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Decision 19-02-022 February 21, 2019

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 REFINING THE RESOURCE ADEQUACY PROGRAM

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DECISION REFINING THE RESOURCE ADEQUACY PROGRAM

Summary

This decision adopts changes to the Resource Adequacy program, including adopting requirements for implementation of multi-year local procurement to begin for the 2020 compliance year.

This proceeding remains open.

1. Background

California Public Utilities Code Section 380(a)[1] established that: "The commission, in consultation with the Independent System Operator, shall establish resource adequacy [RA] requirements for all load-serving entities." Section 380(k) defines a "load serving entity" (LSE) as an "electrical corporation, electric service provider, or community choice aggregator." Accordingly, the Commission's RA program and its requirements apply to all LSEs under our jurisdiction.

In June 2018, the Commission issued Decision (D.) 18-06-030, which adopted local capacity obligations for 2019 and resolved certain issues in Track 1 of this proceeding. The Commission also issued D.18-06-031 in June 2018, which adopted flexible capacity obligations for 2019. D.18-06-030 (referred to as the Track 1 decision), as well as the Order Instituting Rulemaking for this proceeding, provides additional information on the procedural and substantive background of this proceeding.

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on January 18, 2018. The Scoping Memo identified the issues to be addressed in the proceeding and set forth a schedule and process for addressing

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[1] All statutory references are to the California Public Utilities Code unless stated otherwise.

those issues. The Scoping Memo organized the various issues into three tracks (Track 1, Track 2 and Track 3). In general, Track 2 issues are further refinements to the Commission's Resource Adequacy program, some of which are guided by directives adopted in the Track 1 decision. As the Track 1 decision adopted a general multi-year and central procurement framework for local RA, the primary issues in Track 2 involve determining the implementation requirements for multi-year and central procurement of local RA capacity.

Parties served Track 2 opening testimony on July 10, 2018. The parties who submitted testimony were 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, EnerNOC, Inc. (EnerNOC)[2] and EnergyHub (collectively, the Joint DR Parties); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Middle River Power, LLC (Middle River); 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 (CEJA), and Union of Concerned Scientists (UCS) (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. The Commission's Energy Division (Energy

[2] On October 24, 2018, EnerNOC notified the Commission that its name had changed to Enel X North America, Inc. (Enel X). Because the pleadings in this case were primarily filed under the former name EnerNOC, we will refer to this party as EnerNOC in this decision.

Division) served its Track 2 proposals on July 12, 2018. The Administrative Law Judge's e-mail ruling, dated November 16, 2018, that filed and served Energy Division's proposals is affirmed.

A workshop on the multi-year forward procurement and central buyer proposals was held on July 19, 2018. A workshop on the 2019 RA templates and guides was held on August 2, 2018. A Prehearing Conference (PHC) was held on August 1, 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; EnerNOC; GPI; IEP; the Joint DR Parties; the Joint Environmental Parties; Large-scale Solar Association (LSA); LS Power Development, LLC (LS Power); Middle River; NRG; Office of Ratepayer Advocates (ORA)[3]; PG&E; SDG&E; Sentinel Energy Center, LLC (Sentinel) and Diamond Generating Corporation (Diamond) (collectively, Sentinel/Diamond); Shell; Sunrun Inc. (Sunrun); TURN; and WPTF.

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

On October 5, 2018, the Administrative Law Judges (ALJ) requested additional comments on SCE's central procurement proposal. Comments were submitted on October 16, 2018 by AReM, CalCCA, CLECA, Calpine, GPI, the

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[3] Senate Bill 854 (Stats. 2018, ch. 51) amended Public Utilities (Pub. Util.) Code § 309.5(a) to state that the Office of Ratepayer Advocates is now named the Public Advocate's Office of the Public Utilities Commission. Because the pleadings in this case were primarily filed under the name Office of Ratepayers Advocates, we will refer to this party as ORA in this decision.

Joint Environmental Parties, NRG, ORA, 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.

2. Issues Before The Commission

The Scoping Memo identified the following issues as being within the scope of Track 2:

(1) Adopting multi-year local RA program requirements (if such framework was adopted in Track 1).

(2) Refinements to Local Area Rules, as time permits. Further refinements in this category can include:

- (a) adjusted or waived LSE procurement obligations for certain local areas with resource deficiencies or near-term procurement difficulties;
- (b) modified treatment of specific local areas or sub-areas (such as San Diego), and associated cost allocation;
- (c) seasonally varying Local Capacity Requirements (LCRs);
- (d) local penalty waiver requirements; and
- (e) increased transparency for the Commission, and for LSEs procuring RA, regarding which resources are essential for local and sub-area reliability.

(3) Refinements to the RA program. Further refinements in this category can include:

- (a) Flexible RA rule revisions to address ramping over shorter intervals and better allow for participation of renewables and out-of-state resources such as hydropower in Washington and Oregon;
- (b) refinements to production cost modeling algorithms and further integration of modeling-based concepts into RA program rules and other RA waiver and penalty rules; and

(c) other issues identified by Energy Division or by parties in proposals. (Scoping Memo at 7-8.)

All proposals and comments submitted by the parties were considered, but given the large number of parties and issues, some proposals and issues may receive little or no discussion or analysis in this decision. Issues within the scope of the proceeding that are not addressed in this decision, or are only partially addressed, may be addressed in a later phase of this proceeding.

3. Discussion

3.1. Central Procurement

The Track 1 decision discussed and analyzed whether central procurement or LSE-based procurement was most appropriate for a multi-year local RA program. The Commission concluded that a central procurement system, at least for some parts of the local RA requirement, was "most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection." (D.18-06-030 at 30.)

The Commission further directed parties in Track 2 to propose central buyer structures 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) and not just local RA requirements. The Commission did not foreclose the possibility of more than one central buyer per TAC area but stated it was not convinced of the feasibility of that solution. For proposals offering a two-buyer per TAC area solution, the Commission stated that the proposal should be "concrete and implementable, and: 1) address equitable allocation of costs to all customers, and 2) ensure cost-effective, efficient and coordinated procurement for each local and sub-local area within the TAC." (D.18-06-030 at 33.) The Commission added 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." (*Id*.) We also stated that we "remain concerned that a centralized capacity market may not meet these objectives." (*Id*.)

3.1.1. Identity of a Central Buyer

In Track 2 proposals, the Commission finds support among parties for a central buyer structure for at least some portion of local RA procurement.[4] A few parties oppose the central buyer structure in favor of a central capacity market approach[5] or expansion of the CAISO's backstop authority.[6]

Proposals for a central procurement entity generally fall into four categories: (1) the distribution utilities, (2) a special purpose entity, (3) the CAISO, and (4) a centralized capacity market.[7]

3.1.1.1. Distribution Utilities

Energy Division and several parties, including CLECA (with some concerns), CEERT, and TURN, support having the distribution utilities (that is, the investor-owned electric utilities) serve as the central procurement entities for their respective distribution areas.[8] Some favor the distribution utilities serving

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[4] *See, e.g.*, proposals from the CAISO, Calpine, CLECA, Energy Division, GPI, IEP, the Joint Environmental Parties, the Joint DR Parties, Middle River, NRG, PG&E, SCE, SDG&E, TURN.

[5] *See, e.g.*, proposals from AReM, Shell, WPTF.

[6] *See, e.g.*, proposal from CalCCA.

[7] Because parties' proposals contain interrelated components, to the extent that the Commission adopts a requirement in this decision that differs from a party's recommendation, we nevertheless consider the remaining aspects of a proposal, rather than disregard it in its entirety.

[8] *See* CEERT Testimony at 4, CLECA Comments at 5, Energy Division Proposal at 15, TURN Comments at 3.

as central buyers but only on an interim basis.[9] ORA recommends the distribution utilities serve as central buyers but with an independent consultant hired to administer solicitations and select contracts. (ORA Comments at 14.)

