSO) models for distribution utilities; transmission planning policy and alternative transmission and non-wires solutions; international comparison of TSO-DSO coordination models; community energy systems and microgrids; whole-system grid architecture.

Recent projects include:

Participation in and filing of individual comments on the Federal Energy Regulatory Commission technical conference on “Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators”; Docket RM18-9-000; June 2018


Co-author of “Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design”; prepared for the Australian Energy Market Operator (AEMO); May 2018


Principal, Market and Infrastructure Policy (2004-17); Manager, Market Design (1999-2004)

Led major market design and infrastructure policy initiatives, which entailed leading internal cross-departmental teams to develop proposals, conducting public stakeholder meetings to gather input, revising proposals to reflect stakeholder concerns, presenting final proposals to CAISO Board of Governors for approval, working with CAISO Legal department to prepare FERC filings (detailed proposal description and rationale, tariff revisions and expert testimony), appearing at FERC technical conferences, addressing FERC-ordered compliance requirements and supporting internal departments to implement FERC-approved market elements and tariff changes. Most initiatives were CAISO-initiated, but some were in compliance with new FERC rulemakings (e.g., Order 1000).
A central requirement of this position has been to apply whole-system thinking to structure each initiative to align the immediate needs of the problem to be addressed, the diverse objectives and concerns of the stakeholders, relevant regulatory constraints and requirements, and the priorities and responsibilities of the CAISO as a whole and its affected functional departments: grid operations, infrastructure planning, market performance.

Some specific major projects:

Initiated and led ongoing staff working group between CAISO and distribution utilities to identify needs and develop procedures for operational coordination at the transmission-distribution interfaces to enable distribution-connected resources (DER) and aggregations to participate in CAISO markets. (2016-17)

Represented CAISO in ongoing trans-Atlantic working group to describe and compare US and European approaches to transmission-distribution interface coordination with high DER. (2017)

Led CAISO-CPUC staff collaboration to develop a framework for multiple-use applications of energy storage, as part of the CPUC’s Energy Storage Track 2 proceeding. (2016-17)

Led initiative to address cost allocation for existing transmission infrastructure and new projects under an expanded ISO/RTO structure for the western region. (2015-16)

Redesign of CAISO’s new resource interconnection procedures to manage the large volume of new interconnection requests driven by anticipated procurement to meet California’s Renewable Portfolio Standards (RPS), including the interconnection study process, management of the interconnection queue, and coordination between generator interconnection and transmission planning processes. (2011-12)

Redesign of CAISO’s transmission planning process to address impacts of RPS procurement on transmission needs to deliver energy and capacity from renewable generation facilities; included addition of a new public-policy-driven category of transmission, coordination with state agencies to identify RPS procurement patterns that would drive transmission needs, and a competitive solicitation process for third party developers to build, own and operate transmission projects. (2009-10)

Initiated and led internal CAISO Strategic Roadmap Process, a cross-departmental team to map energy industry trends nationally and in the west and identify highest priority areas for CAISO focus in the coming years; performed in 2009, this roadmap led directly to the major redesigns of transmission planning and generator interconnection procedures noted above.

Comprehensive redesign of CAISO markets following the 2000 energy crisis to implement locational marginal pricing (LMP) market structure, including day-ahead and real-time markets, financial transmission rights, and integration of pre-existing bilateral transmission contracts. (2002-09)


Represented the CEC in state proceedings and collaborative working groups to design the new provisions needed to implement the retail choice elements of California’s electric restructuring legislation, AB-1890. Specific subjects included qualification of retail direct access providers, definition of “meter data management agent” (MDMA) function, and creation of distribution node identifier scheme for tracking changes of end-use customer, retail provider and metering device at each end-point of the distribution system. Facilitated several working group activities and co-authored working group reports; co-authored CEC regulatory filings at the CPUC.

Fulbright Scholar, Indonesia (April 1993 to December 1994)

As an independent researcher, met with Indonesian government officials, private companies, consultants, USAID and World Bank personnel to describe and assess economic and structural
landscape for direct foreign investment in electric power infrastructure needed to support and sustain industrial growth.

**Education**

PhD Economics, University of California Davis, 1994

MS Statistics, North Carolina State University, 1969

BS Mathematics, Manhattan College, 1967

**Relevant recent articles**


Professional Experience
Aspen Environmental Group, Senior Associate, 2008-2013
Dames & Moore, Economist, 1985-1986

Academic Background
PhD, Agricultural and Resource Economics, University of California, Berkeley, 1998
MS, Agricultural and Resource Economics, University of California, Berkeley, 1990
MPP, Institute of Public Policy Studies, University of Michigan, 1986
BS, Political Economy of Natural Resources, University of California, Berkeley, 1981

Dr. McCann has analyzed many different aspects of energy utility and market operations in California. He has testified numerous times before the CPUC on impacts of electricity rates on agricultural groundwater pumping, reimbursement to master-metered manufactured housing community customers for utility services, competitive fuel choices, and proposed drought-mitigation policies. He has testified on the appropriate level of exit fees for community choice aggregators, and appropriate protection of solar project investment by customers. He also testified before the Federal Energy Regulatory Commission in the California energy crisis Refund Proceeding. He has worked with the California Energy Commission to estimate the costs for new alternative generating technologies and developing several system modeling tools for local capacity planning and renewable generation integration. For the CEC, he examined the potential consequences of decommissioning the dams on the Klamath River, and for the SWRCB, the changes in greenhouse gas emissions from hydro licensing conditions. He also led the modeling efforts on behalf of the California Public Utilities Commission to assess the environmental impacts of proposed generation plant divestitures.

Projects

Energy, Hydropower and Utilities

Regulatory Analysis and Support, Sonoma Clean Power (2016-present). Testifying at the California Public Utilities Commission (CPUC) in Pacific Gas and Electric’s (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) “exit” fee and other issues.

Regulatory Analysis and Support, CalChoice (2017). Testifying at the California Public Utilities Commission (CPUC) in Southern California Edison’s (SCE) rate proceedings on the power charge indifference adjustment (PCIA) “exit” fee and other issues.

Agricultural Rate Setting Testimony, Agricultural Energy Consumers Association (1992-present). Testified about agricultural economic issues related to energy use, linkage to California water management policy, and utility rates in numerous proceedings at the California Public Utilities Commission, California Energy Commission, and California State Legislature. Analyzed various aspects of electric industry restructuring; proposed innovative pricing options; examined marginal cost principles and applications, and testified in a large number of energy related hearings. Developed innovative rate
Dr. Richard McCann, page 2

allocation methodology that incorporated regional marginal costs and value of service planning based on the Pacific Gas and Electric Co. Area Cost Study.

Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-present).
Testified before the California Public Utilities Commission on

Master-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-present). Examined issues associated with the structure of and cost associated with providing electric service to master-metered mobile home parks. Testified in Pacific Gas and Electric Co., Southern California Edison Co., Southern California Gas Co. and San Diego Gas and Electric Co. rate proceedings on establishing “master-meter/submeter credits” provided to private mobile home park utility systems.

Master-Metered Utility Systems Transfer Program, Western Manufactured Housing Communities Association (2003-present). Prepared petition that opened a rulemaking to facilitate transfer of master-metered utility systems to serving utilities and testified in that proceeding. Testified before the State Legislature on proposed legislation. Persuaded all electric and gas utilities in California to institute a pilot program to convert 10% of privately-owned MHP systems to utility ownership.

Community Solar Gardens Testimony, Sierra Club (2014). Testified in Pacific Gas and Electric and Southern California Edison Green Tariff applications on changes needed to encourage the development of neighborhood and community-scale renewable distributed generation by allowing direct contracting and removing unnecessary transaction costs.

Time of Use Rates in California Residential Rates Rulemaking, Environmental Defense Fund (2013-2014). Modeled how increased penetration of TOU rates in the residential sector for all three investor-owned utilities would reduce peak and energy demand, reduce residential bills, and reduce utility costs. Changes in revenues and costs were developed from the utilities’ most recent general rate case filings.


Professional Affiliations
American Agricultural Economics Association
Association of Environmental and Resource Economists
American Economics Association

Civic Activities
Member, City of Davis Utilities Rate Advisory Commission
Former Member, City of Davis Community Choice Energy Advisory Committee
Co-Chair, Cool Davis Energy Steering Committee
Member, Western Manufactured Housing Communities Association Utilities Task Force
Former Member, City of Davis Citizens Electricity Restructuring Task Force
Former Member, Yolo County Housing Commission
Member, Phi Beta Kappa Honorary Fraternity
Work Experience

The Energy Authority (“TEA”), Oakland, CA

Client Services Manager  (7/16-present)

- Serve as Product Owner relating to the design, development and implementation of day-ahead and real time market services for TEA’s CAISO operations;
- Work with clients and TEA’s Portfolio Management and Analytics groups to define portfolio positions and develop hedging strategies
- Support client procurement activities by developing solicitation materials, including protocols, offer forms and contract templates and by providing assistance evaluating offers

SolarCity, San Francisco, CA

Sr. Manager, Grid Engineering Solutions  (8/15-4/16)

- Led preparation of response to Innovative Storage Models RFI for ConEdison and Orange & Rockland
- Evaluated partnership opportunities with Community Choice Aggregations (CCAs), Electric Service Providers (ESPs), Municipal Utilities and Investor Owned Utilities (IOUs) focused on Distributed Energy Resources (DERs)
- Supported utility scale development team in understanding target wholesale markets

California Clean Power, Windsor, CA

Associate Director of Procurement  (3/15-8/15)

- Authored key technical sections of Feasibility Reports for Community Choice Aggregation (CCA) formation; jurisdictions analyzed include Lake and Humboldt County
- Analyzed utility tariffs and filings to determine risks to company business model with particular focus on Non-Bypassable Charges (NBCs) such as the Power Charge Indifference Adjustment (PCIA) and Cost Allocation Mechanism (CAM)
- Identified potential Scheduling Coordinator (SC) Agents and negotiated contract for services

University of California Office of the President, Energy Services Unit, Oakland, CA

Associate Wholesale Electricity Program Manager  (2/14-3/15)

- Led key implementation efforts for The Regents of the University of California to become its own Electric Service Provider (ESP) and serve its Direct Access campus accounts beginning January 2015
- Managed the Scheduling Coordinator (SC) contract including all relevant activities with the California Independent System Operator (CAISO) to be ready to submit daily load and generation schedules
- Solicited, selected and managed a Back Office provider; all eligible accounts were successfully transferred in January 2015
- Tracked, prepared and submitted numerous regulatory filings at the California Public Utilities Commission (CPUC), California Energy Commission (CEC), California Independent System Operator (CAISO), California Air Resources Board (ARB); all obtained approval
- Developed Request for Offer protocols for long-term solar solicitation; served on the evaluation committee and member of negotiating team that executed two 25-year Power Purchase Agreements (PPAs) totaling 80 MW of capacity

Pacific Gas and Electric Company – Portfolio Management, San Francisco, CA

Manager, Commodity Transactions  (4/12-1/14)

- Managed a team of five employees responsible for:
  1) Preparation of Resource Adequacy (RA) Annual and Monthly Compliance Filings
  2) Execution of RA Request for Offers (RFOs)
  3) Implementation of the Electric Hedging Program
  4) Management of the Congestion Revenue Rights (CRRs) Portfolio
  5) Procurement of GHG Compliance Instruments
  6) Compliance with Energy Delivery Requirements for out-of-state Renewable Resources
- Prepared strategy and informational papers on highly technical material for members of the Risk Policy Committee (RPC)
Pacific Gas and Electric Company – Portfolio Management, San Francisco, CA
Principal, Short Term Portfolio Management (5/11-4/12)
- Led Resource Adequacy Request for Offers (RFOs); coordinated with Portfolio Management, Contract Management, Credit Risk, Legal and Compliance teams to ensure sufficient procurement to meet Resource Adequacy Requirements and ensure full cost recovery for procurement costs
- Coordinated talking points and written comments for AB32 Regulation (“Cap and Trade”) for commercial team; resulted in favorable outcomes for PG&E most notably, obtaining fungibility of compliance instruments within compliance periods
- Contributed extensively to development of new Combined Heat and Power (CHP) Tolling Power Purchase Agreement (PPA), including recommending significant changes to Uninstructed Imbalance Energy and GHG Obligation Settlement sections and led development of a new Operational Flow Order (OFO) section in response to feedback from Electric Fuels Management about the increasing frequency of OFOs and associated commercial risks

Pacific Gas and Electric Company – Market Design and Monitoring, San Francisco, CA
Supervisor, Market Analysis (6/10-5/11)
- Supervised production, presentation and distribution of Market Redesign and Technology Upgrade (MRTU) Quarterly Report that included detailed discussion of CAISO market performance, key market issues, and financial risks for PG&E; presented to Senior Management
- Developed and supervised implementation of a comprehensive Convergence Bidding monitoring framework collaborating with Short Term Electric Supply; spearheaded analysis that identified gaming behavior and resulted in PG&E successfully advocating for suspension of convergence bidding at intertie locations.
- Educated Energy Procurement staff on CAISO markets through biweekly Market Talk Seminar Series that covered a range of CAISO topics including Convergence Bidding, Participating Intermittent Resource Program (PIRP), Oversupply Conditions and Negative Pricing, Congestion Revenue Rights (CRR’s), Locational Marginal Prices (LMP’s), Co-Optimization of Energy and Ancillary Services, Residual Unit Commitment (RUC), and Real Time Imbalance Energy Offset

Pacific Gas and Electric Company – Short Term Electric Supply, San Francisco, CA
Senior Analyst (7/08-6/10)
- Spearheaded development of business case for company participation in Convergence Bidding, including coordinating Risk Policy Committee (RPC) draft, contributing to upfront and achievable standards drafts, working with Information Technology and the Project Management Office to develop implementation cost estimates and collaborating with Market Risk Management, Market Design and Analysis and the Legal Department to identify potential risks
- Reformulated day-ahead optimization problem as a multi-day optimization reducing uneconomic cycling of thermal resources and improving commitment process for long-start resources
- Designed analytical tools and trading guidelines for real-time traders to manage price exposure

Pacific Gas and Electric Company – Quantitative Analysis, San Francisco, CA
Quantitative Analyst (6/04-7/08)
- Designed Microsoft Excel template that calculated energy values, risk-hedging metrics and generates summary sheets for physical assets (evaluated Gateway Generation Station project with template)
- Reformulated day-ahead scheduling optimization problem implemented in Short Term Electric Supply to include startup costs, ramping constraints and ancillary services increasing scheduling efficiency
- Developed gas asset strategy model to simulate cost outcomes for different portfolios of pipeline capacity and storage (model was used to evaluate investment in Ruby Pipeline capacity)

Education
University of California, Berkeley
PhD ABD Industrial Engineering and Operations Research (August 2003 - June 2008)
B.S. Industrial Engineering and Operations Research, August 2003; Public Policy Minor

Merits
8/99-5/03 University of California Regents’ & Chancellor’s Scholarship
10/01-5/03 Alumni Emerging Leader Scholarship