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Decision 20-06-002 June 11, 2020

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.	Rulemaking 17-09-020

DECISION ON CENTRAL PROCUREMENT OF THE RESOURCE ADEQUACY PROGRAM

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DECISION ON CENTRAL PROCUREMENT OF THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts implementation details for the central procurement of multi-year local Resource Adequacy procurement to begin for the 2023 compliance year in the Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) distribution service areas, including identifying PG&E and SCE as the central procurement entities for their respective distribution service areas and adopting a hybrid central procurement framework. The decision declines to adopt a central procurement framework for the San Diego Gas and Electric distribution service area at this time.

This proceeding remains open.

1. Background

In January 2018, a Scoping Memo and Ruling was issued in this proceeding that organized the issues for this rulemaking. Track 1 encompassed top priority modifications to the Resource Adequacy (RA) program and included:

> RA program reforms necessary to maintain reliability while reducing potentially costly backstop procurement. These…may include central buyers, a multi-year procurement framework for Local RA (and associated cost allocation), as well as other proposals to address out-of-market procurement and increase transparency.[1]

In June 2018, the Commission issued Decision (D.) 18-06-030 in Track 1 of this proceeding, in which the Commission discussed and analyzed whether

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[1] Scoping Memo at 6.

central procurement or load serving entity (LSE)-based procurement was most appropriate for local RA procurement. The Commission concluded that:

> [W]e believe that a central buyer system – for at least some portion of local RA – is the solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection.[2]

In D.18-06-030, the Commission directed parties to propose central buyer structures in Track 2 that include a single central buyer or a single central buyer per Transmission Access Charge (TAC) area, and to address the ability of the central buyer to procure all available resource attributes (*e.g.*, flexible RA), not just local RA requirements. We stated that all central buyer proposals must address balancing "economic procurement criteria with other essential state policies, such as greenhouse gas emissions reductions targets and consideration of impacts on disadvantaged communities."[3] We also noted that we "remain concerned that a centralized capacity market may not meet these objectives."[4]

Track 2 opening testimony was served on July 10, 2018 by: the Alliance for Retail Energy Markets (AReM); California Community Choice Association (CalCCA); California Energy Storage Alliance (CESA); California Independent System Operator (CAISO); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); CPower, Enel X North America, Inc. (Enel X), and EnergyHub (collectively, the Joint DR Parties); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Middle

[2] D.18-06-030 at 32.

[3] *Id*. at 33.

[4] *Id*.

River Power, LLC (MRP); NRG Energy, Inc. (NRG); OhmConnect, Inc. (OhmConnect); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US), L.P. (Shell); Sierra Club, California Environmental Justice Alliance, and Union of Concerned Scientists (collectively, the Joint Environmental Parties); Southern California Edison Company (SCE); the Utility Reform Network (TURN); and Western Power Trading Forum (WPTF). The Supply Side Working Group (SSWG) submitted a proposal in the form of comments on July 10, 2018. All testimony was filed with and attached to parties' August 8, 2018 comments, as directed by the Administrative Law Judge (ALJ). The Commission's Energy Division (Energy Division) served its Track 2 proposal on July 12, 2018, which was filed by an ALJ ruling on November 16, 2018.

Comments to parties' opening testimony, in lieu of reply testimony, were served and filed on August 8, 2018. Comments were received from AReM; CalCCA; CEERT; CESA; CAISO; California Large Energy Consumers Association (CLECA); California Wind Energy Association (CalWEA); Calpine; Enel X; GPI; IEP; the Joint DR Parties; the Joint Environmental Parties; Large-scale Solar Association (LSA); LS Power Development, LLC (LS Power); MRP; NRG; Public Advocates Office (Cal Advocates);[5] PG&E; SDG&E; Sentinel Energy Center, LLC (Sentinel) and Diamond Generating Corporation (Diamond) (Sentinel/Diamond); Shell; Sunrun Inc. (Sunrun); TURN; and WPTF. Reply

[5] The Commission's Public Advocates Office (Cal Advocates) was formerly known as the Office of Ratepayer Advocates. Pleadings in this proceeding were filed under both names but the party is referred to as Cal Advocates in this decision.

comments were served and filed on September 14, 2018 by CAISO, CalCCA, Calpine, CEERT, the Joint Environmental Parties, PG&E, SCE, and SDG&E.

On October 5, 2018, the ALJ requested additional comments on SCE's central procurement proposal. Comments were submitted on October 16, 2018 by AReM, CalCCA, Cal Advocates, CLECA, Calpine, GPI, the Joint Environmental Parties, NRG, PG&E, SDG&E, Shell, TURN, and WPTF. On October 24, 2018, CalCCA, CLECA, Calpine, GPI, the Joint Environmental Parties, PG&E, and SCE submitted reply comments.

1.1. Track 2 Decision

In February 2019, the Commission issued D.19-02-022, the Track 2 decision, in which we evaluated proposals for a central procurement structure for local RA procurement, including potential central procurement entities (CPEs) and other implementation details. Considerations for potential CPEs included the distribution utilities, a special purpose entity, and the CAISO. We acknowledged a lack of consensus among parties as to the identity of a central buyer and concluded that:

> The Commission does not find a viable central buyer at this time and thus delays the designation of a central buyer in this decision. The Commission continues to find that a central buyer structure, as outlined in the Track 1 decision, is the appropriate structure to implement multi-year local RA requirements.[6]

The Commission also considered an appropriate central procurement structure – either full procurement, residual procurement, or a hybrid approach.

[6] D.19-02-022 at 14.

We stated again that due to "the lack of a consensus as to a central procurement mechanism that satisfies the objectives outlined in the Track 1 decision, the Commission elects to delay implementation of a central procurement structure to allow additional time for a series of workshops."[7]

We directed parties to undertake a series of workshops to develop "workable implementation solutions for central procurement of multi-year local RA" as follows:

> The implementation details shall include, but are not limited to, the identity of a viable central buyer, the scope of procurement (*e.g.*, full, residual), implementable cost allocation mechanism (*e.g.*, how costs will be tracked and recovered), oversight mechanisms, other procurement details (*e.g.*, resources to be included, selection criteria), market power mitigation tools, and necessary modifications to the RA timeline.
>
> The Commission deems workable implementation solutions are those that specifically address the following known challenges to the local RA program: (1) costly out-of-market RA procurement due to local procurement deficiencies, (2) load migration and equitable allocation of costs to all customers, (3) cost effective and efficient coordinated procurement, (4) treatment of existing local RA contracts, (5) opportunity for and investment in procurement of local preferred resources, and (6) retention of California's jurisdiction over procurement of preferred resources.[8]

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[7] *Id*. at 17.

[8] *Id*.

After workshops, parties were directed to submit informal workshop reports "outlining the recommendations reached and how each recommendation addresses the challenges noted above, into the RA proceeding."[9]

While deferring adoption of the central procurement framework, D.19-02-022 adopted multi-year local requirements to begin for the 2020 compliance year. The decision stated that "LSEs shall procure local resources based on individual local allocations, as is currently done in the RA program, for a three-year forward duration."[10]

1.2. Post-Track 2 Developments

Parties undertook a series of workshops to discuss central procurement proposals, as directed by D.19-02-022. The first and second workshops were held on April 22 and 23, 2019 and were led by PG&E, SDG&E and SCE (collectively, the Joint Investor-Owned Utilities (IOUs)). The third and fourth workshops were held on May 15, 2019 and were led by CalCCA. The fifth and sixth workshops were held on May 22, 2019 and were led by Shell. Informal workshop reports were filed on July 19, 2019 by the Joint IOUs, CalCCA, and Shell.

Comments on informal workshop reports were submitted on August 2, 2019 by: Cal Advocates, CalCCA, CESA, CLECA, Calpine, GPI, MRP, SDG&E, TURN, PG&E, and SCE. Reply comments were filed on August 9, 2019 by CLECA, Calpine, Cal Advocates, NRG, PG&E, SDG&E, and SCE.

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[9] *Id*. at 19.

[10] *Id*. at 28.

On August 9, 2019, a notice of settlement conference was filed by CalCCA, Calpine, IEP, MRP, NRG, SDG&E, Shell, Sunrun, and WTPF. The settlement conference was held on August 20, 2019. On August 30, 2019, a joint motion was filed by CalCCA, Calpine, IEP, MRP, NRG, SDG&E, Shell, and WPTF (collectively, the Settling Parties) for adoption of a settlement agreement for a residual central procurement entity structure for Resource Adequacy.

On September 30, 2019, comments on the proposed settlement were filed by American Wind Energy Association of California (AWEA-CA) and LSA (AWEA-CA/LSA), AReM, CEERT, CESA, Cal Advocates, CAISO, CLECA, Cogeneration Association of America (CAC), Department of Market Monitoring for CAISO (DMM), GPI, the Joint DR Parties, Sunrun, TURN, PG&E, Powerex Corp. (Powerex), SCE, and Vistra Energy Corp. (Vistra). Reply comments were filed on October 15, 2019 by CAISO, CAC, CLECA, Cal Advocates, the Settling Parties, and PG&E. On November 1, 2019, the Commission held a workshop in Sacramento to discuss the proposed settlement, as well as other CPE proposals.

All workshop reports, proposals, and comments have been considered, but given the large number of parties and filings, some proposals and issues may receive little or no discussion or analysis in this decision.

2. Proposed Settlement

2.1. Background

The Settling Parties put forth a proposed Settlement Agreement (Settlement) as to a residual central buyer structure, summarized as follows. The Settlement provides for a CPE that would assume a "default" role in undertaking collective RA procurement in lieu of LSEs' individual procurement obligations.

The CPE would be responsible for ensuring procurement of the "Collective RA Requirement," defined as all RA Capacity required for a delivery period to ensure that aggregated system, flexible and local RA requirements are met. The CPE would "accept all offers at or below the Soft Offer Cap" and "may procure RA Capacity at prices above the Soft Offer Cap when it deems reasonable and consistent with Commission-approved criteria…"[11] After CAISO identifies collective RA deficiencies for the upcoming year, the CPE would use "commercially reasonable efforts to procure additional RA capacity procurement" and "[a]ny deficiency not procured by the RA-CPE may be procured by the CAISO through its backstop procurement authority."[12]

The Settlement does not identify a CPE but asserts that a CPE "will be a competitively neutral, independent, and credit-worthy entity."[13] The CPE will assume responsibility in 2021 for the 2022 RA year.

The Settlement provides that LSEs may voluntarily procure all or some of their share of the local, system, or flexible RA requirements based on the Collective RA Requirement. The Settlement otherwise eliminates individual LSE RA requirements for local, system, and flexible RA to individual LSEs and the need for monthly RA showings. An LSE may voluntarily show procured RA capacity to the CPE on an annual basis and "[a]n LSE's Shown RA will be

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[11] Settling Parties' Settlement Agreement, filed August 30, 2019 (Settlement), Appendix A Term Sheet (Term Sheet) at 4.

[12] *Id*.

[13] *Id*. at 2.

credited against its share of the Collective RA Requirement Target on a MW-for-MW basis, and for Local RA, by local area or subarea."[14]

The CPE's procured capacity costs "will be allocated to each LSE in proportion to the RA Capacity of that type procured on the LSE's behalf. Costs will be allocated on an ex post basis based on the difference between the LSE's actual load, scaled to the prior year's forecast of the Collective RA Requirement, and the LSE's Shown RA."[15] In the event of a default by an LSE, the CPE shall remain revenue neutral through "appropriate cost recovery from remaining LSEs in proportion of their share of the Collective RA Requirement" and "[c]ost recovery will reflect the LSE's actual outstanding Cost Responsibility, net of collateral received."[16]

The Settlement also expands the three-year forward local RA requirement to system and flexible RA and increases the current third year local RA requirement from 50 to 75 percent.

The Settling Parties "request that the Settlement Agreement be reviewed and adopted as a whole. Modification of any one part of the Settlement Agreement would harm the balance of interests and compromises achieved among the Settling Parties."[17]

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[14] *Id*. at 6.

[15] *Id*. at 8.

[16] *Id*. at 9.

[17] *Id*. at 8.

2.2. Responses to the Settlement

Several parties support the Settlement, including AWEA-CA/LSA, AReM, CAISO, Sunrun, and Vistra. Some parties do not explicitly support or contest the Settlement, such as Powerex and DMM, or oppose only parts of the Settlement, such as CESA.[18] CAISO notes that if the Settlement is adopted, CAISO will need to open a stakeholder process to consider several tariff changes or changes to existing CAISO processes, such as updating the Maximum Import Capability calculation and the Net Qualifying Capacity (NQC) and Effective Flexible Capacity (EFC) list to provide new eligible resources, and CAISO cannot guarantee the timing of those processes.[19]

Multiple parties contest the Settlement, including CEERT, CLECA, CAC, Cal Advocates, GPI, Joint DR Parties, PG&E, SCE and TURN. We summarize some of their objections below.

2.2.1. Comments Regarding Process

Several parties assert that the Settlement is not reasonable in light of the record because it does not reflect a diverse group of interests. Parties note that the settling parties do not include a ratepayer representative, an environmental group, or the two largest IOUs in California.[20] CAC contends that the process to participate in the Settlement "was by invitation only and consciously exclusionary to several critically impacted parties…"[21]

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[18] CESA Comments on Settlement at 5.

[19] CAISO Comments on Settlement at 3.

[20] *See, e.g.*, CLECA Comments on Settlement at 13, SCE Comments on Settlement at 13, GPI Comments on Settlement at 1, PG&E Comments on Settlement at 19.

[21] CAC Comments on Settlement at 2.

Parties also claim that the Settlement does not represent a compromise on the fundamental issue of full versus residual central procurement. PG&E views the Settlement as a joint party proposal offered by "like-minded parties that all either expressed support for the residual central buyer structure during the Track 2 workshop process or did not take clear litigation positions opposing such a structure."[22] GPI agrees that the Settling Parties previously favored a residual central buyer structure and "are simply reiterating their positions in this proposed Settlement Agreement."[23]

Others argue that the Settlement is not reasonable because it is a new proposal that was not submitted into the record for consideration or presented at any of the central procurement workshops. SCE states that other proposals raised at the multiple workshops have a significant record of comments, unlike the Settlement.[24] PG&E states that the Settling Parties worked separately from the workshop process and the final workshops were cancelled because no party indicated it had new proposals to discuss. PG&E asserts that parties were given only 10 days to negotiate the Settlement, which "did not offer an opportunity for meaningful negotiations regarding the provisions affecting all parties' interests."[25] CAC states that it and other parties sought an extension of the

[22] PG&E Comments on Settlement at 16.

[23] GPI Comments on Settlement at 1.

[24] SCE Comments on Settlement at 17-18.

[25] PG&E Comments on Settlement at 5-6.

Settlement filing date to continue discussion of the proposal but the request was denied.[26]

TURN, SCE, and CLECA state that in not identifying a CPE, the Settlement fails to address a threshold issue and a key element of a workable implementable solution. CLECA argues that the Settlement is offered "with the expectation that, at some point, an entity will be created to fill it, and the entity will have the desired characteristics."[27]

Several parties assert that the Settlement seeks to adopt substantive issues that are outside the scope of the proceeding, including multi-year procurement of system and flexible RA, and modifications to the third year forward local requirement.[28] These parties argue that the Settlement raises factual and legal issues that were not properly litigated in the proceeding, or raised during the central procurement workshops. CLECA and CESA state that changing the percentages for local RA in Year 3 is contrary to a recent Commission decision.[29]

2.2.2. Comments Regarding Substance

Parties also raise numerous objections to the substance of the Settlement. Many objections are similar to concerns that have been raised in opposition to

[26] CAC Comments on Settlement at 6.

[27] CLECA Comments on Settlement at 8-9.

[28] *See, e.g.*, Cal Advocates Comments on Settlement at 9, CLECA Comments on Settlement at 4, SCE Comments on Settlement at 14, PG&E Comments on Settlement at 2, CESA Comments on Settlement at 5.

[29] CLECA Comments on Settlement at 2-3, CESA Comments on Settlement at 5.

any residual framework and we do not duplicate them here.[30] We summarize some of the major concerns raised specifically for this proposed Settlement.

PG&E, SCE, and CLECA assert that the Settlement will result in inefficient procurement because LSEs get MW-for-MW credit for any self-procured RA, regardless of the effectiveness of the resource.[31] This may result in the Collective RA Requirement being met with low-effectiveness resources and the CPE having to procure additional resources beyond the self-procured RA to meet the collective requirement, which may lead to costly over-procurement.

Some state that the cost allocation mechanism presented in the Settlement is problematic, with SCE cautioning that new complexities result from "a combination of actions taken based upon ex ante determinations (*e.g.*, load forecasts for the entire local area and that of individual LSEs) and ex post determinations (*e.g.*, actual load served and actual procurement of local resources) in order to arrive at a cost allocation."[32] Some parties state the cost recovery may lead to inequitable cost allocation because it does not differentiate LSEs that procure resources with higher effectiveness factors and collective deficiencies are shared by all LSEs.[33] These parties are also concerned that in the event an LSE defaults, costs would be unfairly spread to all other LSEs.[34]

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[30] *See e.g.*, D.19-02-022 at 16-17.

[31] PG&E Comments on Settlement at 9, SCE Comments on Settlement at 23, CLECA Comments on Settlement at 12.

[32] SCE Comments on Settlement at 24. *See also* CLECA Comments on Settlement at 11.

[33] *See* CLECA Comments on Settlement at 12, SCE Comments on Settlement at 25, Cal Advocates Comments on Settlement at 11, PG&E Comments on Settlement at 9.

[34] *Id*.

SCE and Cal Advocates state that there is insufficient oversight over the CPE as it relates to contract costs, including whether costs above the Soft Offer Cap are reasonable, how administrative costs are approved, and how creditworthiness and collateral protocols are developed for LSEs.[35]

The Joint DR Parties note that the Settlement makes no reference to the procurement of preferred resources, or reducing GHG emissions, failing to demonstrate that the CPE will provide an "opportunity for and investment in procurement of local preferred resources," as directed by D.19-02-022.[36]

2.3. Standard of Review

Under Rule 12.1(d) of the Commission's Rules of Practice and Procedure, a settlement will not be approved unless it is reasonable in light of the whole record, consistent with the law, and in the public interest.[37] Proponents of a settlement agreement bear the burden of proof to demonstrate that the proposed settlement meets the requirements of Rule 12.1.[38]

In this proceeding, the proposed Settlement is contested by multiple active parties. The Commission has held that a contested settlement is subject to stricter scrutiny than an all-party settlement. As explained in D.02-01-041:

> In judging the reasonableness of a proposed settlement, we have sometimes inclined to find reasonable a settlement that has the unanimous support of all active parties in the proceeding. In contrast, a contested settlement is not entitled

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[35] *See* Cal Advocates Comments on Settlement at 6, SCE Comments on Settlement at 30.

[36] Joint DR Parties Comments on Settlement at 8.

[37] Unless otherwise specified, all references to a rule are to the Commission's Rules of Practice and Procedure.

[38] *See* D.18-12-021 at 12, D.92-12-019 at 6.

> to any greater weight or deference merely by virtue of its label as a settlement; it is merely the joint position of the sponsoring parties, and its reasonableness must be thoroughly demonstrated by the record.[39]

As to whether a settlement is consistent with the law, the Commission must be assured that no term of the settlement agreement contravenes statutory provisions or prior Commission decisions.[40] To determine whether a settlement agreement is in the public interest, the Commission may inquire into whether a settlement expeditiously resolves issues that otherwise would have been litigated.[41]

2.4. Discussion

We first consider whether the Settling Parties have complied with the requirements under Rule 12.1. Rule 12.1(b) provides that:

> Prior to signing any settlement, the settling parties shall convene at least one conference with notice and opportunity to participate provided to all parties for the purpose of discussing settlements in the proceeding.

The Settling Parties noticed the settlement conference on August 9, 2019, which was at least seven days in advance of the August 20, 2019 conference, as required by Rule 12.1(b). After the settlement conference, the joint motion to adopt the Settlement was filed on August 30, 2019, 10 days following the conference. PG&E asserts that 10 days did not allow "an opportunity for meaningful negotiations regarding the provisions affecting all parties' interests"

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[39] D.02-01-041 at 13.

[40] *See* D.11-12-053 at 74, D.10-12-035 at 26.

[41] *Id.*

and CAC states that requests for an extension of the settlement filing date to provide additional comments were denied.[42]

There are over 60 parties in this proceeding, workshops and comments on central procurement proposals spanned several months, and the Settling Parties' joint motion and Settlement Agreement totaled 40 pages. The Settling Parties may have complied with the literal requirement of Rule 12.1(b) since there is no minimum number of days required to discuss the settlement. Given the complexity of the issues and the significant amount of time and effort parties have expended to collaboratively discuss these issues, however, we agree that 10 days to discuss a new settlement agreement is not a sufficient, meaningful opportunity to participate in the spirit of Rule 12.1(b). It is particularly concerning that some parties requested additional time for negotiations but were denied that opportunity.

Notwithstanding the above, we consider whether the Settling Parties have demonstrated that the Settlement is reasonable in light of the whole record. One significant factor in determining whether a contested settlement is reasonable is the extent to which the settlement is supported by parties representing the affected interests.[43] The Commission will also consider whether the settlement represents a fair compromise of the settling parties' positions and interests.[44]

The Settling Parties assert that:

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[42] PG&E Comments on Settlement at 6, CAC Comments on Settlement at 6.

[43] D.18-12-021 at 13, D.07-03-044 at 259.

[44] *Id*.

> The number of interested parties involved in these negotiations, and the diversity of representation among the parties participating in the discussions, helped to ensure that the interests of LSEs, ratepayers, generators and other stakeholders were fully represented.[45]

The Commission is not persuaded that with over 60 parties in this proceeding, the eight parties represent the affected interests, particularly since the Settling Parties do not include a ratepayer or environmental representative, or the two largest IOUs that represent the majority of statewide retail customer load.

We also find that the Settlement does not represent a fair compromise of the Settling Parties' positions and interests. The Settling Parties were largely in favor of a residual framework throughout Track 2 and during the central procurement workshops. The debate over a full versus residual procurement structure was a fundamental issue in Track 2, one that led the Commission to defer adoption of a central procurement structure to allow time for workshops. While the Settling Parties may have compromised on other issues, the Settlement does not reflect a compromise among parties with different litigation positions with respect to a critical component of the central procurement framework.

The Settlement also fails to address a major implementation detail required by D.19-02-022 for any workable solution - the identity of a central buyer. In response to this, Settling Parties assert that they "have identified issues that will require either further collaboration among parties or a Commission decision,"

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[45] Settling Parties' Joint Motion for Adoption of a Settlement Agreement for a "Residual" Central Procurement Entity Structure for Resource Adequacy (Joint Motion) at 6.

and that the Settlement "meets most of these requirements in greater detail than any other proposal brought to the Commission to date."[46]

The Commission articulated the need to designate a central buyer nearly two years ago in D.18-06-030. Since that decision, we have been unambiguous about the need to identify the appropriate central procurement entity and have set up workshop processes to facilitate reaching a consensus on this issue. We did not direct parties to submit proposals that met some, but not all, of the implementation requirements. Thus, the Settlement does not represent a workable central procurement plan, as directed by D.19-02-022. For the foregoing reasons, the Settling Parties have not satisfied their burden of demonstrating that the proposed Settlement is reasonable in light of the whole record. Accordingly, we reject the proposed Settlement.

Because the Settlement is not reasonable in light of the whole record, we need not reach a conclusion as to whether the Settlement is consistent with the law or whether it is in the public interest. Aspects of the Settlement appear contrary to existing state laws, however, such as potential overreliance on CAISO procurement and potential unreasonable and unjust cost shifting between customer classes and service territories. The Settlement's removal of LSEs' obligation to meet any RA requirements (system, flexible, or local), without a clear method of assuring energy procurement consistent with state policies, is also likely contrary to Public Utilities (Pub. Util.) Code § 380.

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[46] Settling Parties' Reply Comments to Settlement at 21.

The Settlement also seeks to adopt multi-year system and flexible RA requirements. In D.19-02-022, the Commission stated that the expansion of multi-year requirements to flexible and system RA "is premature and needs to be fully explored" and thus we declined to adopt such requirements.[47] Since the issuance of D.19-02-022, there has been no further record development on this issue and the Commission declines to consider it here.

Lastly, because the Settling Parties did not present their proposal at any of the central procurement workshops, or otherwise submit their proposal into this proceeding, parties have had a limited opportunity to discuss the proposal, other than in response to the joint motion to adopt the settlement and at the Commission's November workshop. By contrast, other central procurement proposals raised during Track 2 or presented at the central procurement workshops have a developed record of comments. While we reject the proposed settlement, we conclude that there is insufficient record to consider it as a new joint party proposal in this decision.

3. Central Procurement Entity and Framework

The proposed decision, issued on November 21, 2018, prior to D.19-02-022, adopted a central procurement structure that: (1) identified the distribution utilities as the CPEs for their respective TAC areas, (2) adopted a full central procurement framework, and (3) set forth specific implementation guidelines for a central procurement structure. Based on comments to the November 21, 2018 proposed decision, the Commission elected to defer adoption of a central

[47] D.19-02-022 at 33-34.

procurement structure to allow additional time for workshops and discussion. In D.19-02-022, we stated that:

> The Commission is open to considering new, viable implementation details that effectively address the known challenges identified in the local RA market, including costly out-of-market RA procurement, load migration and the equitable allocation of costs to all customers, cost effective and efficient coordinated procurement, treatment of existing local RA contracts, opportunity for and investment in procurement of local preferred resources, and retention of state jurisdiction over the procurement of preferred resources.
>
> However, to date, we find that the central buyer structure outlined in the proposed decision is the most workable solution presented that addresses these obstacles.[48]

As stated above, parties undertook a series of workshops to discuss central procurement proposals over the past year, submitted three informal workshops reports, and provided comments on the workshops. The Commission appreciates the significant effort and thoughtful discussion among parties, particularly the effort put forth by parties that led the workshops. Based on the workshop reports and comments, however, it is clear that parties were not able to reach consensus as to the appropriate CPE or a central procurement structure that addresses the known challenges identified in the local RA market.[49]

The Commission thus revisits consideration of the appropriate central procurement structure and central procurement entity in light of the additional record to date.

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[48] D.19-02-022 at 38.

[49] *See, e.g.*, Informal Workshop Report of CalCCA at 1, Informal Workshop Report of Shell at 2.

3.1. Scope of Central Procurement

The Commission first considers the scope of local RA that should be centrally procured. In D.19-02-022, the Commission assessed three central procurement structures: full procurement, residual procurement, or a hybrid model. We briefly summarize the proposals below, with more detailed discussion of Track 2 proposals to be found in D.19-02-022.[50]

Under full procurement, a CPE procures the entire amount of required local RA on behalf of all LSEs, and LSEs no longer receive individual local requirements. LSEs that have procured local resources may offer those resources to the CPE by bidding into the CPE's solicitation. If the resource is procured by the CPE, the capacity would count towards the overall local RA obligation. If an LSE-procured local resource is not selected by the CPE, the local resource would still be eligible to count towards the LSE's system or flexible RA obligations, if applicable.[51] Costs would be allocated ex post by directly charging LSEs or customers based on load share, in order to prevent cost shifting between LSEs.[52]

Under residual procurement, LSEs bear the primary responsibility to procure local resources and continue to receive individual local requirements. An LSE may voluntarily show their procured local capacity to the CPE. Based on the shown capacity, the CPE determines the residual amount of local RA that must be procured to avoid individual or collective deficiencies. The CPE would issue a local RA solicitation and select resources that best fit local reliability

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[50] D.19-02-022 at 7-9.

[51] Joint IOUs' Workshop Report at Appendix 1-13.

[52] *Id*. at Appendix 1-14.

needs while using a least cost approach. The CPE would allocate procurement costs directly to LSEs based on each LSE's individual local RA deficiency, if any. Should the CPE be required to procure local RA capacity above the residual requirement, the costs would be allocated to all LSEs in the TAC area based on an LSE's load share ratio. The CPE's cost allocation would be trued-up to account for load migration, to prevent cost shifting between LSEs.[53]

A hybrid procurement model is similar to full procurement while giving LSEs an additional opportunity to procure their own local resources. If an LSE procures its own local resource, it may (1) sell the capacity to the CPE, (2) utilize the resource for its own system and flexible RA needs, or (3) voluntarily show the resource to meet its own system and flexible RA needs, and reduce the amount of local RA the CPE will need to procure for the amount of time the LSE has agreed to show the resource.[54] Under the third option, by showing the resource to the CPE, the LSE does not receive one-for-one credit for shown local resources. Instead, the LSE's local procurement reduces the total CPE procurement costs that will be shared by all LSEs, while retaining the ability to use the shown local resource for its own system and flexible needs. Following the accounting of any LSE-procured resources, the CPE would determine what remains to be procured to avoid collective local deficiencies. Costs incurred by

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[53] *Id*.

[54] *Id*. at Appendix 1-15.

the CPE would be allocated ex post based on load share, ensuring that all customers pay their share of local area costs.[55]

3.1.1. Discussion

In D.19-02-022, the Commission observed that:

> One advantage of full procurement is that the central buyer can procure more efficiently by selecting effective and preferred resources at the lowest cost. By contrast, under a residual approach where LSEs secure their own resources, a procured resource may not be the most effective, potentially leading to inefficient procurement and collective deficiencies that result in backstop procurement.
>
> Another advantage of full procurement is the ease of administration as it eliminates the need to track LSE self-provided portfolios and fairly allocates local requirements and costs to individual LSEs. Full procurement can also effectively account for load migration addressing stranded cost concerns.
>
> Under a residual framework, an LSE who experiences load migration may be potentially stranded with these resources and costs. The uncertainty around load migration discourages LSEs from procuring too far out given that they do not know if they will have a particular set of customers in the future.[56]

Based on the record developed to date, the Commission stands by the observations made above in D.19-02-022 with respect to a full or residual procurement model. The Commission also acknowledges the benefits of a residual procurement model in that it "offers individual LSEs the flexibility and autonomy to procure local resources based on their (and their customers')

[55] *Id*.

[56] D.19-02-022 at 16.

particular objectives or preferences. The residual model also gives LSEs certainty that a procured local resource will receive local RA credit rather than leaving that determination to a central buyer."[57]

The Commission is not persuaded that a residual procurement proposal can address all of the known challenges identified in D.19-02-022. A residual framework creates administrative complexities in that the CPE must track and account for individual LSE procurement and cost responsibility. The Commission believes that when LSEs procure on an individual basis, they are likely to procure the resource that best meets their individual objectives (*e.g.*, lower cost, or local benefits such as providing jobs) rather than the most effective resource for overall grid reliability, which can lead to collective deficiencies and inequitable cost allocation to other LSEs (and their customers).

On the other hand, a full or hybrid procurement framework allows the CPE to secure a portfolio of the most effective local resources, mitigating the need for costly backstop procurement in certain local areas. These approaches also allow the CPE to adapt to load uncertainty and migration by allocating local RA costs equitably to all benefiting end-use customers based on actual load. A full or hybrid model ensures that sufficient capacity is procured to meet local needs over a multi-year duration, reducing the likelihood that strategically located local resources will seek retirement. Lastly, under either model, local procurement can be coordinated by the CPE with the state's environmental goals and preferred resource procurement mandates in mind.

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[57] *Id*. at 17.

We, however, recognize strong concerns disfavoring full procurement, particularly LSEs' loss of autonomy to voluntarily procure and optimize local resources based on an LSE's unique portfolio criteria and loss of certainty for already-procured local resources that may not be selected by the CPE.

Considering the extensive record in this proceeding, the Commission finds that the hybrid procurement model strikes an appropriate, reasonable balance between the residual and full procurement models, and best addresses the known challenges identified in D.19-02-022. The hybrid approach allows a CPE to secure a portfolio of the most effective local resources, use its purchasing power in constrained local areas, mitigate the need for costly backstop procurement in certain local areas, and ensure a least cost solution for customers and equitable cost allocation. The hybrid approach also allows individual LSEs to voluntarily procure local resources to meet their system and flexible RA requirements and count them towards the collective local RA requirements, providing LSEs flexibility and autonomy to procure local resources. By allocating costs directly to end customers, inequitable cost allocation and load migration issues are addressed since all customers pay equitably for the cost of local reliability regardless of which LSE serves them.

Accordingly, the Commission adopts a hybrid central procurement framework beginning for the 2023 RA compliance year. For reasons discussed in Section 3.2, the central procurement framework is adopted only for SCE and PG&E's distribution service territories at this time. LSEs in these TAC areas will no longer receive a local requirement for the 2023 RA compliance year but will have the ability to procure resources to meet system and flexible RA needs. If an

LSE-procured resource also meets a local RA need, the LSE may choose to either (a) show the resource to reduce the CPE's overall local procurement obligation, (b) bid the resource into the CPE's solicitation, or (c) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs.

Some parties contend that only a residual framework can incentivize development of local resources because this framework counts the local capacity shown by an LSE towards the LSE's local requirements.[58] The Commission does not believe that a hybrid procurement model reduces the incentive for LSEs to develop new local resources. If a CCA develops a new local resource, it can choose to either sell the resource to the CPE or retain it for itself and lower the overall local requirements. If the new local resource is a non-CAISO integrated demand-side resource, it flows into the California Energy Commission's (CEC's) load forecast and would in theory reduce overall local needs. While an LSE may not get the full local value of the resource for itself, the hybrid model ensures that all LSEs (and the customers they serve) pay equitably for the portfolio of local resources needed to run the grid reliably, eliminating the incentive to lean on the portfolio of other LSEs, which may also lead to costly backstop procurement.

It is also worth noting that in the last few years, there has been a lower than expected amount of local preferred procurement added to the grid by LSEs. As stated in Energy Division's September 3, 2019 and January 13, 2020 State of the Market Reports, 167.17 MW of August RA capacity were added between

[58] *See e.g.*, Joint IOU Workshop Report at Appendix 1-20.

January 2018 - July 2019 and only 5.4 MW were added between August 2019 and December 2019 (totaling 172.57 MW).[59] Of these new resources, 100 MW were under contract with IOUs and ~59 MW were under contract with CCAs. Given the declining Effective Load Carrying Capacity (ELCC) factors adopted beginning in 2020, these incremental preferred resources would only have August values of 124 MW.

The Commission is aware of the procurement direction made in the Integrated Resource Planning's (IRP's) near-term reliability decision, D.19-11-016, which authorized and allocated 3,300 MW of additional RA capacity to be procured by all Commission-jurisdictional LSEs. In that decision, the Commission chose an LSE-based approach, with the IOU acting in a backstop role if the LSE fails or chooses to opt out. The backstop procurement cost allocation mechanism is still under development in the IRP proceeding. As stated in D.19-11-016, "[t]his is also an appropriate place to test how well the obligated LSEs perform when given a procurement requirement for system reliability and renewable integration resources in the context of IRP."[60]

In addition, the near-term reliability shortfalls identified in the IRP decision are systemwide and targeted at adding incremental procurement to the system. By contrast, the central procurement framework adopted in this decision is specific to local procurement (including sub-local areas) and is primarily

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[59] *See* The State of the Resource Adequacy Market (September 2019) at 12; The State of the Resource Adequacy Market – Revised (January 13, 2020) at 31. The RA values reflect the 2019 ELCC technology factors for solar and wind resources.

[60] D.19-11-016 at 39.

focused on the contracting for existing local resources (although it does not preclude new generation procurement). The local challenges the Commission seeks to address through the adoption of a CPE framework are separate and distinct from the system issues presented in the near-term reliability track. That said, the Commission will consider whether to adopt multi-year system and flexible RA requirements in Track 3 of the successor RA proceeding, Rulemaking (R.)19-11-009.

3.2. Identity of a Central Procurement Entity

We next consider what entity or entities should serve as the central procurement entity. In D.19-02-022, the Commission considered the following central procurement entity proposals: the distribution utilities, a special purpose entity, CAISO, and a centralized capacity market. Parties largely appear to still support their Track 2 proposals.[61] We briefly summarize the CPE proposals below, with a more detailed discussion of proposals to be found in D.19-02-022.[62]

3.2.1. CPE Proposals

Some parties support the IOUs serving as the CPE for their respective distribution areas on an interim basis. Parties acknowledge that the IOUs are likely the only candidates that can take on the central procurement function in the near term.[63] TURN states that the IOUs are the "only feasible entities" to

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[61] Some parties may have modified their Track 2 positions; however, because the informal workshop reports included aggregated summaries of parties' positions, the Commission instead relies on proposals and comments submitted into the record by parties.

[62] *See* D.19-02-022 at 7-13.

[63] *See, e.g.*, CLECA Track 2 Comments (August 8, 2018) at 7, NRG Track 2 Comments (August 8 2018) at 8, Cal Advocates Track 2 Comments (August 8, 2018) at 14, TURN Track 2 Testimony (July 10, 2018) at 23, PG&E Track 2 Opening Testimony (July 10, 2018) at 1-25.

serve as CPEs in the near term as they "have the resources, the knowledge and experience to take on this task effectively."[64] Those that oppose designating the IOUs argue that they cannot be neutral buyers, as they can potentially favor their own resources or select resources that expand their rate base, such as utility-owned storage.[65] Some parties are concerned with IOUs procuring on their behalf, noting the lack of transparency inherent in utility procurement. The IOUs themselves express concern with the financial costs and risks of a CPE role, including the financial commitment required of large-scale procurement that could raise debt equivalency issues.[66]

A second proposal is for a special purpose entity (SPE) to serve as the CPE, which may be a state agency or private entity selected through a solicitation or legislation. An SPE is considered an ideal CPE by some parties because it could be financially stable, neutral, and subject to Commission oversight, while engaging in policy-based procurement without the complications of utility procurement.[67] The main drawback of a governmental SPE is the substantial time and expense involved in establishing a governmental entity, including required legislation.

Others support the CAISO serving as the CPE because it is governed by tariffs and is an independent organization with transparent procurement. Critics

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[64] TURN Track 2 Testimony at 23.

[65] *See e.g.,* AReM Track 2 Comments (August 8, 2018) at 5, CalCCA Track 2 Comments (August 8, 2018) at 19-20, Calpine Track 2 Testimony (July 10, 2018) at A-2.

[66] PG&E Track 2 Reply Testimony (August 8, 2018) at 1-25, SDG&E Track 2 Comments (August 8, 2018) at 6, SCE Track 2 Testimony (July 10, 2018) at 14.

[67] *See, e.g.*, SDG&E Track 2 Comments at 7, PG&E Track 2 Opening Testimony at 2-20.

of this proposal cite CAISO's statements that it will not voluntarily serve this role, potential conflict with Federal Energy Regulatory Commission's (FERC) involvement in the state's capacity market and environmental goals, and the significant time required for stakeholder initiatives to design a new market structure and tariff amendments for approval by FERC.[68]

Lastly, some recommend a centralized capacity market (CCM) as a variation of a CPE. A CCM generally refers to a market clearing mechanism where a resource is selected based on whether it bids at or below a single market price, with consideration for grid reliability constraints. Supporters of a CCM cite a few benefits, such as price transparency with a single market price and ease of transactions.[69] Opponents argue that CCMs procure solely based on system-wide grid reliability and cost considerations and are not set up for targeted procurement for local and sub-local areas or preferred resources. Some state that a CCM would likely be regulated by FERC, exposing California's procurement policies to federal jurisdiction.

3.2.2. Discussion

In D.19-02-022, the Commission stated that:

> The Commission is not convinced that an SPE or the CAISO could readily take on the central procurement role in the near term, given the noted obstacles. Designating a special governmental entity would require administrative and legislative processes that would cause substantial delay.

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[68] *See e.g.*, SDG&E Track 2 Comments at 7, CLECA Track 2 Comments at 8, Joint Environmental Parties Track 2 Comments at 7-8, Cal Advocates Track 2 Comments at 16-17, TURN Track 2 Testimony at 25, CAISO Track 2 Comments at 5.

[69] *See, e.g.,* AReM Track 2 Comments at 3, Shell Track 2 Testimony at 4.

> Likewise, designating the CAISO involves its own administrative challenges, as well as potential federal jurisdictional conflicts.
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> A CCM, by design, procures only based on grid reliability and cost criteria and thus cannot engage in such targeted procurement. As discussed above, establishing a new centralized capacity market would be a complex undertaking with significant risks and unclear benefits for California's procurement goals and policies. As noted in the Track 1 decision [D.18-06-030], we reiterate that we are not convinced that a centralized capacity market is the appropriate central procurement structure, given the objectives outlined.[70]

Based on the record developed since D.19-02-022, we have not identified additional information that compels us to change our conclusions with respect to a special purpose entity or CAISO serving as the CPE, or with respect to a centralized capacity market. Thus, the Commission stands by the above conclusions reached in D.19-02-022.

In D.19-02-022, we also stated that:

> The Commission is persuaded by parties who acknowledge that the distribution utilities are the candidates with the 'resources, knowledge, and experience' to procure local reliability resources on behalf of all LSEs without excessive delay.
>
> We find that designating the distribution utilities as the central buyers for their respective TAC areas is the most practical, feasible solution in the near term.[71]

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[70] D.19-02-022 at 13.

[71] *Id*. at 14.

Again, the Commission has not identified additional information that compels us to change the above conclusion. Rather, the Commission stands more firmly by the conclusion that designating the distribution utilities as the CPEs for their respective TAC areas is the most practical, feasible solution in the near term.

The Commission initially sought to adopt a central procurement structure that could be applied uniformly statewide because such a structure could benefit each TAC area in a similar manner. However, we recognize that the SDG&E TAC area is unique in that the local RA requirements typically meet or exceed the system requirements. In 2020, for example, local RA requirements in SDG&E's TAC area exceed system requirements for eight months of the year. Using the 2020 year ahead forecast, the aggregated system RA peak requirements for SDG&E's TAC area are 4,505 MW[72] and the adopted 2020 local requirements for SDG&E's TAC area are 3,895 MW.[73] Since local MWs are bundled with system MWs (and sometimes flexible MWs), for each local MW procured by the CPE there would be one MW of system capacity that is also procured (and potentially one MW of flexible capacity that is also bundled).

This means that if a CPE procures all the needed local capacity in the San Diego local areas, there would be very little system (or flexible) capacity left to be procured for most months of the year. For 2020, 86 percent of the peak month (September) system requirement would be procured by the CPE, leaving

[72] Total forecasted peak load (3,918 MW) plus a 15 percent planning reserve margin. Peak load occurs in September.

[73] SDG&E Local RA requirements include the San-Diego-IV area and nested subareas.

very little to procure by LSEs that serve load in the SDG&E TAC area.[74] In other words, LSEs in SDG&E's TAC area would have little procurement autonomy for system and flexible RA procurement, undercutting one of the primary rationales for adopting a hybrid procurement framework.

This is not the case for PG&E and SCE's TAC areas, however, where local requirements make up approximately 43 and 38 percent of total peak system requirements, respectively.[75] Even after the CPE procures all of the needed local capacity in these TAC areas, there would still be over 50 percent of system and flexible capacity that LSEs need to procure, providing LSEs with substantial procurement autonomy for these requirements. LSEs in these TAC areas continue to have incentives to procure resources in local areas if doing so provides their customers with system RA benefits (or other benefits, such as job creation, RPS, or GHG / criteria pollutant reductions).

On the other hand, SDG&E's TAC area is considered locally constrained in that nearly all resources located in this area are needed to meet the TAC area's local requirements.[76] The high concentration of local need relative to local supply suggests that there is considerable market power in SDG&E's TAC area. Therefore, the Commission believes there would be considerable benefits to

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[74] For 2020, there would be only 4 months of the year where LSEs would have a system RA requirement. This requirement would be at most 14 percent of their system RAR (load + 15 percent planning reserve).

[75] For SCE's TAC area, 2020 aggregate local requirements for Commission-jurisdictional LSEs are ~8,847 MW and system RAR are ~23,015 MW. For PG&E's TAC area, 2020 aggregate local requirements for Commission-jurisdictional LSEs are ~8,957 MW and system RAR are ~20,681 MW.

[76] *See* D.18-06-030 at 30, 33; D.19-02-022 at 14, 17.

adopting central procurement of local resources in the SDG&E TAC area (as well as PG&E and SCE's service territories), including procurement efficiency, market power mitigation, and equitable cost allocation to all customers.

For the reasons cited in D.18-06-030 and D.19-02-022,[77] the Commission continues to believe that a central procurement structure is appropriate and necessary for procurement of multi-year local RA resources. Weighing the benefits of LSE procurement autonomy for system and flexible RA against the benefits of central procurement, however, the Commission declines to adopt a central procurement framework for the SDG&E TAC area at this time. LSEs in SDG&E's TAC area will continue to receive a local requirement and self-procure local resources as is currently done. The Commission will continue to monitor LSE-based procurement in this TAC area and may consider whether a central procurement structure is necessary in future years.

Accordingly, the Commission designates the distribution utilities (that is, SCE and PG&E) as the appropriate entities to serve as the CPEs for the SCE and PG&E TAC areas to begin for the 2023 RA compliance year.[78] The Commission will continue to evaluate and monitor the central procurement function in SCE and PG&E's TAC areas and remains open to designating a different CPE in future years. To that end, we authorize Energy Division to prepare a report assessing the effectiveness of the CPE structure by 2025. In addition, we note that Track 3 of R.19-11-009 has been scoped to examine the broader RA capacity structure and

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[77] D.18-06-030 at 30-22; D.19-02-022 at 15-17.

[78] SCE and PG&E will undertake procurement of local resources for only Commission-jurisdictional LSEs in their respective distribution service areas.

potential RA program modifications and reforms in light of increasing penetration of use-limited resources, greater reliance on preferred resources, rolling off of a significant amount of long-term tolling contracts held by utilities, and material increases in energy and capacity prices experienced in California over the past years.[79]

The Commission acknowledges concerns raised by the IOUs regarding financial costs and risks associated with the central procurement function. We encourage SCE and PG&E to offer supporting documentation in this proceeding should the central procurement function result in negative financial impact. In addition, we encourage each CPE to make a proposal to recover additional costs resulting from central procurement in the utilities' Cost of Capital proceeding, if needed, as this is the proceeding where the Commission can best evaluate the utility's balance sheet issues.

The Commission recognizes concerns regarding whether state law precludes directing distribution utilities to act as CPEs. Some parties assert that the utilities may not have authority to act as a CPE, citing Pub. Util. Code § 380(c) and (d), which provide that "[e]ach load-serving entity" shall maintain generation and demand response capacity that are adequate to meet their load requirements and that the capacity or demand response shall be deliverable "to locations and at times as may be necessary to maintain electric service system reliability and local area reliability." This excerpt, however, cannot be read in

[79] Assigned Commissioner's Scoping Memo and Ruling in R.19-11-009, issued January 22, 2020, at 7.

isolation without considering the context of § 380. Section 380(h) directs the Commission to "determine and authorize the most efficient and equitable means for achieving" a broad list of RA goals, including ensuring that economical generating capacity is retained, that generating capacity and demand response costs are equitably allocated, and that the broad objectives of § 380 are met. In order to meet these goals, § 380(i) provides that the Commission may "consider a centralized resource adequacy mechanism among other options."

The State Legislature also modified § 380 to add another goal to the RA objectives, directing the Commission to "[minimize] the need for backstop procurement by the Independent System Operator."[80] This additional objective, in light of the other RA objectives in § 380, underscores the Commission's duty to ensure adequate resource availability for grid reliability regardless of which load serving entity offers service. Additionally, the Commission adopts a hybrid procurement model, which provides individual LSEs an opportunity to self-procure local resources if they so choose.

3.3. Procurement Mechanism

We next consider the appropriate procurement mechanism for the CPE's procurement of local RA resources. Some parties recommend a competitive solicitation process, consisting of solicitation for bids through a request for offers (RFO) for RA products.[81] The RFO is a pay-as-bid mechanism in which the CPE

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[80] Pub. Util. Code § 380(h)(7).

[81] *See* Energy Division Track 2 Proposal at 15, Cal Advocates Track 2 Comments at 14, PG&E Track 2 Opening Testimony at 2-6, SDG&E Track 2 Testimony at 4, SCE Track 2 Testimony at 17.

would award RA contracts based on pre-established criteria. Others support a market clearing mechanism where resources are selected based on whether they bid at or below a single market price.[82]

The Commission finds that a RFO process gives the CPE the flexibility to select resources based on multiple targeted criteria, in addition to costs and local needs, including broader environmental goals, such as preferred resources. Accordingly, we adopt a competitive solicitation process as the appropriate central procurement mechanism. The CPE is permitted to conduct multiple solicitations per year, as needed.

Further, the Commission clarifies that if an LSE opts to show a local resource, it may either: (a) do so in advance of the CPE's solicitation if it does not intend to bid it into the solicitation, or (b) bid the resource into the CPE's solicitation but indicate in its bid that the resource will be available to meet local RA requirements even if it is not procured by the CPE, which may reduce the total procurement costs the CPE incurs on behalf of all LSEs. Under the latter approach, the CPE will need to structure its solicitation to accommodate the iterative process of including these resources as bids into the RFO but removing the associated MW from the total procurement requirement if they are not selected based on the selection criteria. The "iterative process" is described as follows:

(1) The CPE recognizes all existing Cost Allocation Mechanism (CAM) resources and any self-shown resources that are not also bid into the CPE's solicitation.

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[82] *See, e.g.,* Shell Testimony at 7.

(2) The CPE determines remaining local area need.

(3) The CPE evaluates all bids regardless of whether any bids have offered to self-show if their bid is not selected, which will result in a selection of the least cost, best fit portfolio to meet the needs.

(4) The CPE determines if any bids not selected indicated that they will self-show if not selected. The CPE will include those, if any, as self-shown and reevaluate the remaining least cost, best fit portfolio to reduce procurement.

(5) If this process results in a reduction of the least cost, best fit portfolio, the CPE will review the newly unselected bids to determine if they have indicated that they will self-show if not selected. This process will repeat until either no unselected bids indicate they will self-show or the total quantity necessary to satisfy the local area has self-shown.

If the LSE shows the resource to reduce the CPE's local RA procurement (either in advance of the solicitation or as an offer that is not selected by the CPE), the LSE may still use the resource to fulfill its system and flexible RA needs. An IOU shall have the same options as other LSEs in deciding whether to bid or show its resources to the CPE.

3.4. Compensation Mechanism

In comments to the proposed decision, several parties propose a one-for-one credit for all shown local RA resources,[83] or for shown preferred resources.[84] PG&E/SCE oppose a one-for-one credit, stating that it will turn the hybrid framework into a residual model and reintroduce the same problems that the

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83 *See, e.g.*, CESA, Calpine, ENGIE, Joint Parties, NRG, OhmConnect, SDG&E, Shell, TURN, Vistra, WPTF.

84 *See, e.g.*, AWEA-CA, SEIA/LSA, Sunrun, Joint Environmental Parties.

decision seeks to address.[85] CalCCA recommends a direct financial credit mechanism that compensates LSEs a local RA premium value for existing preferred or energy storage local resources shown to the CPE. The local RA value would be calculated as the difference between the weighted average system price (developed for use in the PCIA) and the weighted average local price of the resources procured by the CPE in the relevant local area.[86] AReM comments that a crediting mechanism is complicated, raises many unanswered questions, and should be deferred to a working group for further evaluation.[87]

We acknowledge that a hybrid framework may result in some uncoordinated development of preferred and energy storage resources between LSEs. However, we believe the IOU acting as the CPE allows for development of local preferred resources, even without a financial crediting mechanism. This is especially true for locally constrained areas that involve transmission solutions, such as recent successful centralized procurement by IOUs in the Moorpark/Santa Clara and Moss Landing/South Bay sub-local areas. We encourage the CPE to continue these efforts to develop new preferred resources in local areas to ensure reliability and meet the state's greenhouse gas goals, while working collaboratively with CCAs and ESPs.

As discussed above, a hybrid model does not disincentivize procurement of local resources because LSEs procure local resources for many reasons beyond

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[85] SCE Reply Comments on Proposed Decision at 1, PG&E Reply Comments on Proposed Decision at 1-2.

[86] CalCCA Comments on Proposed Decision at 13.

[87] AReM Reply Comments on Proposed Decision at 3-4.

the local RA value. However, we recognize that a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred and energy storage local resources in constrained local areas. But we agree with PG&E and SCE that the addition of a one-for-one credit basically turns the hybrid model into a residual framework and reintroduces the same concerns identified in D.19-02-022. CalCCA's proposal contemplates a one-for-one MW reduction where the resource gets paid its full MW value without considering effectiveness in reducing the LCR need. This could be viewed as a must-take resource being guaranteed a one-for-one MW local premium value (if there is a local premium). CalCCA's proposal thus raises similar concerns (i.e., inefficient procurement and leaning) as identified with a residual model. As discussed, LSEs that procure on an individual basis are likely to procure resources that meet individual objectives rather than the most effective resource. We thus decline to consider a one-for-one-credit or CalCCA's proposal, neither of which accounts for a resource's effectiveness at reducing LCR needs.

For new conventional gas resources, we note that the Commission has prohibited investment in predominantly fossil fuel resources in the IRP proceeding[88] and thus, it is unnecessary to provide financial incentives to procure new local gas generation. For existing local contracts, including gas contracts, a working group process is established in Section 3.5 to consider treatment of these existing contracts.

[88] *See*.D.20-03-028 at 103, D.19-11-016 at Ordering Paragraph 7.

3.4.1. Discussion

The Commission recognizes that a financial credit mechanism for preferred and energy storage resources that considers local effectiveness factors and use limitations to the shown MW value would more closely align the financial compensation with the actual LCR MW reduction the resource provided. For purposes of this discussion, we refer to this as an "LCR reduction compensation mechanism." We consider how such a compensation mechanism could work.

Because resources procured in the CPE solicitation would impact local compensation values and the least cost best fit solution, local resources shown by LSEs seeking a local premium payment would need to be evaluated alongside bid resources to fully assess the cost effectiveness of the local portfolio being considered by the CPE in addressing LCR needs. However, rather than the ex post benchmark proposed by CalCCA, the CPE would need a pre-determined local premium for shown preferred resources to reflect the cost to ratepayers of selecting the shown resources over purchasing bid resources.

A key purpose in creating a CPE framework is to reduce costs to ratepayers by mitigating local market power. To the extent that market power inflates local area capacity prices, an ex post benchmark would exacerbate this problem by providing inflated prices to local resources shown by LSEs. In light of this concern, we observe that another benefit of a pre-determined local premium is that it may be cost-based to reflect the additional costs that LSEs incurred by locating preferred resources close to load, rather than based on market-power inflated price premiums.

An "LCR reduction compensation mechanism" departs from CalCCA's must-take, local price based proposal; however, it would address the concern CalCCA's proposal seeks to address – namely, that the CPE should not discourage LSEs from procuring local preferred and energy storage resources – and it could do so in a manner that ensures that ratepayers are: (1) only compensating resources to the extent they provide ratepayer value, and (2) only compensating LSEs for additional costs of procuring resources close to load rather than simply extending market power premiums to these LSEs.

The Commission will develop an LCR reduction compensation mechanism, if details can be assessed and developed. To that end, we direct a working group to develop this mechanism that properly compensates LSEs for shown local preferred resources. The working group will be co-led by CalCCA and either PG&E or SCE. A working group report on consensus and non-consensus items shall be filed in R.19-11-009 by September 1, 2020. Any proposal to be offered for consideration shall be presented through the working group report. The Commission is not open to considering a one-for-one credit, CalCCA's proposed financial credit mechanism, or a credit mechanism for fossil fuel resources (other than potentially for existing grandfathered contracts).

The working group report should address the resource cost effectiveness concerns outlined above (including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources). The report should also address the following issues (to the fullest extent possible given the expedited timeframe):

(1) How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

- The level of granularity that premiums can be developed may be limited by the availability of sufficient cost data to develop reasonable premium values by location and resource type.

(2) How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

(3) Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process;

- We recognize that the iterative process for shown resources replacing bid resources may not be compatible with or may unnecessarily complicate the compensation mechanism.

(4) How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

Consistent with past Commission direction to IOUs regarding favoring preferred resources in the development of solicitation criteria and weighting of RFO bids, as discussed further below, as well as additional preference for CPE procurement of preferred resources articulated in this decision, the working group should also consider how the CPE will incorporate qualitative and/or quantitative criteria into the bid evaluation process to ensure that gas resource bids are not selected over preferred resources in instances in which price differentials are relatively small.

The Commission will address a proposed LCR reduction compensation mechanism in a subsequent decision to be issued prior to the CPE's 2021 procurement (for the 2023 and 2024 compliance years).

3.5. Transition Period to the CPE Structure

In order to transition to the central procurement framework for the 2023 RA compliance year, we consider adjustments to the current three-year local requirements adopted in D.19-02-022. For 2020, we find that it is reasonable to eliminate the 50 percent local requirement for the 2023 compliance year. Thus, there will be no three-year local requirement in 2020 for LSEs in the PG&E and SCE TAC area. However, the 100 percent two-year requirement will remain such that LSEs will be responsible for 100 percent of their 2021 and 2022 local requirements in 2020, and 100 percent of their 2022 local requirements in 2021.

The adopted three-year local requirements and procurement percentages will apply to the CPE, as they currently do for LSEs. Therefore, the CPE will begin local procurement responsibilities in 2021 for 100 percent of the 2023 local requirements and 50 percent of the 2024 local requirements. In 2022, the CPE will be responsible for procuring the entire current 3-year local requirements for the 2023, 2024, and 2025 compliance years.

The Commission recognizes that some LSEs may have existing local contracts that have been procured in anticipation of multi-year local obligations for 2023 and beyond. Because the CPE will not undertake the central procurement role until the 2023 compliance year (beginning with procurement in 2021), the Commission defers making a determination as to any existing local RA contracts in the PG&E and SCE TAC areas at this time. We direct parties to undertake this issue, in addition to the LCR reduction compensation mechanism, in a combined working group and submit a working group report into the successor RA proceeding R.19-11-009 by September 1, 2020. The working group should submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed LCR reduction compensation mechanism should be applied to existing contracts. At this time, we are not inclined to "grandfather" resources that are not currently online, absent compelling information provided in the working group report.

In order to ensure a smooth transition in implementing the hybrid framework, and to ensure backstop procurement is minimized, Energy Division shall coordinately closely with the CAISO.

3.6. Resources to Be Solicited

The Commission assesses what types of resources may bid into a solicitation administered by the CPE. Some parties recommend that only Cost Allocation Mechanism (CAM) resources[89] and those procured by the CPE should count towards reducing the collective local RA requirements.[90] Some favor keeping RA attributes bundled through the RFO process such that any local resource capable of providing other collateral RA products would be required to

[89] A CAM resource refers to resources procured for reliability purposes through the cost allocation mechanism adopted in D.06-07-029, and further expanded and refined in subsequent decisions.

[90] *See, e.g.*, Energy Division Track 2 Proposal at 15-16, PG&E Track 2 Reply Testimony at 1-7.

sell the other RA products (*e.g.*, local RA with the associated flexible attribute).[91] Energy Division proposes that LSEs receive credits for any system or flexible capacity procured during the local RA or backstop processes, based on coincident load shares.[92]

The Commission previously adopted an open competitive solicitation process in D.04-12-048, which approved the IOUs' long-term procurement plans. In that decision, a requirement of the solicitation process was that "[a]ll-source open solicitations need to be transparent and competitive, and in addition, need to be open to all resources (conventional/renewable – turnkeys, buyouts and PPAs [power purchase agreements])."[93]

The Commission finds it reasonable that the CPE use similar requirements for its solicitation process, as adopted in D.04-12-048. Accordingly, the CPE shall run an all-source solicitation that is transparent, competitive, and open to all resources. Any existing local resource that does not have a contract, any new local resource that can be brought online in time to meet solicitation requirements, or any LSE or third-party with an existing local RA contract may bid into the solicitation. We also find it reasonable that RA attributes should remain bundled and LSEs should receive credits for any system or flexible capacity procured during the local RA or backstop processes, based on coincident peak load shares, as is currently done with CAM resources.

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[91] *See, e.g.*, Energy Division Track 2 Proposal at 16, Joint Utilities' White Paper (August 8, 2018) at 18, PG&E Track 2 Opening Testimony at 2-6, SDG&E Track 2 Testimony at 7.

[92] Energy Division Track 2 Proposal at 16.

[93] D.04-12-048, Ordering Paragraph 26.

The Commission agrees that CAM resources and IOU local demand response (DR) resources should reduce the local RA amount that the CPE must procure. For local procured DR resources (such as IOU DR programs, DRAM and LCR resources), it is reasonable to continue to treat DR resources as is currently done. The amount of local IOU DR (excluding DRAM) shall be based on the three-year period of the applicable load impact protocol studies (or any modified DR counting rules that are established in the RA proceeding) after any Energy Division adjustments, as is the current practice.

It is also reasonable for the IOU to bid its resources into the CPE's RFO, including utility-owned generation (UOG) or contractually committed resources that are not already allocated to all benefitting customers, at their levelized fixed costs, and we direct the utility to do so when it is acting as the CPE. Levelized fixed costs refer to the annual revenue requirement for utility-owned resources or the PPA price for contracted resources. The Commission directs the IOU to submit its procurement bids to the Procurement Review Group and Independent Evaluator, adopted in Section 3.9, in advance of the receipt of bids from any other entities. When the IOU is not acting in its capacity as the CPE, and acting as any other bidder would, it is not required to bid its resources into another CPE's RFO at its levelized fixed costs.

In addition, IOU resources procured by the CPE should be reclassified from their existing cost recovery mechanism designations to the CAM for the duration of the contract/multi-year obligation with the CPE. After that time, the IOU resources should be reclassified back to their existing cost recovery mechanism designation. Where Power Charge Indifference Adjustment (PCIA)-

eligible local resources procured by the CPE are reclassified as CAM, then reclassified back to their existing cost recovery mechanism designation, an exemption of the local resource from the annual PCIA rate cap is allowed.

Energy Division also recommends that the CPE procure dispatch rights along with the local RA products, if applicable, to "help ensure that the local resource fleet is subject to the [Commission's] least cost dispatch rules (ensuring locational price stability)."[94] SCE states that if a contract conveys the dispatch rights, the Commission's existing Least Cost Dispatch standard should be applicable to the dispatch of the resource procured.[95] Calpine expresses concern with requiring acquisition of dispatch rights to resources, given that an LSE that contracted for RA only cannot provide dispatch rights that it does not control.[96]

The Commission finds insufficient record support to require the CPE to acquire dispatch rights alongside RA capacity. However, we do require the CPE to include dispatch rights, or other means that stipulate how local resources bid into the energy markets, in its solicitation, as an optional term that bidders are encouraged to include. We strongly encourage the CPE to procure dispatch rights along with the RA capacity, whenever doing so is in the financial interest of all ratepayers (*e.g.*, when the benefits of least cost dispatch requirements outweigh increased contract costs) because this will reduce the local RA costs paid for by all LSEs after the energy benefits are netted out of the total contract

[94] Energy Division Track 2 Proposal at 16.

[95] SCE Track 2 Testimony at 9.

[96] Calpine Track 2 Comments at 15.

price. If the CPE procures dispatch rights, administration of the contracts shall be submitted for review in the utility's annual Energy Resource Recovery Account (ERRA) compliance application for review of compliance with least cost dispatch requirements. If the CPE procures dispatch rights, allocation of any GHG emissions shall be allocated as they currently are for other CAM resources.

Lastly, in D.19-02-022, the Commission adopted a minimum three-year forward local RA requirement and minimum procurement percentages for multi-year procurement: 100 percent in Years 1 and 2, and 50 percent for Year 3.[97] The Commission clarifies that because these are minimum requirements, this does not preclude the CPE from entering into contracts exceeding three years or from procuring in excess of the adopted percentages, if it is in ratepayers' interest to do so. In the event that the CPE procures more than 100 percent of the local RA requirement for an area (such as in an instance where the LCR requirement decreases between years), the CPE is not required to sell the excess capacity. Because LCR requirements vary from year to year, sometimes unexpectedly, and capacity will have been allocated to LSEs, it is not reasonable for the CPE to make adjustments to accommodate such changes.

3.7. Solicitation Selection Criteria

Parties offered criteria to determine how local resources should be selected by the CPE. Some recommend that the CPE develop at least two portfolios: one based on least cost and one with consideration of preferred resources.[98] Energy

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[97] D.19-02-022 at 22, 27.

[98] Joint IOUs Workshop Report at Appendix 1-14.

Division proposes a set of six selection criteria to guide procurement, including: (1) future needs in local and sub-local areas, (2) local effectiveness factors, as published in the CAISO's Local Capacity Requirements Technical Study (LCRTS), (3) costs, (4) operational characteristics of the resources (including efficiency, age, flexibility, facility type), (5) location of the facility (with consideration for disadvantaged communities), and (6) costs of potential alternatives.[99]

In D.04-12-048, the Commission approved specific all-source solicitation selection criteria to be used in a utility's long-term procurement processes. In pertinent part, the criteria for all-source open solicitations included:

(1) The first priority shall be "cost-effective energy efficiency and demand-side resources," with "renewable generation [] to be procured to the fullest extent possible…"

(2) Investor-owned utilities will "employ the Least-Cost Best-Fit methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative attributes associated with each bid."

(3) "GHG adders are to be used for bids in all-source open RFOs."[100]

D.04-12-048 adopts a "loading order" when soliciting resources, as follows: "energy efficiency and demand-side resources; renewable generation resources

[99] Energy Division Track 2 Proposal at 24-25.

[100] D.04-12-048, Ordering Paragraph 26.

(including renewable [distributed generation] [DG]); clean fossil DG; and efficient, clean fossil generation resources."[101]

In D.07-12-052, the Commission directed IOUs to consider additional criteria for procurement. In particular, the Commission added considerations for determining "project viability" and giving greater weight to "disproportionate resource siting in low income and minority communities, and environmental impacts/benefits (including Greenfield vs. Brownfield development)."[102]

The Commission finds the above criteria adopted for solicitations administered by the utilities to serve as a useful, reasonable guide for consideration in the selection of local resources by the CPE, including the loading order adopted in D.04-12-048. The Commission also finds that Energy Division's selection criteria should guide the CPE's all-source solicitations. To that end, the Commission adopts similar procurement rules to guide local procurement by the CPE, with modifications, as follows:

The CPE shall evaluate resources using the least cost best fit methodology adopted in D.04-07-029.[103] The least cost best fit methodology employed shall include the following selection criteria:

(a) Future needs in local and sub-local areas;

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[101] *Id*. at 31.

[102] D.07-12-052 at 157.

[103] "Least cost best fit" refers to the selection of resources that are least cost, including the direct costs of energy generation and any indirect costs due integration of the resource and needed transmission investment. In addition, utilities are required to consider resources that best fit their system needs.

(b) Local effectiveness factors, as published in the CAISO's LCRTS;

(c) Resource costs;

(d) Operational characteristics of the resources (efficiency, age, flexibility, facility type);

(e) Location of the facility (with consideration for environmental justice);[104]

(f) Costs of potential alternatives;

(g) Greenhouse Gas adders;

(h) Energy-use limitations; and

(i) Procurement of preferred resources and energy storage (to be prioritized over fossil generation).

To assist the CPE in evaluating some of the above criteria, we direct the CPE to require bidders in its solicitation to include the following attributes for the resource: the CalEnviroScreen score of the resource location (or if unavailable, the pollution burden of the resource location), facility age, heat rate, start-up time, and ramp rate. The GHG planning price, adopted in D.18-02-016 of the IRP proceeding, shall guide development of the GHG adder used by the CPE.

The Commission believes the listed criteria are sufficient to guide the CPE through the initial local procurement beginning for the 2023 compliance year. We

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[104] "Disadvantaged community" is defined as: any community statewide scoring in the top 25 percent statewide or in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score, using the most recent version of the California Environmental Protection Agency's CalEnviroScreen tool. Unless an updated version of the tool is adopted prior to the adoption of the 2019 Reference System Plan, LSEs should use version 3.0 of the tool. *See* D.18-02-018 at Ordering Paragraph 6.

recognize that further refinements to the criteria may be necessary through a working group or through future proposals made in the RA proceeding.

3.8. Cost Allocation

The Commission considers how costs associated with the central procurement function will be appropriately allocated and recovered. Some parties support the use of the CAM to facilitate an equitable allocation of costs for resources procured by the CPE.[105] PG&E proposes that the costs recovered by the CPE should include (but not be limited to): contract costs for purchases of local resources, costs for excess local capacity due to decreased load forecast or other changes, administrative costs related to purchase or sale of local capacity, and credit costs related to collateral requirements, credit risks and cashflow variability.[106]

The Commission previously authorized the CAM to allocate costs for investor-owned utilities' procurement of generation required to meet system and local reliability needs on behalf of all LSEs.[107] In designating that the IOUs procure new generation through long-term PPAs, the procured capacity rights were allocated among all LSEs in the service territory and in exchange for those benefits, the LSEs' customers (termed "benefiting customers")[108] paid for the net

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[105] *See, e.g.*, Energy Division Track 2 Proposal at 18, PG&E Track 2 Opening Testimony at 2-10, SCE Track 2 Testimony at 10.

[106] PG&E Track 2 Opening Testimony at 2-9.

[107] *See* D.06-07-029, D.13-02-015.

[108] Benefitting customers have been defined as all bundled service, direct access, and community choice aggregator customers. Benefitting customers are also customers who are located within a utility's distribution territory who take service after the date the new generation goes into service. D.06-07-029, footnote 21.

cost of the capacity. Subsequent decisions and regulations have clarified and amended the CAM.[109] In D.18-06-030, the Commission authorized the use of CAM to allocate the costs of 2019 and 2020 procurement of Ormond Beach and Elwood in order to avoid the costs of a costly out-of-market procurement (future RMR designation). More recently, the Commission authorized the use of CAM to meet local reliability in the Moorpark/Santa Clara sub-areas.[110]

The Commission seeks a cost recovery mechanism that facilitates the CPE's efficient procurement of local resources, as well as provides necessary recovery of costs incurred by the CPE to ensure its financial stability. Considering past decisions authorizing CAM for procurement required to meet local reliability needs, we conclude the CAM recovery mechanism is appropriate for the central procurement process. Accordingly, we apply the CAM methodology as the cost recovery mechanism to cover the procurement costs incurred by the CPE. The CPE is directed to establish a Centralized Local Procurement Balancing Account as a sub-account of the New Generation Services Balancing Account (NGSBA) in order to facilitate the cost recovery process, within 60 days of the issuance of this decision through a Tier 2 Advice Letter.

Additionally, the administrative costs incurred by the CPE in serving the central procurement function shall be recoverable under the cost allocation mechanism. The CPE is directed to submit its administrative costs associated

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[109] *See* D.07-09-044, D.08-09-012, D.11-05-005, D.13-02-015, and D.14-02-040. The CAM is codified in Pub. Util. Code § 365.1(c).

[110] *See* D.19-12-055.

with central procurement for review in its annual ERRA forecast and compliance, where parties have an opportunity to participate. The CPE shall submit supplemental testimony with the forecasted administrative costs associated with central procurement for 2021 in its ERRA forecast proceeding within 75 days of the issuance of this decision.

3.9. Procurement Oversight

Parties urge the adoption of safeguards for the distribution utilities to act as CPEs in order to mitigate conflict of interest and anticompetitive concerns, and maximize transparency.[111] Energy Division recommends that the CPE should be subject to: (1) a stakeholder monitoring committee, similar to the CAM Procurement Review Group (PRG), (2) an Independent Evaluator (IE) to monitor all solicitations and transactions, and (3) a public report prepared by the IE following each solicitation that analyzes local procurement, market power, and aggregate pricing.[112] Energy Division also proposes that the distribution utility establish an independent procurement arm, which would be subject to competitive neutrality rules, as adopted in D.13-12-029.

The Commission's objective in adopting safeguards to oversee the CPE's procurement and solicitation process is to provide LSEs and other market participants with reasonable assurances as to the neutrality and transparency of the process, while also giving the CPE appropriate flexibility and discretion to

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[111] *See e.g.*, CLECA Track 2 Comments at 7, Cal Advocates Track 2 Comments at 14, Enel X Track 2 Comments at 4, SunRun Track 2 Comments at 7.

[112] Energy Division Track 2 Proposal at 15.

efficiently procure local resources given the existing constraints in the RA timeline. We address potential safeguards and mitigation measures in turn.

3.9.1. Procurement Review Group

The Commission initially established Procurement Review Groups in D.02-08-071 as an advisory group to assess the IOUs' procurement strategies and processes, as well as specific proposed procurement contracts. The PRG included non-market participants, as well as Energy Division and Cal Advocates.[113] In D.07-12-052, the Commission approved the establishment of a PRG for the CAM process and defined the membership requirements for the CAM PRG, as well as the obligations of participants.[114] PRG recommendations are deemed advisory to the utility and non-binding.[115]

The purpose of the PRG, as provided in D.02-08-071, is to routinely consult with the IOU, and to review and assess the utility's overall procurement strategy and specific proposed contracts and processes.[116] D.07-12-052 required the IOUs to hold a meeting with the IE, PRG, and Energy Division to outline plans and solicit feedback before drafting RFO bid documents to identify data gaps, confirm fairness of confidential components, and ensure compliance with Commission policies on procurement practices.[117] Additionally, draft bid documents were to be developed under the oversight of an IE and PRG with

[113] D.02-08-071 at 24-25.

[114] *See* D.07-12-052, Appendix D.

[115] *Id*. at 119.

[116] D.02-08-071 at 25.

[117] D.07-12-052, Ordering Paragraph 15.

differences to be resolved by Energy Division staff in advance of the issuance of bid documents.[118]

Considering our objectives in establishing procurement oversight mechanisms and past decisions involving utility procurement, we agree with Energy Division's proposal to use a PRG to advise in central procurement as an appropriate safeguard. Accordingly, we adopt the use of the CAM PRG, as described in D.07-12-052, to advise the CPE. The CPE is required to consult with the CAM PRG members (including Energy Division) and an independent evaluator as the CPE outlines procurement plans, drafts RFO solicitation bid documents, and collects feedback from market participants regarding the RFO process for potential refinements. The IE is also required to brief the CAM PRG on key solicitation elements, as described below.

Additionally, CAM PRG membership should be representative and include a non-market participant representing CCAs that signs the PRG non-disclosure agreements, as provided in D.07-12-052.[119] We encourage Energy Division, the CPE, and CCA representatives to work collaboratively with the CCA community to ensure an appropriate non-market CCA representative is identified for the CAM PRGs.

3.9.2. Independent Evaluator

The Commission has historically authorized the use of independent evaluators to monitor solicitations by IOUs. For example, in D.04-12-048, we

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[118] *Id*., Ordering Paragraph 16.

[119] D.07-12-052 at 301.

authorized the retention of an IE to monitor bids involving affiliate transactions, utility-builds, or utility-turnkey bidders. That decision adopted parameters for IE retention, which, in pertinent part, included:

(a) The IE "should come equipped with technical expertise germane to evaluating resource solicitation power products. … IEs should have experience analyzing the relative merits of the various types of PPAs. IEs should be able to evaluate PPAs, turn-keys, and IOU-builds on a side-by-side basis. An IE should make periodic presentations regarding their findings to the IOU and to the PRG."[120]

(b) The IOUs "may contract directly with IEs, in consultation with their respective PRGs. The IOUs shall allow periodic oversight by the Commission's Energy Division. … Independent evaluators shall coordinate to a reasonable degree with assigned Energy Division management and staff as a check on the process."[121]

Similarly, in D.06-07-029, the Commission required an IE to oversee any competitive RFO administered by the IOUs that resulted in a contract subject to the CAM.[122] In D.07-12-052, the Commission expanded the use of IEs to monitor certain competitive RFOs with additional requirements, including:

(a) The utilities should develop a pool of at least three IEs to be used on a rotating basis for each RFO;

(b) Energy Division should be involved during the selection process and have the right to final approval of the IE;

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[120] D.04-12-048, Finding of Fact 95.

[121] *Id.*, Ordering Paragraph 28.

[122] D.06-07-29 at 28.

(c) The IE report shall be filed with the Commission's Quarterly Compliance Report based on a template developed by the Energy Division; and

(d) The utilities, in collaboration with the PRG and Energy Division, shall develop comprehensive conflict-of-interest disclosure requirements for the IE.[123]

Given the Commission's history authorizing IEs to oversee solicitations for utility procurement, we agree with Energy Division's proposal to authorize an IE to monitor the CPE's solicitation process for local RA procurement, as well as the contract execution process.

Using the above decisions as guidance, we approve a similar IE process that should include, but not be limited to, the following: the CPE is directed to develop a pool of at least three IEs, with the appropriate level of technical expertise and experience, to serve on a rotating basis for solicitations. Energy Division will have final approval over the selection of the IEs.

The IE will prepare a report to be submitted on an annual basis to the Commission, which will assess the neutrality of the procurement process, any market power or aggregate pricing concerns, procurement of preferred resources (*e.g.*, on what basis preferred resources were not selected), consideration of disadvantaged communities (DACs) in the procurement process (*e.g.*, whether factors led to the selection of any conventional generation in DACs), and other relevant issues. In order to reduce potential long-term procurement of gas, the IE report shall include an explanation of the basis for any fossil fuel procurement for any contract that exceeds the minimum multi-year local requirements.

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[123] D.07-12-052, Ordering Paragraphs 10, 12.

The IE will also brief the CAM PRG in its meetings on the procurement process and any concerns related to neutrality, market power, pricing, disadvantaged communities, or other concerns. The CPE shall permit periodic oversight of the IE process by Energy Division. The CPE shall follow the guidance for the IE process provided in D.04-,12-048; however, such guidance shall represent a minimum standard for an effective IE process. In addition, Energy Division's 2025 report assessing the effectiveness of the CPE structure will include an assessment of the IE and CAM PRG function.

3.9.3. Portfolio Approval Process

In D.07-12-052, as part of the bundled procurement plan requirements, the Commission established a preapproval process for contracts with terms of less than five years. If a procurement action complied with the approved methodology, an executed contract of less than five years did not require preapproval and the action could not be subject to after-the-fact reasonableness review.[124] The Commission's objective for a preapproval mechanism was to give achievable standards and criteria for cost recovery, authorize procurement decisions that incorporate the Commission's policy direction, and eliminate the need for after-the-fact reasonableness review of procurement actions that meet certain conditions.[125]

In establishing procurement oversight mechanisms, the Commission finds the objectives of D.07-12-052 to be relevant to the central procurement framework. Thus, we deem it appropriate to adopt a similar preapproval

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[124] D.07-12-052, Ordering Paragraph 19.

[125] *See id*. at 171.

process for central procurement to enable the CPE to efficiently satisfy the local capacity requirements, while providing assurances for cost recovery and minimizing the need for ex post reasonableness review.

Accordingly, the Commission adopts a similar process whereby for an executed contract of five years or less, a procurement action is deemed reasonable and preapproved if the resource procured by the CPE: (1) meets the established local capacity requirements and underlying data supporting those requirements, which are based on the CAISO's LCRTS and adopted annually by Commission decision; (2) if the CAM PRG was properly consulted, as described above; and (3) if procurement was deemed by the IE to have followed all relevant Commission guidance, including least cost best fit methodology and other noted selection criteria. For any executed contract that exceeds a five-year term, the CPE shall submit a Tier 3 Advice Letter for approval.

Additionally, the CPE shall submit any contract management issues, such as contract disputes, amendments, or modifications, to the Commission through the utility's annual ERRA compliance application. The Commission believes this preapproval process is sufficient to guide the CPE. Further refinements, however, may be necessary after the first procurement results and IE reports have been evaluated.

3.9.4. Compliance Reports

In D.02-10-062, which adopted a procurement and cost recovery framework for the IOUs, the Commission required the utilities to submit quarterly filings for procurement transactions via advice letter.[126] The Commission currently requires each IOU to submit a Quarterly Compliance Report (QCR) via an Advice Letter within 30 days of the end of the quarter. The purpose of the QCR is to allow the Commission to review the procurement transactions for compliance with the approved bundled procurement plans and the upfront standards and criteria. The QCRs are reviewed by Energy Division and the Commission's Utility Audit, Finance, and Compliance Branch.

The Commission finds it reasonable to adopt a similar compliance report for the CPE. Accordingly, the CPE shall prepare a compliance report on an annual basis that includes all contract terms and the criteria and methodology used to select local RA resources. The CPE's annual compliance report shall be submitted through a Tier 2 Advice Letter within 30 days after the CPE makes its local RA showing to the Commission, in both confidential and public (redacted) form, subject to the confidential provisions in D.06-06-066 and related materials. The purpose of the annual report is to demonstrate that the CPE has complied with the requirements and objectives adopted in this decision, as well as the multi-year local RA requirements. The final IE report shall also be filed as part of this annual compliance report in both confidential and public (redacted) form.

3.9.5. Competitive Neutrality Rules

Within the central procurement process, potentially market-sensitive information relates to confidential, competitive information received from generators, LSEs, or third-party marketers in the process of enabling the

[126] D.02-10-062, Ordering Paragraph 8. This process was later modified in D.03-06-076, D.07-12-062, and D.12-01-062.

distribution utility to perform duties necessary to conduct solicitations and procure local resources as part of its central procurement role. The Commission recognizes that this competitive information should be appropriately protected in an effort to address anti-competitive concerns and facilitate confidence and certainty in the central procurement process. Energy Division proposes that the distribution utilities establish an independent procurement arm subject to competitive neutrality rules, as adopted in D.13-12-029. D.13-12-029 adopted competitive neutrality rules applicable to demand response providers' participation in the CAISO's wholesale markets. Of relevance here, that decision adopted the following:

> Rule 24 shall include provisions to protect the confidential, competitive information received from a demand response provider (Provider) or from the [CAISO] about the Provider or its customers, to enable the utility to perform duties necessary to implement and administer the Provider's use of a bundled utility load for direct participation under this Rule in the CAISO market. Such confidential, competitive information received from the Provider or the CAISO may not be used to promote the utility's services to customers. The utility staff receiving such confidential, competitive information from the Provider or CAISO in the discharge of the utility's roles and responsibilities under the Rule shall not share such confidential, competitive information with other individuals in the utility who are also responsible for discharging the utility's roles and responsibilities, as a Demand Response Provider, under Rule 24.[127]

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[127] D.13-12-029, Ordering Paragraph 10.

While the competitive neutrality rules in D.13-02-029 may have originated under different circumstances, we find the rules to be relevant guidance and reasonable for use in mitigating anti-competitive and conflict of interest concerns related to the CPE's solicitation process and procurement of local resources. In order to ensure competitive neutrality and prohibit the sharing of confidential information obtained as part of the central procurement process, the Commission agrees with Energy Division's proposal to require the CPE to be subject to competitive neutrality rules and D.13-02-029 may be used as guidance.

Accordingly, the Commission directs the CPE to establish a rule or procedure that will govern how confidential, market-sensitive information received by the CPE from generators, LSEs, or third-party marketers as part of the central solicitation and procurement process will be protected, as well as what firewall safeguards will be implemented to prevent the sharing of information beyond those employees involved in the central solicitation and procurement process. The CPEs shall file and serve their proposed rule(s) into the successor RA proceeding, R.19-11-009, by September 1, 2020. Once the proposals are submitted, parties will have an opportunity to comment and the proposals will be addressed in R.19-11-009.

Additionally, in D.07-12-052, the IOU, along with the IE, PRG and Energy Division, were directed to establish a strict code of conduct to be signed by all IOU personnel involved in the RFO process to prevent sharing of sensitive information between staff involved in developing utility bids and staff who created bid evaluation criteria and selected winning bids.[128]

The Commission finds it reasonable to adopt a similar requirement that the CPE, in collaboration with the IE, PRG and Energy Division, shall create a strict code of conduct, as adopted in D.07-12-052, that prevents the sharing of market-sensitive information beyond employees involved in the central solicitation and procurement function. The CPE can use D.07-12-052 as guidance when developing its own rules of conduct. Any personnel employed by the CPE (including management and officers) who is involved in the solicitation and procurement process shall sign the code of conduct as a precondition to conducting the central solicitation and procurement process.

3.9.6. Market Power Mitigation

Energy Division states that even with distribution utilities as CPEs, there is a "potential for considerable market power, given that resource procurement will be for transmission-constrained local sub-areas, where competition largely does not exist."[129] In order to mitigate this concern, Energy Division proposes that each CPE "exercise its judgment to decide when it would be better for the resource to be procured through the annual backstop mechanisms, which are limited to one year and capped at the soft offer price of $6.31 kW-month…"[130]

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[128] D.07-12-052 at 206.

[129] Energy Division Track 2 Proposal at 18.

[130] *Id*.

SDG&E recommends a price cap (in $/kW-year) be set and if an offer exceeds the price cap, the central entity is not obligated to procure that resource.[131]

PG&E proposes that if any local offers raise market power concerns, "the CPE should raise those concerns to the CPUC in its filing, and the CPE shall not procure resources that it reasonably believes is exercising market power. In the case that the resource is needed for local reliability purposes, CAISO may separately procure that resource under its existing tariff for a limited term."[132]

The Commission supports Energy Division's proposal to give the CPE discretion to defer procurement of a local resource to the CAISO's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high. The Commission finds this to be a reasonable exercise of discretion particularly in light of the other oversight mechanisms adopted in this decision. In the event that the CPE defers to backstop procurement, the Commission requires the CPE to provide, through its annual compliance report, the reasons for the deferral to backstop procurement, the prices offered in the solicitation, which generators did not participate in the solicitation (if any), and other relevant information. The IE report shall also provide its perspective on the CPE's deferral. We do not intend to allow the CPE to rely on CAISO backstop mechanisms to supplant the central procurement process; instead, we seek to minimize backstop procurement while also mitigating market power.

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[131] SDG&E Track 2 Testimony at 15.

[132] PG&E Track 2 Reply Testimony at 2-7.

Relatedly, Energy Division proposes that the CPE should not be assessed penalties for failure to procure resources to meet the local requirements, so long as reasonable attempts are made.[133] If a resource is not procured in the solicitation, it could be procured in the following year's solicitation and if that fails to occur, backstop authority may be used to retain the resource.
Energy Division recommends that the Independent Evaluator report on any market power issues that may have caused the failure to procure.

The Commission agrees that the CPE should not be assessed fines or penalties for failing to procure resources to meet the local RA requirements, as long as the CPE exercises reasonable efforts to secure capacity and the IE report contains the reasons for the failures to procure.

3.10. Modifications to RA Timeline

Energy Division favors keeping the RA timeline as is, except to add an additional filing in late-September for the CPE to file its local showing.[134] The CAISO proposes a significant change to the RA timeline that shifts the compliance year to begin on April 1 instead of January 1, in order to give resource owners additional time for retirement and maintenance decisions, as well as to allow backstop procurement to occur prior to the first monthly showing of the year.[135] SDG&E states that "[s]hifting the RA compliance timeline

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[133] Energy Division Track 2 Proposal at 18.

[134] *Id*. at 16.

[135] CAISO Track 2 Testimony, Chapter 3 at 5.

would require significant modifications to the current RA construct, but would provide limited value."[136]

The Commission does not find sufficient record support to authorize a significant shift in the RA timeline. The current timeline contains multiple inter-dependent events and inputs that occur in parallel. Shifting the timeline by a few months is a major undertaking that should involve a prudent, thorough review and coordination among multiple agencies. Additionally, in light of the changes to the local RA program adopted for SCE and PG&E's TAC areas, it is appropriate to keep the current RA timeline with the modifications proposed by Energy Division.

Accordingly, we adopt the following timeline with modifications to account for central procurement, beginning for the 2023 RA compliance year. A deadline (April – May) is added to allow LSEs to commit to provide local resources on their monthly showing. The CPE is permitted to launch solicitations prior to the final LCR requirements adopted to give the CPE additional time for bid preparation and evaluation. For clarity's sake, the timeline includes dates for the SDG&E TAC area, although the dates do not change for this TAC area from the current RA timeline.

- **April-May 2021**:
  - The CAISO files draft and final LCR one- and five-year ahead studies. LCR studies will include any CAISO-approved transmission upgrades from the Transmission Planning Process (TPP) LCR study.

[136] SDG&E Comments on SCE Proposal at 7.

- LSEs in SCE and PG&E TAC areas commit to CPE to show self-procured local resources in RA filing for 2023 and 2024.
- Parties file comments on draft and final LCR studies.

- **June 2021**:
  - The Commission adopts multi-year local RA requirements for the 2022-2024 compliance years as part of its June decision.
  - CPE receives total jurisdictional share of multi-year local RA requirements for 2022-2024 compliance years.
- **July 2021**:
  - For the SCE and PG&E TAC areas, LSEs receive initial RA allocations, including CAM credits and system, flexible, and local requirements for 2022 (but are not allocated local requirements for 2023 and 2024).
  - For SDG&E TAC area, LSEs receive initial RA allocations (system, flexible, local requirements) and CAM credits.
- **Late September 2021:** CPE and LSEs that voluntarily committed local resources to the CPE make local RA showing to the Commission and the CAISO.
- **Late September/early October 2021:** For PG&E and SCE's TAC areas, LSEs are allocated final CAM credits (based on coincident peak load shares) for any system and flexible capacity that was procured by the CPE during the local RA procurement process or by CAISO through its RMR process.
- **End of October 2021:** LSEs in the SDG&E TAC make system, flexible, and 3-year local RA showing. CAISO determines necessary backstop procurement. LSEs in PG&E and SCE TACs make local showing only for 2022, as well as 2022 year ahead system and flexible showings.

The above timeline would apply for 2022 (and future years), except LSEs in PG&E and SCE TAC areas would no longer receive a local requirement in July and a local showing obligation in October. LSEs would commit self-procurement to the CPE in the April - May timeframe for the local procurement window covered by the RA year (*e.g.*, in 2022, LSEs would submit self-procured local resources for 2023-2025 to the CPE).

4. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 15, 2020 by: AWEA-CA; AReM; CAC; CalCCA; Calpine; Cal Advocates; CLECA; CEERT; CESA; CAISO; CPower, Enel X, Leapfrog Power, Inc., and the California Efficiency + Demand Management Council (CEDMC) (collectively, the Joint Parties); ENGIE North America, Inc. (ENGIE); GPI; IEP; the Joint Environmental Parties; LS Power; Monterey Bay Community Power Authority (MBCP); MRP; NRG; OhmConnect; SCE/PG&E (jointly); SDG&E; Solar Energy Industries Association (SEIA)/LSA (jointly); Shell; Sunrun; TURN; Vistra; and WPTF. Reply comments were filed on April 21, 2020 by AReM, CAISO, CESA, CEERT, CLECA, Cal Advocates, CalCCA, Calpine, Joint Parties, Joint Environmental Parties, IEP, MBCP, MRP, OhmConnect, PG&E, SCE, SDG&E, Shell, TURN, Wellhead Electric Company, Inc. (Wellhead), and WPTF.

All comments have been carefully considered. Significant aspects of the proposed decision that have been revised in light of comments are mentioned in this section. However, additional changes have been made to the proposed decision in response to comments that may not be discussed here. We do not summarize every comment but focus on major arguments made in which the Commission did or did not make revisions in response to party input.

Several parties support the proposed decision with modifications, including Cal Advocates, CAISO, CLECA, GPI, the Joint Environmental Parties, PG&E and SCE. Other parties oppose the hybrid framework in favor of either a residual framework or the status quo, such as CalCCA, CEERT, Calpine, IEP, LS Power, MRP, NRG, SDG&E, Shell, Vistra, and WPTF. Some parties reiterate arguments made during the proceeding in favor of residual framework, arguing generally that the hybrid framework does not assure the CPE will buy an LSE's local resources, that it may disincentivize procurement of local resources or investment in preferred resources, and that it may result in inequitable cost-shifting and leaning. The Commission has evaluated and thoroughly considered these arguments over the past two years.

Numerous parties that oppose the decision propose a one-for-one credit for all shown local RA resources,[137] or for shown preferred resources.[138] As discussed, we do not believe that a hybrid model disincentivizes procurement of local resources. However, we recognize that a financial credit mechanism potentially provides LSEs with additional incentives for investments in preferred local resources in constrained local areas. The Commission is open to

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[137] S*ee, e.g.*, CESA, Calpine, ENGIE, Joint Parties, NRG, OhmConnect, SDG&E, Shell, TURN, Vistra, WPTF.

[138] *See, e.g.*, AWEA-CA, SEIA/LSA, Sunrun, Joint Environmental Parties.

considering a compensation mechanism for preferred and energy storage resources that accounts for local effectiveness factors and use limitations to the shown MW value, if such a mechanism can be developed. The decision has been modified to describe the Commission's rationale in considering such a compensation mechanism and to direct a working group to assess and develop this compensation mechanism.

Some parties assert that problems identified in 2018 no longer exist and that a CPE is unnecessary.[139] We disagree and observe that the initial concerns from 2018 remain and continue to grow: the local RA market remains tight, market power concerns remain, and RMR designations are growing for 2020.[140] In addition, a tranche of long-term local gas contracts for a significant amount of MWs will be expiring over the next several years, including resources in LA Basin and Greater Bay Area. These resources will likely need to be re-contracted and may create opportunities for exertion of market power.

CalCCA, MRP, and Sunrun argue that the adopted framework violates Pub. Util. Code § 380(b)(5) and (h)(5). As discussed, § 380(h) directs the Commission to determine the "most efficient and equitable means" of achieving a broad list of RA goals, one of which is § 380(h)(5): to ensure "that [CCAs] can determine the generation resources used to serve their customers." We reiterate

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139 *See generally*, CEERT Comments on Proposed Decision, MRP Comments on Proposed Decision.

140 *See* March 18, 2020 CAISO Memorandum, available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=95DD1499-4A5C-4F12-8AA4-E66E3564FC4C.

that an excerpt of § 380(h) cannot be read in isolation without the context of § 380 and the Commission's related State Constitutional duties.

Some parties contend that the decision does not reduce backstop procurement because it allows the CPE to use the backstop mechanism if offers are unreasonably high.[141] CAISO comments that the CPE should not rely on backstop mechanisms to front-run the adopted procurement process.[142] We clarify that it is not our intent to allow the CPE to rely on backstop mechanisms to supplant the CPE process but rather, to minimize backstop procurement while mitigating market power. The CPE compliance report and IE report will indicate whether the CPE deferred to backstop procurement; if significant MW amounts are being deferred, we will reevaluate this aspect of the framework.

Some parties support the CPE working with CAISO to ensure procurement of the most effective resources, including PG&E/SCE. CAISO states that it and Energy Division should coordinate to ensure smooth implementation of the hybrid framework.[143] We agree that Energy Division should coordinate with CAISO on both ensuring a smooth implementation of the hybrid framework and sharing CPE procurement information to ensure backstop procurement is minimized.

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[141] *See e.g.*, CalCCA, Calpine, IEP, NRG, Shell, Sunrun.

[142] CAISO Reply Comments on Proposed Decision at 1.

[143] CAISO Comments on Proposed Decision at 2.

SDG&E recommends that Energy Division prepare a report by 2025 that assesses the CPE framework's effectiveness.[144] We agree that such a report would be beneficial and authorize Energy Division to prepare this report.

While some parties request addressing "grandfathering" contracts in this decision, there is insufficient record to do so at this time. We modify the decision to direct a working group (combined with the compensation mechanism working group) to address the treatment of existing contracts.

Several parties recommend adding a preference for preferred resources in the RFO selection process.[145] IEP opposes a preference for certain resources, noting that the guidelines for all-source solicitations in D.04-12-048 already includes a priority that reflects the Commission's loading order.[146] The Joint Environmental Parties also request that the IE report include an assessment of preferred resources and DAC considerations made in the procurement process. We agree that D.04-12-048 outlines the Commission's loading order, which includes preferential treatment for preferred resources. We also agree that the IE report should include an assessment of preferred resources and DAC considerations. The decision has been modified as such.

The Joint Environmental Parties and TURN recommend that to assist the orderly retirement of gas generation, the CPE should be solely responsible for gas procurement so that one entity can evaluate which generators receive local

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[144] SDG&E Comments on Proposed Decision at 7.

[145] *See, e.g.*, CESA Comments on Proposed Decision at 9, Joint Parties Comments on Proposed Decision at 6, Joint Environmental Parties Comments on Proposed Decision at 3.

[146] IEP Reply Comments on Proposed Decision at 3.

capacity contracts.[147] We acknowledge that when the time comes, California's fleet of gas-fired plants should be retired in an orderly fashion. While we find merit in the proposed concept, there is insufficient record developed and numerous outstanding questions. We encourage parties to offer developed proposals on how the CPE could act as the sole procurer of gas generation for local reliability needs in Track 4 of R.19-11-009, which is scheduled for completion in June 2021. We also encourage proposals on how the Commission can encourage the orderly retirement of gas power plants, with or without the CPE acting as the sole procurer of gas generation.

Meanwhile, we believe the CPE framework should increase transparency into gas-fired procurement and ensure resources that are not needed are not procured. It would thus be beneficial for the IE report to include the basis for any fossil fuel procurement that exceeds the minimum multi-year requirements. The decision has been modified to reflect this.

Parties recommend limiting the length of the contract the CPE can execute, with some proposing a limit on the preapproval process for contracts up to three years,[148] or up to five years.[149] PG&E, SCE, and Cal Advocates state that contracts exceeding five years should be approved through a Tier 3 Advice Letter. The Joint Environmental Parties suggest that contracts beyond the

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[147] Joint Environmental Parties Comments on Proposed Decision at 5, TURN Comments on Proposed Decision at 5.

[148] *See, e.g.,* AReM Comments on Proposed Decision at 8, CalCCA Comments on Proposed Decision at 9.

[149] *See, e.g.*, PG&E/SCE Comments on Proposed Decision at 10, Cal Advocates Comments on Proposed Decision at 4.

minimum term should be limited to preferred resources and energy storage.[150] We find it reasonable that the preapproval process should be limited to contracts up to a five-year term, similar to the preapproval process in D.07-12-052. For contracts exceeding five years, the CPE should seek approval via a Tier 3 Advice Letter. The decision has been modified as such.

Parties request clarification that the IOUs have the same show/sell bidding options as other LSEs.[151] CalCCA opposes the IOUs having the same options as other LSEs stating that they are not like other LSEs. CalCCA adds that IOU resources were procured for the benefit of all customers who pay the PCIA and IOUs should not be able to withhold needed local RA for bundled customers' system and flexible needs and deny these resources to other LSEs.[152] We disagree with CalCCA's assertions. Resources shown by the IOU will presumably reduce the local RA need and therefore, needed local RA will not be withheld. Further, shown resources are still subject to the local PCIA benchmarks adopted in D.19-10-001, which provide an RA capacity offset to the PCIA charge. The IOUs should be able to maximize ratepayer benefit for bundled customers, as other LSEs do, and thus should have the same show/sell bidding options. The decision has been modified clarify this.

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[150] Joint Environmental Parties Comments on Proposed Decision at 7.

[151] *See* PG&E/SCE Comments on Proposed Decision at 11, SDG&E Comments on Proposed Decision at 13, TURN Comments on Proposed Decision at 4, CLECA Comments on Proposed Decision at 5-6, Cal Advocates Comments on Proposed Decision at 2.

[152] CalCCA Reply Comments on Proposed Decision at 3.

PG&E/SCE seek clarification on whether the levelized fixed cost bid applies to solicitations where the IOU is a bidder but not acting as the CPE.[153] SCE states that the IOU should be treated like any other bidder when it is not acting as the CPE because the levelized cost rule is intended to avoid self-dealing when the IOU is both seller and buyer. We agree with SCE and the decision has been modified.

TURN seeks clarification that levelized cost bids should not be interpreted as market prices, particularly for valuing the PCIA benchmark. While this may have merit, it is beyond the scope of this proceeding to determine what should or should not be included in PCIA market benchmarks.

CalCCA comments that LSEs should receive notice of CPE awards at least six months before the compliance deadline, and notice of system and flexible allocations by the CPE at least five months before the compliance deadline.[154] This schedule is not feasible given the current RA forecast timeline, which includes the annual LCR study, load forecast, NQC process, and allocation process, which are required to determine procurement obligations and allocations.

Some parties, including TURN, PG&E, SCE, request clarification on the "iterative process" to evaluate bids to account for resources that were not selected through the solicitation but shown if not selected. In comments,

[153] PG&E/SCE Comments on Proposed Decision at 12.

[154] CalCCA Comments on Proposed Decision at 10.

PG&E/SCE outlines their interpretation of the iterative process.[155] PG&E/SCE's interpretation is accurate as to what we intended, and the decision has been modified to reflect this.

Several parties oppose the option to procure dispatch rights, stating generally that many complexities and costs arise by mixing a capacity and energy product.[156] PG&E/SCE alternatively propose modifying the decision to include dispatch rights "or other means that stipulate how local resources bid into the energy markets," as an optional term bidders are encouraged to include. We agree with PG&E/SCE's modification and the decision has been amended to include this.

Cal Advocates states that the Commission should track and allocate to LSEs the responsibility for GHG emissions of resources procured by the CPE.[157] TURN, PG&E, and SCE support this. We agree with Cal Advocates and modify the decision to clarify that if the CPE procures dispatch rights, allocation of any GHG emissions shall be allocated as they are today for other CAM resources.

SCE/PG&E seek clarification about the classification of IOU resources for purposes of PCIA, Competitive Transmission Charge (CTC), and CAM treatment. The utilities request that resources procured by the CPE be reclassified from their existing cost recovery mechanism to the CAM for the duration of the contract with the CPE. After that time, the resources should be

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[155] PG&E/SCE Comments on Proposed Decision at 12.

[156] *See, e.g.,* AReM, CESA, IEP, LS Power, MRP, NRG, CESA, Wellhead.

[157] Cal Advocates Comments on Proposed Decision at 6.

reclassified back to their existing cost recovery designation. Where PCIA-eligible resources are reclassified as CAM, then reclassified back, the resource should be exempt from the annual PCIA rate cap.[158] TURN supports the IOUs' clarification.

AReM and CalCCA oppose, asserting that procured PCIA resources should remain in the PCIA cost recovery. We disagree with CalCCA and AReM, as this would break cost causation principles and impede implementation of the adopted CAM. CPE cost recovery through the PCIA would result in costs recovered from vintage portfolios of customers rather than all customers and would raise questions about what load ratios should be used to allocate system and flexible capacity benefits. To implement CAM as the CPE cost recovery mechanism, IOU resources awarded by the CPE must be treated as CAM resources for the duration of their contracts. We find SCE/PG&E's approach to be reasonable and modify the decision to reflect this.

Calpine states it is unclear how UOG and tolling contracts would be offered into the RFO without their dispatch rights. Calpine recommends that costs could be shifted from bundled load (with appropriate PCIA vintages) to all load.[159] IEP and MRP state that the decision does not address how existing tolling agreements will be addressed in an RFO.[160] The CPE solicitation will include dispatch rights (or other means that stipulate how resources will bid into

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[158] PG&E/SCE Comments on Proposed Decision at 13.

[159] Calpine Comments on Proposed Decision at 8.

[160] IEP Comments on Proposed Decision at 8, MRP Comments on Proposed Decision at 8.

the energy markets) as an optional term, and IOUs will bid their resources into the solicitation at the resources' levelized fixed costs. If an IOU resource includes tolling or dispatch rights, the levelized fixed cost bids will be reflected in the bid price and will be evaluated alongside other bid resources in the CPE's selection process. If the IOU bid is selected, any revenue associated with the resource's dispatch will be allocated to all benefiting customers paying for the resource via the CAM, as is the standard practice today for CAM resources.

Some parties comment that the competitive neutrality measures require further development.[161] We directed the CPE to submit a proposed rule into the proceeding and parties will have an opportunity to comment. We decline to modify this process, but a September 1 deadline is added for the CPE's submission.

Cal Advocates recommends a 60-day deadline for the CPEs to submit supplemental testimony in their respective ERRA forecast proceedings for 2021 with the forecasted administrative costs associated with central procurement.[162] PG&E agrees with Cal Advocates but states that a 90-day deadline is more appropriate.[163] We find Cal Advocates' proposal to be reasonable, with a compromise 75-day submission deadline. The decision has been modified.

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[161] *See, e.g.,* MRP Comments on Proposed Decision at 9, Joint Parties Comments on Proposed Decision at 12, IEP Comments on Proposed Decision at 10, CalCCA Comments on Proposed Decision at 11.

[162] Cal Advocates Comments on Proposed Decision at 4.

[163] PG&E Reply Comments on Proposed Decision at 5.

CAISO and the Joint Parties comment that it is premature to use load impact protocols to set multi-year local procurement for DR and recommend deferring the issue until a decision on the issue in R.19-11-009.[164] We clarify that the DR value should be based on the most recently adopted DR valuation methodology for IOU DR resources.

CAISO requests clarification as to how MCC bucket requirements will align with CPE procurement and the impact of availability limitations in each local area.[165] We agree that the resource use-limitations should be used in the CPE selection process and should align with CAISO's LCRTS process. The MCC buckets, or its successor, should also be used in the CPE selection process to ensure that use-limited resources are not overly relied upon to meet local and sub-local needs. We find it reasonable to add "energy-use limitations" as a criterion in the selection process, and the decision has been modified.

Some parties state that the Commission should adopt multi-year forward requirements for system and flexible RA, including CAISO and LS Power. We agree this is an issue that should be considered and that Track 3 of R.19-11-009 is an appropriate place for consideration.

CalCCA comments that a CCA representative should be on the PRG and that the CCA community should select the representative. AReM recommends removing reference to expanding the CAM PRG membership to include CCA representatives since this was established in D.07-12-052. We agree that CCA

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[164] CAISO Comments on Proposed Decision at 4, Joint Parties Comments on Proposed Decision at 7.

[165] CAISO Comments on Proposed Decision at 4.

membership in the CAM PRG was directed in D.07-12-052 and reiterate that a non-market CCA representative should be part of the CAM PRG.

AReM requests that the CPE be required to report to the Commission all concerns raised by CAM PRG members about the procurement process.[166] The CAM PRG process has historically been effective in ensuring proper procurement oversight. However, Energy Division's 2025 report evaluating the CPE framework should also evaluate effectiveness of the IE and PRG processes.

5. Assignment of Proceeding

Liane Randolph is the assigned Commissioner and Debbie Chiv is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. On August 30, 2019, the Settling Parties filed a joint motion for adoption of a settlement agreement.

2. The proposed Settlement is not reasonable in light of the whole record.

3. The proposed Settlement fails to address a major implementation detail required by D.19-02-022 for any workable solution – the identity of the central procurement entity.

4. In D.19-02-022, the Commission elected to defer adoption of a central procurement structure, including designation of a central procurement entity, to allow additional time for workshops and discussion.

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[166] AReM Comments on Proposed Decision at 10.

5. The Commission continues to seek to designate a central procurement entity and framework that allows for targeted procurement necessary to address local and sub-local reliability needs.

6. In D.19-02-022, the Commission stated that it considered a workable central procurement solution as one that addresses the known challenges in the local RA market: (1) costly out-of-market RA procurement due to local procurement deficiencies, (2) load migration and equitable allocation of costs to all customers, (3) cost effective and efficient coordinated procurement, (4) treatment of existing local RA contracts, (5) opportunity for and investment in procurement of local preferred resources, and (6) retention of California's jurisdiction over the procurement of preferred resources.

7. As directed in D.19-02-022, parties undertook a series of workshops on central procurement proposals, submitted informal workshop reports, and provided comments on workshops. Parties were unable to reach consensus as to a central procurement entity or framework that addresses the known challenges identified in the local RA market.

8. A hybrid central procurement framework strikes a reasonable balance between the residual and full procurement models and best addresses the known challenges identified in the local RA market.

9. The distribution utilities are the central procurement entity candidates with the resources, knowledge and experience to procure local reliability resources on behalf of all LSEs in the near term.

10. SDG&E's TAC area is unique in that the local RA requirements typically meet or exceed the system requirements, such that LSEs would have little

procurement autonomy for system and flexible RA under a hybrid central procurement framework.

11. Weighing the benefits of LSE procurement autonomy for system and flexible RA against the benefits of central procurement, it is appropriate to decline to adopt a central procurement framework for the SDG&E TAC area at this time.

12. It is reasonable to consider an LCR reduction compensation mechanism for shown preferred and energy storage resources, if such a mechanism can be developed.

13. It is appropriate for the CPE to use a solicitation process for local RA procurement because it gives the CPE flexibility to select resources based on targeted criteria, in addition to costs and local needs.

14. The requirements pertaining to an all-source solicitation process adopted in past Commission decisions are reasonable guidance for procurement by a CPE.

15. It is reasonable that a distribution utility acting as the CPE has the same options as other LSEs in deciding whether to bid or show its resources into the CPE's solicitation process.

16. It is reasonable and consistent with the current RA program that RA attributes should remain bundled and LSEs should receive credit for procured system or flexible capacity, based on coincident peak load shares.

17. It is reasonable and consistent with the current RA program that CAM and IOU local DR resources should reduce the local RA amount procured by the central procurement entity.

18. It is reasonable to require a distribution utility that is acting as the CPE to bid its own resources into the solicitation at their levelized fixed costs.

19. It is reasonable that the central procurement solicitation includes quantitative and qualitative criteria that the CPE can employ in selecting local resources.

20. The least cost best fit methodology and other selection criteria adopted in past Commission decisions serve as useful guidance for the selection of local RA resources by the central procurement entity.

21. The cost recovery mechanism for the central procurement framework should facilitate the CPE's efficient procurement of local resources and provide necessary recovery of costs incurred by the CPE.

22. The CAM methodology is a cost recovery mechanism that allows the CPE to efficiently procure local resources and recover costs incurred.

23. The Commission seeks an oversight mechanism that provides market participants with reasonable assurances as to the neutrality and transparency of the central procurement process, while giving the CPE necessary flexibility and discretion to efficiently procure local resources.

24. It is reasonable to use the CAM PRG to advise the CPE through the solicitation process.

25. It is appropriate to retain an independent evaluator to monitor the CPE's solicitation and contract execution process.

26. The Commission seeks a portfolio approval process that gives the CPE achievable standards for cost recovery, authorizes procurement decisions that

incorporate the Commission's policy direction, and eliminates the need for after-the-fact reasonableness review of procurement actions.

27. A portfolio approval process for contracts up to a five-year term, similar to that adopted in D.07-12-052, satisfies the Commission's objectives for a preapproval process.

28. It is reasonable to require the CPE to demonstrate compliance on an annual basis with the requirements adopted in this decision, as well as the adopted local RA requirements.

29. To mitigate anti-competitive concerns, it is reasonable to require that confidential, market-sensitive information received by the distribution utilities through the solicitation and procurement process is adequately protected.

30. It is reasonable to give the CPE discretion to defer procurement of a local resource to the CAISO's backstop mechanisms if bid costs are deemed unreasonably high.

31. It is unnecessary to assess penalties or fines on the CPE for failing to procure resources to meet local RA requirements, so long as the CPE exercised reasonable efforts to secure capacity.

32. It is reasonable to maintain the current RA timeline with adjustments for hybrid central procurement.

Conclusions of Law

1. Pursuant to Rule 12.1(d), the Commission will only approve settlements that are reasonable in light of the whole record, consistent with the law, and in the public interest.

2. Proponents of a settlement agreement have the burden of proof of demonstrating that the proposed settlement meets the requirements of Rule 12.1. Consistent with Commission precedent, contested settlements are subject to more scrutiny than an all-party settlement.

3. The Settling Parties' settlement agreement fails to meet the requirements of Rule 12.1, and therefore, should be rejected.

4. A hybrid central procurement framework should be adopted for the central procurement of local resources beginning for the 2023 RA compliance year.

5. PG&E and SCE should be designated as the central procurement entities for their respective distribution service areas.

6. A central procurement framework should not be adopted for the SDG&E distribution service area at this time.

7. For 2020, the 50 percent local procurement requirement for 2023 for LSEs in PG&E and SCE's TAC areas should be eliminated, and the 100 percent requirement for 2021 and 2022 should remain.

8. A working group should assess and develop an LCR reduction compensation mechanism for shown preferred and energy storage resources to be submitted to the Commission for consideration.

9. A competitive, all-source, transparent solicitation process should be used by the CPE for local RA procurement.

10. RA attributes should remain bundled throughout the solicitation process and LSEs should receive credits for system or flexible capacity procured during the local RA or backstop processes.

11. CAM resources and IOU local DR resources should reduce the local RA amount that the CPE must procure.

12. IOU local DR resources should be counted based on the three-year period of the applicable load impact protocol studies (or any modified DR counting rules) after any Energy Division adjustments.

13. The CPE should include dispatch rights, or other means that stipulate how local resources bid into the energy markets, in its solicitation as an optional term that bidders are encouraged to include.

14. A distribution utility acting as the CPE should bid its own resources into the solicitation process at their levelized fixed costs. A distribution utility that is not acting as the CPE should not be required to bid its resources into another CPE's solicitation at their levelized fixed costs.

15. To guide the selection of local resources, the CPE should evaluate resources using the least cost best fit methodology and including the following criteria: (1) future needs in local and sub-local areas, (2) local effectiveness factors, (3) resource costs, (4) operational characteristics of the resources, (5) location of the facility, (6) costs of potential alternatives, (7) greenhouse gas adders, (8) energy-use limitations, and (9) procurement of preferred resources and energy storage (to be prioritized over fossil generation).

16. The CAM methodology should be adopted as the cost recovery mechanism to cover procurement costs associated with serving the central procurement function.

17. The administrative costs incurred by the CPE in serving the central procurement function should be recoverable under the cost allocation mechanism.

18. The CAM Procurement Review Group should be adopted to advise the CPE, in consultation with Energy Division and an independent evaluator, through the procurement process.

19. An independent evaluator should be retained to monitor the CPE's solicitation process and contract execution process.

20. A portfolio approval process should govern when a procurement action by the CPE is deemed reasonable and preapproved.

21. The CPE should submit an annual compliance report 30 days after it makes it local RA showing to the Commission that includes all contract terms, as well as the criteria and methodology used to select local RA resources.

22. The CPE should establish a rule that will govern how confidential, market-sensitive information will be protected to prevent the sharing of information outside of personnel involved in the central solicitation and procurement function.

23. The CPE should establish a strict code of conduct that governs the sharing of sensitive information beyond personnel involved in the central solicitation and procurement function (including management and officers).

24. The CPE should have discretion to defer procurement of a local resource to CAISO's backstop mechanisms if bid costs are deemed unreasonably high.

25. The CPE should not be assessed fines or penalties for failing to procure resources, so long as the CPE made reasonable efforts to secure capacity.

26. Energy Division's proposed timeline with adjustments to accommodate the hybrid procurement model should be adopted.

O R D E R

IT IS ORDERED that:

1. The Settling Parties' Joint Motion for Adoption of a Settlement Agreement for a Residual Central Procurement Entity Structure is denied.

2. Pacific Gas and Electric Company and Southern California Edison Company shall serve as the central procurement entities for their respective distribution service areas for the multi-year local Resource Adequacy (RA) program beginning for the 2023 RA compliance year.

3. The hybrid central procurement framework for local resources is adopted for Pacific Gas and Electric Company (PG&E) and Southern California Edison's (SCE) distribution service areas. Load serving entities in PG&E's and SCE's distribution service areas will no longer receive a local allocation beginning for the 2023 Resource Adequacy compliance year.

4. The hybrid central procurement structure is adopted as follows:

   a. If a load serving entity's (LSE) procured resource also meets a local Resource Adequacy (RA) need, the LSE may choose to: (1) show the resource to reduce the central procurement entity's (CPE) overall local procurement obligation and retain the resource to meet its own system and flexible RA needs, (2) bid the resource into the CPE's solicitation, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs.

   b. If an LSE elects to show a local resource, it may either: (1) do so in advance of the CPE's solicitation, if it does not intend to bid it into the solicitation, or (2) bid the resource into the CPE's solicitation but indicate in its bid that the resource will be available to meet local RA requirements even if it is not procured by the CPE, which may reduce the total procurement costs the CPE incurs on behalf of all LSEs.

5. A working group is authorized to assess and develop a Local Capacity Requirement (LCR) reduction compensation mechanism that properly compensates load-serving entities for shown local preferred and energy storage resources. A working group report on consensus and non-consensus items shall be filed in Rulemaking 19-11-009 by September 1, 2020. The working group report shall address resource cost effectiveness concerns, including local effectiveness and use limitations of a shown resource to be evaluated alongside bid resources. The working group report shall also address the following issues, to the fullest extent possible:

a. How granular the premium should be (*e.g.*, should different premiums be developed for different types of preferred resources, for new versus existing resources, and/or for sub areas, individual local areas, or TAC-wide local areas);

b. How to make the premium as transparent as possible given the market sensitive nature of this information and its potential impacts on bid resource prices;

c. Whether the compensation mechanism would preclude the option for an LSE to both bid and show a resource in the solicitation (or require potential revisions to the iterative process), due to the complexity of overlaying both of these mechanisms into the bid evaluation process; and

d. How to best adjust the local compensation from year to year to account for changes in the effectiveness of the resource reducing the local requirements.

6. The working group directed in Ordering Paragraph 5 shall also consider and submit a proposal on the treatment of existing contracts, which may include consideration of whether any proposed Local Capacity Requirement reduction compensation mechanism should be applied to existing contracts. A working group report on consensus and non-consensus items shall be filed in Rulemaking 19-11-009 by September 1, 2020.

7. To transition to the central procurement framework in Pacific Gas and Electric Company and Southern California Edison's distribution service areas, the following adjustments to the three-year local requirements are adopted:

a. For 2020, the 50 percent requirement for the 2023 compliance year is eliminated. The 100 percent two-year requirement remains.

b. Therefore, in 2020, load serving entities (LSEs) shall be responsible for 100 percent of their 2021 and 2022 local requirements. In 2021, LSEs are responsible for 100 percent of their 2022 local requirements.

8. The central procurement entity (CPE) shall conduct a competitive, all-source solicitation for local Resource Adequacy (RA) procurement with the following requirements:

a. Any existing local resource that does not have a contract, any new local resource that can be brought online in time to meet solicitation requirements, or any load serving entity (LSE) or third-party with an existing local RA contract may bid into the solicitation.

b. If an LSE-procured local resource is not selected by the CPE, the local resource may still count towards the LSE's system or flexible RA obligations, if applicable.

c. RA attributes shall remain bundled and LSEs shall receive credits for any system or flexible capacity procured during the local RA or backstop processes, based on coincident peak load shares, as is currently done with Cost Allocation Mechanism (CAM) resources.

d. CAM resources and investor-owned utility local Demand Response resources shall reduce the local RA amount that the CPE must procure.

e. The CPE shall include dispatch rights, or other means that stipulate how local resources bid into the energy markets, in its solicitation as an optional term that bidders are encouraged to include.

9. A distribution utility shall have the same options as other load-serving entities in deciding whether to bid or show its resources into the central procurement entity's solicitation process.

10. Investor-Owned Utility local Demand Response (DR) resources shall be counted based on the three-year period of the applicable load impact protocol studies (or any modified DR counting rules that are established in the Resource Adequacy proceeding) after any Energy Division adjustments, as is the current practice.

11. A distribution utility that is acting in its capacity as a central procurement entity (CPE) shall bid its own resources, that are not already allocated to all benefiting customers, into the solicitation process at their levelized fixed costs. A distribution utility that is not acting in its capacity as the CPE is not required to bid its resources into another CPE's solicitation at their levelized fixed costs.

12. Investor-owned utility (IOU) resources procured by the central procurement entity shall be reclassified from their existing cost recovery mechanism designations to the Cost Allocation Mechanism (CAM) for the duration of the contract with the central procurement entity. After that time, IOU resources shall be reclassified back to their existing cost recovery mechanism designation.

13. All Investor-Owned Utility bids, including utility-owned generation, shall be submitted to the Cost Allocation Mechanism Procurement Review Group and independent evaluator, in advance of the receipt of bids from any other entities.

14. To guide the selection of local resources procured by the central procurement entity (CPE), the CPE shall use the all-source selection criteria, including the loading order, and least cost best fit methodology adopted in Decision (D.) 04-07-029. The least cost best fit methodology employed shall also include the following selection criteria:

a. Future needs in local and sub-local areas;

b. Local effectiveness factors, as published in the California Independent System Operator's Local Capacity Requirement Technical Studies;

c. Resource costs;

d. Operational characteristics of the resources (efficiency, age, flexibility, facility type);

e. Location of the facility (with consideration for environmental justice);

f. Costs of potential alternatives;

g. Greenhouse Gas (GHG) adders;

h. Energy-use limitations; and

i. Procurement of preferred resources and energy storage (to be prioritized over fossil generation).

The GHG planning price, adopted in D.18-02-016, shall guide development of the GHG adder used by the central procurement entity.

15. In its solicitation, the central procurement entity shall direct bidders to include the following attributes for a resource: the CalEnviroScreen score of the resource location (or if unavailable, the pollution burden of the resource location), facility age, heat rate, start-up time, and ramp rate.

16. The Cost Allocation Mechanism methodology is adopted as the cost recovery mechanism to cover procurement costs incurred in serving the central procurement function. The administrative costs incurred in serving the central procurement function shall be recoverable under the Cost Allocation Mechanism.

17. The central procurement entity (CPE) shall establish a Centralized Local Procurement Balancing Account as a sub-account of the New Generation Services Balancing Account within 60 days of the issuance of this decision to facilitate the cost recovery process. The CPE shall submit its administrative costs associated with central procurement for review in its annual Energy Resource Recovery Account forecast and compliance process.

18. The central procurement entity shall submit supplemental testimony with the forecasted administrative costs associated with central procurement for 2021 in its Energy Resource Recovery Account forecast proceeding within 75 days of the issuance of this decision.

19. If the central procurement entity (CPE) procures dispatch rights, administration of the contracts shall be submitted for review in the distribution utility's annual Energy Resource Recovery Account compliance application for review of compliance with least cost dispatch requirements. If the CPE procures dispatch rights, allocation of any greenhouse gas emissions shall be allocated as they currently are for other Cost Allocation Mechanism resources.

20. The Cost Allocation Mechanism (CAM) Procurement Review Group (PRG), as adopted in Decision 07-12-052, is authorized to advise the central procurement entity (CPE). The CPE shall consult with CAM PRG members (including Energy Division and an independent evaluator) to outline procurement plans, draft solicitation bid documents, and collect feedback regarding the solicitation process.

21. An independent evaluator (IE) shall be retained to monitor the central procurement entity's (CPE) solicitation process and contract execution process, as follows:

a. The CPE shall develop a pool of at least three IEs, with the appropriate level of technical expertise and experience, to serve on a rotating basis for solicitations. Energy Division will have final approval over the selection of the IEs.

b. The IE shall prepare a report to be submitted on an annual basis to the Commission, assessing the neutrality of the procurement process, market power or aggregate pricing concerns, procurement of preferred resources, consideration of disadvantaged communities made in the procurement process, and other relevant issues.

c. The IE report shall include an explanation of the basis for any fossil fuel procurement for any contract that exceeds the minimum multi-year local procurement requirement.

d. The IE shall brief the Cost Allocation Mechanism Procurement Review Group (PRG) in meetings on the procurement process and concerns related to neutrality, market power, pricing, disadvantaged communities, or other relevant concerns.

e. The CPE shall permit periodic oversight of the IE process by Energy Division.

f. The IE shall brief the PRG on key solicitation elements.

g. The CPE shall rely on the requirements for the IE process adopted in Decision 04-12-048 as guidance; however, such guidance shall represent a minimum standard for the IE process.

22. A portfolio approval process is adopted whereby a procurement action for an executed contract with a five-year term or less shall be deemed reasonable and preapproved if the following conditions are met:

a. The procured resource meets the established local capacity requirements and underlying data supporting those requirements, which are based on the California Independent System Operator's Local Capacity Requirements Technical Study;

b. If the Cost Allocation Mechanism Procurement Review Group was properly consulted, as described in Ordering Paragraph 13; and

c. If procurement was deemed by the independent evaluator to have followed all relevant Commission guidance, including the least cost best fit methodology and other noted selection criteria.

For any executed contract that exceeds a five-year term, the central procurement entity shall submit a Tier 3 Advice Letter for approval.

23. The central procurement entity (CPE) shall submit an annual compliance report that includes all contract terms, as well as the criteria and methodology used to select local Resource Adequacy (RA) resources, 30 days after the CPE makes it local RA showing to the Commission. The annual compliance report shall be submitted through a Tier 2 Advice Letter in both confidential and public (redacted) form, subject to the confidentiality provisions in Decision 06-06-066 and related materials. The final independent evaluator report shall be filed with the annual compliance report in both confidential and public (redacted) form.

24. The central procurement entity (CPE) shall establish a rule or procedure that will govern how confidential, market-sensitive information received from third-party market participants during the solicitation process will be protected and what firewall safeguards will be implemented to prevent the sharing of information beyond those employees involved in the solicitation and procurement process. As guidance to develop the rule or procedure, the CPE may use the competitive-neutrality rules adopted in Decision 13-02-029. The CPE shall file and serve the proposed rule into the successor Resource Adequacy proceeding, Rulemaking 19-11-009, by September 1, 2020.

25. The central procurement entity (CPE), in collaboration with the independent evaluator, Cost Allocation Mechanism Procurement Review Group, and Energy Division, shall create a strict code of conduct, similar to that adopted in Decision 07-12-052, that prevents the sharing of confidential, market-sensitive information beyond those employees involved in the solicitation and

procurement process. Personnel employed by the CPE and involved in the solicitation and procurement process (including management and officers) shall sign the code of conduct as a precondition to engaging in the central solicitation and procurement process.

26. The central procurement entity (CPE) shall have discretion to defer procurement of a local resource to the California Independent System Operator's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high. If the CPE defers to backstop procurement, the CPE shall provide, through the independent evaluator report and annual compliance report, the reason for the deferral to backstop procurement, prices offered in the solicitation, which generators did not participate in the solicitation (if any), and other relevant information.

27. The central procurement entity (CPE) shall not be assessed fines or penalties for failing to procure resources to meet the local Resource Adequacy requirements and deferring local procurement to the California Independent System Operator backstop mechanism, as long as the CPE exercises reasonable efforts to secure capacity and the independent evaluator report contains the reasons for the failure to procure.

28. The Resource Adequacy timeline outlined in Section 3.10 is adopted in anticipation of the 2023 compliance year and future years.

29. Energy Division is authorized to prepare a report assessing the effectiveness of the central procurement entity framework, including the independent evaluator and the Cost Allocation Mechanism Procurement Review Group function, by 2025.

30. Rulemaking 17-09-020 remains open.

This order is effective today.

Dated June 11, 2020, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners