Report on the 2021-2023 Central Procurement Entity Framework

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CALIFORNIA PUBLIC UTILITIES COMMISSION

ENERGY DIVISION

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Acronyms

AAEE	Additional Achievable Energy Efficiency
AS	Ancillary Services
ATE	Additional Transportation Electrification
BTM	Behind the Meter
CAISO	California Independent System Operator
CAM	Cost-Allocation Mechanism
CARB	California Air Resources Board
CEC	California Energy Commission
CCA	Community Choice Aggregator
CCGT	Combined-Cycle Gas Turbine
CHP	Combined Heat and Power
CPM	Capacity Procurement Mechanism
CPE	Central Procurement Entity
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CSP	Competitive Solicitation Process
CT	Combustion Turbine
DA	Direct Access
DG	Distributed Generation
DR	Demand Response
DRAM	Demand Response Auction Mechanism
ED	Energy Division
EE	Energy Efficiency
ELCC	Effective Load Carrying Capacity
EFC	Effective Flexible Capacity
ESP	Electric Service Provider
ExD	Exceptional Dispatch
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HE	Hour Ending
IE	Independent Evaluator
IOU	Investor-Owned Utility
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
IV	Imperial Valley
kW	Kilowatt
LCR	Local Capacity Requirement
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
LMDR	Load Modifying Demand Response
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LSE	Load Serving Entity
LTPP	Long Term Procurement Plan
MCAM	Modified Cost Allocation Mechanism
MCC	Maximum Cumulative Capacity
MOO	Must Offer Obligation
MA	Month Ahead
MMT	Million Metric Ton
MW	Megawatt
NERC	North American Reliability Corporation
NQC	Net Qualifying Capacity
PCIA	Power Charge Indifference Adjustment
PCM	Production Cost Modeling
PMax	Maximum capacity of a resource
PMin	Minimum capacity of a resource
PRG	Procurement Review Group
PV	Photovoltaic
QC	Qualifying Capacity
QF	Qualifying Facility
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RCM	Reduction Compensation Mechanism
RESOLVE	Renewable Integration Solutions Model
RFO	Request for Offer
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
RUC	Residual Unit Commitment
SERVM	Strategic Energy Risk Valuation Model
SSDR	Supply Side Demand Response
SPD	Save Power Day
SFTP	Secure File Transfer Protocol
TAC	Transmission Access Charge
TPP	Transmission Planning Process

I. Introduction

In 2020, in response to the increasing difficulties faced by load serving entities (LSEs) in procuring local resources to meet their local resource adequacy (RA) requirements, the California Public Utilities Commission (CPUC) adopted a local procurement framework that designated a central buyer to be responsible for procuring multi-year local RA resources in the Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) distribution service areas.[1] Under this hybrid framework, the CPUC authorized Central Procurement Entities (CPEs) to procure the entire amount of required local RA on behalf of all LSEs, while also allowing individual LSEs to procure their own local resources. Beginning in 2021, PG&E and SCE began serving as CPEs (i.e., PG&E-CPE and SCE-CPE) for their respective distribution service areas, with each CPE procuring local RA starting with the 2022 and 2023 compliance years.

This report, as authorized by Decision (D.) 20-06-002, evaluates the CPUC's CPE Framework and summarizes the CPE procurement results for the 2023-2026 RA compliance years.[2] The report evaluates the effectiveness of procurements conducted under the CPE Framework, including aspects of the solicitation such as the local showing option and adherence to other procurement requirements.[3] This report also assesses the effectiveness of the Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM), which was established to encourage the procurement of new preferred resources in local capacity areas (LCAs).[4] Under this price mechanism, the Commission permits CPEs to choose whether or not to select LSEs' shown local resource; if selected, the showing LSE would receive a premium price. This report will assess the success of this mechanism and present summaries of LCR RCM offers submitted.[5]

The Commission originally authorized this report to be released by 2025,[6] which was subsequently changed to May 31, 2024. After issuance of this report, parties are invited to file proposals on structural modifications and/or refinements to the CPE Framework on June 24, 2024.[7] Additional details on the schedule for this rulemaking can be found in Section VII, which provides the timeline for this proceeding and the next steps.

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[1] The CPUC excluded the San Diego Gas & Electric (SDG&E) distribution area from the framework as there is little distinction between local area requirements and overall system requirements.

[2] OP 29 of Decision (D.20-06-002) on Central Procurement of the Resource Adequacy Program in R.17-09-020, June 11, 2020, at 100.

[3] OP 10 of Decision (D.13-12-029) Addressing Petitions to Modify D.12-11-025 in R.07-01-041, December 5, 2013, at 42.

[4] Decision (D.20-12-006) on Track 3.A Issues: Local Capacity Requirement Reduction Compensation Mechanism and Competitive Neutrality Rules in R.19-11-009, December 30, 2020.

[5] FOF 9 of D.20-06-002 at 44; D.20-12-006, at 26.

[6] *See* 2.

[7] Assigned Commissioner's Scoping Memo and Ruling in R.23-10-011, December 18, 2023, at 6 and 9; ALJ's Ruling Modifying Track 2 Schedule, May 2, 2024, at 2.

A. Purpose and Outline

This report is organized as follows. This first section introduces the motivation for the Central Procurement Entity Framework and the objective of this report. Section II provides a background history of California's RA program. Section III summarizes the key Commission decisions underpinning the CPE Framework. Section IV describes how local capacity requirements are established and each CPE's allocations, followed the CPEs' procurement results. Section V evaluates the CPE Framework's effectiveness in achieving the Commission's local RA procurement objectives. Section VI outlines potential approaches for the Commission and parties to consider. Finally, Section VII discusses this proceeding's schedule for considering changes to the CPE Framework and the next steps in this process.

II. Background

The Resource (RA) program was developed in response to the 2001 California energy crisis, an event that was fueled by shortages in generating capacity and the state's reliance on the spot market for wholesale power. These factors exacerbated the bargaining strength of merchant generators, signaling the enormous profits that could be gained through supply shortages and increasing their prices above the costs of generating power. Because the market design in effect during the crisis did not require generators serving the California electric market to make their power plant available, this encouraged generators to withhold capacity, causing artificial scarcity, extreme price spikes, and rolling blackouts. Additionally, because LSE entities were not required (and in some cases not allowed) to make forward energy or capacity purchases, consumers risked high exposure to energy market prices.

In 2003, the California Legislature enacted Section 380 of the Public Utilities Code, which requires the CPUC, in cooperation with the CAISO, to adopt a program that would require all LSEs to "[m]aintain physical generating capacity… adequate to meet its load requirements, including but not limited to, peak demand and planning and operating reserves." [8] In short, LSEs are required to own or contract for sufficient resources to meet their share of the CAISO's system peak demand, plus a Planning Reserve Margin (PRM), which was initially set at 15 percent.[9] The essence of this resource adequacy (RA) obligation is a requirement that capacity be procured by LSEs such that the capacity product procured must offer bids into the short-term energy markets.

The RA obligation is comprised of three distinct, yet related capacity procurement obligations: (1) system RA consists of resources that will be available to serve CAISO demand when needed to meet CAISO system needs; (2) local RA consists of resources that are sited in certain load pockets where generation supply is needed to meet reliability needs due to insufficient transmission to serve the entire load under certain outage conditions; (3) and flexible RA consists of resources that can ramp up or down on short notice to meet variations in load and intermittent energy production. The CPUC sets the annual and monthly requirements for each of these types of RA products for all CPUC-jurisdictional LSEs. After its adoption, LSEs made their first system RA showings for the 2006 compliance year, and made their first local RA requirements showings for the 2007 compliance year.

Because local RA obligations facilitated LSEs to procure resources directly -- rather than relying on backstop mechanisms -- the number of generators in locally constrained areas subject to

[8] CPUC jurisdictional LSEs include Investor-Owned Utilities (IOUs), Electricity Service Providers (ESPs), and Community Choice Aggregators (CCAs).

[9] Recent analysis questioned the sufficiency of the 15% reserve margin to ensure reliability, and D.22-06-050 raised the reserve margin to 16% for 2023 and 17% for 2024. D.23-06-029 reaffirmed use of the 17% PRM for 2024 and 2025.

emergency Reliability Must Run (RMR) contracts fell from 10,776 MW in 2006 to 3,264 MW in 2008.[10]

In the years prior to the adoption of the CPE Framework in 2020, the CPUC allocated local RA requirements for each LCA to each CPUC-jurisdictional LSE using the LSE's forecasted peak load ratio for each Transmission Access Charge (TAC) area, which is informed by the annual load forecast allocations. The local RA capacity program covers 45 local sub-areas that form ten LCAs across California. These include Humboldt, North Coast/North Bay (NCNB), Sierra, Stockton, Greater Fresno, Kern, Greater Bay Area, LA Basin, Big Creek/Ventura, and San Diego/Imperial Valley. Because these LCAs are a part of an interconnected electric system, the total for each LCA is not simply a summation of the sub-area needs.

In developing the local RA program, the Commission chose to aggregate six of the LCAs in PG&E's TAC area to mitigate local market power concerns, noting, "Market power issues can arise when procurement obligations are established for small local areas, and aggregation of such areas for the purpose of establishing local procurement obligations can mitigate market power; however, aggregation of local areas could possibly lead to over-procurement in some areas and under-procurement (with CAISO backstop procurement required) in others."[11]

Beginning in 2017, the Commission acknowledged several emerging trends affecting the state's electric sector and procurement outlook, including (1) the growth in Community Choice Aggregation (CCA) entities which, at the time, had fewer long-term RA contracts,[12] (2) the transition of the gas fleet and continuing consideration of their impacts on disadvantaged communities, and (3) the persistence of more extreme and variable weather, and the increase in weather-dependent generation.[13] The Energy Division reasoned that numerous small CCA LSEs purchasing small strips of available local RA was cost-ineffective and potentially creates market power concerns. Moreover, because CAISO's backstop authority is based on the sub-area needs – not the aggregated area needs – IOUs procure according to each sub-local level requirement to avoid backstop procurement. This in turn, resulted in smaller LSEs leaning on the incumbent IOUs' local procurement to fill their sub-local level requirements. As IOUs lose load shares to CCAs however, there is less incentive and reason for IOUs to procure these local RA resources

[10] CPUC, 2007 Resource Adequacy Report, April 15, 2008, at 38.

[11] FOF 23 of Opinion (D.06-06-64) on Local Resource Adequacy Requirements in R.05-12-013, June 29, 2006, at 79.

[12] A map listing all California energy providers, including approximately 38 CCAs, can be found on the CalCCA Interactive CCA Map/Address Lookup webpage.

[13] CPUC, Community Choice Aggregation En Banc Background Paper, February 1, 2017, at 7; CPUC, Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge in R. 17-09-020, January 18, 2018, at 4.

more comprehensively.[14] For example, in 2020 PG&E and SCE load comprise 66.4 percent of the total peak load share; in 2024, they comprise 60.70 percent of the total peak load share.

To address these trends, the Energy Division undertook an assessment on whether structural modifications to the RA program were necessary, given the: (1) decrease in forward procurement, (2) growing requests from LSEs for waivers of their local requirements, (3) increase in CAISO back-stop procurement using Reliability-Must-Run (RMR) contracts and CPM (Capacity Procurement Mechanism) designations, (4) acceleration in load migration from the IOUs to both new and existing CCAs, and (5) divergent trends in local procurement activity, with the portion of contracted capacity held by CCAs remaining low, whereas the portion of contracted capacity held by IOUs through 2022 remain high. [15] Additionally, the retirements of large generators -- such as natural gas power plants meeting their Once-Through-Cooling (OTC) requirements -- contributed to additional uncertainty both for market participants procuring capacity for a shifting amount of load and for generators selling their capacity to new market entrants.[16]

After considering several options, the Commission concluded that a centralized procurement structure would ensure sufficient capacity while reducing the risk of strategically located resources from being mothballed or retired. This centralized structure would also enable distribution utilities to leverage their purchasing power in constrained local areas, by executing solicitations that follow existing all-source procurement requirements, including least-cost best-fit (LCBF) principles and preferred resources mandates.[17] Thus, in 2020, the Commission adopted a hybrid procurement framework using central entities to procure multi-year local RA capacity, while also allowing LSEs to self-show or bid local resources into these solicitations. In adopting this Central Procurement Entity (CPE) Framework, the Commission states that the hybrid model best addresses the known challenges to the local RA program and strikes a balance between the proposals for residual and full procurement models.[18]

Consequently, the CPUC now allocates individual LSE local RA requirements only for LSEs serving load in the SDG&E TAC area. For the PG&E and SCE TAC areas, the entire local requirements are allocated solely to the CPEs. For the 2024 compliance year, local requirements for CPUC jurisdictional LSEs comprise 40.68 percent of CPUC system peak requirements.[19] For the SCE and PGE TAC areas, local requirements comprise 24.18 percent and 53.19 percent respectively,

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[14] CPUC, Current Trends in California's Resource Adequacy Program, Energy Division Working Draft Staff Proposal, February 16, 2018, at 58.
[15] *Ibid*.
[16] CPUC, California Customer Choice Project: Choice Action Plan and Gap Analysis, December 2018, at 51.
[17] FOF 15 of D.20-06-002, at 85.
[18] OP 3 of Decision (D.19-02-022) Refining the Resource Adequacy Program in R.17-09-020, February 21, 2019, at 42.
[19] CAISO, 2023 Local Capacity Technical Study Final Report and Study Results, April 28, 2022, at 27; CAISO, 2022 Local Capacity Technical Study Final Report and Study Results, April 30, 2021, at 26.

of the peak system TAC area requirements. In the September 2024 compliance month, the system RA requirements is 49,892 MW, with flex and local requirements representing a portion of the subset of the overall system requirements: 22,226 MW for flex and 20,297 MW for local.[20]

In addition, the CPUC is responsible for other procurement obligations -- the Renewable Portfolio Standard (RPS) and Integrated Resource Planning (IRP) programs – which are intended to meet greenhouse gas (GHG) reduction goals by increasing clean energy procurement while ensuring a reliable grid. Under the RPS program, all LSEs are required to procure 60 percent of their supply from renewable sources by 2030. Similarly, the IRP process was established in 2015 to ensure that LSEs meet mid- and long-term energy procurement. Resources procured under both mechanisms may meet LSEs' RA obligations if they fulfill the requirements of the RA program. In the last five years, the Commission has authorized 18,800 MW of new procurement to come online over the 2021-2028 period. This procurement order was needed to help meet near and mid-term system reliability needs, given several factors: (a.) the expected retirement of OTC gas units; (b). the planned retirement of Diablo Canyon Nuclear Power Plant (DCNPP); and (c.) increases in summer peak load resulting from long term load growth and extreme weather events, such as those that occurred in 2022.

In response to these decisions, LSEs procured resources throughout the state, as well as imports from other areas in the West. However, despite the retention of DCNPP and the new procurement, the system capacity market has remained tight due to a variety of factors: (a.) demand increases in the short term load forecast for 2021-2024; (b.) reductions in resource accounting (decreases in the effective load carrying capability, or ELCC, for wind and solar resources as penetration of variable resources have increased); (c.) market fragmentation and lumpiness of procurement contracting resulting from 38 LSEs attempting to balance their individual energy and capacity portfolios; and (d.) the planned exit of OTC units from the RA market, and uncertainty about the online dates of new resources. This near-term tight supply and demand balance has caused capacity prices to increase substantially for both existing and new generation, leading local generators to forego multi-year local contracts with CPEs and instead contract with individual LSEs for system capacity RA obligations.

In the following section, we discuss the decisions leading to the adoption of the CPE Framework and their subsequent modifications.

[20] These values are exclusive of credits and only represent allocations for CPUC-jurisdictional LSEs.

III. Commission Decisions

As mentioned previously, in January 2018 the Commission issued a Scoping Memo and Ruling to consider modifications to the RA program, including the reforms necessary to maintain reliability while reducing costly backstop procurement. The Commission identified several procurement challenges such as the early generator retirements and the inability of some LSEs to procure sufficient local resources for their 2018 year-ahead (YA) RA showing, which led to the CAISO issuing CPM and Reliability Must Run (RMR) contracts for backstop procurement.

The Commission prioritized its consideration of potential approaches in reducing future out-of-market RA procurements, including establishing a multi-year local RA program and/or one or more central buyers (e.g., large IOUs). The Commission also suggested other ways it might address the issue, such as increasing transparency for procuring LSEs – and the Commission – on which resources are essential for local and sub-area reliability. The approach would involve additional CAISO studies, increased transparency of CAISO modeling inputs and assumptions, and improved data sharing. It was the Commission's intent that, with increased transparency, the LSEs could more accurately assess the value of competing RA resources, while simultaneously allowing the Commission to consider more targeted alternatives to generation located in disadvantaged communities.[21]

A. Decision Adopting Local Capacity Obligations for 2019 and Refining the Resource Adequacy Program (D.18-06-030)

In D.18-06-030 the Commission considered proposals for multi-year local requirements and central buyers. Multiple parties and the Energy Division submitted proposals that included variations of a multi-year procurement framework for local as well as some that included system and flex. The Energy Division outlined two approaches to a local multi-year RA requirement, one with the IOUs acting as the central buyer, and one with LSEs responsible for meeting their own local and sub-local RA requirements.[22] Parties raised concerns with both approaches and the Commission ultimately adopted a general multi-year and central procurement framework for local RA, while directing parties to further develop implementable solutions in Track 2 of the proceeding.[23] Included in this general framework, the Commission dictated some minimum requirements for years one and two, specified a duration for multi-year local requirements of three to five years and stated, "a central buyer – for at least some portion of local RA – is the

[21] Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge in R. 17-09-020, January 18, 2018, at 4.

[22] CPUC, Current Trends in California's Resource Adequacy Program, Energy Division Working Draft Staff Proposal, February 16, 2018, at 52.

[23] *See* 23, at 55.

solution most likely to provide cost efficiency, market certainty, reliability, administrative efficiency, and customer protection," in addition to meeting GHG emissions reductions targets and the consideration of impacts on disadvantaged communities.[24]

B. Decision Refining the Resource Adequacy Program (D.19-02-022)

In D.19-02-022 the Commission considered multi-year local RA framework proposals that took into consideration the general framework the Commission had laid out in D.18-06-030. These proposals included details on what entities would be suited to function as central buyers (i.e., the distribution utilities, a special purpose entity, a central capacity market, and the CAISO) and what structures would be appropriate (i.e., full procurement, residual procurement, and a hybrid approach).[25] However, due to a lack of consensus as to the appropriate central buyer and procurement mechanisms, the Commission delayed implementation to allow for additional time for parties to develop implementation details.[26]

The Commission reiterated continuing challenges in the local RA program: (1) costly out-of-market RA procurement due to local deficiencies, (2) load migration and equitable allocation of costs, (3) cost effective and efficient coordinated procurement, (4) treatment of existing local RA contracts, (5) opportunity for and investment in procurement of new local preferred resources, and (6) retention of the state's jurisdiction over the procurement of preferred resources. Given these challenges and notwithstanding the lack of a central buyer framework, the Commission adopted multi-year local requirements beginning with the 2020 compliance year, to be procured by LSEs based on individual local allocations.

Under these adopted requirements, all LSEs were responsible for annually procuring local RA with a three year forward showing of 100% for Year 1, 100% for Year 2, and 50% for Year 3.[27] Local requirements were to be based on an LSE's YA load share as determined by the CEC forecasting process. The Commission also disaggregated the "PG&E Other" LCA to aid in minimizing inefficient procurement that may lead to backstop procurement under an LSE-based procurement structure.[28]

In D.19-02-022 the Commission also recognized that it was critical for parties to understand the state of the RA market more fully, as certain information about the broader RA procurement

[24] *Ibid.*, at 33.
[25] *Id.*
[26] *See* 23, at 17.
[27] *Ibid.*, at 28.
[28] D.19-02-022, at 40.

outlook was only visible to Energy Division staff.[29] The Commission directed Energy Division to prepare reports that address:

1. The 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 LSEs as to the reason for the deficiency; and
5. Resources on the NQC list that are now shown in RA filings as under contract to an LSE.

The Commission ordered that the first report cover RA filings from the 2019 YA filings through to the September 2019 Month-Ahead (MA) filings. The second report was to cover RA filings from the 2020-2022 RA compliance years and was to be filed by the end of October 2019.[30]

To further facilitate transparency in the RA process, the Commission directed Energy Division to disclose on its webpage[31] a summary list of resources used to satisfy LSEs' monthly RA obligations the previous year, including scheduling resource and coordinator IDs, zonal location, and local area.[32]

C. Decision on Central Procurement of the Resource Adequacy Program (D.20-06-002)

In 2019, at the direction of D.19-02-022, parties undertook a series of central procurement framework workshops and filed informal workshop reports detailing the results of these efforts. Subsequently, a group of parties filed a joint motion to adopt a Settlement Agreement (Settlement) for a residual CPE structure. In D.20-06-022, after considering the full record, the Commission found that the Settlement was not reasonable and that it failed to provide any workable solution on major implementation details of the CPE. The Commission reiterated that the debate between a full versus residual structure was resolved in previous decisions, and that

[29] *Ibid*., at 32.
[30] *Ibid*., at 43 and 44.
[31] See Transparency Report under each compliance year on the CPUC's Resource Adequacy Compliance Materials webpage.
[32] *See* 30, at 48.

the Commission had articulated the need to designate a central buyer beginning in 2018. The Commission also noted that the Settlement created a potential overreliance on CAISO procurement, which would result in cost shifting between customer classes and service territories, in contravention of existing state laws.

In this same decision, the Commission adopted the hybrid CPE Local Framework allowing CPEs to recover costs through the Cost Allocation Mechanism (CAM) and for the CPEs to use the CAM PRG and independent evaluators (IE) to independently evaluate their solicitations.[33] The Commission found that the approach addressed the issue of inequitable cost allocation and load migration as it allocated costs to end customers and ensured that all customers pay equitably for the cost of local reliability, regardless of which LSE serves the customer.[34]

Under the framework, the CPEs are directed to use the existing all-source selection criteria, along with the established GHG planning price, and the CalEnviroScreen score[35] when seeking a approval for portfolio contracts with up to five-year terms.[36] In the event a CPE deems bid costs to be unreasonably high, the CPE was allowed discretion to defer procurement of local resources to the CAISO's backstop mechanism. Additionally, penalties and fines would not be assessed so long as the CPE demonstrates that it exercised reasonable efforts to secure capacity.[37] CPEs are also directed to submit an Annual Compliance Report (ACR) summarizing its prior year's procurement process.[38]

Based on their legacy experience and purchasing power, the Commission found SCE and PG&E the best candidates to function as CPEs. Because SDG&E's TAC area is unique in that the local RA requirements typically either meet or exceed the system requirement -- such that LSEs would have little procurement autonomy for system and flexible RA under a hybrid CPE Framework – the Commission declined to adopt a CPE Framework for the SDG&E TAC area.

The Commission noted that because the framework is a hybrid model, individual LSEs still have the flexibility and autonomy to procure their own local resources to meet their system and flexible RA requirements and to count them towards the collective local RA requirements. If an LSE procures its own local resource, it may (1) sell the capacity to the CPEs, (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 CPEs will need to

[33] FOFs 21, 24-25 and OPs 16, 20-22 of D.20-06-002, at 86 and 96.
[34] *Ibid*., at 84.
[35] California Office of Environmental Health Hazard Assessment, CalEnviroScreen 4.0.
[36] *See* 35, at 95.
[37] *Ibid*., at 87.
[38] *Id*.

procure for the amount of time the LSE has agreed to show the resource.[39] The Commission also provided that the distribution utilities shall have the same options as other LSEs in deciding whether to bid or show its resources into the CPEs solicitation process. However, the Commission required distribution utilities that were acting in their capacity as a CPEs (i.e., PG&E-CPE, SCE-CPE) to bid their own resources -- that were not already allocated to benefiting customers -- into the solicitation process at their levelized fixed costs.[40]

The Commission also recognized the need for a financial credit mechanism that aligns compensation for preferred and energy storage resources with their actual LCR MW reduction.[41] This involved creating a mechanism ("Local Capacity Requirement Reduction Compensation Mechanism" or LCR RCM) that ensured that ratepayers were (1) only compensating resources to the extent they provide value, and (2) only compensating LSEs for additional costs of procuring resources close to load, rather than simply extending market power premiums to the LSEs. It was important for the Commission that a pre-determined local premium reflected the cost of selecting these resources over the cost of purchasing bid resources, thus mitigating inflated prices and local market power. Thus, a working group was tasked to develop an LCR RCM proposal.

D. Decision on Track 3A Issues: LCR RCM and Competitive Neutrality Rules (D.20-12-006)

In its next Decision, the Commission adopted a proposal for the LCR RCM and determined that any new preferred or energy storage resources with contracts executed after June 17, 2020 -- including Commission-approved UOG resources -- are eligible for the LCR RCM.[42] If an eligible resource elected to use the LCR RCM, it could not also bid into the CPE's solicitation; that resource, however, could still have the option to show for no compensation.[43] If an eligible resource elects not to show for the LCR RCM, it can: (1) show the resource for no compensation in advance of the CPE solicitation, (2) bid the resource into the solicitation, (3) bid the resource into the solicitation and indicate that the resource will be available to show the local RA attribute for no compensation *if* the bid is not accepted, and (4) retain all RA attributes for the LSE. Moreover, a local preferred resource could be eligible for the LCR RCM local premium up to the life of the resource's original contract, depending on whether the resource's effectiveness in reducing local requirements. A shown resource that qualifies for the LCR RCM would have a

[39] *See* 35, at 91.
[40] *Ibid*., at 94.
[41] *Ibid*., at 92.
[42] *Ibid*., at 47.
[43] *Ibid*., at 22.

commitment equivalent to the period it is under contract, where the start date may be any year within the three-year forward compliance period. LSEs intending to show resources to the CPE are encouraged to enter into an enabling agreement with the CPE in advance of a solicitation. If more cost-effective resources are available, the CPE could accept or reject the shown local resource. [44]

For Year 1, the calculation for the LCR RCM premium uses the weighted average price from the last four quarters of Energy Division Power Charge Indifference Adjustment (PCIA) responses for both system and local RA, with a subtraction of the system RA price from local RA. In subsequent years, the calculation uses the weighted average price from the last four quarters of Energy Division's PCIA responses for system RA and the most recent weighted average price reported in the CPE solicitation results (i.e., prior year's results) for local RA, with a subtraction of the system RA price from the local RA price.[45]

E. Decision on Phase 1 of the Implementation Track: Modifications to the CPE Structure (D.22-03-034)

In 2022 the Commission made several observations about the inaugural 2021 CPE solicitations and results. The Commission noted that a limited number of non-compensated local resources were self-shown to the PG&E-CPE and a lower-than-expected number of local resources were bid. The Commission reiterated that, by self-showing local resources, LSEs could lower the CPEs' overall local RA obligations, lowering the procurement costs for ratepayers in the CPEs' service area. Because of the continued shortfalls in procurement and low participation rates in PG&E-CPE's solicitation, the Commission adopted several amendments to encourage self-show offers.

First, the Commission required that backstop costs be covered by ratepayers in the CPEs' service area when resources fail to perform due to a planned outage, or for any reason when the self-showing LSE is outside the CPEs' service area. Accordingly, any CPM costs associated with local RA deficiencies in a CPEs' service areas are allocated directly to the CPE, and the CPE will distribute those costs evenly to ratepayers through the CAM; the costs are then allocated to all LSEs in the TAC area on a load ratio share basis. The Commission adopted this modification, because it recognized that, in the event an LSE's self-shown resource fails to perform, it could risk exposure to additional costs, which in turn would disincentivize the LSE from self-showing. LSEs are also allowed to substitute for another resource in the event self-shown resources did not perform.

[44] *Ibid.*, at 45-47.
[45] *Ibid.*, at 46.

Second, the Commission adopted several revisions to the requirements for self-shown local resources and selection criteria.[46] For entities that elect to self-show a local resource to the CPE, the LSE is required to execute an attestation that: (1) it has the capacity rights to the RA resource for the period it is self-showing, (2) it intends to self-show the RA resource on annual and monthly plans to satisfy its system and/or flexible RA needs, and (3) when applicable, the resource that it intends to self-show for compensation under LCR RCM meets the eligibility requirements of D.20-12-006. In the event their local resource bid is not selected, an LSE is directed to self-show the local resource for no compensation.[47]

Additionally, LSE bidders that provide compensated offers could also provide a back-up option to self-show for no compensation if their compensated offer was not selected. If that occurred, the evaluation teams would use the back-up self-shown resource's RA capacity to reduce the total local RA requirement and rerun the selection process with the remaining compensated offer set.

Third, the Commission updated the LCR RCM price calculation and stated that, "if selected, the LSE shall be paid the showing price (pre-determined or below) without annual adjustment for effectiveness. The showing price shall not exceed the pre-determined local price, which is calculated (by using) the weighted average price from the last four quarters of the Energy Division Power Charge Indifference Adjustment responses for system and local RA; (and) subtract(ing) system RA price from local RA price."[48] Self-shown resources could only be offered by the LSE, which would not receive any compensation, unless the self-shown resources were preferred (as defined by the CPUC's loading order statutes) resources, in which case the LSE could submit an offer for compensation under a LCR RCM.

Fourth, the Commission modified the IOU levelized fixed cost bidding requirement adopted in D.20-06-002 to permit the IOUs to bid their resources into the CPE's solicitation at competitive market prices, as this restriction may result in the CPE procuring IOU resources at inefficient, improper prices that do not reflect market costs, and that may disincentivize IOUs from participating in the CPE's solicitation.

Fifth, the Commission revised the CPE procurement timeline to strike a reasonable balance between the need for LSEs to have sufficient time for RA portfolio planning and the need for the CPEs to have adequate time to complete an all-source solicitation. The adopted timeline

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[46] Decision (D.22-03-034) on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structures in R.21-10-002, March 17, 2020, at 4.

[47] Decision (D.23-06-029) Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements in R.21-10-002, June 29, 2023, at 45.

[48] OP 15 of Decision (D.22-03-034) on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure in R.21-10-002, March 17, 2022, at 77.

provides LSEs and CPEs a similar amount of time (6-8 weeks) to complete necessary procurement after receiving allocations.

F. Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements (D.23-06-029)

In 2023 the Commission found that additional data reporting would help LSEs to manage upfront system RA procurement and understand the inventory of available resources. This transparency would allow LSEs to assess the potential for CAISO backstop procurement, while enabling market participants to understand how the CPE Framework is functioning. Thus, the Commission adopted requirements for the CPE to additionally report on (1) resources not offered in deficient areas; (2) procurement deferrals due to unreasonable prices or inability to reach term agreements; and (3) the results on outreach to non-participants or participants who withdrew.[49]

Additionally, the Commission opined that allowing LSEs to sell a self-shown local resource may increase the amount of self-shown resources by removing a potential disincentive and provide additional opportunities for LSEs to procure system and/or flexible RA. Accordingly, LSEs that has self-shown its resources to the CPE are allowed to sell the capacity to other LSEs so long as the purchasing LSE assumes the selling LSE's self-show obligations.[50]

[49] OPs 12-13 of D. 23-06-029 at 133.
[50] OPs 14-15 of D.23-06-029 at 140-141.

IV. Procurement Requirements and Results

In this section we provide a summary of procurement requirements and results from each IOU-CPE's annual solicitations conducted between 2021-2023. We begin by providing a broad description of how local capacity requirements are established.

The annual process of establishing local RA requirements[51] begins with the CAISO annual Local Capacity Technical Study process to determine needs across identified LCAs and sub-areas. The draft and final study results are filed by the CAISO in the CPUC's annual RA proceeding and are then annually adopted in June for the upcoming compliance years. For example, during the scope of the compliance years being reported in this document, the 2022-2024 Local Capacity Requirements (LCRs) were adopted in June 2021; the 2023-2025 LCRs in June 2022; and the 2024-2026 LCRs in June 2023.[52]

Concurrent to the Commission's consideration of the LCR study, the CEC conducts the annual forecast to develop individual monthly LSE load forecasts used for upcoming year. Through this process individual LSE's monthly coincidence factors are calculated using the historic hourly load data.[53] These factors adjust each LSE's peak load forecast to reflect the LSE's contribution to total load when CAISO's load peaks. The process also includes a pro rata adjustment that reconciles the aggregate of the jurisdictional LSEs' monthly peak load forecasts against the CPUC's share of the CEC's monthly 1-in-2, weather normalized peak-load forecast for each IOU service area.

Using both the adopted CAISO LCR results and the outputs from the load forecast process, the CAISO assigns proportional responsibility for the needed local capacity within each TAC Area to the Local Regulatory Authorities (LRAs) in CAISO's Balancing Authority Area (BAA). Specifically, the CAISO allocates the local capacity need to each LRA based on that LRA's proportional share of the relevant TAC Area load which accounts for the coincidence adjustment. For CPUC-jurisdictional LSEs, the CAISO provides the total LCR by TAC Area to the CPUC.

Under the CPE Framework, IOU-CPEs are obligated to procure local requirements on behalf of all CPUC-jurisdictional LSEs within the CPEs' respective TAC areas. Seven LCAs comprise PG&E-CPE's LCAs: Greater Bay Area, Greater Fresno, Humboldt, Kern, North Coast/North Bay, Sierra, Stockton. Two LCAs comprise SCE-CPE's: Big Creek/Ventura and LA Basin.

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[51] Opinion (D.06-06-064) on Local Resource Adequacy Requirements in R.05-12-013, June 29, 2006.

[52] Decision (D.21-06-029) Adopting Local Capacity Obligations for 2022-2024 in R.19-11-009 at 75; Decision (D.22-06-050) Adopting Local Capacity Obligations for 2023-2025 in R.21-10-002, at 124; Decision (D.23-06-029) Adopting Local Capacity Obligations for 2024-2026 in R.21-10-002, at 6.

[53] OP 4 of Decision (D.12-06-025) Adopting Local Procurement Obligations for 2013 and Further Refining the Resource Adequacy Program in R.11-10-023, June 21, 2012, at 41.

The CPUC then allocates its portion of the LCRs to LSEs and CPEs using the annual peak load share provided by the CEC. Initial LCR allocations are sent to LSEs and CPEs in July of each year and include demand response (DR) and CAM credits that reduce LCR obligations.

The IOU-CPEs launch their annual LCR solicitations in the Spring of each year, ahead of receiving initial allocations from the CPUC. In advance of these solicitations, Energy Division Staff publish annual LCR RCM benchmark prices that provide LSEs with a maximum price LSE's may receive if they elect to show qualified resources to the CPE. We note here that the first CPE-RFO cycle in 2021 covered only 2023 and 2024 (year 2 and year 3) of the three-year compliance period, as individual LSEs serving load were still responsible for 2022 (year 1) procurements.

The IOU-CPE's use the July LCR allocations and bids received in their annual solicitation in determining their resource selection for the upcoming compliance periods. Non-compensated self-shown resources reduce the total CPE local RA requirement for an area. The CPUC validates LSE and CPE resource showings for the coming year in its YA process (annual deadlines are set for October 31st). CAISO subsequently reviews these filings to determine if the resources meet the needs identified in the annual LCR study for the coming compliance year and issues a deficiency report.

In the next section we report on the CPEs' solicitations and procurement results by reviewing elements of the framework, including whether each IOU-CPE succeeded in procuring preferred resources to meet their LCRs using the various prescribed Commission requirements. We also report on the extent participants chose the local self-shown option and whether the LCR RCM encouraged the development of preferred resources in LCAs.

Because seven LCAs comprise PG&E-CPE's area, we have aggregated the annual procurement results. We provide the results based on LCRs for each solicitation: the 2021 IOU-CPE RFO procured for the 2023 and 2024 compliance years; the 2022 IOU-CPE RFO for the 2023-2025 compliance years; and the 2023 IOU-CPE RFO on the 2024-2026 compliance years.

A. SCE-CPE Solicitations

In 2021, 2022 and 2023, SCE-CPE launched its competitive all-source solicitations for multi-year local RA capacity for four products in the two local areas within its service territory: 1. Local RA Capacity (RA-Only); 2. Tolling Products with Local RA Capacity; 3. Self-Show Local RA Resource; and 4. Self-Show Local RA Resource. Each solicitation was announced and distributed to 2,500-2,700 market participants, with SCE-CPE requesting offers of products for delivery beginning on January 1, 2022. These products are summarized below in Table 1.

Table 1. 2021-2023 SCE-CPE Framework Solicitations

Product	Participants
1. Local RA Capacity (RA Only, Compensated) 2. Tolling Products w/Local RA (Compensated) (i.e., gas fired generation (GFG), In Front of the Meter Energy Storage (IFOM ES), or Combined Heat and Power (CHP) Facilities	1. Any new resource developer with a product that could be brought on-line in time to meet the RFOs' requirements. 2. Any owner of an existing local resource whose RA was not under contract
3. Self-Show Local RA Resource (LCR RCM, Compensated) 4. Self-Show Local RA Resource (Compensated)	3. Any LSE or third-party that had an existing contract for a local resource

The solicited products are to meet the LCRS based on initial procurement targets forecasted by the SCE-CPE. These initial targets were subsequently reduced by the CAISO non-jurisdictional LSEs' load allocations, and CAM and DR resources, leaving an updated final net capacity target sent by Energy Division Staff to SCE-CPE in early July 2021, 2022, and 2023. The LCR requirements net of DR resource are summarized in Table 2.

Table 2. SCE-CPE Overall Local Requirements for 2023-2026 Compliance Years

Compliance Year	SCE-CPE Allocations, Exclusive of DR (MWs)[54]
2023[55]	6,414
2024[56]	7,304
2025[57]	5,374
2026[58]	2,880

[54] Requirements for compliance year 2023 is based on the SCE-CPE Year-Ahead Initial Allocation provided by the CPUC on July 8, 2022. Requirements for compliance years 2024-2026 are based on SCE-CPE 2023 Year-Ahead Initial Allocations provided by the CPUC on July 11, 2023, and updated on August 1, 2023.

[55] SCE AL 4626-E at 41, 42.

[56] SCE AL 4865-E at 40, 41.

[57] SCE AL 5104-E at 38.

[58] *Id*.

In its solicitations, SCE-CPE aimed to reach its targets first by selecting the self-show offers, resulting in a procurement target *after* removing self-shown resources (post-self-shown procurement target). After selecting self-show offers, SCE-CPE then determined whether it needs to move forward with the solicitation process. In the event SCE-CPE needs to still fill the net procurement target, an LCBF selection is performed to create an initial portfolio. Compensated offers with back-up self-show provisions that were not included in the initial LCBF portfolio were then selected to self-show, which further reduced the post-self-shown procurement target. Using the updated net procurement target, the LCBF selection process is repeated. When no more offers with back-up self-show provisions were selectable, the iterative process ended. All eligible offers were required to provide local RA capacity in at least one month of the relevant compliance years. If that requirement was met, SCE was willing to entertain offers that extended through specific dates.

A comprehensive list of SCE-CPE's solicitation design, selection process, and bid evaluation criteria can be found in SCE's CPE Annual Compliance Reports for 2021, 2022, and 2023.[59]

1. 2021 SCE-CPE RFO

In its 2021 RFO SCE-CPE was able to nearly meet its allocated LCRs for 2023 and 2024. As noted above, local CAM resources reduced the overall LCRs for the CPE and represented 32-53 percent of the 2023 requirement and 43 percent of the 2024 requirement. The 2021 RFO resulted in a slight deficiency of 10-16 MW between October to December 2023 in the LA Basin (LAB) local area. SCE-CPE chose not to select additional bids because the costs of the remaining offers were deemed unreasonably high or would result in over-procurement. SCE-CPE instead chose to defer procurement of the remaining requirements to its 2022 RFO.[60] No LCR was deferred to the CAISO's backstop mechanism. [61]

SCE-CPE received numerous self-show non-compensated offers and a handful of RA-only compensated offers. Several offers from bidders were disqualified because they failed to adhere to contract term requirements. Some bidders proposed resources with non-dispatchable must-take energy that were not eligible, while others submitted RA-Only offers. These bidders cured the problem in subsequent offers. No SCE affiliates bid into the solicitation.[62]

Based on participant feedback, SCE-CPE's initial two-year terms discouraged participation from resources whose contracts were expiring in the near term. Because SCE-CPE-solicited contract delivery dates were set no later than December 31, 2024, any extensions to the existing

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[59] SCE AL 4246-E at 47-57; SCE AL 4865-E at 45-69; SCE AL 5104-E at 44-54.
[60] SCE AL 4246-E at 15.
[61] *Ibid.*, at 18.
[62] SCE AL 4246-E at 15; SCE AL 4865-E at 10; SCE AL 5104-E at 8.

contracts would only be effective for 1.5 years or less. This means that, in the event longer-term contracting was available, the resources could be sold elsewhere, including to out-of-state entities. SCE-CPE contract terms were subsequently extended to four-year terms, similar to those offered by PG&E-CPE.

The summary in Table 3 reflects that much of the procurement was filled by non-compensated self-show offers from SCE-IOU, CPASC and DCE. Approximately 90 percent of the self-shown resources came from SCE-IOU. As shown on the bottom row, SCE-CPE selected a 483.13 MW resource from Walnut Creek Energy that was falling off an existing long-term CAM contract in 2023.

Table 3. 2021 SCE-CPE RFO Results

2021 SCE-CPE RFO Results for LA Basin (LAB) and Big Creek/Ventura (BCV) LCAs					
Seller	**Contract Type**	**Resource Types**	**LCA**	**No. of Contracts**	**Period and Contracted Capacity (MW)**
SCE	Self-Show No-Compensation	Limited Energy Storage Resource, Combined Cycle Natural Gas, Steam Natural Gas Wind, Solar PV Hydro	LAB	55	2023, 2024: 1,117 MW–2,362 MW
			BCV		2023, 2024: 330 MW – 660 MW
Clean Power Alliance of Southern California (CPASC)	Self-Show No-Compensation	Combined Cycle Natural Gas, Solar PV	LAB	5	2023, 2024: 24 MW – 248 MW
			BCV		2023, 2024: 50 MW – 202 MW
Desert Community Energy (DCE)	Self-Show No-Compensation	Combined Cycle Natural Gas, Solar PV, Wind	LAB	3	2023-2024: 2 MW – 24 MW
	Self-Show LCR RCM			1	1 MW – 4 MW
Walnut Creek Energy LLC	RA Only	Combustion Turbine Natural Gas	LAB	1	Jun. 1, 2023 – Dec. 31, 2026: 483 MW

On the next page, Figures 1-2 illustrate SCE-CPE's positions in LAB for the 2023 and 2024 compliance years. The drop in procurement seen in Figure 1 between July and August reflects several long-term CAM contracts falling off from existing contracts and which were not subsequently procured by SCE- CPE.

Figure 1. 2021 SCE-CPE RFO: LA Basin, 2023

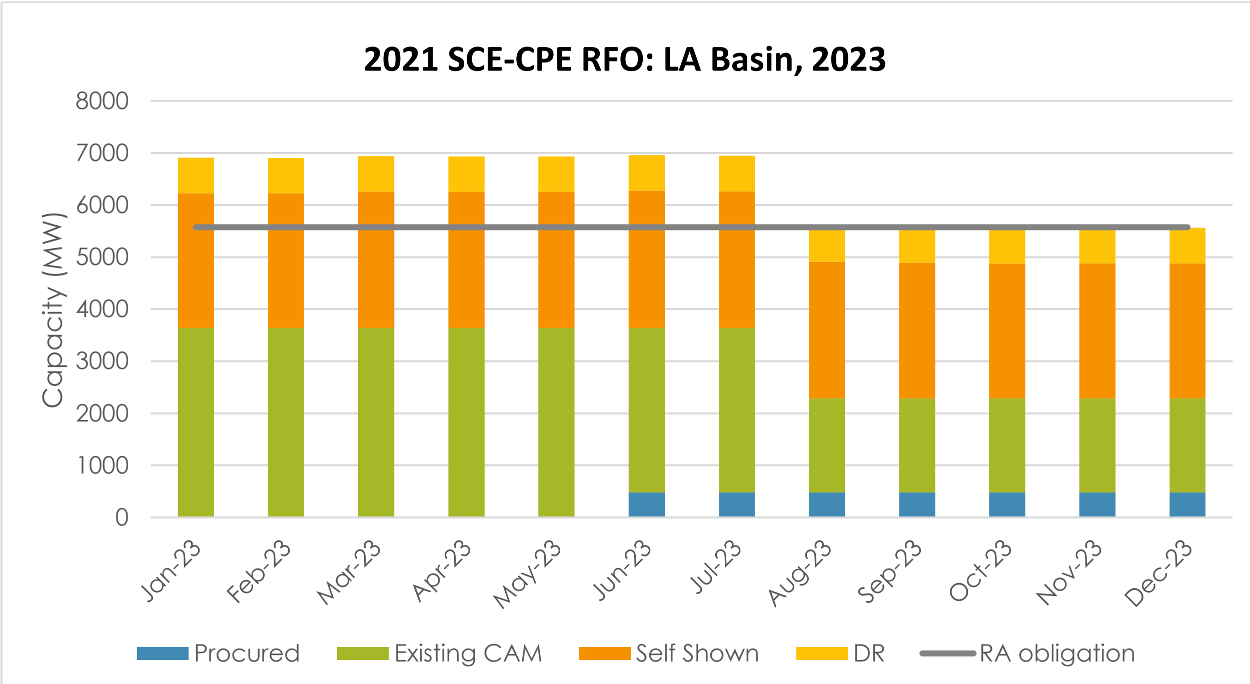
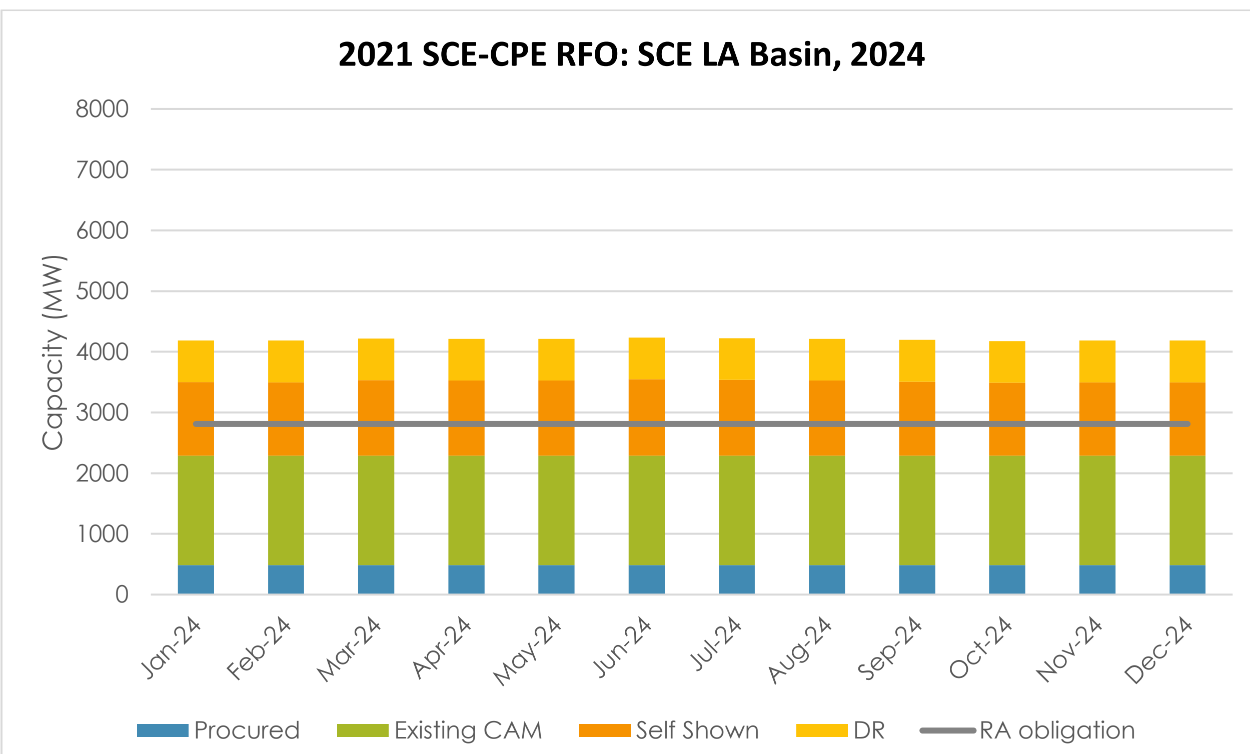


Figure 2. 2021 SCE-CPE RFO: SCE LA Basin, 2024



Figures 3-4 below illustrate SCE-CPE's positions in the Big Creek/Ventura (BCV) local area for the 2023 and 2024 compliance years; the BCV local area's entire needs were met by existing CAM, DR, and self-show resources.

Figure 3. 2021 SCE-CPE RFO: Big Creek/Ventura, 2023

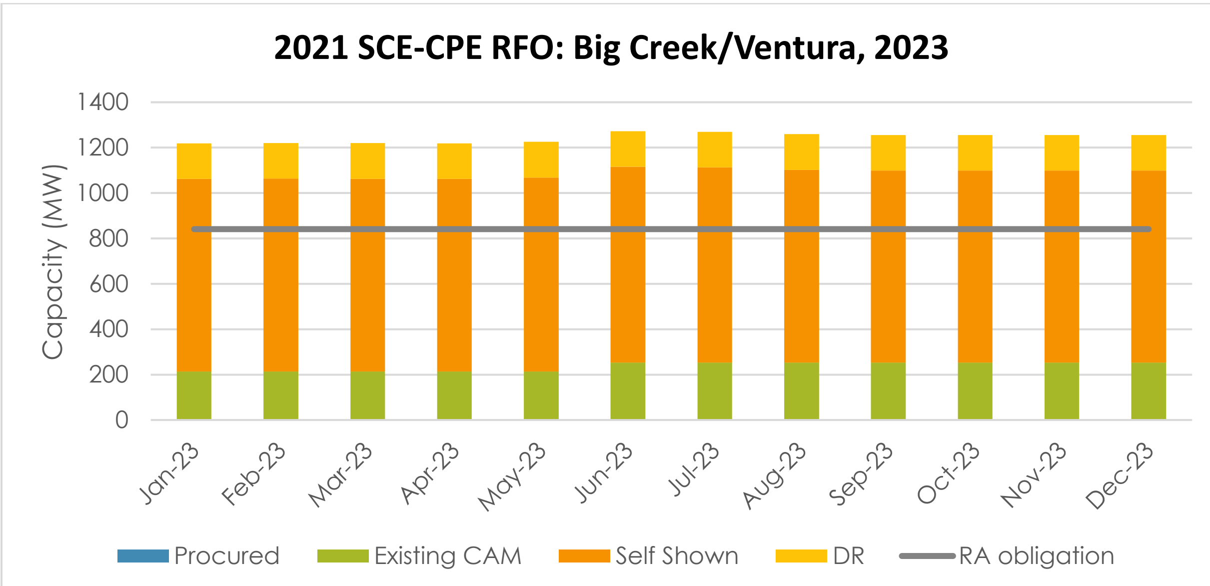
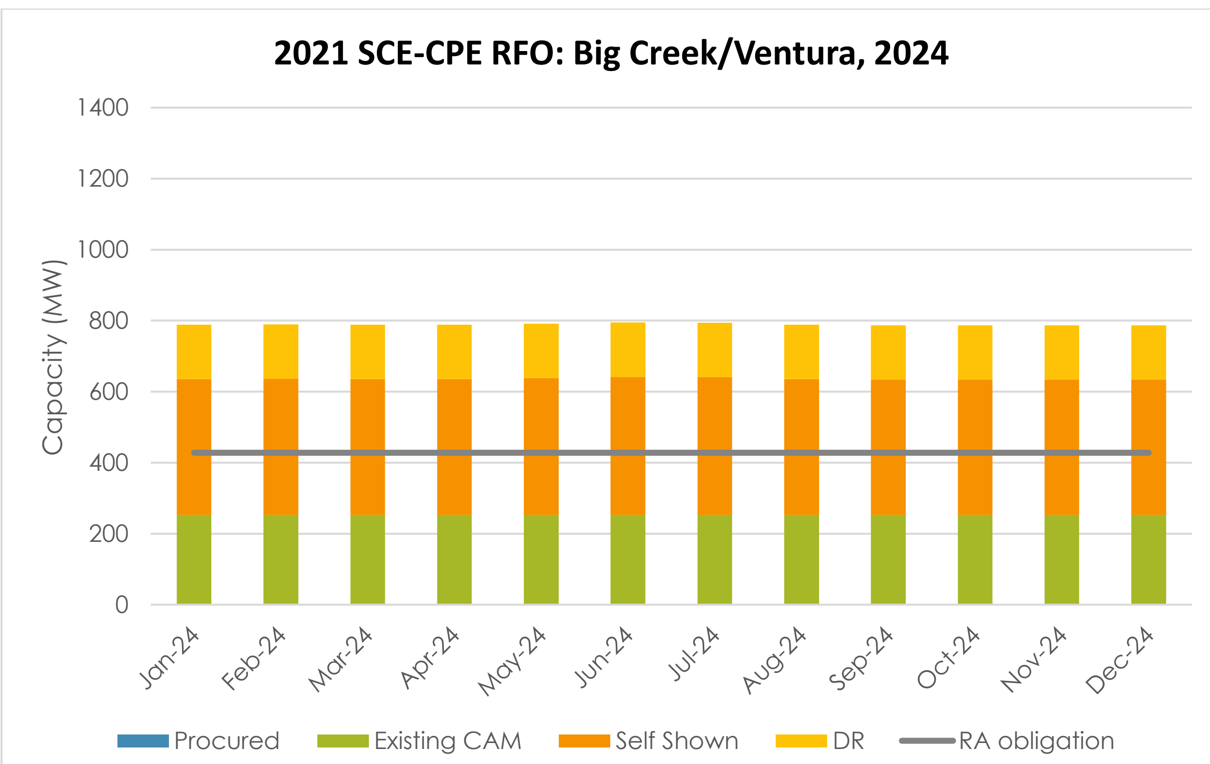


Figure 4. 2021 SCE-CPE RFO: Big Creek/Ventura, 2024



2. 2022 SCE-CPE RFO

In its second solicitation in 2022, SCE-CPE solicited resources to meet its allocated 2023, 2024, and 2025 LCR obligations. As shown in Figure 5, SCE-CPE was able to procure sufficient resources for the LAB local area for the 2023 compliance year, with CAM resources fulfilling 51 percent of the requirements for January to May; 41 percent for June to July; and 25 percent for August to December.[63] SCE-CPE received less than five offers for compensation from large facilities. One supplier, which recently upgraded its facility to increase capacity, contracted with off takers in the near term, but did not offer into the solicitation for later years.[64]

SCE-CPE was not able to fill its LAB requirements for 2024 resulting in a ~340 MW deficiency. (Figure 6) However, SCE-CPE states that it was confident the deficiency would be met by the large volume of Mid-Term Reliability (MTR) contracts expected to be signed before the next SCE-CPE RFO in 2023. In the event the MTR contracts do not come to fruition, SCE-CPE planned to procure additional resources in the next annual CPE RFO.[65] Thus, SCE-CPE did not defer any requirements for CAISO backstop procurement.

Table 4. 2022 SCE-CPE RFO Results[66]

<table>
<tr><th colspan="6">2022 SCE-CPE RFO Results for LA Basin (LAB) and Big Creek/Ventura (BCV) LCAs</th></tr>
<tr><th>Seller</th><th>Contract Type</th><th>Resource Type</th><th>LCA</th><th>No. of Contracts</th><th>Period and Contracted Capacity (MW)</th></tr>
<tr><td>Clearway:
El Segundo 5/6,
El Segundo 7/8</td><td>RA Only</td><td>Combined Cycle Natural Gas</td><td>LAB</td><td>1</td><td>2023-2026: 274-546 MW</td></tr>
<tr><td rowspan="2">SCE</td><td rowspan="2">Self-Show No-Compensation</td><td rowspan="2">Steam Natural Gas, Hydro, Pumped Storage, Solar PV</td><td>BCV</td><td>24</td><td>2023: 843 MW
2024: 1,331 MW</td></tr>
<tr><td>LAB</td><td>3</td><td>2023-2024: 322 MW</td></tr>
<tr><td>EBCE</td><td>Self-Show No Compensation</td><td>Combustion Turbine Natural Gas</td><td>LAB</td><td>4</td><td>2023: 245-320 MW</td></tr>
<tr><td rowspan="2">CPA</td><td rowspan="2">Self-Show No Compensation</td><td rowspan="2">FTUR Natural Gas, LESR, Combined Cycle Natural Gas, Hydro, Solar PV, Reciprocating Engine Natural Gas</td><td>BCV</td><td>5</td><td>2023-2025: 50-81 MW</td></tr>
<tr><td>LAB</td><td>7</td><td>2023-2025: 211 MW</td></tr>
<tr><td rowspan="2">Calpine Energy Solutions</td><td rowspan="2">Self-Show No Compensation</td><td rowspan="2">Combustion Turbine Natural</td><td>BCV</td><td>1</td><td>2023: 125 MW</td></tr>
<tr><td>LAB</td><td>3</td><td>2023-2024: 25-75 MW</td></tr>
</table>

[63] SCE AL 4865-E at 69.
[64] IE Confidential Appendix A on 2022 SCE-CPE RFO, September 19, 2022, at 4.
[65] SCE AL 4626-E at 15.
[66] SCE AL 4865-E at 68.

		Gas, FTUR Natural Gas			
Constellation Energy	Self-Show No Compensation	Combine Cycle Natural Gas, FTUR Natural Gas,	LAB	1	2023: 180 MW
Shell	Self-Show No Compensation	Combustion Turbine Natural Gas, Wind	LAB	3	2023: 151 MW
PG&E	Self-Show No Compensation	Solar PV, LESR	BCV	6	2023, 2024: 1-23 MW

Figure 5. 2022 SCE-CPE RFO: LA Basin, 2023

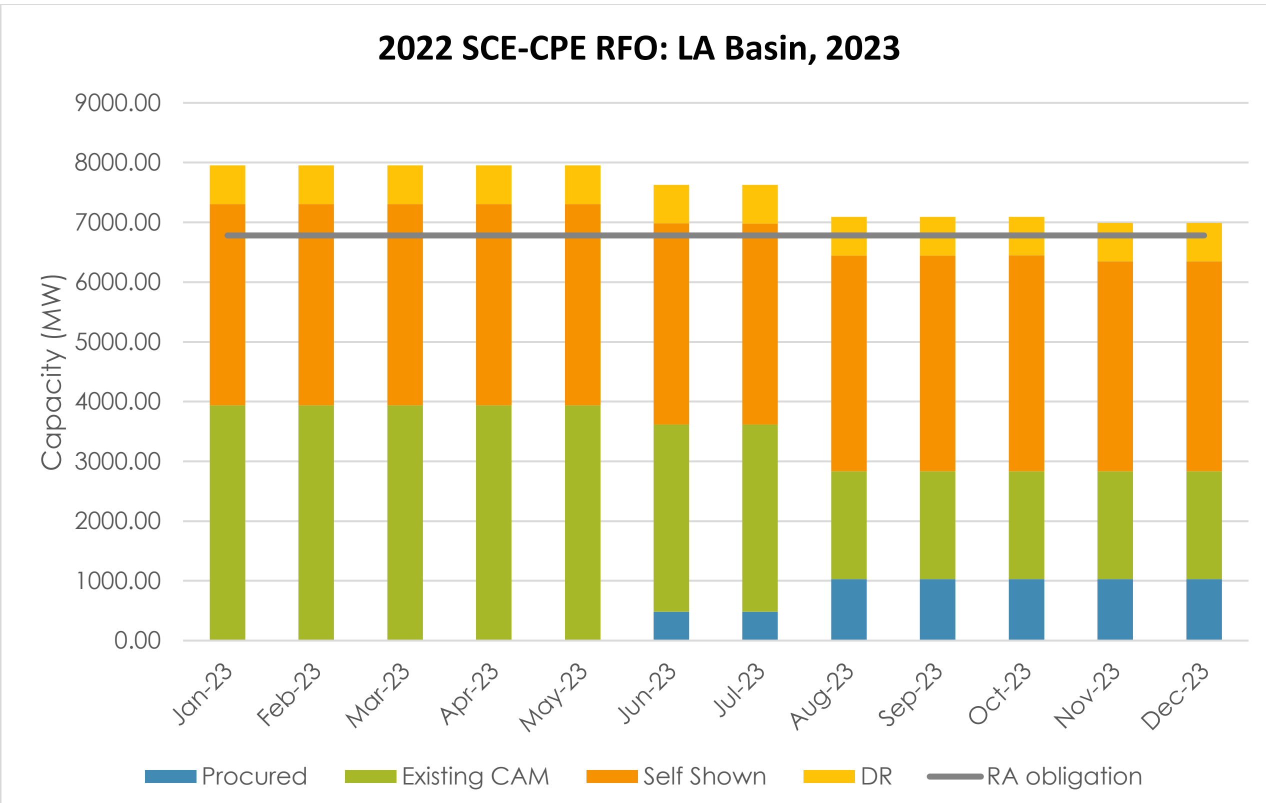


Figure 6. 2022 SCE-CPE RFO: LA Basin, 2024

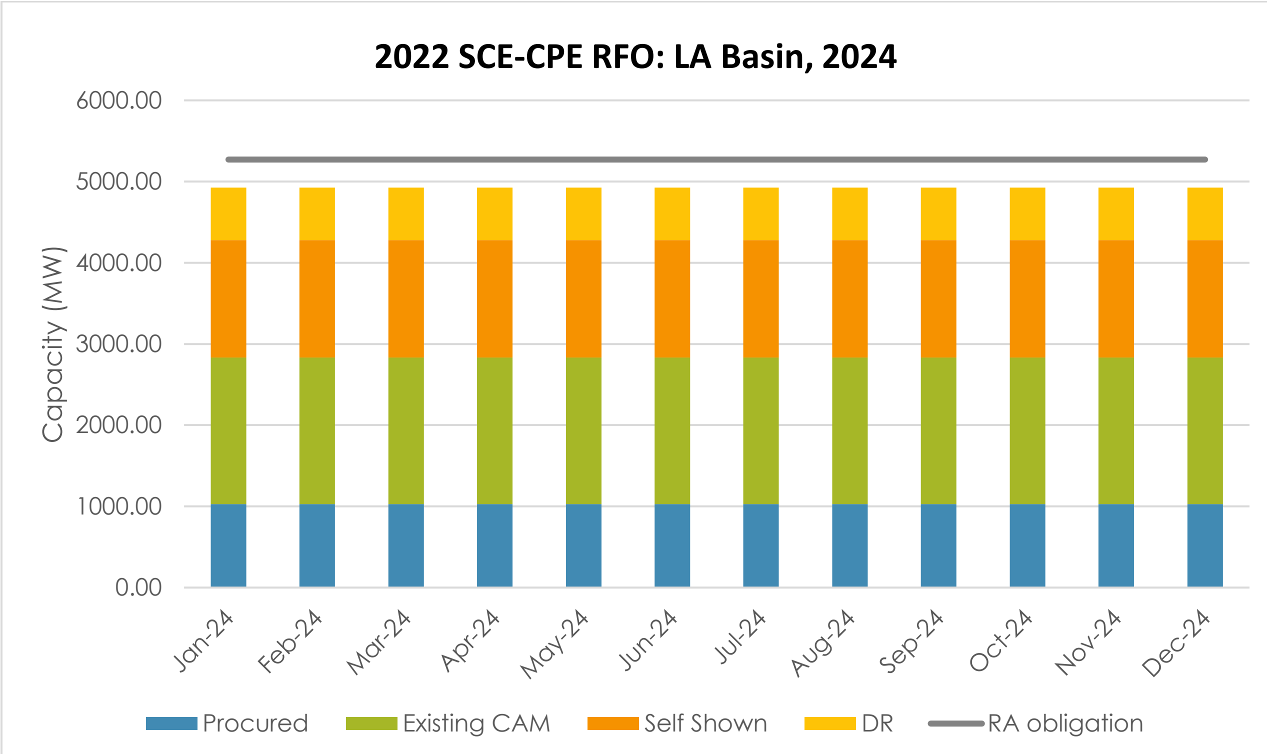


Figure 7. 2022 SCE-CPE RFO: LA Basin, 2025

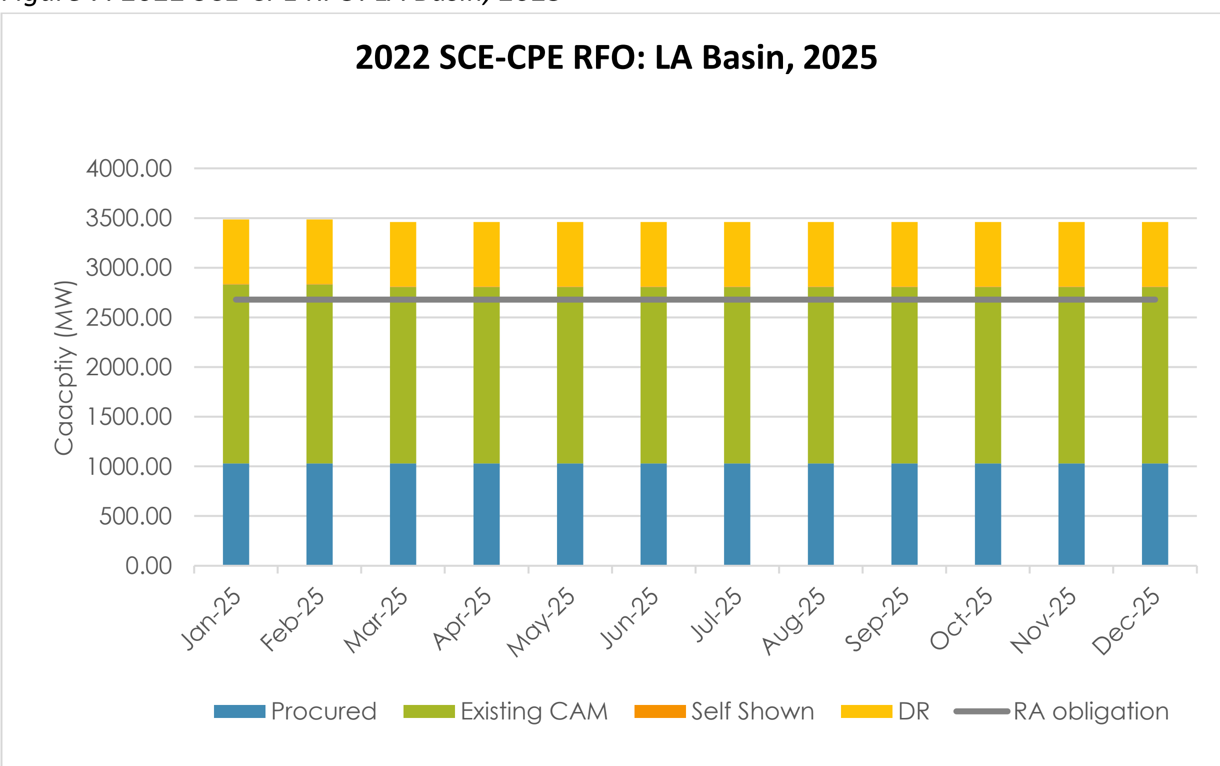


Figure 8. 2022 SCE-CPE RFO: Big Creek/Ventura, 2023

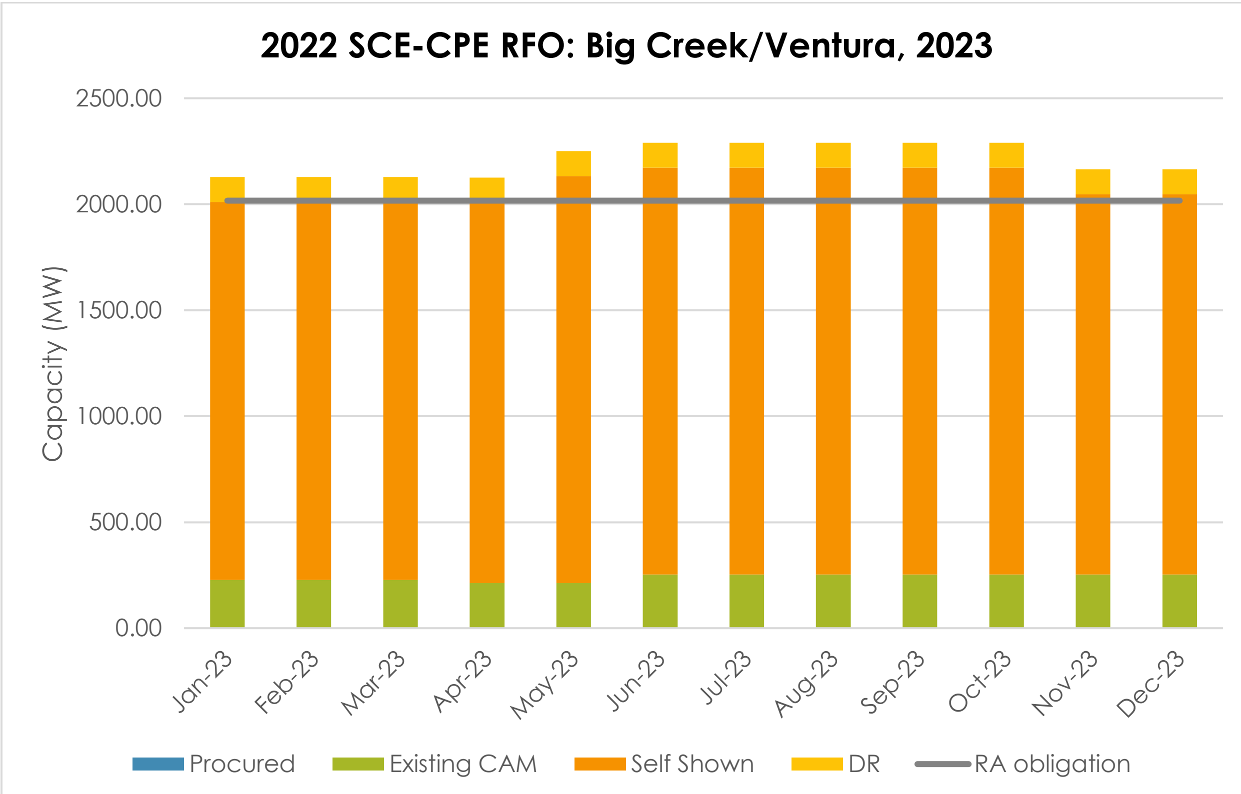


Figure 9. 2022 SCE-CPE RFO: Big Creek/Ventura, 2024

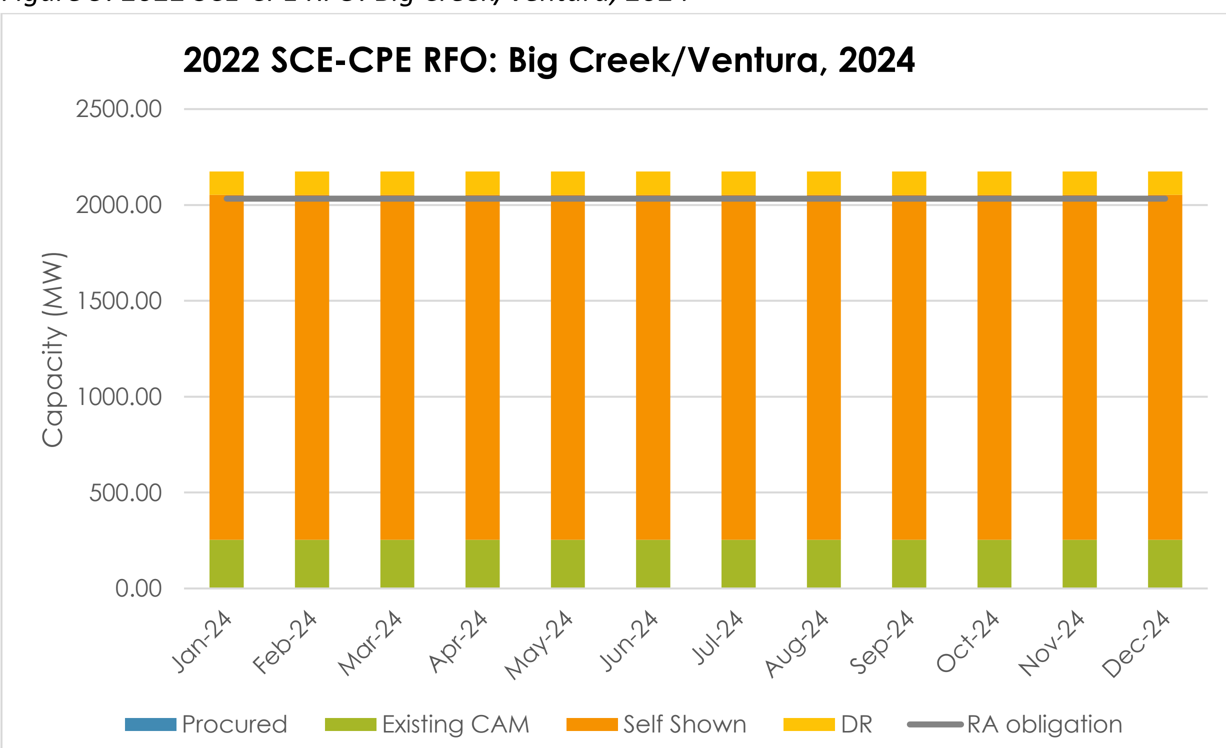
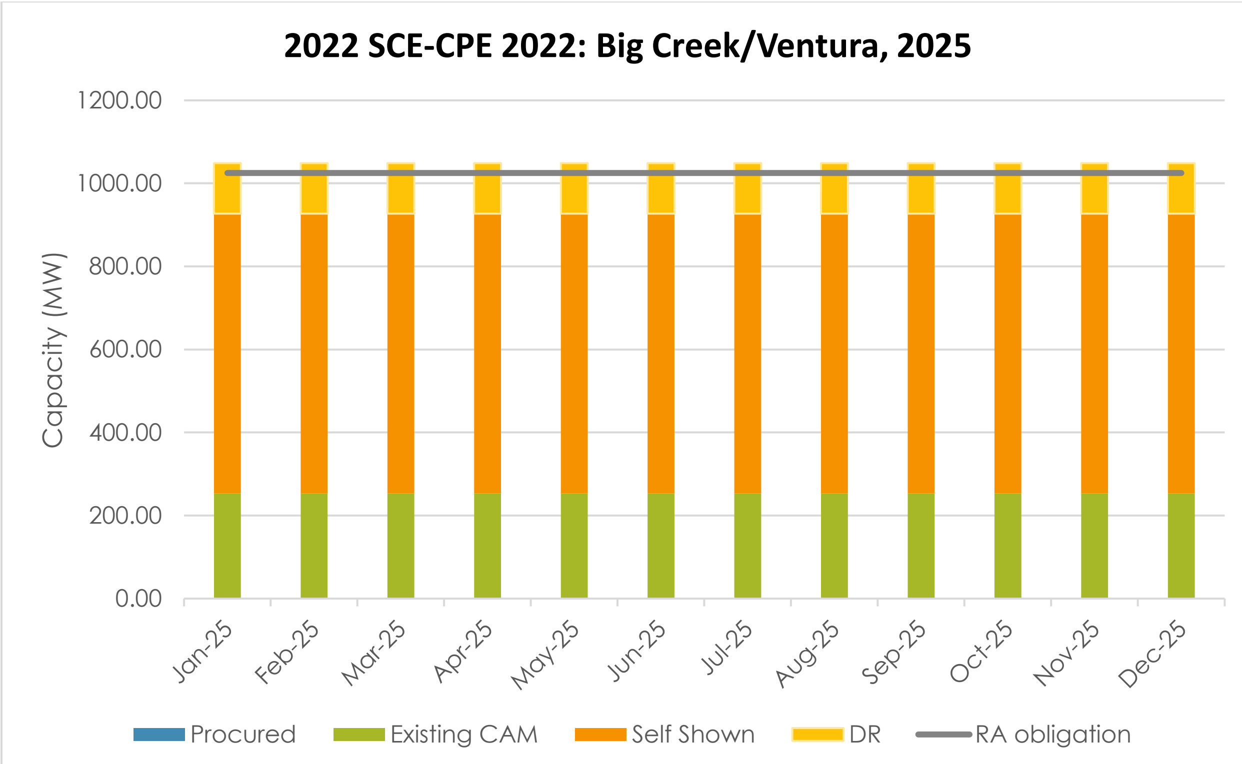


Figure 10. 2022 SCE-CPE RFO: Big Creek/Ventura, 2025



3. 2023 SCE-CPE RFO

As a result of the 2023 RFO, SCE-CPE procured enough resources to meet almost all the LCR needs in the LAB and BCV local areas for the 2024, 2025, and 2026 compliance years. Additionally, because local requirements for the 2024 compliance year decreased in the LAB area by approximately 28 percent (4,017 MW in 2024 compared to 5,573 MW in 2023), SCE-CPE was long in capacity.

As seen in Table 5, SCE-CPE selected 28 self-show non-compensation offers from five counterparties filling LCRs in both the LAB and BCV local areas. The 2024 LCRs in the BCV local area were almost entirely met with SCE self-show non-compensation resources, as can be seen in Figure 11.

Table 5. 2023 SCE-CPE RFO Results

2023 SCE-CPE RFO Results for LAB and BCV LCAs					
Seller	**Contract Type**	**Resource Type**	**LCA**	**No. of Contracts**	**Period and Contracted Capacity (MW)**
SCE	Self-Show Non-Compensation	Combined Cycle Natural Gas, Hydro	BCV	6	2025: 135 MW 2026: 210 MW
			LAB	2	2025: 1,110 MW
Calpine	Self-Show Non-Compensation	Hydro, FTUR Natural Gas	BCV	2	2025: 0-70 MW 2026: 49 MW
			LAB	2	2024: 75 MW
CPA	Self-Show Non-Compensation	LESR, Hydro, Reciprocating Engine Natural Gas, Solar PV, Combustion Turbine Natural Gas	BCV	4	2025-2026: 51-62 MW
			LAB	8	2024: 404 MW 2025: 404 MW 2026: 277 MW
CPSF	Self-Show Non-Compensation	LESR	BCV	1	2024-2026: 11 MW
Constellation Energy	Self-Show Non-Compensation	Combined Cycle Natural Gas, FTUR Natural Gas	LAB	3	2024: 180 MW

Figure 11. 2023 SCE-CPE RFO: LA Basin, 2024

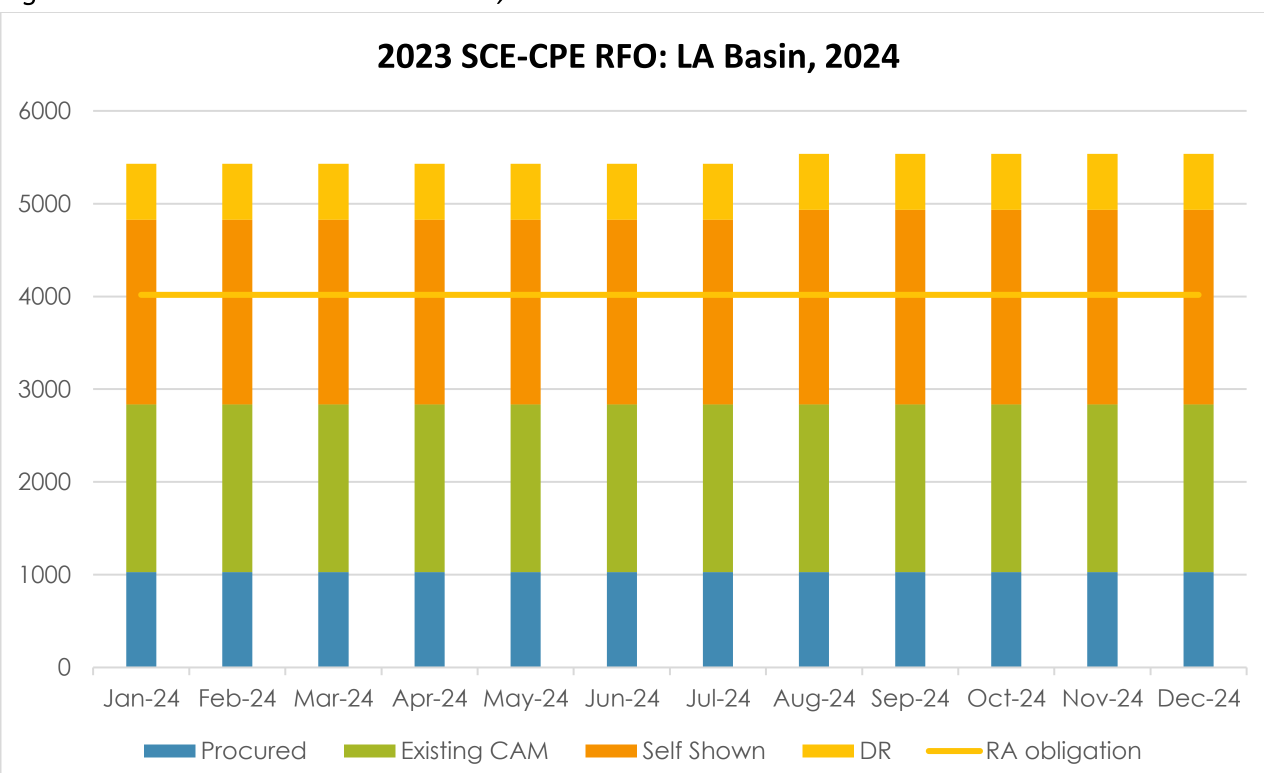


Figure 12. 2023 SCE-CPE RFO: LA Basin, 2025

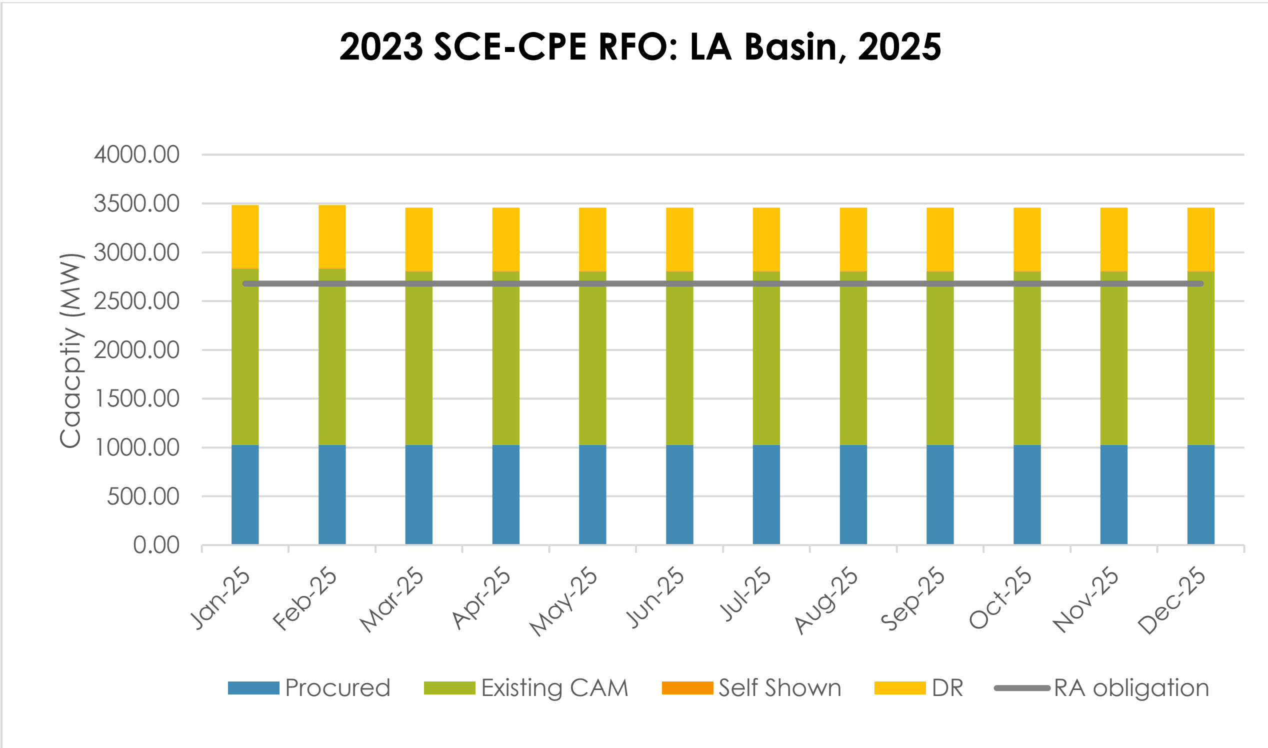


Figure 13. 2023 SCE-CPE RFO: Big Creek/Ventura, 2024

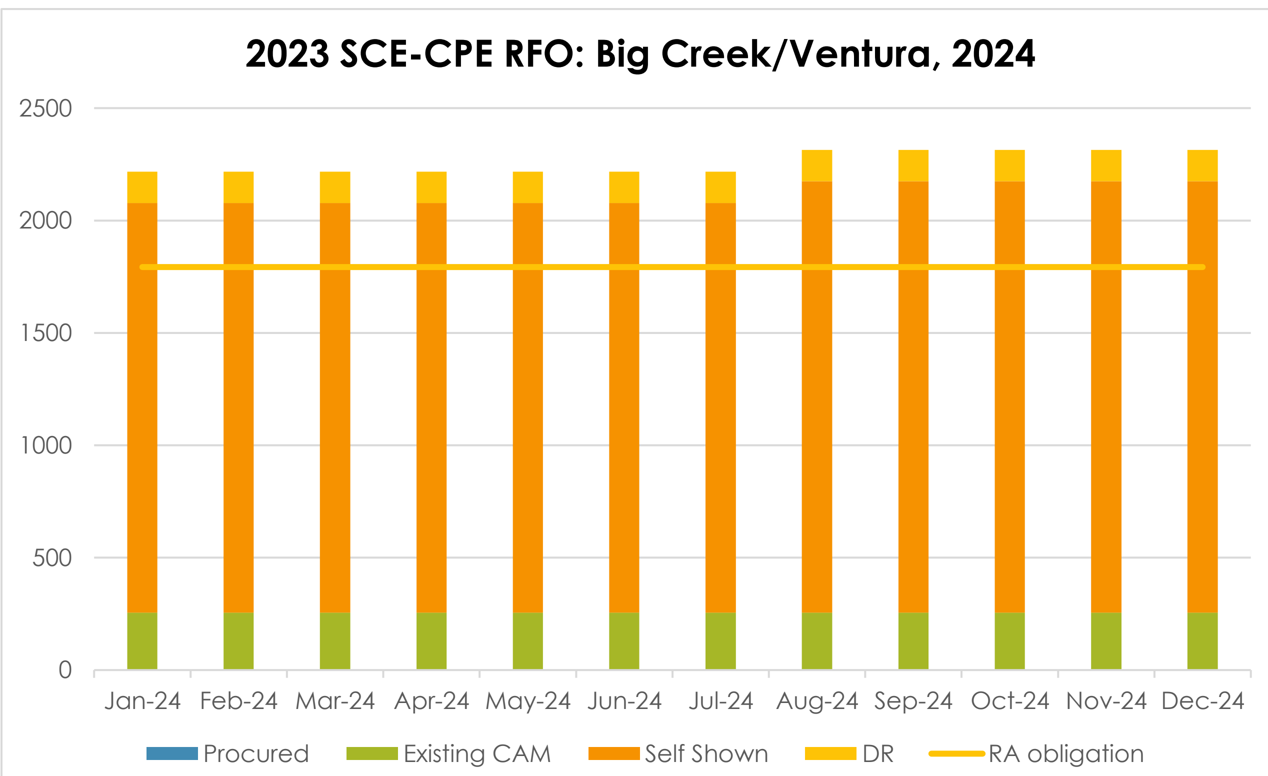
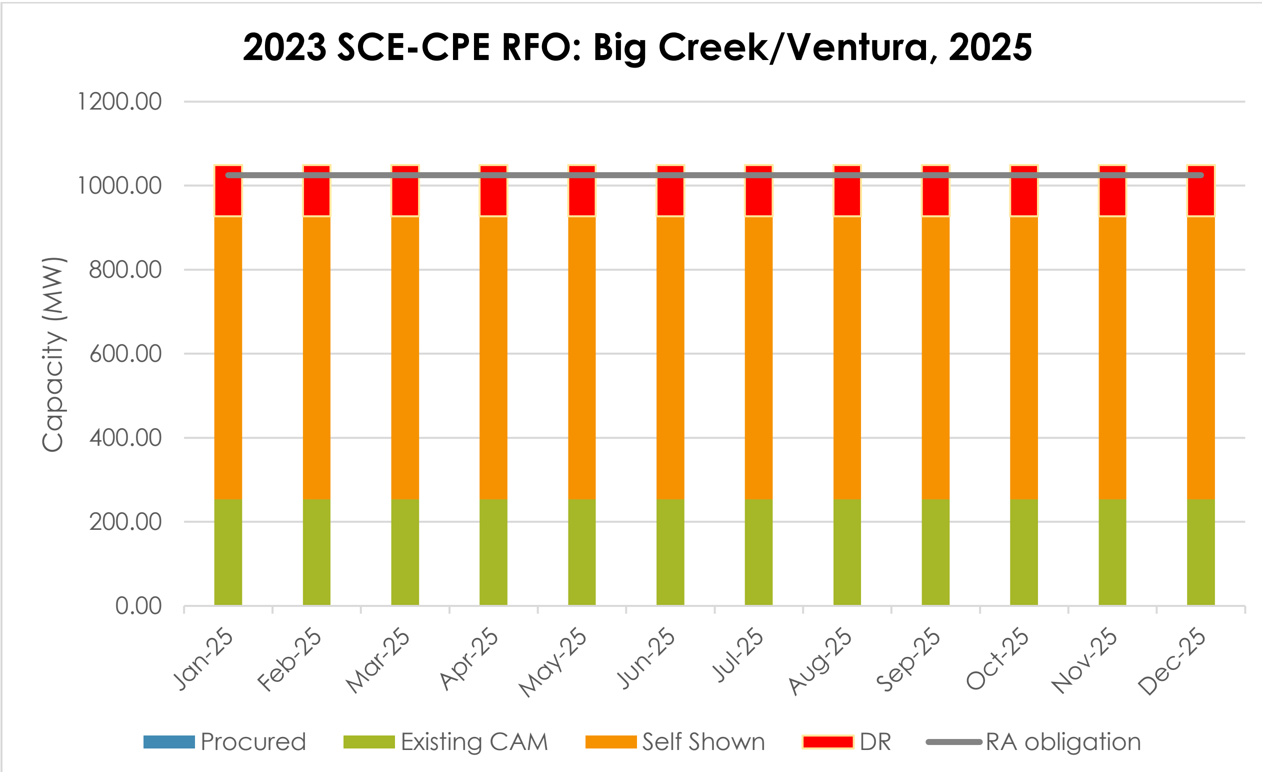


Figure 14. 2023 SCE-CPE RFO: Big Creek/Ventura, 2025



B. PG&E-CPE Solicitations

PG&E-CPE issued annual RFOs in April 2021, April 2022, and March 2023, to meet its forward local RA requirements. The PG&E-CPE's aggregated local requirements for compliance years 2023-2026 are shown in Table 6. PG&E-CPE's aggregated local requirements have increased over time, leaving a larger position to fill for each subsequent RFO. The products and participants solicited for local RA capacity offers are shown in Table 7 below.[67]

Table 6. PG&E-CPE Overall Local Requirements for the 2023-2026 Compliance Years

Compliance Year	PG&E-CPE CPUC Allocation (Excluding DR) (MWs)[68]
2023	11,056
2024	11,543
2025	12,019
2026	6,129

Table 7. 2021-2023 PG&E-CPE Framework Solicitations

Process and Product	Participant
Non-Compensated Self-Shown Commitment	Commission-Jurisdictional LSEs
Competitive Offer Process, Compensated Self-Shown Commitment (LCR RCM)	Commission-Jurisdictional LSEs
Competitive Offer Process, Compensated Offered Resources[69] Competitive Offer Process, Bundled RA**,** or Bundled RA with Energy Settlement[70]	All market Participants

PG&E-CPE used the RFO selection criteria required by Commission decisions, including the use of the loading order and the LCBF methodology.[71] PG&E-CPE also evaluated contract offers according to Commission directive to consult the CAM PRG and the IE throughout the process, including for bilateral contracts or for contracts generated by a preapproved broker. [72]

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[67] PG&E AL 6386-E at 5-6; PG&E AL 6706-E at 6-7; PG&E AL 7027-E at 7-8.

[68] Requirements for compliance year 2023 is based on PG&E-CPE 2022 Year-Ahead Initial Allocation provided by the CPUC on July 8, 2022. Requirements for compliance years 2024-2026 are based on PG&E-CPE 2023 Year-Ahead Initial Allocations provided by the CPUC on July 11, 2023, and updated on August 1, 2023.

[69] PG&E AL 6386-E at 5.

[70] PG&E AL 6706-E at 6; PG&E AL 7027-E at 7.

[71] OP 14 D.20-06-002, at 95.

[72] OP 12 of Decision (D.22-03-034) on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure in R.21-10-002, March 17, 2022, at 74.

In its first RFO PG&E-CPE used a standard pro forma contract for non-compensated self-show offers. The stringent contract requirements yielded a low volume of self-show offers as the contracts did not conform with LSEs' upstream agreements. In response to Commission order, PG&E-CPE modified the self-show requirement from a pro-forma contract to an attestation process, which subsequently increased offers in the 2022 and 2023 RFOs.[73]

Additionally, in response to participants' feedback, PG&E-CPE amended its process to facilitate a more streamlined procurement for the 2024 compliance year and to provide greater certainty on the credits participants would receive for the upcoming compliance year. Accordingly, PG&E-CPE separated its 2023 RFO into two tracks: Track 1 focused on prioritizing negotiations for offers with a 2024 delivery date, while Track 2 prioritized remaining negotiations for 2025 and 2026.

1. 2021 PG&E-CPE RFO

PG&E-CPE heavily redacted the results of its first ACR filing -- including its procurement position – and the filing was protested due to limited transparency. At the request of Energy Division Staff, PG&E-CPE submitted a supplemental filing to which provided additional information on the procurement. The information provided in the supplemental filing is shown in Figures 17 and 18. As shown, PG&E-CPE's position reflects a significant shortfall for 2023 aggregate requirements and a much smaller shortfall in meeting the 50 percent requirement for 2024.

Parties subsequently filed comments in Phase I of R.21-10-002 protesting that the volume of redactions made it impossible to determine whether the solicitation met the LCRs or whether there was any deferment to CAISO backstop procurement. In response to party transparency concerns, the Commission modified the reporting requirements for future ACR filings in D.22-03-034.[74]

As shown in Figures 15-16, there was not sufficient self-shown offers to fill the LCRs for the whole of 2023 and part of 2024, resulting an aggregate deficiency of ~4,264 MWs to 6,015 MWs in the 2023 May to October summer months and ~183 MWs to 649 MWs in the 2024 summer months. The CAISO's 2022 RA Evaluation Report identified individual and collective deficiencies in several LCAs within the PG&E TAC Area. Aggregate deficiencies in PG&E's TAC totaled 308.41 MW, while individual LSE local deficiencies totaled 481.02 MW. [75]

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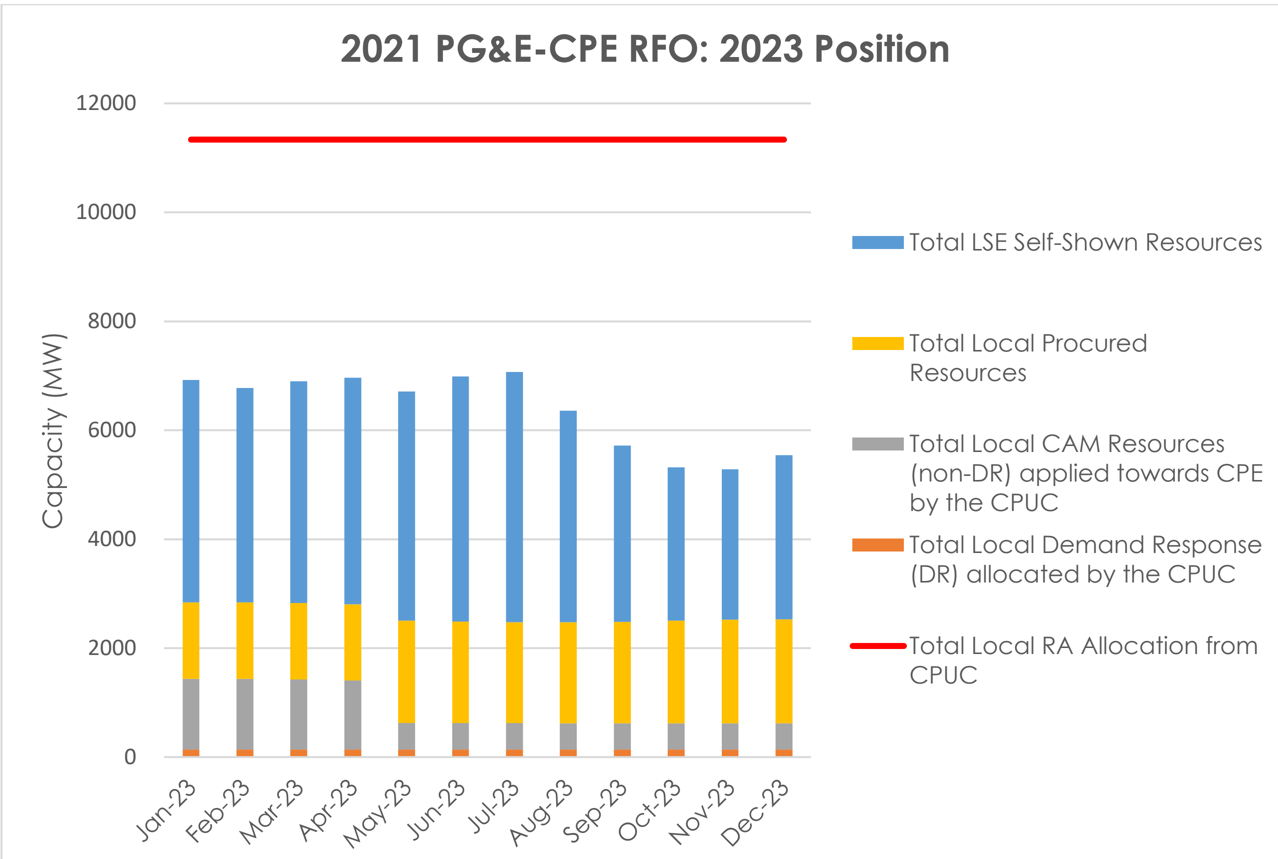
[73] *Ibid*., at 72.
[74] *Ibid*., at 77.
[75] CAISO, Evaluation Report of Load Serving Entities' Compliance with 2022 Resource Adequacy Requirements, November 12, 2021, at 2-3.

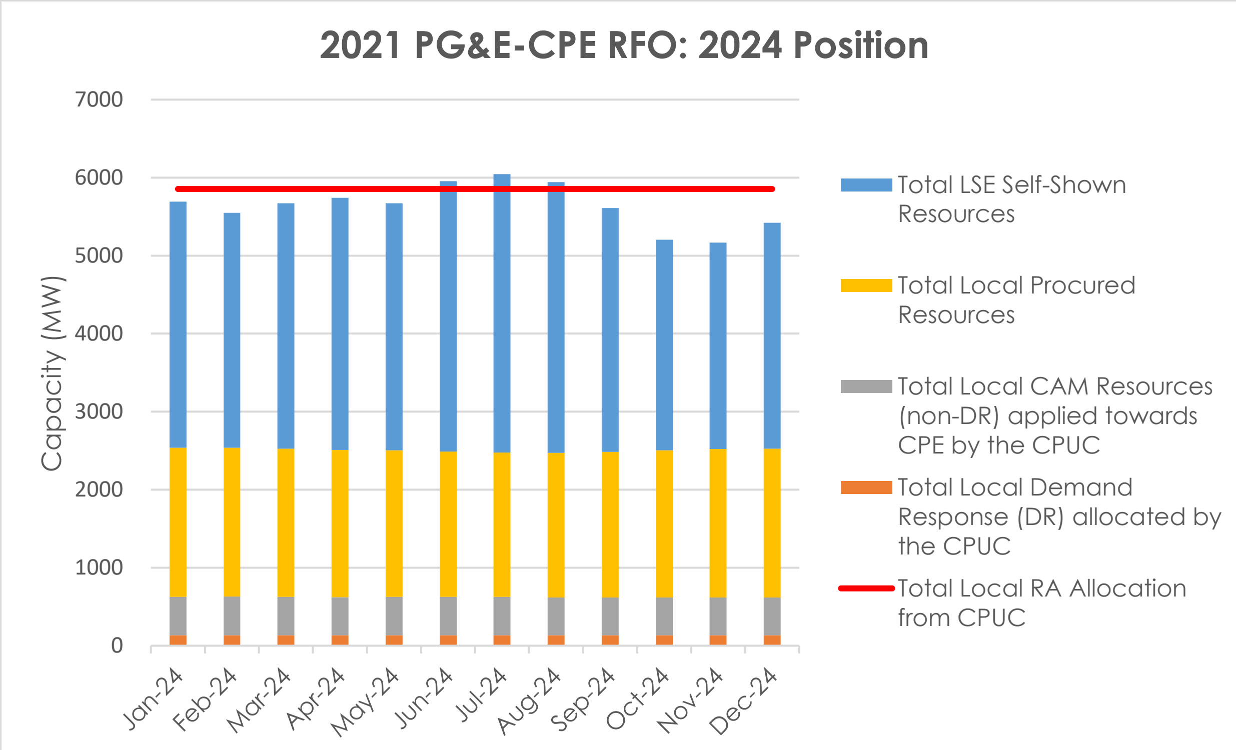
Based on this first solicitation, parties noted that PG&E-CPE's inclusion of overly prescriptive contract restrictions beyond what was required by D.20-06-002 may have discouraged LSE self-show offers. For example, parties cite cases in which available local resources have upstream contract replacement options that are not tied to that specific local area. Under PG&E-CPE's existing contract, should these LSEs choose to self-show, they risk potential liability because their upstream contracts did not conform with PG&E-CPE's provisions.[76] PG&E-CPE subsequently amended its contract terms, which eased conflicts with LSEs and resulted in higher amounts of self-show offers.

Figure 15. 2021 PG&E-CPE RFO: 2023 Position [77]



[76] D.22-03-034, at 15.
[77] PG&E AL 6386-E-A Supplemental Attachment 1.

Figure 16. 2021 PG&E-CPE RFO: 2024 Position



2. 2022 PG&E-CPE RFO

In its second RFO, PG&E-CPE attempted to fill the remaining 2023 -2025 positions with self-shown and competitive offers. The simplified attestation for self-shows – which replaced the contract requirements – appeared to have encouraged more offers because it removed the performance risk for participants.[78] The attestation process also eliminated the need for negotiations, further streamlining contract execution. PG&E-CPE's IE noted that the 2022 RFO yielded a significant increase not only in the number of participants, but also in the magnitude of capacity offered for non-compensated self-show resources; additionally, PG&E-CPE received offers for new resources. With the increased participation, two LCAs received more self-shown capacity than was required for 2023, 2024, and 2025.[79] PG&E-CPE was also able to execute competitively priced contracts with some these offers for up to 60 months.

Notwithstanding the increased participation however, PG&E-CPE did not receive sufficient resources to fill its 2023 and 2024 positions, but also secured a long position for 2025, as shown in Figures 17-19. As further reflected in Figures 17-18, the 2023 and 2024 deficiency ranged

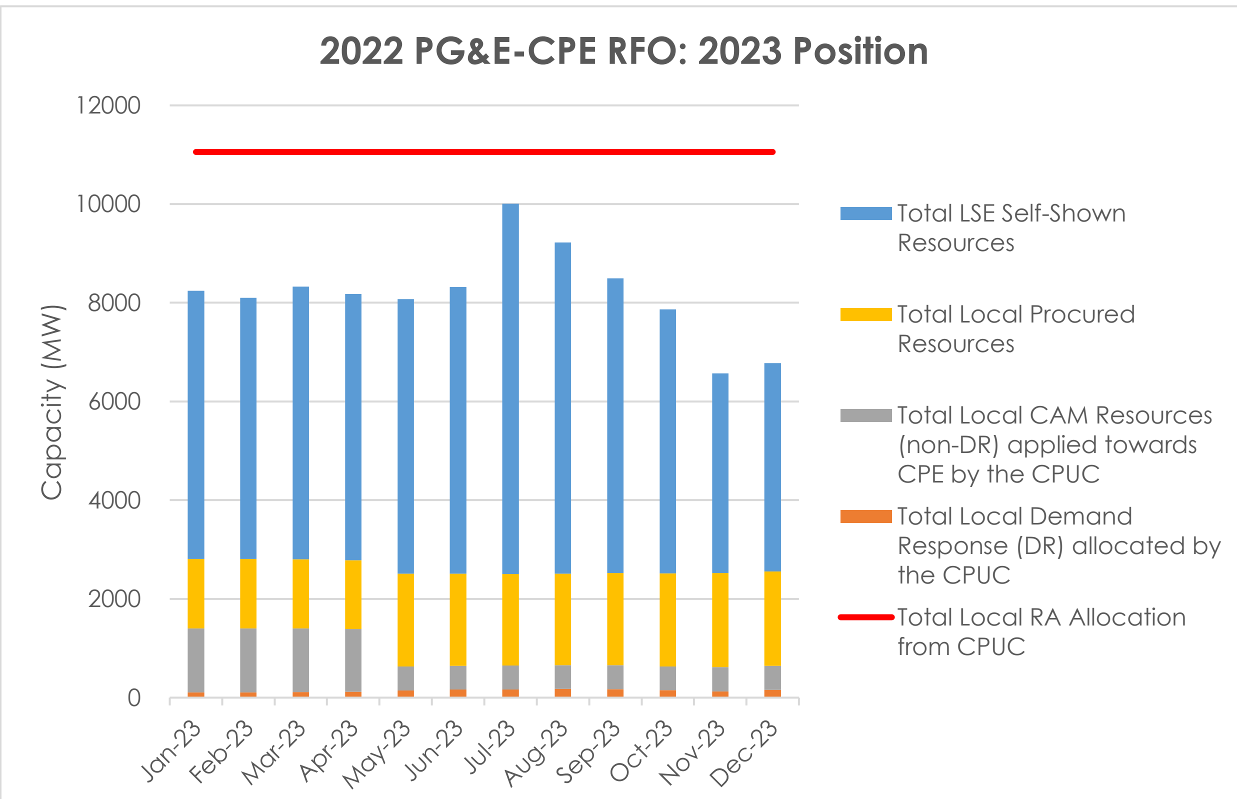
[78] IE Confidential Report on 2022 PG&E-CPE RFO, September 19, 2022, at 59.
[79] *Ibid.*, at 58.

from ~1,050 MWs to 3,190 MWs in the 2023 May – October summer months and ~2,245 MWs to 3,297 MWs in the 2024 summer months.

PG&E-CPE engaged in bilateral outreach to procure additional capacity to meet 2023 local RA requirements, but because no contracts were executed, it deferred to the CAISO for potential backstop procurement. We will further discuss out-of-market procurements in the next section.

The results of PG&E-CPE's procurement were further confirmed by the CAISO in its 2023 RA Evaluation Report, which presented all LSE and CPE supply plans for each local area.[80] In that study, the CAISO identified individual and collective capacity deficiencies in LCAs within the PG&E TAC Area. Aggregate deficiencies in PG&E's TAC amounted to 374 MW, while individual local deficiencies total 9,222 MW.

Figure 17. 2022 PG&E-CPE RFO: 2023 Position [81]



[80] CAISO, Evaluation Report of Load Serving Entities' and Central Procurement Entities' Compliance with 2023 Resource Adequacy Requirements, November 10, 2022, at 2-3.
[81] PG&E AL 6706-E Public Attachment A.

Figure 18. 2022 PG&E-CPE RFO: 2024 Position

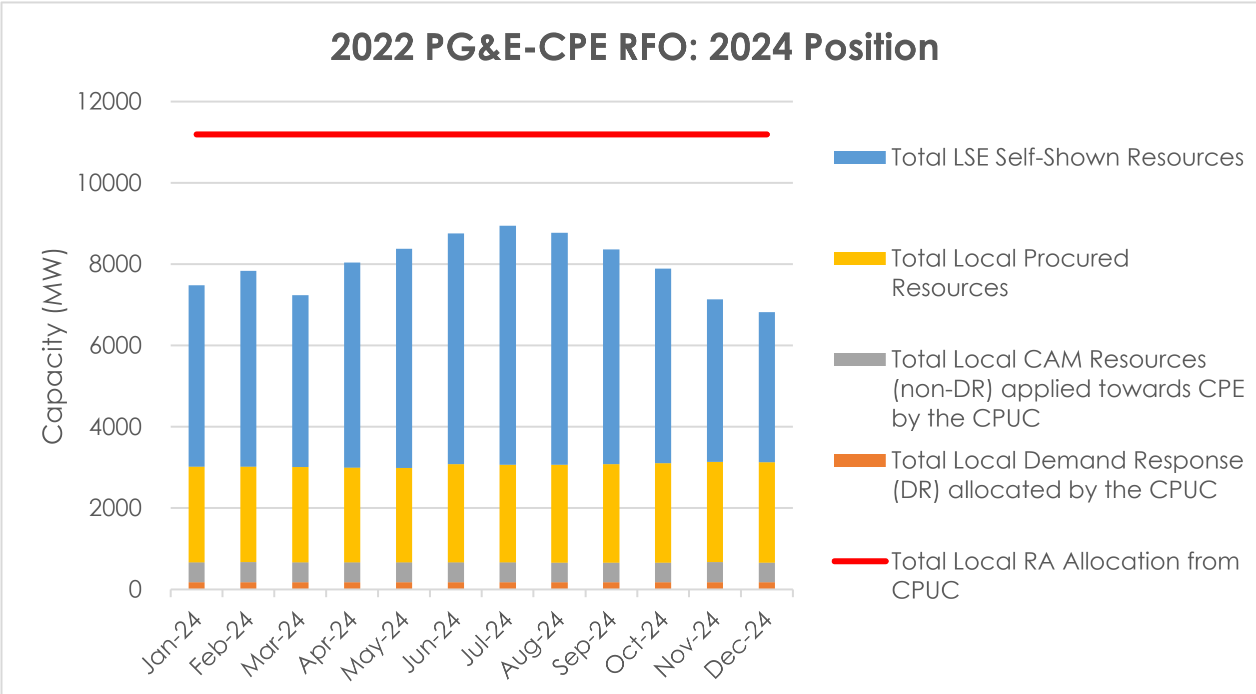
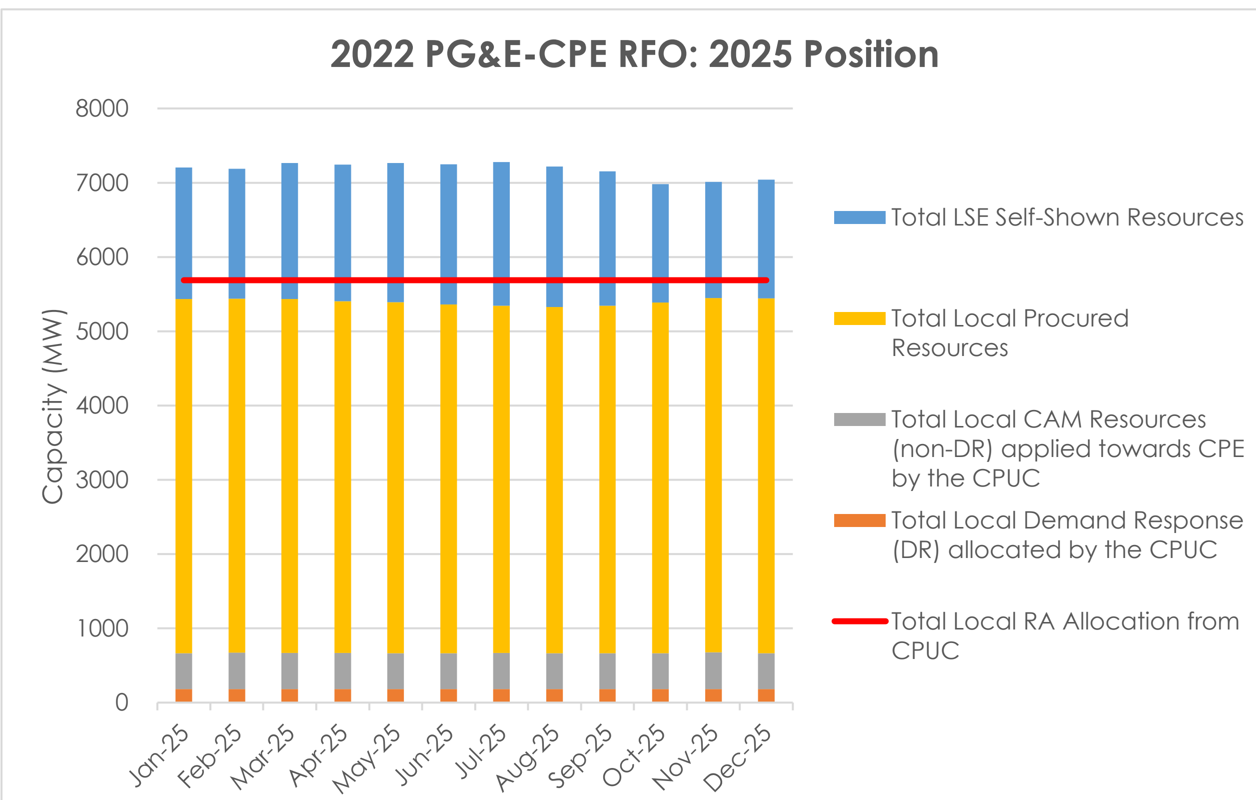


Figure 19. 2022 PG&E-CPE RFO: 2025 Position



3. 2023 PG&E-CPE RFO

As previously discussed, PG&E-CPE conducted its 2023 RFO under two tracks, with Track 1 focusing on near term procurement for the 2024 compliance period and Track 2 focusing on the 2025 and 2026 compliance years.

As with the 2022 RFO, the 2023 solicitation experienced a decline in the number of non-compensated self-shown participants and commitments. Similarly, there was a decline in overall participants and offers. PG&E-CPE's IE speculates that this was likely due to most capacity already being committed.[82] After accounting for self-shown capacity and resources contracted through the competitive solicitations in the 2021-2023 RFO processes, PG&E-CPE deferred its deficiency to CAISO backstop procurement.[83]

As reflected in Figures 20-21, the self -shown offers could not sufficiently meet LCR needs, resulting in a deficiency between ~2,542 MWs to 3,150 MWs during the 2024 May – October summer months; between ~2,233 MWs to 2,693 MWs for the 2025 summer months; and ~72 MWs to 733 MWs during the 2026 summer months. While PG&E-CPE will not conduct further outreach for the 2024 compliance year, it will do so for the 2025 and 2026 compliance years.

PG&E-CPE's shortfalls were reported by the CAISO in its 2023 Annual Report of RA Compliance, which identified individual and collective capacity deficiencies in LCAs within the PG&E TAC area.[84] The CAISO found that the local deficiency in PG&E's TAC total 639 MW, while individual LSE/CPE local deficiencies total 9,500 MW.[85]

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[82] PG&E AL 7027-E at 89.
[83] PG&E AL 7027-E at 112.
[84] CAISO, Evaluation Report of Load Serving Entities' and Central Procurement Entities' Compliance with 2024 Resource Adequacy Requirements, November 10, 2023, at 2-3.
[85] PG&E AL 7027-E, Substitute Sheet, Attachment A.

Figure 20. 2023 PG&E-CPE RFO: 2024 Position[86]

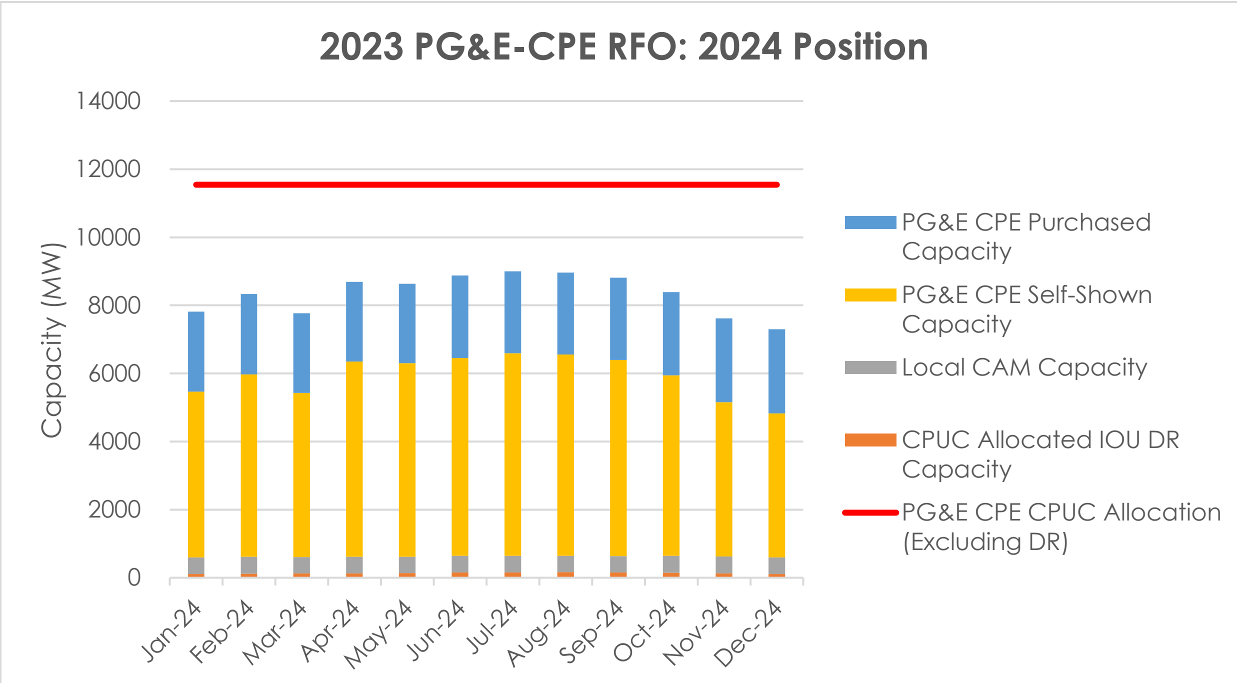


Figure 21. 2023 PG&E-CPE RFO: 2025 Position

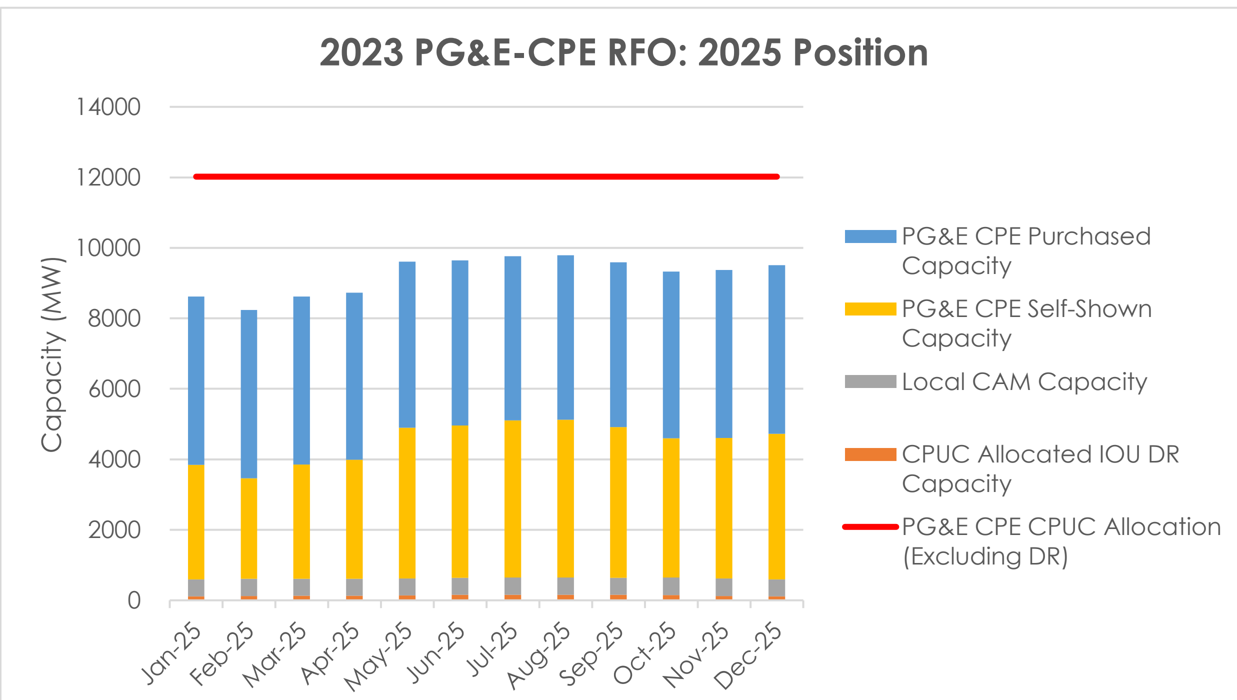
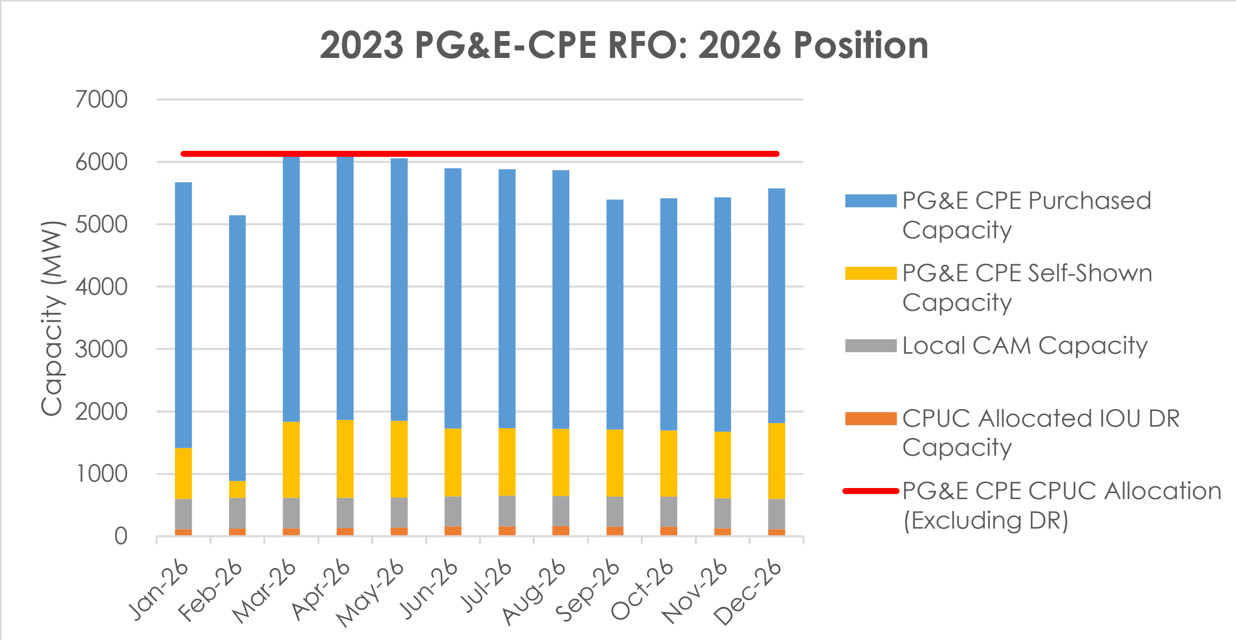


Figure 22. 2023 PG&E-CPE RFO: 2026 Position



C. Backstop Procurement

This sub-section briefly summarizes how the results of the CPEs' first three RFOs interacted with the CAISOs backstop procurement mechanism. For SCE-CPE, given that it was able to secure sufficient capacity for the 2023 and 2024 compliance years in its 2022 and 2023 RFOs, it did not refer any deficiency to CAISOs backstop procurement mechanism.

This was not the case for the PG&E-CPE, as it was unable to meet its LCR obligations for the 2023 and 2024 compliance years and deferred the shortfalls to the CAISO backstop procurement mechanism. PG&E-CPE provided several reasons for making its deferral:[87]

1. In 2022, despite overall increased participation relative to the prior year, PG&E-CPE did not receive sufficient competitive or self-show offers. PG&E-CPE also noted that if it had only selected preferred resources, it would have resulted in a more significant deficit position.
2. In 2023, PG&E-CPE experienced decreased participation from the previous year's RFO.
3. Prior to launching its 2023 solicitation, PG&E-CPE received market feedback from over 30 participants who stated that there would be limited 2024 capacity offered due to:
   a. Capacity already being contracted by either the CPE or other entities.
   b. Participants could better optimize their portfolio of local RA assets through more lucrative opportunities in the bilateral markets.

[87] PG&E AL 7027-E Attachment D IE Report at 27 and Attachment E Deferred Procurement at 3-8.

   c. Current rules around self-show resources are too restrictive and participants expressed a desire to maintain portfolio flexibility even after self-showing resources to the CPE.
   d. CPUC-jurisdictional LSEs are concerned over the impact of Slice of Day implementation on the CPE procurement process.
   e. DR providers were hesitant to contract farther out than the prompt year due to uncertainty behind changes to the NQC rules.
4. Unreasonably high prices.
5. Inability to reach agreement on contractual terms.

Tables 8-10 highlight the results provided by CAISO's Annual Report on RA Compliance for the 2022, 2023 and 2024 compliance years. CAISO's reports also provided the list of relevant resources from which capacity is needed to satisfy the LCR criteria.[88] Please note that the CPEs' procurement did not cover the 2022 compliance period, and therefore the results of the 2022 report (reflecting the 2021 PG&E-CPE RFO) reflect the deficiencies seen when looking at individual LSE filings. The 2023 and 2024 reports, which reflect the 2022 and 2023 PG&E-CPE RFOs respectively, include both CPE and individual LSE flings.

All three tables reflect similar local areas that are deficient. The MW deficiency quantities vary for the Fresno LCA for the CAISO Annual Evaluation Reports for 2023 and 2024 (which were procured in the 2022 and 2023 PG&E-CPE RFOs). The Bay Area LCAs also have varied MW deficiency quantities for the CAISO Annual Evaluation reports from 2022-2024 (procured in the 2021-2023 PG&E-CPE RFOs).

CAISO reports that the results of these three evaluations did not result in any backstop procurement as it was determined during the cure period that the identified resources needed to fill the deficiencies were already under contract.

Table 8. 2021 PG&E-CPE RFO: 2022 CAISO Annual Evaluation Report -- Locational Deficiencies[89]

LCA	Sub-Area	Deficiency/Remaining Need
Bay Area	San Jose	29.40 MW
Bay Area	Bay Area Overall	46.97 MW
Sierra Area	Drum-Rio Oso	34.40 MW
Sierra Area	Gold Hill-Drum	9.84 MW
North Coast/North Bay Area	North Coast/North Bay Overall	170.57 MW
Stockton Area	Tesla-Bellota	3.65 MW
Fresno Area	Borden Sub-Area	0.01 MW

[88] CAISO, 2020 Evaluation Report of LSEs' and CPEs' Compliance with 2021 RA Requirements, at 6-7; 2021 Evaluation Report of LSEs' and CPEs' Compliance with 2022 RA Requirements, at 6-7; 2022 Evaluation Report of LSEs' and CPEs' Compliance with 2023 RA Requirements, at 6-7.
[89] CAISO, 2021 Evaluation Report of LSEs' Compliance with 2022 RA Requirements, at 2-3.

Fresno Area	Wilson 115kV	12.96 MW

Table 9. 2022 PG&E-CPE RFO: 2023 CAISO Annual Evaluation Report -- Locational Deficiencies[90]

LCA	Sub-Area	Deficiency/Remaining Need
Bay Area	San Jose	65.46 MW
Sierra Area	Drum-Rio Oso	53.34 MW
Sierra Area	Gold Hill-Drum	2.89 MW
North Coast/North Bay Area	Eagle Rock	25.11 MW
North Coast/North Bay Area	North Coast/North Bay Overall	211.59 MW
Stockton Area	Tesla-Bellota	28.43 MW
Fresno Area	Wilson 115kV	12.62 MW

Table 10. 2023 PG&E-CPE RFO: 2024 CAISO Annual Evaluation Report -- Locational Deficiencies[91]

LCA	Sub-Area	Deficiency/Remaining Need
Bay Area	San Jose	8.06 MW
Bay Area	Bay Area Overall	231.85 MW
Sierra Area	Drum-Rio Oso	32.25 MW
Sierra Area	Gold Hill-Drum	1.89 MW
North Coast/North Bay Area	North Coast/North Bay Overall	278.28 MW
Stockton Area	Tesla-Bellota	0.29 MW
Fresno Area	Wilson 115kV	94.42 W

D. Use of the Local Capacity Requirement Reduction Compensation Mechanism

In 2020, the Commission adopted the LCR RCM to encourage the development of preferred and energy storage resources in LCAs.[92] Using PCIA contract data covering Q1-Q4 of the prior year, the Energy Division publishes the LCR RCM annually, ahead of the CPEs' RFOs. For example, the 2021 CPE RFO uses the data published in March 2022 to set its benchmarks for procuring resources for the 2022-2024 compliance years.

In 2022 the Commission updated the LCR RCM price calculation and instructed that, "if selected, the LSE shall be paid the showing price (pre-determined or below) without annual adjustments for effectiveness. The showing price shall not exceed the pre-determined local price, which is calculated as follows:

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[90] CAISO, 2022 Evaluation Report of LSEs' and CPEs' Compliance with 2023 RA Requirements, at 2-3.
[91] CAISO, 2023 Evaluation Report of LSEs' and CPEs' Compliance with 2024 RA Requirements, at 2-3.
[92] OP 3 of D.20-12-006, at 46.

- Use the weighted average price from the last four quarters of the Energy Division Power Charge Indifference Adjustment responses for system and local RA; subtract system RA price from (the) local RA price."[93]

In the following section, the Energy Division provides a summary of the LCR RCM benchmarks and the number of contracts that used the LCR RCM in the 2021-2023 RFOs.

1. 2021 IOU-CPE RFO

Table 11 summarizes the LCR RCM premiums posted in March 2021 for resources delivered in 2021 and 2022. For local areas with weighted average price greater than the system price, the local premium is the difference between the two; otherwise, it is $0. The Humboldt, Sierra and Kern reflected the largest premiums at $1.78, $1.75, and $1.56 kW-month. Smaller premiums were also seen in North Coast/North Bay, Stockton, and LA Basin LCAs. In their 2021 RFOs, SCE-CPE executed one LCR RCM contract with Desert Community Energy (DCE) for the 2023 compliance year,[94] while PG&E-CPE executed one LCR RCM contract for the 2023 and 2024 compliance years.[95]

Table 11. LCR RCM Premiums Posted March 2021[96]

Weighted Average Price for System and Local RA in SCE and PG&E Territory Based on contracts entered between Q1-Q4 2020 for 2021 and 2022 deliveries March 2021				
Local Area	Capacity (MW-mo.)	% of Total Capacity	Weighted Avg. Price ($kW-mo.)	Local Premium
Bay Area	50,304	24.2%	$6.28	$0.00
Big Creek/ Ventura	41,551	20.0%	$6.20	$0.00
Fresno	9,231	4.4%	$6.41	$0.00
Humboldt	296	0.1%	$8.23	$1.78
Kern	2,220	1.1%	$8.01	$1.56
LA Basin	41,511	20.0%	$6.48	$0.03
NCNB	3,514	1.7%	$6.82	$0.37
Sierra	2,916	1.4%	$8.20	$1.75
Stockton	1,162	0.6%	$6.57	$0.12
System	55,020	26.5%	$6.45	-

93 OP 15 of D.22-03-034, at 76.
94 SCE AL 4626-E at 70.
95 IE Confidential Report on 2021 PG&E-CPE RFO, October 27, 2021, at 99.
96 Energy Division, Resource Adequacy Compliance Materials, 2021 Guides and Resources: LCR RCM Prices for 2021 and 2022, March 2021.

2. 2022 IOU-CPE RFO

Table 12 summarizes the LCR RCM premiums posted in March 2022 for use in the 2022 and 2023 deliveries. For local areas with weighted average price greater than the system price, the local premium is the difference between the two; otherwise, it is $0. The premiums for resources in the Big-Creek/Ventura and Sierra LCAs are the highest at $1.48 and $1.35 kW-month. Smaller premiums were seen in the Kern, North Coast/North Bay, and Stockton LCAs. In their 2022 RFOs, SCE-CPE received one offer for 2023 to 2024 but did not contract for any resources under the LCR RCM;[97] PG&E received one eligible offer for 2023 and 2024 but did not contract for any resources.[98]

Table 12. LCR RCM Premiums Posted March 2022[99]

Weighted Average Price for System and Local RA in SCE and PG&E Territory. Based on contracts entered between Q1-Q4 2021 for 2022 and 2023 deliveries. March 2022				
Local Area	Capacity (MW-mo.)	% of Total Capacity	Weighted Avg. Price (kW-mo.)	Local Premium
Bay Area	39,539	32.1%	$6.97	$0.00
Big Creek/ Ventura	4,700	3.8%	$8.88	$1.48
Fresno	4,106	3.3%	$6.93	$0.00
Humboldt	128	0.1%	$7.15	$0.00
Kern	813	0.7%	$8.29	$0.89
LA Basin	27,774	22.5%	$7.21	$0.00
NCNB	1,781	1.4%	$8.17	$0.77
Sierra	1,766	1.4%	$8.75	$1.35
Stockton	659	0.5%	$8.13	$0.74
System	42,094	34.1%	$7.40	-

3. 2023 IOU-CPE RFO

Table 13 summarizes the LCR RCM premiums posted in March 2023 for use in the 2023 CPE RFOs. The North Coast/North Bay, Big-Creek/Ventura, and Bay Area LCAs reflected the largest premiums at $2.63, $2.01, and $1.69 kW-mo. Smaller premiums were also seen in the Kern, Fresno, Stockton, LA Basin, and Sierra LCAs. In the 2023 RFO, SCE-CPE received two offers each

[97] IE Confidential Appendix on the 2022 SCE-CPE RFO, September 19, 2022, at 11.

[98] IE Confidential Report on the PG&E-CPE RFO, September 19, 2022, at 53, 55.

[99] Energy Division, Resource Adequacy Compliance Materials, 2022 Guides and Resources: LCR RCM Prices for 2022 and 2023, March 2022.

for the 2025 and 2024-2026 compliance periods, none of which were selected.[100] PG&E-CPE received two ineligible LRC RCM offers which were not contracted.[101]

Table 13. LCR RCM Premiums Posted March 2023

Weighted Average Price for System and Local RA in SCE and PG&E Territory. Based on contracts entered between Q1-Q4 2022 for 2023 and 2024 deliveries. March 2023				
Local Area	Capacity (MW-month)	% of Total Capacity	Weighted Average Price (kW-month)	Local Premium
Bay Area	15,693	14.5%	$8.70	$1.69
Big Creek/ Ventura	6,471	6.0%	$9.02	$2.01
Fresno	1,867	1.7%	$7.71	$0.70
Humboldt	0	0.0%	-	$0.00
Kern	5,005	4.6%	$7.77	$0.77
LA Basin	22,857	21.1%	$7.34	$0.33
NCNB	335	0.3%	$9.63	$2.63
Sierra	7,199	6.7%	$7.31	$0.31
Stockton	92	0.1%	$7.60	$0.60
System	48,578	44.9%	$7.01	-

E. Transparency, Treatment of Confidential Information, and Adherence to Neutrality

SCE-CPE's IE reported that in all three RFOs, the process was sufficiently transparent, with the CPE striking an appropriate balance in providing the bidding community sufficient evaluation information without divulging market-sensitive information that could introduce potential gaming.[102] In all three RFOs, PG&E-CPE's IE found the CPE's offer forms to be generally transparent, with a few participants requesting updated offer forms due to errors or missing information;[103] additionally, the IE noted that PG&E-CPE provided supporting webinars allowing participants the opportunity to submit questions and to understand the requirements of the inaugural CPE RFO.[104]

100 IE Confidential Appendix A on the 2023 SCE-CPE RFO, September 19, 2023, at 1-2, 5, 6-7.
101 IE Confidential Report on 2023 PG&E-CPE RFO, September 19, 2023, at 49, 54.
102 SCE AL 4626-E at 48; SCE AL 4865-E at 48; SCE AL 5104-E at 44.
103 PG&E AL 6386-E at 52; PG&E AL 6706-E at 75; PG&E AL 7027-E at 76.
104 *Ibid*., at 104; *Ibid*., at 124; *Ibid*., at 115.

In all three solicitations, IEs reported that their respective IOU-CPEs followed to a structured approach, adhered to competitive neutrality rules, and protected third-party confidential, market-sensitive information from being shared with the IOUs' bundled customer bidding personnel. These requirements prevented bidders from knowing the IOU-CPEs' position – whether short or long – in each of their local areas. For example, while PG&E-LSE offered a significant amount of self-shown capacity, PG&E-LSE and other LSEs were required to submit their self-shown offers *before* other participants submitted their competitive offers. As a result, PG&E-LSE did not know the pricing offered by competitors.

Similarly, SCE-CPE developed a Code of Conduct that walled off the bundled customer bidding personnel ("Utility Offer Development Team") from those who were involved in administering the CPE solicitation ("CPE Procurement Team"). SCE-CPE function and personnel were distinct and separate from those that would be bidding bundled customer resources into the CPE solicitation.[105]

The IEs found that both IOU-CPEs' bid evaluation and selection processes across all solicitations were designed fairly for all resource types and bidders, with no differences in the evaluation methodology for different technologies or product types that could not be explained in a technology-neutral manner. The IOU-CPEs' methodologies facilitated a broad comparison of resources that could include RA-Only transactions, along with dispatchable Energy Storage (ES), GFG, and CHP.[106]

SCE-CPE's IE determined that the selection processes treated all technologies and types of bidders fairly, while recognizing justifiable offer-specific differences such as project development status.[107] For example, SCE-CPE expected a majority of offers to come from existing resources that were already interconnected and hence would not have any incremental transmission-related costs that needed to be factored into the CPE evaluation process. In instances in which a bidder might offer a new yet-to-be-developed resource, SCE-CPE required that the bidder provide a transmission cost cap that would be incorporated into an executed final agreement if the offer was selected. This cost cap represented the limit for reimbursable network upgrade costs that a counterparty might encounter in the interconnection process. If the final study's network upgrade costs are higher than the cap, SCE-CPE would have the right to terminate the contract.[108]

[105] SCE AL 4626-E at 44; SCE AL 4865-E at 45; SCE AL 5104-E at 41.
[106] *Ibid*., at 11; *Ibid*., at 12-13; *Ibid*., at 11.
[107] SCE AL 4865-E at 51.
[108] SCE AL 5104-E at 52.

F. Compliance with Least Cost Best Fit Methodology

The Commission requires the application of Least Cost Best Fit (LCBF) methodology when IOU-CPEs evaluate procurements.[109] The LCBF criteria were established in 2004 and are to be applied when assessing the: (a) future needs in local and sub-local areas; (b) local effectiveness factors as published in the CAISO's Local Capacity Requirement Technical Study; (c) resource costs; (d) operational characteristics of the resources (efficiency, heat rate, age, ramp rate, flexibility, start-up time, facility type); (e) location of the facility (with consideration for DACs); (f) cost of potential alternatives; (g) adopted GHG adders; (h) energy-use limitations; (i) procurement of preferred resources (to be prioritized over fossil generation).[110]

PG&E-CPE's IE reports that the CPE adhered to the LCBF criteria. PG&E-CPE identified specific quantitative evaluation methods to calculate the energy value of each resource, based on comparing cost and benefit components associated with each resource type. PG&E-CPE also combined quantitative and qualitative factors to assess and inform selection of the various qualified resources. Specifically, PG&E-CPE ranked order of offers using a Net Market Value (NMV) evaluation metric, based on how each type of offer would be evaluated. PG&E-CPE's IE observed that the CPE followed all relevant CPUC guidance and fairly administered the criteria when assessing offers.[111] It also noted that there were no cases in any of the PG&E-CPE 2021-2023 solicitations in which PG&E-LSE's bids of its own resources were accepted by PG&E-CPE.

SCE-CPE's IE reports that, although the CPE expected that most compensated offers would be for RA-Only products, it designed RFO evaluations to involve a combination of quantitative and qualitative assessments that also could be consistently applied to dispatchable GFG, ES, or CHP Tolling offers. SCE-CPE's analysis also focused on NMV and, if applicable, energy and ancillary services (all of which are valued based on SCE-CPE's forecast of future market prices), minus any fixed and variable offer-related costs. SCE-CPE used the same forward RA capacity prices, energy prices, ancillary services prices, and where applicable, gas prices and GHG costs, in evaluating all product types. SCE-CPE's qualitative analysis included assessments of the counterparties' qualifications and project viability, especially in instances where new resources were being proposed. SCE-CPE's IE observed that its evaluation methodologies were consistent with all CPUC guidance.[112]

G. Consideration of DACs

[109] Opinion (D.04-07-029) Adopting Criteria for the Selection (of) Least-Cost and Best-Fit Renewable Resources in R.04-04-026, July 8, 20024.
[110] OP 14 of D.20-06-002, at 19.
[111] PG&E AL 6386-E at 106; PG&E AL 6706-E at 126; PG&E AL 7027-E at 121.
[112] SCE AL 4626-E at 25; SCE AL 4865-E at 25; SCE AL 5104-E at 25.

The Commission requires the consideration of environmental justice concerns when IOU-CPEs evaluate the location of a facility and -- in cases where conventional generation was selected in a DAC -- to provide the factors that led to its selection. Bidders are to include the "CalEnviroScreen of the resource location where available, or the pollution burden of the resource location."[113] PG&E-CPE executed contracts in DAC areas for the 2023, 2024, and 2025 compliance years.[114] PG&E-CPE's IE found that the rationale for selecting these resources were reasonable, as they reduced the likelihood of backstop procurement. PG&E-CPE did not execute any contracts in DACs in its 2023 RFO as the offers' high prices did not confer quantitative benefits.[115] SCE-CPE did not execute any contracts in DAC areas.

113 OP 14-15 of D.20-06-002 at 97.

114 IE Confidential Report on 2021 PG&E-CPE RFO, October 27, 2021, at 74; IE Confidential Report on 2022 PG&E-CPE RFO, September 19, 2022, at 84.

115 IE Confidential Report on 2023 PG&E-CPE, September 19, 2023, at 76.

V. Evaluation of CPE Framework

In this section, we provide an evaluation of the Framework's effectiveness in achieving the Commission's local RA procurement objectives.[116] This assessment is made by determining whether the procurements addressed the known key challenges as previously stated: costly out-of-market RA procurement due to local procurement deficiencies; cost ineffective and inefficient uncoordinated procurement; and the opportunity for and investment in new local preferred resources. The outcomes are organized under the following categories:

- Participation, offers received, and use of the LCR RCM
- Market power mitigation
- Contract terms and duration
- Length of solicitation process and timeframe

We also describe the factors that may have affected procurement outcomes. The inventory is not intended to be exhaustive and is provided as potential inputs for future consideration.

A. Participation, Offers Received, and Use of the LCR RCM

Participation in the 2021-2023 CPE RFOs differed between the SCE-CPE and the PG&E-CPE, which can be attributed to the differences in LCRs between the SCE and PG&E TAC areas, the number of LSEs in the PGE and SCE TAC areas, and the different approaches employed by each CPE to meet its LCR obligations. Specifically, PGE's TAC area has a more complicated LCR area as it includes seven aggregated LCAs compared to SCE's two. The PG&E TAC area also contains a significantly more CCAs serving load versus SCE's TAC area. Finally, the pro forma contract provisions employed by each CPE – particularly in the 2021 RFO -- also played a role.

In all three of the SCE-CPE RFOs, the LCR positions were largely met with non-compensated self-shown resources, shown by SCE-LSE. It should be noted that SCE-LSE still has a large load share in its TAC area relative to PG&E-LSE's share in its TAC area (covering the relevant compliance period). While the PGE-CPE received a sizeable amount of non-compensated self-show offers, these amounts were not enough to fill the LCRs. The SCE-CPE RFOs did result in the procurement of one large gas-fired resource falling off a long-term CAM contract, while the PG&E-CPE RFOs resulted in a larger magnitude of capacity offered by many resources in several local areas.

The PG&E-CPE RFO self-shown and compensated bids remained insufficient in filling the LCR position in all three of RFOs. In the first RFO, this outcome may have been driven by the more

[116] FOF 6 of D.20-06-002, at 84.

stringent pro-forma contracts for both self-shown and compensated offers. As a result of modifications to these provisions, subsequent RFOs in 2022 and 2023 presented less barriers to participants. The lack of self-shown participation in PG&E-CPEs RFO may have also been the result of LSEs holding local capacity contracts with resources outside their load TAC areas, because there are no incentives to self-show for no-compensation since the LSEs customers would not receive a lower CPE procurement cost allocation.

The parameters of CPE solicitations raise additional challenges in procuring new resources, especially when sellers have other procurement opportunities to bring their resources online. Because of the limitations previously stated, participants may gain better incentives by submitting offers into the various IRP MTR solicitations, which are focused on procuring longer-term preferred resources for system needs, while filling local requirements as a secondary outcome. Additionally, solicitations concurrently being conducted by CCAs for projects with near-term delivery potentially require less oversight (i.e., no IE), allow more flexible solicitation timelines, while offering attractive contractual obligations. This, coupled with the view that RA solicitations for capacity have historically procured from existing resources, may have led developers to overlook the CPE as a mechanism for offering new projects.

Another key consideration in RFO participation is the tightening of the system RA market. In the last several years, the CAISO balancing area has seen a narrowing in the supply of system resources as local area generators may have opted to sign both short-term and/or long-term RA contracts with LSEs to meet their system RA requirements. Therefore, generators may not be participating in CPE RFOs because they are already subscribed, and LSEs may not be attempting to sell these resources to the CPEs because they need them to meet anticipated system requirements. (Additionally, LSEs may be reticent in letting go of resources given uncertainty about how Slice-of-Day will impact their portfolio and because doing so may limit their ability to resell later. Alternatively, selling the resources now also may not be beneficial if they are located outside the TAC area in which the LSE is serving load.)

The hybrid CPE Framework is designed to encourage new resource development through compensated bid and self-show offers, either by offering an LSE a local premium price to additional clean resources being developed in locally constrained areas or awarding a new resource bid compensation for its offer. Based on a comparison of results, it appears that the mechanism may not be effectively encouraging investment in new clean resources, as no new resources have been procured and very little LCR RCM contracts have resulted from the CPE RFOs. From 2021 to 2023, LSEs have been focused on building new resources to meet their MTR obligations under IRP procurement directives. The lack of participation in the LCR RCM mechanism may indicate that either LSEs are not constructing clean resources in local areas where there are underlying needs, or that the CPE Framework is failing to recognize the associated value of selecting these resources for payment of a local premium. Additionally, because LCR RCM premiums fluctuate significantly each year, it may not provide the right incentives to show and/or build in certain areas. Parties also note that there are no incentives for LSEs to contract with local gas units if they are not able to realize a local premium.

It is important for all LSEs under contract with existing or new local resources to participate, as lack of participation will lead to inefficiencies in local reliability planning. LSEs serving load in SCE and PG&E TACs no longer have zonal and local requirements, so they may fulfill their system RA needs with resources that serve load outside their TAC areas. This removes the incentive for LSEs to show their resources to a CPE, as it does not reduce local costs for their own customers. Furthermore, the new resources being procured for MTR are not required to be zonal or location-specific, which leads to new resources being developed regardless of LCR needs.

Table 14 provides a breakdown of September 2024 NQC by fuel source across each aggregated local area and Zone. While most new resources (in yellow) are being developed in non-LCA areas in the South of Path 26 zone, there are also thousands of MW being added in LCAs. While not all these new resources are eligible under the LCR RCM criteria, many could likely be eligible. However, even with eligibility, these resources may not be selected by the LSEs if LCAs are already oversubscribed with non-compensated self-shown resources.

Table 14. September 2024 NQC List Breakdown by LCA and Zone Across Fuel Types[117]

Fuel	North (MW)									South (MW)						Total
	Bay Area	Fresno	Humboldt	Kern	NCNB	Sierra	Stockton	***Total Local NP-26***	***CAISO System NP-26***	Total NP-26	Big Creek-Ventura	LA Basin	San Diego-IV	***Total Local SP-26***	***CAISO System SP-26***	Total SP-26	
SUN	4	172		24	0	0	5	***33***	***272***	477	154	5	152	***311***	***1,089***	1,400	**1,877**
WIND	252	4						***252***	***85***	342		67	79	***146***	***385***	531	**872**
BIOGAS	20	0		4	6	9		***39***	***30***	69	24	70	9	***103***		103	**172**
BIOMASS	1	15	14	40		44	21	***120***	***185***	320	0			***0***		0	**320**
GEOTHERMAL					958			***958***	***0***	958				***0***	***292***	292	**1,250**
WATER	127	1,751	0		8	1,190	155	***1,479***	***2,020***	5,250	1,216	193	40	***1,449***	***89***	1,538	**6,788**
URANIUM								***0***	***2,280***	2,280				***0***			**2,280**
HYBD		220						***0***	***6***	226	7	12		***19***	***398***	417	**643**
LESR	1,133	157				5	132	***1,270***	***712***	2,139	511	737	697	***1,946***	***3,614***	5,559	**7,698**
NATURAL GAS	6,478	724	163	333		553	360	***7,887***	***3,825***	12,436	3,200	7,836	3,585	***14,621***	***1,766***	16,387	**28,823**
DISTILLATE	110							***110***		110				***0***			**110**
WASTE TO POWER							19	***19***	***24***	44		35		***35***		35	**79**
OTHER	0	0	0	0	0	0	0	***0***	***4***	4	2	15	4	***21***	***18***	39	**44**
Total	8,125	3,042	177	400	972	1,802	691	***12,167***	***9,444***	24,654	5,115	8,971	4,565	***18,651***	***7,651***	26,302	**50,955**

[117] Fuel types are from the CPUC Master Resource Database: April 21, 2024, and magnitude of resources are from the CPUC 2024 NQC List for CPUC Compliance: May 16, 2024.

B. Market Power Mitigation

The need to increase capacity to meet system RA requirements has been exacerbated by the delayed effects of supply chain constraints, the risks and challenges facing new project developments, and the multitudes of LSEs competing for limited resources. These factors drive prices higher for both new and existing resources. While there was no definitive demonstration of market power observed in the CPE RFOs, the current scarcity conditions point to significant potential for its exertion.

The Energy Division observes that in LCAs with limited resources to meet LCR needs, there has been limited participation by generators that control a substantial proportion of the available capacity. In one SCE-CPE RFO, the Energy Division was not able to gain any insights into the reason why a large facility did not bid its capacity, as off-taker information is difficult to track and is frequently confidential. To better understand lack of participation in its RFOs, PG&E-CPE reports that it similarly conducts additional outreach to non-participants.

Under more competitive conditions, existing generators may be more willing to sign longer-term contracts with the CPEs. However, it appears that the tight system supply conditions are resulting in generators not choosing this procurement path for their resources. In limited cases where existing resources are participating, the bid prices have been found to be unreasonably high leading to the CPEs deferring to backstop procurement. It also should be noted that existing resources have largely been paid long-term contract prices associated with their needs to recover the fixed costs associated with developing these resources. Given the outcomes of the 2021-2023 procurements, close monitoring is warranted to determine whether the Commission should more precisely measure the degree to which contract prices exceed their going–forward marginal capacity costs.

PG&E-CPE's IE observes that the potential for market power exertion is particularly compelling where Calpine owns 3,330 MW in generation, representing 46 percent of all Bay Area local capacity, and 491 MW in North Coast/North Bay, representing 71 percent of that local area's total capacity.[118] In the 2022 and 2023 CPE ACRs, PG&E-CPE's IE stated that while it did not witness pricing concerns, it conducted an analysis to determine the potential for market power exertion. The IE compiled 2022 NQC data by generator and capacity for each LCA and compared this data relative to the capacity bid in the LCA and the ownership of that capacity according to LCA. After conducting this exercise, the IE arrived at the same conclusion as in the earlier RFO –

[118] PG&E AL 6386-E at 96.

given the concentration of resources controlled by one generator/owner, there is potential for market power exertion.[119]

We provide in Table 15 the breakdown of September 2024 NQC across LCAs. The ratios presented on the bottom row reflect the amount 2024 LCRs for each LCA, divided by the total installed capacity in each LCA. Ratios closer to 1 reflect higher concentrations of the potential for market power exertion, whereas lower ratios reflect abundant local capacity resources in the LCA to meet requirements. In LCAs with a ratio exceeding 1 there is insufficient installed capacity to meet LCRs, signaling the need for new resource development in these areas.

Table 15. September 2024 NQC Across LCAs Compared to LCRs[120]

	North										**South**						**Total**
	Bay Area	Fresno	Humboldt	Kern	NCNB	Sierra	Stockton	***Total Local NP-26***	***CAISO System NP-26***	Total NP-26	Big Creek-Ventura	LA Basin	San Diego-IV	***Total Local SP-26***	***CAISO System SP-26***	Total SP-26	
Total Sept NQC	8,125	3,042	177	400	972	1,802	691	***12,167***	***9,444***	24,654	5,115	8,971	4,565	***18,651***	***7,651***	26,302	**50,955**
Total LCR 2024	7,329	2,028	133	427	983	1,212	750	***12,862***		12,862	1,971	4,413	2,834	***9,218***		***9,218***	**22,080**
Ratio LCR to Total (%)	0.90	0.67	0.75	***1.07***	***1.01***	0.67	***1.08***	***1.06***		0.52	0.39	0.49	0.62	***0.49***		0.35	***0.43***

C. Contract Terms and Duration

Contract terms have affected CPE RFO procurement results. Although the terms have evolved to encourage more participation from resources and LSEs, they still present a hurdle for executing both existing and new resource contracts. Some changes were made to address concerns raised by LSEs after the 2021 CPE RFO -- such as modifying non-compensated self-show offers from contract requirements to an attestation – which aimed to remove disincentives for LSEs.[121] Further changes were made to provide LSEs with more flexibility for self-shown resources that they may want to sell later, so long as the purchasing LSE takes on the selling LSE's obligation to self-show.[122] These changes have yet to be evaluated, as the 2024 CPE RFOs will be the first to implement them.

Regarding compensated bids, in 2021 Calpine noted that operations of its Geysers geothermal facility, which accounts for most of the capacity in the North Coast/North Bay local area, requires significant going forward fixed costs. Calpine's concerns about the bundling of resource

[119] PG&E AL 6706-E at 115; PG&E AL 7027-E at 110.

[120] CAISO, 2024 Local Capacity Technical Study Final Report and Study Results, April 28, 2023 at 4 as adopted by OP 1 of D.23-06-029 at 38.

[121] OP 5 of D.22-03-034 at 74.

[122] OPs 14-15 of D.23-06-029 at 140-141.

attributes show that the contract terms may not be adequate in accommodating specific resource procurement. [123]

Participation was also dampened by the option for sellers to instead participate in the MTR RFOs, which offered greater certainty through longer-term contracts. For example, although brownfield, greenfield, and repowering projects were eligible in all SCE-CPE solicitations, the short term need targeted – no longer than four years in duration – made contracts for such new capacity development challenging.[124]

Energy Division also observes that new resources likely need more than a five-year contract term to be viable procurement options. The current CPE Framework requires a formal Application process for contracts that exceed the five-year period, whereas Tier 3 Advice Letters were allowed for MTR procurement contracts signed by IOUs (and various approval processes for MTR procurement contracts signed by CCAs or ESPs). This regulatory hurdle may present a significant barrier in procuring new resources. Furthermore, the development timelines would hardly allow new resources to be procured and come online in time to meet the near term three-year forward compliance periods.

Energy Division also observes that in the near future, for the CPEs to effectively use their purchasing power to secure contracts with existing natural gas generators, the durations of the contracting terms may need to include longer pre-approved durations and start dates beyond the three-year time horizon. These changes may help provide CPEs with the flexibility to enter into longer-term contracts that are needed for local reliability during the energy transition. Amending these terms would help achieve the goal of securing these resources at more reasonable prices.

D. Length of Solicitation Process and Timeframe

The current CPE RFO timeframe provides IOU-CPEs around six months to issue the RFO, negotiate contract terms, and award contracts. The CPE timeline, which was adopted in 2020[125] and later modified in 2022, [126] revolves around the annual RA requirement showing timeline. This requires LSEs and CPEs to make YA showings on or around October 31st for the upcoming compliance year. The timeline takes into consideration the Energy Division's need to allocate the CPE system and flexible credits to LSEs for use in their annual RA showings. However, this

[123] Energy Division Workshop in R.21-10-002: Proposals to Modify the Central Procurement Entity Structure, December 14, 2021, at 26.

[124] SCE AL 4626-E, SCE-CPE 2021 ACR, November 1, 2021, at 13; SCE AL 4865-E, 2022 SCE-CPE ACR, September 19, 2022, at 15; SCE AL 5104-E, 2023 CPE RFO, September 19, 2023, at 13.

[125] OP 28 of D.20-06-002 at 102.

[126] OP 13 of D.22-03-034 at 77.

tight timeline may not allow for more complex contract negotiations for new and existing resources. [127] While bilateral negotiations are allowed as per the changes made to the CPE Framework in 2020, this allowance has not yet led to the procurement of any new or existing LCR resources. In addition to an extended timeline, the solicitation process could benefit from clarification on the earliest period that an LSE can self-show their resources. Reporting the IOU-CPE RFO results could also be better timed so that LSEs know their positions and can conduct additional procurements if necessary.

[127] *Ibid.*, at 74.

VI. Issues for Consideration

The Energy Division staff offers several observations and poses questions for the Commission to consider its next steps for the CPE Framework. At a high level, the Commission has several options to consider:

A. Retain the CPE Framework with modifications to address known issues, including timing, transparency, procurement levels, and coordination with the IRP proceeding's orders for new resources.
B. Repurpose the CPE Framework to focus on areas of concern. For example, the CPE could be directed to focus on the retention of large gas-fired resources located in local areas that likely need long-term contracts until retirement and/or focus on the procurement of new resources to meet local needs that are necessary to address retirements of existing resources.
C. Dismantle the CPE Framework, considering that many of these resources are being procured by LSEs to meet system RA requirements. If dismantled, the Commission could revert to the former local RA program or remove local RA obligations entirely.

We consider each of these options in turn and pose questions for the Commission and stakeholders to consider.

A. Retain the CPE Framework with Modifications

Should the Commission keep the current CPE Framework? If so, what changes should be made? For example, should the Commission consider different percentages of procurement? Should the IOU-CPEs be required to target procurement in specific local areas? Should the timelines for the RFO processes and the "showing" processes be adjusted? Should the five-year contract term limit be removed? Should contract start date terms be modified to eliminate near-term competition with LSEs for system RA and MTR procurement? Should additional coordination with IRP procurement be required? If the Commission allows for contracts greater than five years for the CPE to be submitted via Advice Letter, should they also allow for non-CPE contracts of greater than five years for IOU-LSE procurements to avoid creating an unlevel playing field for contract approval between the IOU-CPEs and the IOU-LSEs?

B. Repurpose the CPE Framework to Procure and Plan for Gas Retirements

Should the Commission repurpose the CPE Framework to focus on procuring gas plants and new, clean resources in local areas to address the retirement of resources in the future? If so, should the Commission allow the IOU-CPEs to execute longer-term contracts for both existing gas and new, clean resources? Additionally, are there other targeted procurement efforts in local areas that could be undertaken by the IOU-CPE?

C. Dismantle the CPE Framework

Should the Commission consider dismantling the CPE Framework, given that these requirements are a subset of system resources and the local RA resources are being procured to meet system needs in any case? If the Commission pursues this path for these reasons, should the Commission consider eliminating the local requirement altogether, since these resources have been procured to meet system needs? Alternatively, should the Commission consider moving the local requirement back to LSEs? If the CPE Framework is dismantled, should the Commission revert to the former one-year local RA program with per-LSE requirements, establish three-year forward Local RA obligations with per LSE requirements, and/or remove local RA obligations entirely and rely solely on backstop procurement? In addition to the above three options, the Commission's IRP Proceeding has scoped its intention to issue a proposal in the Reliable Clean Power Procurement Program (RCPPP) to establish a programmatic approach to long-term procurement obligations for all LSEs. Any CPE Framework modifications will need to closely align with the IRP's approach.

VII. Proceeding Timeline and Next Steps

The CPUC's December 18, 2023, Scoping Memo in R.23-10-011 categorized the RA proceeding into three tracks. Track 1 focuses on the most time-sensitive issues in the RA proceeding, including refinements to the CPE Framework that can be implemented for the 2025 compliance year. Track 2 examines issues that require more time for party and Commission consideration and includes structural modifications and/or refinements to the CPE Framework, a revised loss of load expectation (LOLE) study and the applicable planning reserve margin (PRM) that the Commission will implement for the 2026 and 2027 RA compliance years, and coordination with the IRP proceeding's work on the Reliable and Clean Power Procurement Program (RCPPP).

The Revised Track 2 Schedule, as shown below, is expected to conclude by December 2024. However, if any of the scoped issues cannot be addressed in a December 2024 final decision, those remaining issues may be incorporated into a later track of the RA proceeding.

Table 16. RA Rulemaking (R.) 23-10-011 Track 2 Schedule

Revised Track 2 Schedule	
Energy Division Report on CPE Framework published	May 31, 2024
Proposals on Track 2 issues filed	June 24, 2024
Energy Division's RA LOLE Study published	July 19, 2024
Workshop on Track 2 proposals and LOLE Study	July 25-26, 2024
Opening comments on all proposals and LOLE Study filed	August 9, 2024
Reply comments on all proposals and LOLE Study filed	August 23, 2024
Proposed Decision on Track 2	November 2024
Final Decision on Track 2	December 2024

Energy Division staff appreciates the continued participation from stakeholders through the CPE review process and looks forward to continuing its work with stakeholders.