SCE supports the distribution utilities as central buyers provided certain conditions are met, such as durable cost recovery and equitable cost allocation, and only on an interim basis. (SCE Testimony at 17.) PG&E acknowledges that the utilities are likely the only candidates to perform this function in the immediate term, although they do not believe immediacy is required. (PG&E Opening Testimony at 1-25.) Energy Division proposes that the distribution utilities serve as central buyers for their TAC area but that mitigation measures be adopted to address anti-competitive and transparency concerns. (Energy Division Proposal at 15.)

Those who oppose designation of the distribution utilities raise several concerns. Some argue that the utilities cannot be neutral buyers, as they could potentially favor their own resources over third-party resources or select solutions that expand their rate base, such as new transmission or utility-owned storage.[10] Some Community Choice Aggregation (CCA) and Electric Service Provider (ESP) parties are broadly concerned with having utilities procure on their behalf, while others note the lack of transparency inherent in utility procurement.[11] Some find it problematic to designate a central buyer who, based on various estimates, will eventually provide generation to a minority of

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[9] *See, e.g.*, CLECA Comments at 5.

[10] *See, e.g.*, AReM Comments at 5, CalCCA Comments at 19-20, Calpine Testimony at A-2.

[11] *See, e.g.*, EnerNOC Comments at 4, SunRun Comments at 7.

customers as a result of increasing load migration to CCAs and growth in distributed energy resources, such as rooftop solar.[12]

Lastly, the distribution utilities express concern with the potential financial costs and risks associated with the central procurement function, particularly in light of inverse condemnation risk.[13] The utilities are concerned that the increased financial commitment associated with large-scale procurement could raise debt equivalency issues. Debt equivalence applied to a utility's balance sheet, as SDG&E contends, without corresponding increase in equity or compensation could negatively impact the utility's credit standing and financial stability. (SDG&E Comments at 6.) In comments to the proposed decision, numerous parties cite concerns for PG&E's precarious financial position with respect to exposure to wildfire damages and solvency issues.[14]

On the other hand, parties who support designating the distribution utilities (and even some who oppose) acknowledge that the investor-owned utilities are likely the only candidates who can serve the central procurement function in the immediate term.[15] As TURN states, the investor-owned utilities are the "only feasible entities" to serve as central buyers as they "have the resources, the knowledge and experience to take on this task effectively." (TURN Testimony at 23.) ORA also agrees "that the IOUs [investor-owned utilities] are the only practical entities who could centrally procure some portion

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[12] *See, e.g.,* PG&E Testimony at 2-21, NRG Testimony at 25-26, White Paper: Resource Adequacy and Wholesale Market Structure for a Future Low-Carbon Power System in California, submitted by SDG&E, PG&E, and SCE (Joint Utilities' White Paper) at 1.

[13] PG&E Reply Testimony at 1-25, SDG&E Comments at 6, SCE Testimony at 14.

[14] *See, e.g.,* Calpine, CalCCA, Diamond/Sentinel, Joint DR Parties, NRG.

[15] *See, e.g.*, CLECA Comments at 7, NRG Comments at 8, ORA Comments at 14, TURN Testimony at 23.

of multi-year local RA on behalf of the LSEs in the near term." (ORA Comments at 14.)

3.1.1.2. Special Purpose Entity

SDG&E and PG&E advocate for a special purpose entity (SPE) to serve as the central buyer. A SPE may be a new state agency or private entity selected through a competitive solicitation process or through legislation. SDG&E and PG&E propose that an SPE collaborate with the CAISO and the Commission to select an optimal portfolio to meet local needs.[16] SDG&E believes an SPE is the ideal central buyer because such entity would be financially stable, neutral, and subject to Commission oversight. (SDG&E Comments at 7.) PG&E favors an SPE because it believes the entity could engage in policy-based procurement without the complications of utility procurement. (PG&E Opening Testimony at 2-20.)

The primary drawback with a governmental SPE, as raised by multiple parties, is the substantial time and expense involved in establishing an independent governmental entity, including the potential for required legislation to do so.[17] Parties acknowledge that adopting this proposal would carry administrative and legislative hurdles that would delay use of an SPE for an unknown period. Another criticism expressed by parties is that a third-party entity that purchases and resells capacity in the wholesale market would to some degree be subject to the Federal Energy Regulation Commission's (FERC) jurisdiction, which could potentially lead to conflicts between federal policy and the state's environmental goals. (*See, e.g*., CalCCA Comments at 20.)

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[16] PG&E Testimony at 2-20, SDG&E Testimony at 5.

[17] *See, e.g.,* AReM Comments at 8, CalCCA Comments at 20, CLECA Comments at 8, ORA Comments at 17, PG&E Testimony at 2-20.

3.1.1.3. CAISO

A third proposal (offered by CalCCA, Calpine, Middle River, NRG, and WPTF) identifies the CAISO as the central buyer.[18] Some parties propose the CAISO act as a central buyer using various procurement mechanisms (*e.g.*, Calpine, CalCCA) while others propose that the CAISO serve as the administrator of a centralized capacity market (*e.g.*, WPTF). Proponents view the CAISO as an ideal central buyer because it is governed by tariffs and is an independent organization with transparent procurement. (*See* Calpine Testimony at A-2.) CalCCA believes the CAISO has the tools and legal authority to spread costs across the utilities' service territories on cost-of-service rates, if contract negotiations fall through. (CalCCA Testimony at 22.)

Other parties raise concerns with the CAISO serving as the central buyer. Parties note the potential conflict with FERC's involvement in California's capacity market and the state's environmental goals.[19] SDG&E cites the significant time involved in establishing the CAISO as the central buyer, as it would require a stakeholder initiative process to design a new market structure and tariff amendments for approval by FERC. (SDG&E Comments at 7.) The Joint Environmental Parties add that the CAISO has little experience in administering competitive resource solicitations. (Joint Environmental Parties Comments at 8.)

[18] CalCCA Comments at 20, Calpine Testimony at A-2, Middle River Comments at 9, NRG Testimony at 9, WPTF Testimony at 7.

[19] *See* CLECA Comments at 9, Joint Environmental Parties Comments at 7-8, ORA Comments at 16-17, TURN Testimony at 25.

Particularly noteworthy, however, is the CAISO's own response that it "will not voluntarily accept a role as central buyer, and the Commission should explore other options." (CAISO Comments at 5.)

3.1.1.4. Centralized Capacity Market

Several parties recommend a centralized capacity market (CCM) as a variation of a central buyer, including AReM, Joint DR Parties, Middle River, NRG, Shell, and WPTF.[20] A CCM typically refers to a market clearing mechanism where resources are selected based on whether they bid at or below a single market price, along with consideration of grid reliability constraints.

Parties supporting a CCM identify several advantages, including price transparency with a single market price, market liquidity (at least in local areas where more than one resource owner is present), and ease of transactions based on relatively simple clearing parameters.[21] Opponents of a CCM model argue that CCMs procure resources solely based on system-wide grid reliability and cost considerations and are thus not set up for targeted procurement for small local and sub-local areas, preferred resources, and/or disadvantaged communities.[22] Another criticism is that a CCM model would likely be regulated by FERC since it involves purchase and sale of wholesale capacity, which exposes California's procurement policies to federal jurisdiction and limits the Commission's ability to oversee procurement with an eye towards state

[20] AReM Comments at 4, Joint DR Parties Testimony at 15, Middle River Testimony at 9, NRG Testimony at 9, Shell Testimony at 7, WPTF Testimony at 5.

[21] *See, e.g.,* AReM Comments at 3, Shell Testimony at 4.

[22] *See, e.g.*, CLECA Comments at 10, ORA Comments at 12.

environmental goals.[23] Others cite the administrative hurdles and complexity in establishing a CCM, such as setting demand curves. (*See, e.g.*, Shell Testimony at 10.) Additionally, ORA argues that a CCM could increase ratepayer costs due to increased capacity payments determined by the market clearing price which would be applied to all cleared capacity, as well as potential increased costs to support state preferred resources through a mechanism such as a minimum offer price rule. (ORA Comments at 12.)

3.1.1.5. Discussion

The Commission is not convinced that either 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. Likewise, designating the CAISO involves its own administrative challenges, as well as potential federal jurisdictional conflicts. Moreover, the CAISO's statement that it is unwilling to accept the central procurement role voluntarily underscores our finding that the CAISO is not an appropriate entity to take on this role.

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, we reiterate that we are not convinced that a centralized capacity market is the appropriate central procurement structure, given the objectives outlined.

[23] *See, e.g.*, ORA Comments at 4, PG&E Reply Testimony at 1-16, Shell Testimony at 8, TURN Comments at 8.

The Commission is persuaded by parties who recognize that the distribution utilities are the candidates with "the resources, knowledge and experience"[24] 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.

That said, the Commission recognizes that a broad range of parties oppose the distribution utilities serving as central buyers. Indeed, the distribution utilities themselves are either unwilling to take on this role or agree to do so on an interim-only basis. SDG&E opposes the utilities serving as the central buyer, citing the significant administrative costs and negative financial risk and impact of debt equivalence on the utilities' credit ratings.[25] PG&E, while not opposed to being the central buyer, agrees to do so on an interim basis and also emphasizes the substantial financial risks associated with inverse condemnation that may negatively impact credit standing.[26] SCE does not object to serving as the central buyer for an interim period, but believes the distribution utilities may not be the appropriate entities on a long-term basis.[27]

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. In the interim, the Commission directs parties to undertake a

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[24] *See* TURN Testimony at 23.

[25] *See* SDG&E Comments on Proposed Decision.

[26] PG&E Comments on Proposed Decision at 3-5.

[27] SCE Comments on Proposed Decision at 2.

series of workshops to develop workable central buyer proposals, as further discussed in Section 3.1.2. The Commission intends to issue a decision in the fourth quarter of 2019 that addresses the central buyer designation.

3.1.2. Central Procurement Structure

The Commission must consider the scope of local RA that shall be procured by a central buyer. In Track 2, parties generally propose either a full procurement or residual procurement model, with some variations.

PG&E and Energy Division support a full procurement model. Both proposals would operate similarly, as follows: A central procurement entity procures the entire amount of required local RA, and LSEs do not receive individual local requirements. LSEs that have procured local resources may offer those resources to the central entity by bidding into the procurement entity's solicitation. If an LSE-procured local resource is not selected by the central buyer, the local resource would still be eligible to count towards the LSE's system or flexible RA obligations, if applicable.[28]

SCE offers a hybrid full procurement model in that LSEs no longer receive a local requirement. LSEs will continue to procure RA to meet system and flexible requirements "with the assumption that their procurement objective will be to secure the least-cost resources to meet their RA needs." If, in doing so, the least-cost resources also meet local area needs, the local resource may reduce the total local RA amount the central buyers must procure if certain conditions are met.[29]

Several parties advocate for a residual procurement model, including CalCCA, CLECA, the Joint Environmental Parties, NRG, ORA, SDG&E, Shell,

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[28] Energy Division Proposal at 15-16, PG&E Opening Testimony at 2-1, 1-4.

[29] SCE Reply Comments on SCE Proposal at 4.

and WPTF.[30] The proposed residual procurement models generally function as follows: an LSE receives a local RA requirement (either an optional or required allocation) to procure its own local resources. An LSE makes its local RA showing and then based on an assessment of what is not procured, the central buyer procures for an individual or collective deficiency. In effect, the central buyer acts in a backstop role to procure local resources to meet collective deficiencies.

3.1.2.1. Discussion

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. (*See* PG&E Reply Testimony at 1-7.)

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. (*See id*. at 1-12.)

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[30] CalCCA Testimony at 6, CLECA Comments at 11, Joint Environmental Parties Testimony at 9, NRG Comments at 8, ORA Comments at 18, SDG&E Testimony at 4, Shell Comments at 3, WPTF Testimony at 5.

By contrast, supporters of a residual procurement model identify several benefits. A residual model offers individual LSEs the flexibility and autonomy to procure local resources based on their (and their customers') particular objectives or preferences.[31] 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. Another benefit of residual procurement is that LSEs, such as CCAs, retain the buying power and corresponding value proposition that they can offer their customers. (*See, e.g.*, Joint DR Parties Testimony at 13.)

As discussed in the Track 1 decision, the Commission seeks a multi-year central buyer framework that will, among other things, reduce costly out-of-market RA procurement due to procurement deficiencies, account for increased load migration, and ensure that necessary resources are procured in an orderly manner. (D.18-06-030 at 24-25.) The Track 1 decision also directs any proposal involving more than one procurement entity – as a residual approach effectively is – to demonstrate it can "address equitable allocation of costs to all customers" and "ensure cost-effective, efficient and coordinated procurement for each local and sub-local area within the TAC." (*Id*. at 33.)

In consideration of parties' extensive comments and 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.

The Commission directs parties to develop workable implementation solutions for central procurement of multi-year local RA through workshops.

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[31] *See, e.g.*, CalCCA Comments at 13, CLECA Comments at 12, SCE Comments at 8.

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 as 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. We also encourage parties to consider how central buyer solutions may include options for procuring dispatch rights, or requiring capacity owners to economically bid into energy markets, if doing so is in the financial interest of ratepayers.

Accordingly, parties shall undertake a minimum of three workshops over the next six months, with the first workshop to take place in April 2019. Each workshop will be facilitated by a different market representative(s) (CCA, distribution utility, ESP), or a facilitator chosen by the representative. Within 30 days of this decision, parties shall reach agreement and inform the Commission of the following:

(1) The date for an April workshop and placeholder dates for at least two subsequent workshops;

(2) The facilitator(s) who will lead each workshop;

(3) The scope of issues for each workshop; and

(4) Identified part(ies) who shall prepare a post-workshop report following each workshop for submission to the Commission.

When developing the content and schedule for these workshops, parties should consider the order in which the identified challenges and issues should be addressed, or if certain challenges and issues should be considered jointly. Parties may consult with Energy Division on establishing the order of topics for each workshop, as well as on workshop logistical support.

At the conclusion of the workshops, the part(ies) identified to develop a report shall file an informal workshop report outlining the recommendations reached and how each recommendation addresses the challenges noted above, into the RA proceeding. Following the submission of the workshop report, parties shall have an opportunity to comment.

The Commission intends to issue a decision in the fourth quarter of 2019 that addresses and adopts implementation details for a central procurement structure.

3.2. Multi-Year Ahead Procurement

The Track 1 decision discussed the substantive history of the Commission's consideration of a multi-year ahead procurement framework. (D.18-06-030 at 24.) In the Track 1 decision, the Commission concluded that there "is value to having a multi-year local RA requirement to ensure that resources needed for reliability are procured in an orderly fashion, and the Commission intends to implement a multi-year local RA requirement in Track 2 of this proceeding." (*Id*.) The Commission did not adopt multi-year requirements for flexible and system RA, although we stated that this may be considered at a future date.

While we are not adopting a central procurement structure in this decision, we consider adoption of a multi-year local RA program since the foundation for a multi-year local RA framework was set forth in the Track 1 decision. We consider the specifications and implementation details of this framework in this decision so that implementation may begin for the 2020 RA compliance year.

3.2.1. Duration of the Multi-Year RA Program

The Commission considers the duration of a multi-year forward local RA program. In the Track 1 decision, the Commission directed parties to propose a multi-year local RA requirement with a three- to five-year duration in Track 2 of the proceeding, to be implemented beginning with the 2020 RA program year. (D.18-06-030 at 28.)

Energy Division and a few parties, including Diamond/Sentinel, IEP, PG&E, and SDG&E, support a five-year forward multi-year local requirement.[32] Middle River supports either a three- to five-year requirement.[33] Supporters of a five-year duration believe that longer duration contracts may provide financial stability and greater transparency for necessary resources, while giving resources that are not contracted an important signal that may inform retirement decisions.[34] Others state that generators can offer more efficient pricing on a longer-term contractual basis. (*See* Middle River Testimony at 6.) Some argue that a longer duration provides greater opportunity for investment and development of new generation and transmission alternatives that can compete with existing generation. (*See* PG&E Reply Testimony at 1-17.)

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[32] Diamond/Sentinel Comments at 1, Energy Division Proposal at 18, IEP Testimony at 11, PG&E Reply Testimony at 1-17, SDG&E Testimony at 25.

[33] Middle River Testimony at 6.

[34] *See, e.g.,* Diamond/Sentinel Comments at 1, IEP Testimony at 11, PG&E Opening Testimony at 1-13.

A broad range of parties support a three-year duration, including AReM, CAISO, CalCCA, Calpine, CLECA, GPI, the Joint DR Parties, the Joint Environmental Parties, Middle River, NRG, ORA, Shell, SCE, and TURN.[35] Proponents of a shorter duration cite the many changes that can arise in five years (such as transmission upgrades and new generation) as a basis for why procurement beyond three years greatly increases the risk of over-procurement.[36] ORA and the Joint Environmental Parties reference PG&E's proposed transmission solution in the South Bay/Moss Landing sub-area as an example of how quickly solutions can be deployed to reduce local needs. PG&E's proposed solution was approved by the CAISO in March 2018 and planned to be in place for 2019.[37] Others note that the longer the forward duration period, the more impactful changes in load migration become. (*See* SCE Testimony at 5.)

Some parties claim that the arguments made in favor of a five-year duration can likewise be made in support of a three-year period, while avoiding added risks and preserving flexibility.[38] The Joint Environmental Parties comment that those advocating for a five-year requirement "have not adequately explained why five-year contracts provide additional reliability benefits or savings" over three-year contracts. (Joint Environmental Parties Comments at 5.) Supporters of a three-year duration urge the Commission to adopt and evaluate

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[35] AReM Testimony at 5, CAISO Testimony, Chapter 2 at 1, CalCCA Testimony at 4, Calpine Comments at 5, CLECA Comments at 12, GPI Comments at 3, Joint DR Parties Testimony at 4, Joint Environmental Parties Testimony at 7, Middle River Testimony at 7, NRG Comments at 8, ORA Comments at 20, Shell Testimony at 4, SCE Testimony at 15, TURN Testimony at 14, WPTF Testimony at 8.

[36] *See, e.g.,* CLECA Comments at 13, Joint Environmental Parties Testimony at 7, TURN Testimony at 22.

[37] Joint Environmental Parties Testimony at 7-8, ORA Comments at 21.

[38] *See, e.g.*, Joint Environmental Parties Comments at 7, ORA Comments at 21.

a shorter duration before implementing a five-year requirement that locks in resources where local capacity may no longer be needed.[39]

The Commission observes a consensus for a three-year duration among a broad group of parties and is persuaded by the arguments made in support thereof. We agree that local requirements can significantly change from year to year as transmission projects come online and modeling assumptions change. Adopting a shorter duration will likely reduce the financial risks and costs of over-procurement of local RA, as identified by parties. A three-year requirement still provides preferred alternatives an opportunity to develop and reduce local capacity need in later years.

Accordingly, the Commission adopts a minimum three-year forward multi-year RA requirement. We adopt this three-year multi-year requirement without a central buyer structure and LSEs shall procure to meet their individual three-year allocations beginning in the 2020 RA compliance year.

3.2.2. Amount of Central Procurement

The Commission next considers the specific percentage of local RA capacity that shall be procured on a multi-year basis. To assess the specific amount that LSEs shall procure, the Commission first evaluates the appropriate inputs and studies that shall inform the local RA requirements.

3.2.2.1. Local RA Studies

In the Track 1 decision, the Commission recognized the need for further study in setting procurement requirements, while also continuing to rely on existing studies to move forward with the initial implementation of multi-year local procurement and maintain the integrity of the RA program. The

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[39] *See, e.g.*, AReM Testimony at 6, Joint DR Parties Testimony at 4, Joint Environmental Parties Testimony at 7.

Commission concluded that the CAISO's existing Local Capacity Requirement Technical Studies (LCRTS) would be a primary input into the Commission's determination of multi-year local RA needs. (D.18-06-030 at 34.) Under the existing RA program, the CAISO produces one-year and five-year ahead local capacity technical studies that identify the minimum local resource capacity required in each local area. The studies are provided to the Commission for consideration in the RA proceeding. The Commission directed Energy Division to propose additional studies in Track 2 that could be used in setting RA requirements. (*Id*.)

The CAISO affirms that it will adjust its studies as needed for a multi-year RA framework. (CAISO Testimony, Chapter 2 at 6.) In its Track 2 proposal, Energy Division recommends that the Commission use the CAISO's existing one-year ahead study to develop the Year 1 and Year 2 requirements and use the five-year ahead study to develop the Years 3 to 5 requirements (depending on the adopted duration). (Energy Division Proposal at 10.) Energy Division also recommends that for Years 2 and 3, the CAISO use engineer-managed adjustments to revise the power flow results to account for approved transmission upgrades scheduled for that year. Such adjustments would allow for transmission planning assumptions to be part of the local requirements and minimize the potential for over-procurement of local RA after Year 1. (*Id*.)

Other parties, including AReM, IEP, PG&E, and SDG&E, support the CAISO's LCRTS to be performed for all forward years.[40] SDG&E adds that the study should be updated annually to ensure procurement decisions are aligned. (SDG&E Testimony at 26.) AReM recommends that the CAISO establish a fixed

40 AReM Testimony at 4,11, IEP Testimony at 15, PG&E Opening Testimony at 2-4, SDG&E Testimony at 26.

amount for the entire period with periodic true-ups to address load migration. (AReM Testimony at 4, 11). PG&E and SCE recommend that the CAISO create a new study window to propose transmission solutions to reduce or address local reliability needs.[41]

The Commission finds the use of the CAISO's existing one- and five-year studies, with the requirement to incorporate engineer-managed adjustments for CAISO-approved transmission projects, to be a reasonable input to inform multi-year local requirements. As proposed by Energy Division, the one-year ahead study will form the basis for local requirements for Years 1 and 2 and the five-year study will inform the Year 3 requirements. If CAISO management approves any transmission upgrades for Years 2 and 3, the CAISO shall incorporate such projects into the associated year's studies through engineer-managed adjustments. The inputs and assumptions for the LCRTS shall be filed in the RA proceeding where parties may file comments. This solution allows the Commission to evaluate the local RA requirements for the initial implementation of the multi-year program without extensive modification to the CAISO's existing studies. It also minimizes the risk that resources will be procured longer than they may need to be, by accounting for new transmission and load forecast assumptions with engineer-managed adjustments.

Additionally, the CAISO offers to produce a study that identifies specific resources deemed essential to reliability in local or sub-local areas (called essential reliability resources or ERRs). (CAISO Testimony, Chapter 3 at 6.) The CAISO states that identifying ERRs may inform the central procurement entity and/or LSEs to make appropriate procurement decisions. While the CAISO's

[41] PG&E Opening Testimony at 2-4, SCE Comments at 10.

study may prove useful, the Commission finds it unnecessary to adopt it at this time since the existing LCRTS identifies essential resources (with effectiveness factors) that can meet capacity needs in local and sub-local areas.

3.2.2.2. Specific Percentages for Procurement

In the Track 1 decision, the Commission concluded that in the interest of market certainty in the near term, the percentage for the first year of multi-year local RA procurement should be a 100% requirement. For the second year, to address concerns of potential over-procurement of local RA, the local requirement was set to at least 95%. (D.18-06-030 at 29-30.) The Commission directed parties in Track 2 to propose a "reasonable amount of local RA procurement for Year 3 (and beyond, if a longer program is proposed) basing their proposals on data such as that presented by Energy Division in its [Track 1] proposal." (*Id*. at 30.) The Commission also stated that generally, the procurement requirements should be greater than current voluntary local RA forward procurement levels.

Track 2 proposals cover a broad range of percentages with no general consensus. We note that numerous proposals offer percentages without clarifying what the percentage would be based on, such as adjustments to the LCRTS.

All parties support a continuation of the 100% local procurement requirement for Year 1, although we note some parties offered this support under a residual proposal. Proposals for Years 2 and 3 are summarized as follows: at the high end of the spectrum, Calpine, NRG, PG&E, SCE, and WPTF support a 100% requirement for the entire multi-year duration.[42] The CAISO proposes 100% for Years 1 and 2, and 80% in Year 3. (CAISO Testimony, Chapter 2 at 4.) At the low end, the Joint DR Parties and Shell support a 50% requirement for Year 3.[43] Year 3 proposals cover the widest ground with the majority falling between 70% and 100%.[44]

Proponents of a lower percentage for Year 3 (and in some cases, Year 2) cite arguments similar to those raised in favor of a three-year duration. Parties note that a high percentage requirement increases the risk of over-procurement due to year-over-year variations in local need determination as a result of load forecasts, new generation, transmission upgrades, etc.[45] ORA reiterates the example of PG&E's transmission solution in the South Bay/Moss Landing sub-area (in which local need was reduced from 2,221 MW in 2018 to 1,653 in 2019) in support of a 80% requirement in Year 3. (ORA Comments at 23.)

Supporters of a 100% requirement for the entire duration assert the importance of giving generators certainty as to which resources are needed and minimizing the risk that necessary resources are excluded from procurement. (*See, e.g.*, PG&E Reply Testimony at 1-19.) The CAISO supports 100% procurement through Year 2, arguing that analysis of over-procurement risk is overstated "while ignoring the risks of under-procurement, which has both reliability and financial/economic impacts." (CAISO Comments at 6-7.) The CAISO believes that reductions in local capacity requirements "are largely driven

[42] Calpine Comments at 5, NRG Testimony at 9, PG&E Reply Testimony at 1-19, SCE Testimony at 15, WPTF Testimony at 4.

[43] Joint DR Parties Testimony at 4, Shell Testimony at 4.

[44] For example, CLECA and TURN support 70%; AReM, CAISO, CalCCA, and ORA support 80%; Energy Division and IEP support 90%; and SDG&E supports 95%.

[45] *See* AReM Comments at 22, ORA Comments at 22, TURN Testimony at 9.

by transmission system upgrades, which the CAISO and stakeholders typically know about years in advance" and are therefore included in the CAISO's LCR studies. (*Id*.)

As discussed in the Track 1 decision, we intend to adopt a high percentage of procurement for Years 1 and 2 in an effort to increase certainty and stability for necessary resources, as well as provide market signals for resources that are not contracted. The Commission acknowledges the over-procurement concerns with respect to year-to-year variations in LCRTS results. In weighing the Track 2 comments and comments to the proposed decision, the Commission finds an appropriate balance with a 100% requirement for Years 1 and 2 and a 50% requirement for Year 3. Because we are not adopting a central procurement structure at this time, and load migration and cost allocation issues are not addressed under an LSE-based procurement framework, setting a lower 50% requirement in Year 3 minimizes stranded cost issues that may arise. Additionally, a lower requirement in Year 3 provides necessary flexibility for market variabilities that may relieve local constraints in future years, such as development of new generation and transmission upgrades (that have not been incorporated into the engineer-managed adjustments). In conjunction with a shorter three-year forward requirement, we find these percentages will likely minimize over-procurement risk in later years.

In addition to taking these actions to limit risk of over-procurement of the local RA attribute, we further note that any excess local RA resources will nevertheless have value towards system (and potentially flexible) RA requirements, which mitigates the costs of over-procurement. As with the three-year forward duration, the Commission's adopted percentages of 100% for Years 1 and 2 and 50% in Year 3 are minimum requirements.

The Commission recognizes that as this is the initial implementation of a multi-year local program, there may be a need for further refinement in the near future. We intend to continue to monitor and evaluate the multi-year local procurement process and may refine the requirements adopted herein.

3.3. LSE-Based Multi-Year Procurement

As discussed, the Commission moves forward with a three-year multi-year local RA requirement without a central buyer. LSEs shall procure local resources based on individual local allocations, as is currently done in the RA program, for a three-year forward duration.

Under the current RA program, LSEs are required to submit load forecasts on a one-year forward basis. Additionally, new LSEs are required to register and participate in the RA year-ahead process one year before beginning service, as adopted in the Track 1 decision. As the Commission is unable to anticipate when new LSEs will form or how load will migrate among LSEs beyond the one-year timeframe, at this point, all LSEs will be allocated local requirements for each of the three forward years based on their load share in the first year resulting from the adopted California Energy Commission (CEC) load forecasting process. Requirements for Years 2 and 3 will be updated during the following year's year-ahead allocation process.

In comments to the proposed decision, the CAISO expresses concern that procurement targets for Years 2 and 3 will be ineffective without an enforcement mechanism.[46] If procurement falls well below the established targets, the result "would fail to achieve the purpose of having multi-year procurement in the first

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[46] CAISO Comments at 5, CAISO Comments on Proposed Decision at 2.

instance."[47] The Commission agrees that an enforcement mechanism is necessary for individual LSE procurement, as is currently enforced in the local RA program. Accordingly, we apply the local penalty and waiver process instituted on a one-year basis, pursuant to D.06-06-064 and D.07-06-029, to apply to the three-year forward requirement for LSEs.

In addition, we note that contracts with once-through cooling (OTC) resources that terminate one year or less before the State Water Resources Control Board (SWRCB) compliance deadline must be submitted to the Commission for approval via a Tier 3 Advice Letter, pursuant to D.12-04-046. However, this requirement does not align with the RA timeline. Accordingly, we eliminate the Tier 3 Advice Letter filing requirement established in D.12-04-046 for contracts with OTC resources subject to SWRCB compliance deadlines, if that contract ends prior to the OTC compliance deadline.

Lastly, the Commission does not modify the RA compliance timeline for the implementation of multi-year local procurement. Flexible and system capacity showings will be due at the same time as the three-year ahead local showings on October 31.

While the Commission adopts LSE-based multi-year local requirements at this time, the Commission intends to revisit the LSE-based component of multi-year local procurement in a decision to be issued in the fourth quarter of 2019.

3.3.1. Disaggregation of Local Areas

The CAISO has continually supported disaggregation of local capacity areas to the local and sub-local capacity area, arguing that this would more

[47] *Id.*

closely tie procurement to local capacity needs and operational requirements, result in more efficient and effective local capacity procurement and reduce the need for backstop procurement.[48] Under its transitional LSE-based proposal, PG&E recommends that the "PG&E Other" area be disaggregated to the local capacity area. (PG&E Opening Testimony at 1-7.)

The Commission understands that local area requirements are driven by constraints in sub-local areas and collective deficiencies may arise when procurement does not address certain sub-local constraints, even if all LSEs meet their individual local requirements. The CAISO's backstop authority and decisions are made based on sub-local needs and collective deficiencies. The Commission also recognizes that the decision to aggregate local areas in the first instance was to mitigate market power in constrained local areas. There appears to be considerable tension between the goals of mitigating market power and minimizing the risk of backstop procurement.

While the Commission agrees with the CAISO that the disaggregation of all local areas to the sub-local area level will more closely tie procurement requirements with local capacity needs and operational requirements, reducing the potential for inefficient local procurement and CAISO backstop procurement, we are not convinced that this level of disaggregation is workable in the current bilateral market and may lead to LSE deficiencies and inevitable backstop procurement, which the Commission is attempting to avoid in this proceeding.

Because we adopt LSE-based requirements, we believe that the disaggregation of the "PG&E Other" local area is a necessary first step towards

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[48] CAISO Comments at 5, CAISO Comments on Proposed Decision at 4.

addressing inefficient procurement that may lead to backstop procurement.[49] This level of disaggregation will also provide useful feedback to the Commission in assessing further disaggregation to the sub-local area level. The Commission also encourages LSEs to consider sub-local needs when making procurement decisions so as to avoid inefficient procurement.

Additionally, PG&E proposes that the Cost Allocation Mechanism (CAM) be applied to all of its existing non-Renewable Portfolio Standard (RPS) utility-owned generation and non-RPS resource contracts in the "PG&E Other" area. (PG&E Opening Testimony at 2-11.) PG&E asserts that "in many local areas, PG&E resources constitute most, if not all, of the local resources. These resources have been approved by the Commission and therefore, should be fully taken into account in each local area, so that other LSEs are not obligated to obtain other resources where PG&E resources are already in place." AReM opposes expansion of CAM for this purpose based on a lack of statutory authority.[50]

The Commission sees value in PG&E's proposal to allocate its non-RPS local resources in the "PG&E Other" area through the CAM mechanism. However, we decline to do so at this time, absent adoption of a central procurement mechanism for this area.

3.4. Additional Studies

As parties undertake workshops and offer new proposals, it is critical that parties have reasonable insight about the current and future state of the RA market. We recognize that certain information regarding the broader RA

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[49] The "PG&E Other" local area includes Humboldt, Sierra, Stockton, Greater Fresno, and North Coast, and Kern.

[50] AReM Comments at 16.

procurement outlook is not publicly available and only visible to Energy Division staff. Therefore, to increase transparency into the state of the RA market, the Commission directs Energy Division staff to prepare two reports that will address the following:

(1) Total MW for any/all resources procured (gas, storage, renewal/DER) to meet RA requirements;

(2) Development of preferred resources in local and system areas;

(3) Information regarding local deficiencies, including the number of LSEs that are deficient, type of LSE (IOU, CCA, ESP), location of deficiencies, amount of deficiencies (in MW), number of local RA waiver requests, and anonymized statements from the LSE as to the reason for the deficiency (such as which generators bid into the solicitation, whether the bids included dispatch rights or other terms addressing how local resources bid in the energy market);

(4) Information regarding system and flexible capacity deficiencies, including anonymized statements from the LSE as to the reason for the deficiency; and

(5) Resources on the Net Qualifying Capacity list that are not shown in RA filings as under contract to an LSE(s).

The first report shall be issued by Energy Division within 60 days of the decision setting the year-ahead RA requirements. The second report shall be issued by Energy Division within 60 days of the October 31, 2019 filings for the 2020-2022 RA compliance years

3.5. Expanding Multi-Year Framework to System or Flexible RA

In the Track 1 decision, the Commission concluded that limiting central procurement to local RA resources was appropriate in order to "preserve procurement flexibility for all LSEs and limit program modifications to only the most critical areas." (D.18-06-030 at 32.) The Commission stated that as the flexible RA construct is under evaluation, the Commission did not intend to adopt multi-year system and flexible RA requirements at this time. (*Id*. at 8.)

In Track 2 proposals, several parties support expanding multi-year and/or central procurement to system and flexible requirements, in addition to local requirements.[51] Parties primarily comment that procurement will be needlessly complicated if different RA products are procured at different durations or percentage obligations.

Parties who oppose expanding multi-year procurement beyond local RA argue that the Commission should await evaluation of the multi-year local program before expanding to system and flexible RA.[52] PG&E and AReM assert that the concerns about RA procurement to date primarily affect local RA, such as the use of local waivers, increased use of backstop procurement, and anticipated retirement of local resources.[53] Likewise, SCE cautions that there has been "no clear demonstration that the existing RA program has failed in ensuring adequate System and Flexibility capacity to the grid." (SCE Comments at 12.)

The Commission agrees that the RA procurement issues observed thus far pertain to local RA and therefore, expansion to flexible and system RA is premature and needs to be fully explored. The Commission declines to adopt

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[51] *See, e.g.*, Calpine Comments at 5, CAISO Testimony Chapter 2 at 1, Diamond/Sentinel Comments at 2, IEP Testimony at 10, Middle River Testimony at 6, NRG Testimony at 9, WPTF Testimony at 4.

[52] *See, e.g.*, AReM Comments at 23, ORA Comments at 23, PG&E Opening Testimony at 2-17, SCE Comments at 12.

[53] AReM Comments at 21, PG&E Reply Testimony at 1-22.

multi-year requirements for system and flexible RA at this time. However, the Commission agrees that there may be potential benefits to expanding multi-year requirements to system and flexible RA, and will continue to monitor and evaluate the multi-year local RA program to consider expansion to flexible and/or system RA in the future.

3.6. Expanding CAISO Backstop Authority

Under the multi-year local procurement process adopted in this decision, any local deficiencies after LSEs have made their local showings will still be subject to the CAISO's backstop procurement, as is currently done in the RA program. The existing backstop mechanisms include the Capacity Procurement Mechanism (CPM) designation and Reliability Must Run (RMR) contracts.

The CAISO states that it will not implement backstop procurement on a multi-year basis in the initial 2020 multi-year procurement cycle. However, the CAISO intends to "conduct its own stakeholder initiative to implement multi-year backstop procurement commencing with the 2021 procurement cycle." (CAISO Comments at 6.)

PG&E, Energy Division, and ORA oppose expanding the backstop mechanisms beyond the annual process. Energy Division believes the CPM process should remain an annual process to incentivize generators to execute multi-year contracts though a bilateral process rather than through backstop mechanisms. (Energy Division Proposal at 18.) Energy Division adds that an annual backstop process is consistent with the purpose of backstop authority which is to provide operational reliability, as compared to the RA program which is intended as a longer-term planning mechanism. (*Id*.) PG&E and ORA state that expanding backstop authority also runs counter to one of the

Commission's objectives in this proceeding which is to avoid costly backstop procurement.[54]

The Commission agrees that the CAISO backstop mechanisms should not be expanded beyond an annual process at this point, as that would interfere with efficient procurement of local RA through the Commission's RA program.

3.7. Transparency

In Track 1 of this proceeding, Sierra Club submitted a proposal relating to greater transparency in RA contracting. In the Track 1 decision, we stated that while the Commission supports transparency, "[g]iven the complexity of this issue and the relatively thin record currently before the Commission," it is more appropriate to address transparency proposals in Track 2.

In their Track 2 proposal, the Joint Environmental Parties propose that each December, the LSEs provide certain non-market sensitive information on RA contracts for that year.[55] Energy Division recommends that at the beginning of each year, portions of an LSEs' RA plans from the previous year should be released but that certain information, such as megawatts contracted or contract length, remain confidential to ensure that an LSE's forward position be protected. Energy Division posed several questions in its proposal for further comment by parties. (Energy Division Transparency Proposal at 3-4.) AReM argues that both proposals violate D.06-06-066, which states that LSEs' RA

[54] ORA Comments at 20, PG&E Reply Testimony at 1-16.

[55] Joint Environmental Parties Testimony at 4-6. The information disclosed would include: resource name, technology type, CalEnviroScreen score, megawatts, type of RA contracted, local and sub-local area (if applicable), months contracted for, and duration of contract (if publicly available). Additionally, the LSE would disclose loading order compliance, disadvantaged community impacts, and preferred resources contracting. (*Id.*)

contract information is confidential three-years forward and one-year back. (AReM Comments at 30.)

In response to Energy Division's proposal, PG&E recommends that one way to make information available concerning RA resources in an LSEs' portfolio, in a manner that protects market sensitive information, is to disclose all resources used to satisfy an LSE's RA obligation in the previous year without identifying the number of megawatts associated with the resources. According to PG&E, this would protect market sensitive information such as an LSE's load share and open position while satisfying Sierra Club's request to determine which resources LSEs have contracted with.[56]

The Commission finds that PG&E's recommendation is a reasonable first step to promoting transparency in RA contracting. Accordingly, early each calendar year, we direct Energy Division to post a summary list of the resources listed on each LSE's monthly RA plans for the previous year. As proposed by Energy Division, the information to be shared shall include scheduling resource ID, scheduling coordinator ID or counterparty, zonal location, and local area (if applicable).

4. Comments on Proposed Decision

The proposed decision of Administrative Law Judges Allen and Chiv 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 December 11, 2018 by the following parties: AReM, CEERT, CESA, CAISO, CalCCA, CLECA, California Municipal Utilities Association (CMUA), Calpine, Department of

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[56] PG&E Comments at 2-5 - 2-7.

Market Monitoring of the CAISO (DMM), Diamond/Sentinel, GPI, IEP, Joint DR Parties, Joint Environmental Parties, LS Power, LSA, Middle River, NRG, ORA, PG&E, Regents of the University of California, SDG&E, Shell, Sonoma Clean Power Authority (SCPA), SCE, Sunrun, TURN, Wellhead Electric Co., and WPTF.

Reply comments were filed on December 17, 2018 by the following parties: AReM, CalCCA, California Efficiency + Demand Management Council, Calpine, CEERT, CLECA, DMM, IEP, Joint Environmental Parties, NRG, ORA, PG&E, SDG&E, Shell, SCE, and TURN.

All comments and reply comments have been carefully considered. Significant aspects of the proposed decision that have been revised in light of the comments are mentioned specifically 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 rather, focus on major arguments made in which the Commission did or did not make revisions in response to party input.

A large volume of comments criticized the proposed decision's designation of the distribution utilities as the central buyers. Commenters generally reiterated arguments asserted in their Track 2 proposals and comments. The distribution utilities, however, either oppose serving as the central buyer or are willing to do so on an interim-only basis. PG&E states it is prepared to undertake the central buyer role but only for an interim period.[57] SDG&E opposes the adoption of the distribution utilities as central buyers, citing significant administrative costs and negative financial impact on the utility's

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[57] PG&E Comments on Proposed Decision at 3-4.

credit ratings.[58] SCE does not oppose the distribution utilities as the central buyers but only for an interim period.[59]

Based on comments, and without a viable alternative central buyer, we agree to delay the designation of a central buyer to provide additional time for workshops. The decision has been modified to decline to designate a central buyer at this time.

Another aspect of the proposed decision that received extensive comments was the adoption of a full procurement mechanism. Commenters generally reiterated arguments asserted in their Track 2 proposals and comments. Numerous parties, including AReM, CalCCA, IEP, LSA, LS Power, NRG, and SCPA, are concerned that full procurement, among other things, leaves LSE-procured capacity at risk if it is not selected by a central buyer. We continue to believe that a central procurement structure is the appropriate framework for multi-year local RA procurement, for the reasons outlined in the Track 1 decision. However, based on comments and a lack of consensus among parties, we agree to delay the implementation of a central procurement structure at this time to provide additional time for workshops.

The Commission intends to issue a decision in the fourth quarter of 2019 to address and adopt implementation details for a central procurement structure. This decision has been modified to decline to adopt a central procurement structure at this time.

We added specific direction in this decision for a series of workshops to facilitate the development of workable details for a central procurement

[58] SDG&E Comments on Proposed Decision at 4.

[59] SCE Comments on Proposed Decision at 2.

structure. 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.

In an effort to provide parties with reasonable insight into the state of the RA market while new proposals are being developed, we added language directing Energy Division staff to produce reports that provide transparency on the extent of RA deficiencies, development of preferred resources, and other RA market dynamics.

Several parties, including CalCCA, IEP, Middle River, NRG, and Shell, support delaying (or reversing) the proposed decision's adoption of a central procurement structure pending further workshops, but support moving forward with multi-year local requirements to begin for the 2020 compliance year. Other parties, including AReM, CEERT, CESA, SCPA, and Sunrun, argue that there is no urgent need for multi-year procurement, given that less backstop procurement occurred for 2019, and the proposed decision should be delayed. Some parties, including the CAISO and several generators, continue to support multi-year local RA. For example, the CAISO "strongly supports the Proposed Decision's three-year forward local capacity procurement requirements and the procurement levels."[60] While the CAISO did not procure any additional local, system or flexible resources through its backstop mechanisms for compliance year 2019, we believe this was due in part to the proactive measures taken in the Track 1 decision directing SCE to attempt to contract with Ormond Beach and Ellwood, which otherwise would have resulted in RMR contracts for these facilities.

We conclude that it is reasonable and prudent to move forward with multi-year local requirements to address emerging issues, including the potential exertion of market power in constrained local and sub-local areas. Therefore, we have modified the decision to adopt multi-year local requirements, without a central buyer structure, to be procured by LSEs based on individual local allocations. In order to facilitate multi-year LSE-based local procurement, we have added implementation details, including disaggregation of the "PG&E Other" areas.

The CAISO comments that procurement targets in Years 2 and 3 may be ineffective without an enforcement mechanism. We agree that an enforcement mechanism is necessary for LSE-based procurement and add language to extend the local penalty and waiver process from a one-year basis to the three-year requirement.

A large volume of comments addressed specific aspects of the central procurement structure adopted in the proposed decision, such as the selection criteria, the procurement oversight process, etc. Because we have elected to delay the implementation details of the central buyer structure pending

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[60] CAISO Comments on Proposed Decision at 1.

workshops, we do not further address comments on the proposed decision's adopted central buyer structure.

Some parties, such as the Joint DR Parties and CESA, support a lower Year 3 requirement and SCE recommends that Year 3 should be capped to minimize over-procurement risk. In consideration of these comments, as well as Track 2 proposals, we agree to modify the Year 3 requirement to 50% in order to provide additional flexibility for LSE-based multi-year local procurement.

SCE argues that the filing requirements for some contracts with OTC resources conflicts with the RA timeline, potentially delaying the ability to meet local requirements.[61] D.12-04-046 states that contracts with OTC resources ending one year prior to the State Water Resources Control Board compliance deadline must be submitted via a Tier 3 Advice Letter. Since the main purpose for the requirement was to ensure OTC deadlines were met and contracting up to the compliance date would not delay compliance with SWRCB OTC requirements, we have added language to eliminate the Tier 3 Advice Letter filing requirement for these OTC contracts.

5. Assignment of Proceeding

Liane Randolph is the assigned Commissioner and Peter V. Allen and Debbie Chiv are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. While the Commission continues to find that a central procurement structure is the appropriate framework for implementing multi-year local requirements, a lack of consensus exists among parties as to the appropriate central buyer and central procurement mechanism.

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[61] SCE Comments on Proposed Decision at 12.

2. Additional time for workshops would be beneficial to develop workable central buyer and central procurement mechanism solutions.

3. The challenges to the local RA program continue to be costly out-of-market RA procurement due to local procurement deficiencies, load migration and 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 California's jurisdiction over procurement of preferred resources.

4. It is reasonable at this time to move forward with a multi-year local RA framework, without a central buyer structure, that relies on LSE-based procurement.

5. It is important to adopt a multi-year forward duration that accommodates year-to-year changes in local requirements and provides flexibility for market variabilities in later years that may relieve local constraints.

6. A three-year multi-year forward duration strikes a reasonable balance in accommodating yearly variations in local capacity requirement results and providing flexibility for preferred alternatives to develop and potentially reduce local capacity needs.

7. Reliance on the CAISO's existing Local Capacity Requirement Technical Studies, with the incorporation of new transmission planning assumptions, will minimize over-procurement of local RA after Year 1.

8. It is important to adopt a procurement percentage that accommodates year-to-year changes in local requirements and provides flexibility for market variabilities in later years that may relieve local constraints.

9. A 100% procurement requirement for Years 1 and 2, and a 50% requirement for Year 3 under a LSE-based procurement framework strikes a

reasonable balance in minimizing stranded cost issues, accommodating yearly variations in local capacity requirement results and providing flexibility for market variabilities in later years that may relieve local constraints.

10. In establishing three-year ahead local requirements, the use of an LSE's one-year ahead load share resulting from the adopted CEC load forecasting process is a reasonable proxy.

11. An enforcement mechanism for LSE procurement on a three-year ahead basis is reasonable.

12. It is unnecessary to modify the RA compliance timeline for multi-year local procurement without a central buyer.

13. The disaggregation of local capacity areas is a necessary first step towards addressing inefficient procurement that may lead to backstop procurement under an LSE-based procurement structure.

14. It is critical that parties have reasonable insight about the current and future state of the RA market while undertaking workshops and offering central procurement proposals.

15. The Commission supports facilitating transparency in the RA contracting process. A proposal to disclose all resources used to satisfy an LSE's RA obligation in the previous year, without disclosing the number of megawatts associated with the resource, is a reasonable first step towards promoting transparency.

Conclusions of Law

1. Due to a lack of consensus among parties, a central buyer and central procurement mechanism should not be adopted at this time.

2. Parties should engage in a series of workshops to develop workable central buyer and central procurement structure proposals.

3. A multi-year local requirement framework should be adopted with LSE-based procurement.

4. A minimum three-year forward requirement should be the required duration adopted for the multi-year local resource adequacy program.

5. The CAISO's existing one- and five-year Local Capacity Requirement Technical Studies, incorporating engineer-managed adjustments for CAISO-approved transmission projects, should continue to form the basis for the local requirements for the multi-year RA program.

6. The minimum percentages required for multi-year local procurement by the central buyers should be 100% for Years 1 and 2 and 50% for Year 3.

7. Three-year ahead local requirements should be based on an LSE's load share in the first year resulting from the adopted CEC load forecasting process and updated during each following year's year-ahead allocation.

8. The current local penalty and waiver process for a one-year basis should be applied to three-year forward requirements for LSE-based procurement.

9. The current RA compliance timeline should not be modified for multi-year LSE-based local procurement.

10. The "PG&E Other" local area should be disaggregated under an LSE-based multi-year local procurement structure.

11. Energy Division staff should publish reports that provide reasonable insight into the current and future state of the RA market for parties to consider.

12. Early each calendar year, Energy Division should post a summary list of the resources listed on each LSE's monthly resource adequacy plans for the previous year.

O R D E R

IT IS ORDERED that:

1. A central procurement structure for multi-year local requirements is not adopted at this time.

2. Multi-year local Resource Adequacy requirements shall be adopted with procurement by individual load serving entities.

3. Parties shall undertake a minimum of three workshops over the next six months to identify workable central buyer and central procurement structure proposals.

4. Parties shall develop workable implementation solutions for the central procurement of multi-year local Resource Adequacy (RA) that 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.

5. Workable implementation solutions shall specifically address the known challenges to the local Resource Adequacy (RA) program, including (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.

6. Each workshop will be facilitated by a different market representative (Community Choice Aggregation (CCA), distribution utility, and Electric Service

Provider (ESP) representative), or a facilitator chosen by that representative. Within 30 days of this decision, parties shall reach agreement and inform the Commission of the following:

(a) The date for an April workshop and placeholder dates for at least two subsequent workshops;

(b) The facilitator(s) who will lead each workshop;

(c) The scope of issues for each workshop; and

(d) Identified part(ies) who shall prepare a post-workshop report following each workshop for submission to the Commission.

7. At the conclusion of the workshops, part(ies) identified to develop a report shall file an informal workshop report outlining the recommendations reached and how each recommendation addresses the stated challenges.

8. A minimum three-year forward duration shall be the required duration adopted for the multi-year local resource adequacy program.

9. The California Independent System Operator's (CAISO) existing one- and five-year ahead study, with the requirement to incorporate engineer-managed adjustments for CAISO-approved transmission projects scheduled for that year, shall form the basis for the local resource adequacy requirements. The inputs and assumptions used for the CAISO's Local Capacity Requirements Technical Studies shall be filed in the resource adequacy proceeding.

10. The California Independent System Operator's existing one-year ahead study shall form the basis for the local requirements for Years 1 and 2. The existing five-year study shall inform the local requirements for Year 3.

11. The minimum required percentage for procurement by the central buyer in Years 1 and 2 shall be a 100% requirement. The minimum required percentage for procurement in Year 3 shall be 50%.

12. Load serving entities shall be allocated three-year forward local requirements based on their load share in the first year resulting from the adopted California Energy Commission load forecasting process. Local requirements for Years 2 and 3 shall be updated during the following year's year-ahead allocation process.

13. The local penalty and waiver process instituted on a one-year basis, pursuant to Decision (D.) 06-06-064 and D.07-06-029 shall apply to the three-year forward requirement.

14. Flexible, system, and three-year ahead local showings shall be due on October 31.

15. The "Pacific Gas and Electric Company (PG&E) Other" local area shall be disaggregated to the local capacity area.

16. Energy Division staff shall prepare two reports that will address the following:

(1) Total megawatts (MW) for any/all resources procured for Resource Adequacy (RA) (gas, storage, renewal/DER) to meet RA requirements;

(2) Development of preferred resources in local and system areas;

(3) Information regarding local deficiencies, including the number of load serving entities (LSE) that are deficient, type of LSE, location of deficiencies, amount of deficiencies (in MW), number of local RA waiver requests, and anonymized statements from the LSE as to the reason for the deficiency (such as which generators bid into the solicitation, whether the bids included dispatch rights or other terms addressing how local resources bid in the energy market);

(4) Information regarding system and flexible capacity deficiencies, including anonymized statements from the LSE as to the reason for the deficiency; and

(5) Resources on the Net Qualifying Capacity list that are not shown in RA filings as under contract to an LSE(s).

17. Energy Division's first report shall be submitted within 60 days of the decision setting the year-ahead Resource Adequacy (RA) requirements. The second report shall be issued by Energy Division within 60 days of the October 31, 2019 filings for the 2020-2022 RA compliance years.

18. Early each calendar year, Energy Division shall post a summary list of the resources listed on each load serving entity's monthly resource adequacy plans for the previous year. The disclosed information shall include scheduling resource ID, scheduling coordinator ID or counterparty, zonal location, and local area (if applicable).

19. This proceeding remains open.

This order is effective today.

Dated February 21, 2019, at San Francisco, California.

MICHAEL PICKER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners