California Public Utilities Comm

January 20, 2023

APPENDIX A

Energy Division Proposals

for Proceeding R.21-10-002

Table of Contents

Proposal 1: Planning Reserve Margin (PRM) and Effective PRM

Summary and Background

The Commission has considered the need for additional planning reserves several times over the past few years.[1] In the Summer Reliability Proceeding, R.20-11-003, the Commission determined that additional resources were needed for reliability during extreme events, but given tightness of the market, an effective planning reserve margin (effective PRM) was adopted. The Summer Reliability decisions directed the investor-owned utilities (IOUs) to procure additional contingency resources on top of the 15 percent LSE planning reserve margin, to provide additional reliability during extreme events. D.21-12-015 set a procurement target of 2,000-3,000 MW for the summers of 2022-2023 which was designed to provide for the procurement of contingency resources to meet an effective PRM of 20-22.5%.[2]

The PRM was originally adopted in D.04-01-050 and had remained constant at 15% through 2022. In the recent resource adequacy (RA) Decision, D.22-06-050, the Commission considered whether the 15 percent PRM should be increased, given significant changes to the generator fleet and acceleration of climate impacts over the past decade. The Commission determined that there was an urgent need to increase the PRM, but that additional loss of load expectation (LOLE) modeling was needed to inform the decision. In balancing those considerations, the Commission adopted a marginally increased PRM of 16% for 2023 and a minimum PRM of 17% for 2024 stating that any additional increase for 2024 would be considered once new LOLE results were available.[3]

D.22-06-050 did not modify the effective PRM adopted in D.21-12-015, the 2,000-3,000 MW procurement target for contingency resources to meet the effective PRM for summer 2023, despite the changes made to the PRM for LSEs.

While the PRM was being considered in 2021 and 2022, the California Energy Commission load forecast increased substantially. As shown in the table below, the 2021 IEPR demand forecast, used to set 2023 RA requirements, increased by about 1,100

[1] Note that he discussion here is focused on the resource adequacy program and the Summer Reliability Proceeding, R.20-11-003, not other PRMs, including those used in the Integrated Resource Planning Proceeding, R.20-05-003 "Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026)" June 24, 2021 at 86.
[2] "Phase 2 Decision Directing PG&E, SCE and SDG&E To Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023," December 2, 2021 at 12-15.
[3] "Decision Adopting Local Capacity Obligations for 2023-2025, Flexible Capacity Obligations for 2023, and Reform Track Framework," June 23, 2022 at 22-23.

MW for August and 900 MW for September from the prior 2020 IEPR for 2023. Table 1 also highlights the estimated increase in load for 2024 when comparing the 2021 IEPR with the Draft 2022 IEPR. The CPUC-jurisdictional LSEs are responsible for approximately 90% of the load shown in Table 1.

Table 1. IEPR Load Forecasts For August and September 2023, 2024

Load Forecast	August 2023	September 2023	August 2024	September 2024
2019 IEPR	44,616	45,447	44,750	45,610
2020 IEPR	44,891	45,826	45,300	46,451
2021 IEPR	46,060	46,727	46,500	47,325
2022 IEPR (draft)	46,074	46,829	46,569	47,445

The increased load forecast coupled with the increased PRM levels has resulted in higher RA requirements for 2023 and expected or estimated RA requirements for 2024. As shown in Tables 2-4, there was a large change in the CPUC year ahead (YA) Load Forecast that applied to 2023, and that led to July-September RA requirements in 2023 that were 4-5% higher than the RA requirements for 2021. If adopted, the monthly summer RA requirements in 2024 will be as much as 8% higher than the 2021 RA requirements when accounting for another slight increase in the load forecast and a 17% PRM.

Table 2. July Load and PRMs

Year	CPUC YA July Load Forecast (change from 2021)	RA Requirement in MW (Applicable PRM%)	RA Requirement change relative to 2021 in MW (% above 2021 RA Requirement)
2021	39,595 (+0)	45,534 (15%)	0
2022	39,585 (-10)	45,522 (15%)	-12 (0%)
2023	40,855 (+1,260)	47,391 (16%)	1,857 (4%)
2024 (estimate)	41,344 (1,749)	48,373 (17%)	2,838 (6%)

Table 3. August Load and PRMs

Year	CPUC YA Aug Load Forecast (+increase from 2021)	RA Requirement in MW (Applicable PRM%)	RA Requirement change relative to 2021 in MW (% above 2021 RA Requirement)
2021	39,739 (+0)	45,700 (15%)	0
2022	39,864 (+125)	45,844 (15%)	144 (0%)
2023	41,443 (+1,704)	48,734 (16%)	2,374 (5%)
2024 (estimate)	41,912 (2,173)	49,039 (17%)	3,337 (7%)

Table 4. September Load and PRMs

Year	CPUC YA Sept Load Forecast (+increase from 2021)	RA Requirement in MW (Applicable PRM%)	RA Requirement change relative to 2021 in MW (% above 2021 RA Requirement)
2021	40,363 (+0)	46,417 (15%)	0
2022	40,585 (+222)	46,673 (15%)	256 (1%)
2023	42,192 (+1,829)	48,943 (16%)	2,526 (5%)
2024 (estimate)	42,700 (2,961)	49,960 (17%)	4,260 (8%)

Energy Division (ED) staff have performed the additional LOLE modeling directed in D.22-06-050. Results are presented in the Energy Division proposal entitled "Loss of Load Expectation and Slice of Day Tool Analysis for 2024." As described in the proposal, results of this study recommend a PRM of 18-20% based on the modeled generation fleet and CEC load profiles.[4] The modeled 2024 resource fleet assumes 5,823 MW of nameplate capacity of resources that were in development as of November 2022.[5]

Proposal

Given the large number of resources currently in development that were modeled for 2024 and the significant delays developers have experienced over the past few years, ED staff question whether this assumption will fully materialize, and the resources will be available to meet estimated RA requirements. For this reason, ED staff propose an extension of the effective PRM beyond 2023 in lieu of adopting the PRM proposed in the LOLE study.

Table 5 shows a range of PRM options between 16% and 20% using the estimated 2024 September YA load forecast.

Table 5. PRM Options for 2024 PRM shown with 2024 Estimate YA September Load Forecast

Year	CPUC YA Sept Load Forecast (+increase from 2021)	RA Requirement in MW (Applicable PRM%)	RA Requirement change relative to 2021 in MW (% above 2021 RA Requirement)
2024 (estimate)	42,700	49,534 (16% PRM)	3,116 (7% above 2021)
2024 (estimate)	42,700	49,960 (17% PRM)	3,543 (8% above 2021)
2024 (estimate)	42,700	50,387 (18% PRM)	3,970 (9% above 2021)

[4] "Energy Division Study for Proceeding R.21-10-002: Loss of Load Expectation and Effective Load Carrying Capability Study Results for 2024," February 18, 2022 at 27.

[5] *Id*. at 8.

2024 (estimate)	42,700	50,814 (19% PRM)	4,397 (9% above 2021)
2024 (estimate)	42,700	51,241 (20% PRM)	4,824 (10% above 2021)

ED staff have identified four options for the 2024 PRM:

1. Status quo (17%) - Maintain the already adopted 17% PRM and do not raise it further
2. Retain at 2023 level (16%) - Reduce the PRM to 16% for 2024 RA year
3. Increase to modeled level (19-20%) proposed in LOLE study- Adopt a PRM for 2024 of 18-20%
4. An intermediate level between 16% and 20%

ED staff have also identified that any of the four options above can be simultaneously considered with an extension of the effective PRM through 2025. The effective PRM allows for IOUs to attempt to buy additional MWs beyond their RA obligations and charge for those above-RA costs to all customers as contingency resources. The effective PRM process has required IOUs to first offer excess MWs to the market prior to holding onto them for the effective PRM. In 2021 and 2022, the IOUs were able to secure some effective PRM resources that supported reliability using the effective PRM mechanism.

The effective PRM also allows both RA and non-RA eligible resources to count towards the effective PRM, so long as the resource supports reliability. One of the non-RA resources that has been counted in the effective PRM bucket has been the Emergency Load Reliability Program (ELRP). Since the ELRP Program is authorized through 2025, the decision to extend the effective PRM beyond 2026 is not determinative of whether ELRP continues as a contingency resource.

ED staff recommend Option 1, maintain the previously adopted decision to have a PRM of 17% as adopted in D.22-06-050 for 2024-2025. While it appears that some LSEs may have trouble meeting 2023 RA requirements at just a 16% PRM, we expect that sufficient resources will be available in 2024 to make the currently adopted PRM feasible. All LSEs are subject to new resource procurement obligations via the Integrated Resource Planning proceeding, and those obligations are expected to bring online over 8,800 MW NQC of new resources between 2023 and 2024.

ED staff propose to retain the 17% PRM while also extending the effective PRM through 2025 given the uncertainty about the amount of additional capacity that will be online by 2024. The effective PRM could be set at a level equal to the difference between the modeled and adopted PRMs. For example, if a 17% PRM is retained and the modeled PRM is 20%, then the effective PRM would be a range of MWs roughly equivalent to 3% of the CPUC share of September load, or approximately 1,300 MW. It would continue to apply only for the peak summer months of June through October with IOUs able to use excess resources from their existing portfolios to meet minimum target levels in June and October.

If the effective PRM is extended through 2025, ED staff propose that all resources that are now eligible to be in the contingency resource bucket can remain contingency resources. Resources eligible to count towards the effective PRM would remain unchanged from D.21-12-015. A resource can continue to contribute towards the effective PRM target unless an IOU opts to convert a resource towards meeting midterm reliability or other bundled customer procurement needs as is currently allowed.

Further, ED staff propose that the procurement targets be divided between the three IOUs similarly to the targets adopted in D.21-12-015 (900-1350 MW for SCE and PG&E and 200-300 MW for SDG&E).[6] Given that it is possible that the effective PRM procurement will first cover any LSE RA requirement deficiencies, before adding to above PRM procurement, ED staff solicits comments on whether it would be appropriate for the CPUC to assign the costs to those deficient LSEs before allocating those costs to all customers through the Cost Allocation Mechanism.

[6] "Phase 2 Decision Directing PG&E, SCE, and SDG&E to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023," December 2, 2021 at 18.

Proposal 2: Demand Response Related Proposals

A: Proxy Demand Resource-Specific Bid Cap

Summary and Background

The Commission should consider establishing a bid cap for RA-eligible Proxy Demand Resources (PDRs) bidding into the California Independent System Operator (CAISO) wholesale energy market that is below the price trigger for Reliability Demand Response Resources (RDRRs).

PDRs are demand response (DR) resources that participate economically in the CAISO energy market. PDRs qualifying as RA and receiving RA capacity payments have a must-offer obligation to bid into the CAISO market. PDRs include resources in IOU DR programs such as the Capacity Bidding Program (CBP) and some air conditioning (A/C) cycling programs, as well as third-party DR resources enrolled in the Demand Response Auction Mechanism (DRAM) pilot or contracted for RA with non-IOU load serving entities such as community choice aggregators.

Like other market-integrated resources, PDRs are allowed to bid up to $1,000 per MWh (the "soft energy bid cap") under most circumstances. (The hard energy bid cap of $2,000 per MWh only goes into effect if the CAISO accepts a bid whose price exceeds the soft energy bid cap.) In contrast, some IOU-managed DR resources such as the Base Interruptible Program (BIP) and SCE's Agriculture and Pumping Interruptible Program (AP-I) participate in CAISO market as RDRRs. While RDRRs are allowed to bid economically into the CAISO market, some RDRRs, including BIP and AP-I, only become available to the market when Energy Emergency Alert (EEA) 2 is in effect and CAISO chooses to activate RDRRs in order to avoid a supply shortage per Operating Procedure 4420. CAISO activates RDRR by inserting bids at 95% of applicable bid cap or by dispatching the resources through its exceptional dispatch procedures.

Challenges

Energy Division staff has identified two issues with the bidding practices associated with many PDRs.

First, multiple studies have found that many PDRs bid strategically to reduce their likelihood of being selected in the market, even on days when grid emergencies are anticipated based on the demand forecast. The CAISO Department of Market Monitoring (DMM) found that more than half of the third-party PDR capacity was bid at or near the cap in the day-ahead market (DAM) on high-load days during the August and September 2020 heatwave.[7] Furthermore, most of the capacity bid at or near the cap was not scheduled, even though prices were very high. Similarly, in the Demand Response Auction Mechanism Evaluation, Resource Innovations (formerly known as Nexant) in collaboration with Gridwell Consulting found that there was considerable variability between DR providers (DRPs) in terms of bidding behavior, and that DRPs who bid at lower prices tended to have higher scheduling rates.[8]

Secondly, wholesale energy prices in the CAISO market, especially in the DAM, are not always reliable indicators of a grid emergency. In both the 2020 and 2022 heatwaves, CAISO declared an EEA for hours that cleared at less than $1,000 in the DAM and/or the Real-Time Market (RTM). However, CAISO inserts bids for RDRRs at $950 and will accept them if there are insufficient resources at a lower price. As a result, there may be times when RDRRs are dispatched, while "economic" PDRs that bid at the market cap would not have been dispatched by CAISO, especially long-start PDRs that can only bid into the DAM. This effectively creates an irrational dispatch order where emergency DR gets triggered while other "economic" DR resources receiving ratepayer-funded RA compensation become stranded assets during a grid emergency.

Proposal

To address the above challenges, the Commission should consider establishing an energy bid cap specific to RA-eligible PDRs that is below the trigger price set for RDRRs. To assess compliance, ED staff would review the applicable tariffs or load serving entity (LSE) contracts to determine that they include a bid cap provision. If tariffs/contracts require resources to bid below the PDR bid cap, LSEs will be considered provisionally compliant in meeting their RA requirements. Once the data becomes available "ex post," ED staff would review the bid data set to assess whether any PDRs were in violation of the cap. If ED staff identify a PDR in violation of the cap, the resource would be treated as if it were not made available to the CAISO on a Supply Plan. As with other RA resources, a deficiency notice would be issued, depending on if the LSE has enough capacity to meet its RA requirement without the violating PDR(s).

The value of the PDR-specific bid price cap should be no greater than $949 per MWh so that PDR bid prices are less than the RDRR bid insertion price. As a starting place, ED

[7] Figure 2.5, "CAISO Demand Response Issues and Performance," CAISO Department of Market Monitoring, February 25, 2021, at 16.

[8] Attachment 1,"Assigned Commissioner's Scoping Memo and Ruling," filed in A.22-05-002, July 5, 2022, at 98.

staff suggests a PDR-specific bid cap of $500 per MWh for both the day ahead and real time markets. Prices[9] rarely exceeded $500 per MWh (<1% of intervals) from July 2021 to August 2022, but the DAM price exceeded $500 per MWh in about 3% of intervals in September 2022,[10] which is on par with the minimum monthly availability requirement currently in place for RA-eligible DR of 24 hours per month.

B: Expanding the Prohibited Resources Policy

Summary and Background

The Commission should consider expanding its DR Prohibited Resource (PR) policy to all RA-eligible DR resources, including those procured by non-IOU LSEs.

As far back as 2003, the Commission has expressed support for a definition of demand response that does not include fossil-fueled emergency backup generation.[11]

In D.11-10-003, the Commission adopted a policy statement that any DR program, whether operated by an IOU or non-IOU, that uses fossil-fueled emergency back-up generation should not count towards RA obligations; however, the Commission did not make any changes to the RA rules that would implement the policy statement.[12]

In D.16-09-056, the Commission adopted the PR policy, which prohibited the use of distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas (collectively referred to as "prohibited resources") to achieve incremental load reduction in supply-side demand response programs managed by the IOUs. This decision also directed the IOUs to require attestations for new non-residential customers and design an audit verification plan.[13] The IOUs jointly filed their verification plan via Tier 3 Advice Letters in 2017, and the Commission adopted Resolution E-4906 in 2018, which approved, with modifications, Applicants' Demand

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[9] DMM reported DAM and RTM prices for the three largest Default Load Aggregation Points (DLAPs) corresponding to PG&E, SCE, and SDG&E's service territories. ED staff acknowledges that SLAP prices may exhibit more variability.

[10] "Q3 2022 Report on Market Issues and Performance," CAISO Department of Market Monitoring, December 14, 2022 at 9.

[11] Attachment 2, "Interim Opinion in Phase 1 Addressing Demand Response Goals and Adopting Tariffs and Programs for Large Customers," June 5, 2003 at 2.

[12] D.11-10-003 COL 5: "[I]t is reasonable to adopt as a policy statement that fossil-fuel emergency back-up generation resources should not be allowed as part of a demand response program for RA purposes, subject to rules adopted in future RA proceedings." The current version of the Prohibited Resources Policy, adopted five years after this decision, is more nuanced than just "fossil-fuel emergency back-up generation resources."

[13] "Decision Adopting Guidance for Future Demand Response Portfolios and Modifying Decision 14-12-024," OP 3-5 at 94-95.

Response Prohibited Resources Policy Verification Plan (Verification Plan) and Applicants' proposal to conduct a test pilot of interval meter and data logger installations. The Verification Plan was subsequently modified by D.22-12-004, which added device-based (data logger) monitoring of randomly selected PRs during each annual audit period, starting in 2024.

Challenges

In recent years, demand response resources have been used by non-IOU LSEs to meet the RA obligations, in line with the loading order. Because the existing PR policy in D.16-09-056 was adopted for IOU-procured DR, there is a risk that some customers with PRs could circumvent the current PR policy (and thus defeat the Commission's goal for RA-eligible DR to be clean) by participating in DR procured by non-IOU LSEs. This would also create a competitive disadvantage for customers participating in IOU-managed DR programs.

Proposal

The Commission should consider requiring all RA-eligible DR resources to abide by the Prohibited Resources Policy as defined in D.16-09-056 and subsequent decisions and resolutions.[14] The Commission should extend the Prohibited Resources Verification Plan[15] to all RA-eligible DR resources. The recovery of any increased costs of the Verification Plan could continue to be the same as existing authorized mechanism or sought by the IOUs through some other mechanism and cost allocation scheme via the five-year DR programs and budget applications.

C: Dispatch Requirements for Emergency Demand Response Resources Qualifying for Resource Adequacy

Summary and Background

In 2010, the Commission adopted a Settlement Agreement which transitioned reliability-based and emergency-triggered demand response into price-responsive products.[16] The Commission enacted this change to make these programs "more useful," and to make them available for dispatch prior to the CAISO's procuring

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[14] Subsequent decisions and resolutions include D.18-06-012, Resolution E-4906, Resolution E-4838, D.21-03-056, D.21-12-015, D.22-12-004, and future decisions in the open proceeding A.22-05-002 *et al.*

[15] The Prohibited Resources Verification Plan is described in Resolution E-4906 and was subsequently modified by D.22-12-004, which monitors and enforces the prohibition for non-residential customers participating in the RA-eligible DR programs overseen directly by the Commission.

[16] "Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs," June 24, 2010, at 1.

emergency or exceptional dispatch capacity. In adopting the Agreement, the Commission stated, "This new practice would eliminate the anomalous treatment whereby emergency-triggered demand response counts for Resource Adequacy yet, unlike all their power that counts for Resource Adequacy, the CAISO currently procures costly 'exceptional dispatch energy or capacity' before using this energy resource, a practice that has led to charges that ratepayers 'pay twice' for this power."[17]

The Settlement Agreement adopted by the Commission explicitly stated that the reliability demand response product (RDRP) would be designed to support demand response products with, among other provisions, the following attributes:

- "RDRP will help mitigate, or limit the duration of, Scarcity Pricing events." [18]
- "The RDRP product design will modify the existing system trigger from pre-Stage 1 imminent to the point immediately prior to the CAISO need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity. That is, the DR resource will be eligible for dispatch once the CAISO has issued a Warning Notice under its Emergency Operating Procedures and immediately prior to the CAISO need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity. Parties will not propose to change this RDRP trigger for any year prior to 2015. When RDRP is eligible for dispatch by the CAISO, notification will take place through normal notification channels, *i.e.*, Automated Dispatch System (ADS) to the responsible Scheduling Coordinator."[19]

CAISO's Emergency Operating Procedures, in effect until changed in 2021, defined its Emergency Operating Procedures in the following fashion, as explained in the Final Summer 2020 Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave Report.[20]

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[17] *Id*. at 3.

[18] "Joint Motion of CAISO Corporation, CLECA, Division of Ratepayer Advocates, Enernoc, Inc., PG&E, SDG&E, SCE, and TURN for Adoption of Settlement," February 22, 2010, at 4.

[19] *Ibid*.

[20] "Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave," January 13, 2021, at 24.

The CAISO's operational actions are communicated largely through Restricted Maintenance Operations (RMO), and Alerts, Warnings, and Emergencies (AWE) per Operating Procedure 4420.[24] Each is explained briefly below:

- **Restricted Maintenance Operations** request generators and transmission operators to postpone any planned outages for routine equipment maintenance and avoid actions that may jeopardize generator or transmission availability or both, thereby ensuring all grid assets are available for use.
- **Alert** is issued by 3 p.m. the day before anticipated contingency reserve deficiencies. The CAISO may require additional resources to avoid an emergency the following day.
- **Warning** indicates that grid operators anticipate using contingency reserves. Activates demand response programs (voluntary load reduction) to decrease overall demand.
- **Stage 1 Emergency** is declared by the CAISO when contingency reserve shortfalls exist or are forecast to occur. Strong need for conservation.
- **Stage 2 Emergency** is declared by the CAISO when all mitigating actions have been taken and the CAISO is no longer able to provide for its expected energy requirements. Requires CAISO intervention in the market, such as ordering power plants online.
- **Stage 3 Emergency** is declared by the CAISO when unable to meet minimum contingency reserve requirements, and load interruption is imminent or in progress. Notice issued to utilities of potential electricity interruptions through firm load shedding.

Under this paradigm, RDRP was expected to be available when the grid operator "anticipated" using contingency reserves, which was before declaration of a Stage 1 emergency. The CPUC further clarified this policy in D.18-11-029,[21] when it explicitly stated, "[w]e confirm that the use of Reliability Demand Response Resource (RDRR) can occur anytime within the Warning State, in the case of both In-Market dispatch and Out-Of-Market dispatched, otherwise known as exceptional dispatch. Given the collective concern regarding the frequency of notices, we conclude that the Commission should not allow RDRR to be triggered prior to the Warning Stage at this time."
In terms of RDRR usage during the outages on August 14, 2020, the Final Root Cause Analysis indicates the following timeline:

- "At 11:51 a.m. the CAISO re-issued a Warning effective August 14 from 5 p.m. through 9 p.m. still forecasting possible reserve deficiencies for those times and requesting additional ancillary services and energy bids. The CAISO reached out

[21] "Decision Resolving Remaining Application Issues for 2018-2022 Demand Response Portfolios and Declining to Authorize Additional Demand Response Auction Mechanism Pilot Solicitations," December 10, 2018.

to PG&E, SCE, and SDG&E advising them that the CAISO anticipated the need to call on emergency demand response (Reliability Demand Response Resources [RDRR]) later that day. The CAISO operators contacted other BAs for potential emergency assistance."

- "Throughout this time, the CAISO operators continuously canvassed for additional unladed capacity and potential emergency assistance from other BAs."
- "At 3:20 p.m. the CAISO enabled RDRR in the real-time market. Unlike other resources in the resource adequacy program or in the market, RDRR can be accessed only by the CAISO after, at minimum, a Warning is issued."
- At 3:24 p.m. the CAISO declared a stage 2 Emergency for the CAISO BAA from 3:20 p.m. to 11:59 p.m."
- "Throughout this time, the CAISO was having difficulty maintaining the 6% WECC reserve requirement with generating resources and began to rely on meeting part of its requirement with firm load available to be shed within 10 minutes, counting it as non-spinning contingency reserves. The AISO worked directly with PG&E, SCE, and SDG&E to designate roughly 500 MW of non-spinning contingency reserves based on a pro rata share."
- "By 5 p.m., conditions had not improved and the CAISO manually dispatched about 800 MW of RDRR. Per RDRR program requirements, the full response is required to be realized within 40 minutes following the dispatch, which is a request to respond. Actual metered response was 476 MW during the 5 p.m. hour increasing to 762 MW in the 6 p.m. hour."

During the ten-day heat wave in September 2022, the CAISO only utilized RDRR on a subset of days. CAISO dispatched about 800 MW of RDRR capacity each day on September 5, 6, and 7 when EEA 2 was in effect. In addition, some RDRRs bid economically into the DAM and were dispatched on other days during the heatwave, but the capacity was much lower.[22]

In recent years, CAISO increased its bid cap from $1,000/MWh to $2,000/MWh when a cost justified bid above $1,000/MWh is accepted in its system. In addition, when the bid cap is increased from $1,000/MWh to $2,000/MWh, CAISO moves the price of RDRR from $950/MWh to $1,900/MWh, even if the cost-justified bid is only marginally higher

[22] "CAISO Summer Market Performance Report for September 2022," November 2, 2022 at 40.

than $1,000/MWh. This has the effect of substantially increasing prices, should RDRR set the marginal clearing price, which it would do if it is dispatched by the market. This is illustrated in the following figures – showing that virtual bids were the high-priced offers in the day-ahead market and that RDRR were the high-priced offers in the real-time market on September 6, 2022, hour ending 19 (6 – 7 pm).[23]

Figure 160: Bid stack for DAM September 6, hour-ending 19

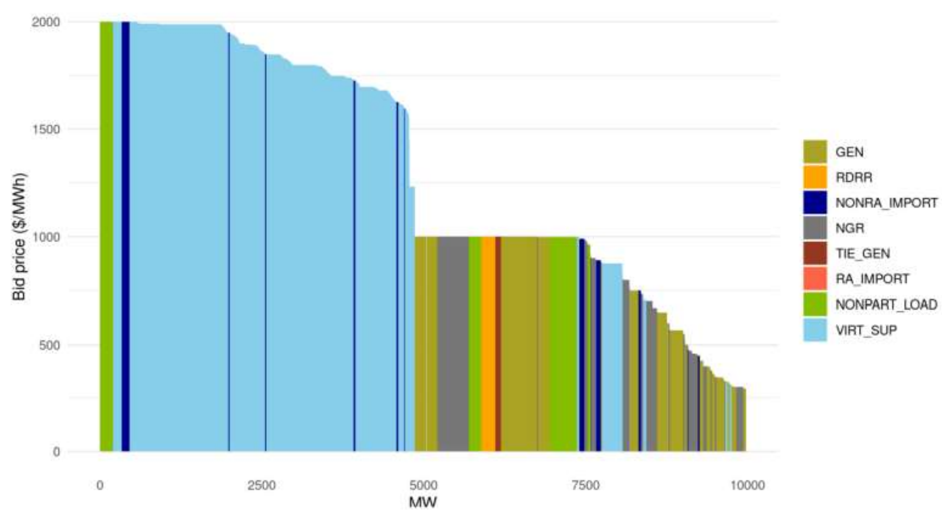
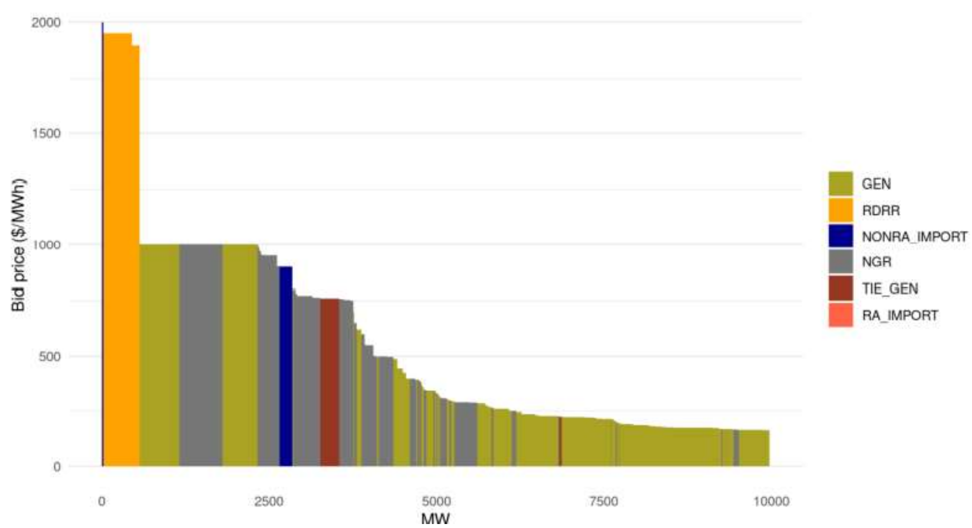


Figure 161: Bid stack for RTM on September 6, hour-ending 19



Challenges

It is ED staff's understanding that CAISO's interpretation of North American Electric Reliability Corporation (NERC) protocols prevents these resources from being

[23] "CAISO Summer Market Performance Report for September 2022," November 2, 2022 at 166 – 167.

dispatched during or before an Energy Emergency Alert (EEA) 1 and only allows them to be dispatched at an EEA 2. Furthermore, if these resources are dispatched, then the CAISO is automatically put into an EEA 2 and market prices tend to increase substantially when the marginal clearing price is set by RDRR bids. This effectively means that RDRR resources are not providing resource adequacy when they are not usable to avoid an emergency, but only to manage in an emergency; the resources are not used for mitigation or avoidance, but just mid-emergency management. Moreover, while CAISO can declare an EEA Watch in the day-ahead or day-of timeframe before losing contingency reserves, an EEA 2 must be declared in real-time as contingency reserves are anticipated to be, or are, depleted.

As a result, these resources are infrequently dispatched and are only called when, or after, purchases are made at the interties or emergency assistance is obtained from other balancing authorities. Thus, rather than displacing procurement and preventing scarcity conditions (preventing an emergency), RDRR's infrequent dispatch contributes to the very condition it is meant to avoid, emergency procurement from neighboring balancing authorities and scarcity pricing.

In effect, ratepayers are continuing to pay twice because RDRR – as currently implemented -- receives RA capacity payments but does not appear to be meeting its intended objective of displacing procurement, addressing or mitigating scarcity pricing, or avoiding reliability event emergency conditions.

Proposal

To address these challenges, ED staff propose that RDRR (including the Base Interruptible Program (BIP)) not count towards RA requirements unless it is available to be dispatched before an EEA 2. Thus, ED staff propose that either 1) RDRR not count towards RA requirements under the current paradigm in which these programs are only dispatched by CAISO at an EEA 2, or 2) RDRR count toward RA requirements, but only if the IOUs are able to dispatch the RDRR at a day-of EEA Watch, or before or during an EEA 1. The IOUs should also be able to dispatch the RDRR at their discretion to avoid an EEA Watch condition occurring. ED staff proposes that the IOUs be given discretion regarding when to dispatch RDRR to avoid the need for EEA Watch, but be required to dispatch it under all EEA conditions, including a day-of EEA Watch notice. For example, if an EEA Watch is called at 2 pm for emergency conditions that are expected to occur at 5 pm, the IOUs would be required to dispatch the RDRR for the upcoming emergency period, such as occurred this past September. In another example, if the IOUs observed the potential for shortage, or near-shortage, conditions in the 7 day ahead forecast[24] then the IOUs would dispatch the RDRR with the express goal to avoid the shortage from occurring, i.e., avoid the need for an EEA Watch instead of responding to an EEA watch. A resource that does not provide reliability services to avoid an EEA Watch is not providing resource adequacy, even if it is very useful in responding to a reliability event.

D: Transmission Loss and Planning Reserve Margin Adders for Demand Response Resources

Summary and Background

Energy Division staff propose removing the Transmission Loss Factor (TLF) and PRM adders for demand response resources in order to reduce administrative burdens and achieve parity in treatment with other resources.

In 2006, the Commission assigned a common, simplified transmission loss factor of 3%. In 2010, the Commission determined that DR resources should be awarded an adder as these resources are supplied at the customer meter level and, as a result, eliminate the need to account for transmission line losses. Under this method, the Qualifying Capacity (QC) values for DR resources are "grossed up" for avoided line losses.[25]

In 2015, the Commission adjusted the source of data and directed the Energy Division to use the most recently adopted planning scenarios and assumptions available at the time DR QC values are allocated for the next RA compliance year, which to date is the Long-Term Procurement Plan adopted in R.13-12-010 and is shown in the table below.[26]

Table 6

Transmission Loss Factors			
	PG&E	SCE	SDG&E
Peak, transmission losses	0.030	0.025	0.025

[24] *See* for example, CAISO's 7-Day Resource Adequacy Trend

[25] "Decision Adopting Local Procurement Obligations for 2011 and Further Refining the Resource Adequacy Program," June 24, 2010, OP 6 at 64.

[26] "Assigned Commissioner's Ruling on Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP," May 14, 2014 at 15.

Additionally, under the RA framework, each LSE's CEC-adjusted forecast includes a PRM adder. In D.20-06-031, the Commission clarified that the PRM adder for DR QC only applies to system RA because the system RA requirement is based on a load forecast that includes this adder, while local and flexible requirements are based on the results of CAISO studies that have no association with the PRM.[27]

In 2021, the Commission reduced the PRM adder from 15% to 9%. It also requested the California Energy Commission (CEC)-led working group to make recommendations on several issues, including whether any further changes to DR adders should be adopted.[28] While the forthcoming CEC working group is expected to make recommendations on the DR adders, ED staff submit this proposal to ensure that this issue is reviewed and considered by the Commission and parties and to explain the attendant administrative burden on ED staff.

Challenges

Because transmission-level losses and the PRM cannot be dispatched by the CAISO, they cannot be bid and are not incorporated into NQC values. To count both adders, ED staff has continued the existing process of providing RA credits to CAISO to account for these adders.

ED staff propose that the current practice be revisited for several reasons. First, ED staff's practice of grossing up RA filings and sending both adders to the CAISO increases administrative burdens, especially when weighed against the ratio of the small MWs being processed. As the number of LSEs purchasing DR and DR providers has increased, the administrative complexity of applying the DR adders has grown tremendously, but the calculations often add credits of only a fraction of a MW.

With regards to the PRM, DR resources do not reduce the need for operating reserves in the real-time market. Additionally, CAISO's practice of excluding DR from its load forecast results in procuring additional operating reserves negates the DR adder altogether. Moreover, while the PRM accounts for forecast error and

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[27] "Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program," June 25, 2020 at 47.

[28] "Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program," June 24, 2021, OP 11 at 77.

forced outages, DR does not lower either factor because if the CAISO did not procure to meet load, there would be no DR load to curtail. [29]

This is demonstrated in the Department of Market Monitoring's (DMM) Report on System and Market Conditions, which found that the capacity represented by the PRM adder did not materialize as supply that could be called upon on high load days during the 2020 heatwave; the capacity also did not reduce the load CAISO procured on those days.[30] In August 2020, the PRM adder represented 193 MW that was arguably not available to the CAISO, nearly 40% of the shortfall on first day of rotating outages.[31] The CAISO states that there is also no evidence that DR lowers the system forecast error or the system average forced outage rate.[32]

Proposal

ED staff propose removing both the TLF and PRM adders. The crediting function is a considerable administrative burden which adds to program complexity without adding to or supporting reliability. Further, because no other distribution-connected resources receive a transmission adder, its removal would result in consistent treatment of all resource types.

Second, ED staff propose removing the 9% PRM adder because the adder assumes a permanent load reduction, while no actual reduction occurs in the procurement of planning reserves. The adder should not be broken into further pieces, as this would create further allocation, tracking, and implementation issues.

E: RA Availability Requirements

Summary and Background

ED staff propose to require demand response resources to meet the requirements of system peak demand. Specifically, DR resources must be available a minimum of four hours per day, and a *minimum* of three days per week *plus* during all additional days declared as a Governor's state of emergency proclamations or CAISO's issuance of Flex Alerts.

[29] "Track 4 Proposals of the CAISO," January 28, 2021 at 9-10.
[30] "CAISO Department of Market Monitoring, "Q3 2020 Report on Market Issues and Performance," February 4, 2021 at 20-21
[31] *Ibid*.
[32] "Track 4 Proposals of the CAISO," January 28, 2021 at 9.

In 2005, the Commission established the operational requirements for resources qualifying for resource adequacy.[33] Subsequently, in 2011, the Commission established that these same requirements apply to all DR resources receiving qualifying capacity.[34] Under these rules, all resources must be available for a block of at least four consecutive hours on three consecutive days. In addition, the resource must be able to run a minimum aggregate number of hours per month based on the number of hours that loads under CAISO control exceed 90% of peak demand in that month, which are during summer months.[35]

In 2014, the Commission bifurcated DR programs into Supply-Side Resources and Load Modifying Resources.[36]

Challenges

The CAISO Department of Market Monitoring's report on resource performance in 2020 and 2021 shows that "a large portion of DR resource RA capacity was not available for dispatch during key peak net load hours."[37] Due to the existing financial incentive framework, DR resources "fail(ed) to perform when needed most under critical system conditions."[38] In 2022, regional demand reached historically high levels from August 31-September 9, causing numerous areas to declare emergencies.[39]

Because of DR's current availability practice, DR resources are not available beyond three days. For example, under the existing requirement, while resources were required to be available between August 31-September 2, 2022, they were not required to be available between September 3-5, 2022. This availability is inconsistent with the Commission's goal to reliably provide resources to meet demand and to ensure that sufficient resources are available under peak conditions to meet demand at least cost. As a result, DR value to the system, specifically DR contribution to providing reliability during peak events, is observed to be

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[33] "Opinion on Resource Adequacy Requirements," October 27, 2005, OP 1 at 105.
[34] "Decision Adopting Local Procurement Obligations for 2012 and Further Refining the Resource Adequacy Program," June 23, 2011, OP 12 at 74.
[35] "Opinion on Resource Adequacy Requirements," October 27, 2005, OP 16 at 104.
[36] "Decision Addressing Foundational Issue of Bifurcation of Demand Response Programs," March 27, 2014.
[37] "2021-Annual-Report-on-Market-Issues-Performance.pdf (caiso.com)," CAISO and WEIM Department of Market Monitoring, July 27, 2022 at 26.
[38] *Ibid*.
[39] "Q3 2022 Report on Market Issues and Performance," CAISO Department of Market Monitoring, December 14, 2022 at 1.

significantly reduced even though the resource continues to be counted fully for RA.

Proposal

ED staff propose that all RA resources must be available *prior* to when the CAISO issues a call for voluntary conservation under its Flex Alerts.[40]

Under Flex Alert conditions, consumers are called to voluntarily conserve electricity when the CAISO anticipates using nearly all available resources to meet demand. If demand is sufficiently reduced, subsequent dire measures such as EEA conditions, emergency procedures, and rotating power outages could be averted.[41]

Consequently, the ED staff propose that supply-side demand response resources be available to provide supply *before* all resources are projected to be used to meet demand. Consistent with all other resources counted for resource adequacy, DR should be available during peak conditions so that CAISO can fully consider all available resources *for avoiding emergencies, warnings, events and even stressful system conditions*.

Under this proposal, DR resources eligible for RA would be available for the minimum of three days *plus* the additional days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning or the Governor's Office, an Emergency notice. For example, in the event of a dispatch on day T, the resource must be available for a minimum of four hours on each of the following days:

> (3 Days [including day of dispatch, T]) + Flex Alert Days + Additional Days of Grid Warning or Governor-Issued Emergency Notice

This requirement would harmonize the availability requirements between DR resources and the needs of peak load demand.

[40] Flex Alerts are issued when CAISO anticipates using nearly all available resources to meet demand. In the event demand is still not expected to be met, CAISO issues an EEA Watch, encouraging participants to offer supplemental energy. The EEA Watch is issued the day before or in the event of a sudden shortfall.
[41] *Ibid*.

F: Treatment of Late Requests of Demand Response Monthly Net Qualifying Capacity

Summary and Background

ED staff request that the due date for filings of Demand Response Net Qualifying Capacity (NQC) value requests be formalized.

Currently, DR resources seeking qualifying capacity may submit their Resource ID-specific NQC capacity values on a monthly basis to the Energy Division. Energy Division staff then review the filings and submit approved values to the CAISO.

This process was established between Energy Division staff and CAISO as previous filings made directly to the CAISO far exceeded the resources that were approved through the load impact protocols (LIPs) or demand response auction mechanism (DRAM) processes. Under the existing practice, Energy Division reviews filings to ensure that listed DR resources are within the approved limits.

Challenges

DRPs are frequently submitting their filings later than the deadline as published in the RA guideline for submitting monthly DR NQCs.[42] Late filings create negative cascading effects for the ED staff in its review and processing of these filings.

Proposal

ED staff seek to formalize the deadline for monthly DR NQC requests to minimize administrative burden. ED staff propose DR NQC filings to be made the first business day of the month two months prior to the requested month. The submission deadline for the August 2023 RA showing, for example, is June 1, 2023. Failure to meet the deadline requirements can disqualify the month-ahead supply plan request.

G: Treatment of Demand Response Resources Failing to Perform During Testing

Summary and Background

ED staff propose enforcing performance requirements and de-rating resources unable to achieve their stated capacity. We provide further details in the following sections.

[42] "Instructions for Adding Demand Response Resource IDs to the Monthly Net Qualifying Capacity List," October 16, 2022 at 2.

In 2014, the Commission ruled that DR resources must abide by testing requirements.[43] This was updated in 2020, with a decision that established specific testing requirements for third-party DR resources procured by all non-IOU LSEs, including:

- The DR resource must be dispatched for four consecutive hours in the RA window at least once every quarter, with dispatches fulfilled either through a CAISO market dispatch or an out-of-market test.
- The quarterly dispatch must be performed at the Resource ID (RID) level and concurrently within the same Sub-Load Aggregation Point (Sub-LAP)
- Dispatch performance results must be averaged over the four consecutive hours for each day.[44]

Challenges

Available test results show that 2022 performance was similarly low in comparison to monthly supply plans, with performance ranging from 27-35% in Q2 and 23-58% in Q3.

In making its 2020 Decision, the Commission was "persuaded that enhanced testing requirements" were necessary to determine whether new and changing resources can demonstrate reliable performance.[45] The Commission sought to verify whether projected load reduction values can demonstrate typical resource performance under a variety of weather and conditions. At the current levels of performance during test events, these resources are unacceptable.

Also, as part of the 2020 Decision, the Commission required both IOUs and DRPs to submit an updated filing when the resource portfolio falls below the threshold of 20% or 10 MW less than the assigned QC value.[46] Based on collected test results, it appears that DRPs are not submitting updates with lower capacity values.

Proposal

As part of the continuum of implementing the 2020 Decision, ED staff propose considering test performance failures when making capacity awards to non-IOU demand response resources procured by third-party DR providers under the LIPs.

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[43] "Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program," June 26, 2014, OP 6 at 73.

[44] "Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program," June 25, 2020, OPs 13 and 14 at 93-94.

[45] *Id*. at 40.

[46] *Id*. OP 15 at 94.

In order to account for the weather-dependent nature of DR, ED staff propose applying de-rates that correspond to their respective performance during test events for a particular quarter. The average performance results of each quarter will inform the capacity awarded through the LIPs for the respective sub-LAP. For example, under this scenario, a 50% performance in Q1 2023 may lead to a corresponding de-rate of up to 50% in the Q1 2024 capacity awarded through the Load Impact Protocols as filed in April 2023. Additionally, ED staff could further adjust this capacity based on other relevant factors such as market dispatch performance results and reasonable enrollment forecasts.

Proposal 3: Clarification of RA Compliance and Penalty Provisions

A: RA Penalty Point System

Summary and Background

D.21-06-029 established a point system for system RA deficiencies. The adopted point and tier penalty structure for system RA deficiencies are as follows:

Table 7

Months	Points for Each Instance of System RA Deficiency
Non-Summer (January – April; November – December)	1
Summer (May – October)	2

Table 8

Tier	Accrued Points	System RA Penalty Price
1	0-5	Applicable system RA penalty price
2	6-10	2x the applicable system RA penalty price
3	11+	3x the applicable system RA penalty price

Points are accrued for month-ahead deficiencies but not for year-ahead deficiencies.[47]

Proposal

To clarify, ED staff proposes that the penalty price corresponding to an LSE's tier shall apply to all penalties awarded to the LSE, including year-ahead penalties. For example, if an LSE has accrued points 6-10 points and is in Tier 2, the LSE is expected to pay double the system RA penalty price for any year-ahead deficiency or month-ahead deficiency.

In addition, if the LSE enters a higher tier during a year in which it had year ahead deficiencies, the higher penalty should apply beginning with the monthly deficiency when the LSE enters the higher tier. For example, in the case where an LSE has year-ahead deficiencies for May to September and the same deficiencies for May to September in the month-ahead process, no prior points, and the LSE pays the penalty for the year-ahead deficiencies, the LSE will accrue two points for the month-ahead May deficiency, and two points for month-ahead June deficiency, bringing the total points to four points. Assuming there is no incremental deficiency in the month-ahead, the LSE will not pay additional penalties in the month-ahead process for May and June.

[47] "Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program," June 24, 2021 at 59-60.

However, the LSE will accrue two points for the month-ahead July deficiency, bringing the total points to six points and the LSE into the Tier 2 system RA penalty price. In this case, even assuming there is no incremental deficiency in the month-ahead for July, ED staff clarify that the LSE will pay the difference between the double system RA penalty price for July and the year-ahead penalty for July and subsequent deficiencies.

When an LSE accrues points that bring them to the next tier, Energy Division proposes the higher penalty will apply to the deficient month for which the points are accrued. For example, if an LSE is deficient in July and has total of six points accrued due to the deficiency in July, the double system RA penalty price will apply in July.

ED staff propose that these clarifications will apply to 2023 compliance.

B: Provision of Q1 Cost Allocation Mechanism and Reliability Must Run Credits

Summary and Background

Pursuant to D.14-06-050, the Cost Allocation Mechanism (CAM) and Reliability Must Run (RMR) credits are allocated quarterly. The allocations are due 45 days before the RA filings are due.[48] For example, the Q1 2023 CAM and RMR credits are due October 3, 2022, 45 days before the January 2023 filings are due on November 17, 2022. However, RMR allocations depend on CAISO providing the total CPUC jurisdictional share of RMR credits, which are generally not provided until October.

Proposal

Energy Division staff propose that they will provide Q1 CAM and RMR credits to LSEs no later than five business days after CAISO provides the CPUC jurisdictional RMR credits to Energy Division.

C: Treatment of Late Local Waiver Advice Letter Filings

Summary and Background

Pursuant to D.19-06-026, local RA waiver requests must be submitted via a Tier 2 Advice Letter (AL) process with service to the service list of the RA proceeding open at the time.[49] Pursuant to the 2023 Resource Adequacy Guide, local waiver Advice Letters are due the same time as the Year Ahead and Month Ahead filings are due. The due

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[48] "Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program," June 26, 2014 at 56.

[49] "Decision Adopting Local Capacity Obligations for 2022-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program," June 27, 2019 at 17-18.

dates are outlined in Section 2 of the RA Guide.[50] Some LSEs have repeatedly filed local waiver ALs late. There is no penalty established for late local waiver AL filings as they are voluntary.

Proposal

ED staff propose to not accept the late local waiver AL filings and propose to deny any late local waiver AL filings. Formalizing this rule would provide all LSEs equal understanding of the rules for local waiver AL filings.

D: Publishing Load Serving Entities' Deficiencies and Citations

Summary and Background

Currently, LSEs' citations and penalties are made public by Consumer Protection Enforcement Division (CPED) on the CPUC website.[51] However, the type of citation (RA deficiency or other program violation such as late filing), the type of RA deficiency (local, system, and/or flexible), the month of deficiency, the deficiency amount (MW), the amount of the deficiency as a portion of the LSE's requirement, and any points accrued for system deficiencies are confidential.

Table 9. Types of RA Citations Issued, 2009-2022

Type of Citation	Number of Citations
Flexible Only	8
Flexible and Local	2
Local Only	7
Program Violations	44
System Only	66
System and Flex	15
System and Local	1
Grand Total	**143**

As shown in Table 9, the RA program has issued and received payment on 143 citations since 2009. There were at least eight system RA citations issued for RA deficiencies in either August or September 2022, although collectively the CPUC jurisdictional LSEs were sufficient for RA in all key month of 2022. System deficiencies are occasionally *de minimus* relative to an LSE's overall RA obligation, but the lack of information on the

[50] "2023 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings," September 30, 2022, at 55.

[51] See "Energy Citations Issued," of the CPUC's webpage on Waiver and Penalties.

magnitude and frequency and type of deficiency obscures the ability of policy makers to understand and address program violations.

Challenges

The purpose of penalties and citations is to deter non-compliance and obfuscation of non-compliance activities. In recent years, there has been a large increase in non-compliance events and yet, the frequency and type of non-compliance events is not readily available to support the public's understanding of LSE performance, risks to reliability, or the RA program effectiveness.

Proposal

For Month Ahead deficiencies, ED staff propose to make public an LSE's type of deficiency, the month of deficiency, deficient amount (MW), the amount of the deficiency as a portion of the LSE's requirement, and any points accrued for system deficiencies. These will remain confidential for the Year Ahead deficiencies until after the compliance month to avoid revealing market sensitive information because the LSE still has a chance to cure the Year Ahead deficiencies before the Month Ahead process. ED staff also propose that citations for other program violations, such as late load forecast or late RA filings should not be redacted.

Proposal 4: Central Procurement Entity Reporting Requirements

Summary and Background

ED staff propose additional reporting requirements for the Central Procurement Entities (CPEs) to assist LSEs in assessing the potential risk for backstop procurement. CPEs would provide this information as part of their annual mid-August compliance filings.

On June 17, 2020, the Commission designated PG&E and SCE as the CPEs responsible for local RA procurement on behalf of all LSEs in their respective distribution service areas.[52] In designating the CPEs, the Commission adopted implementation details for the CPEs in executing their multi-year RA procurements beginning with the 2023 compliance year. As CPEs, SCE and PG&E are directed to conduct competitive, all-source solicitations under specified requirements and selection criteria. Once resources are selected as part of a portfolio, those with contract terms that are five years or less will be pre-approved, provided they meet certain conditions. CPE procurement contracts that exceed five-year terms are subject to review and approval under a Tier 3 AL process.[53]

The Commission also established reporting requirements for the CPEs to annually report on their solicitations, including details on contract terms, and the criteria and methodology used in selecting local RA resources.[54] Thirty days after the CPE makes its local RA showing to the Commission, the CPE is required to submit a Tier 2 AL with its annual compliance report (ACR). In submitting this data, the CPEs are directed to adhere to the competitive neutrality rules that govern the treatment of confidential, market-sensitive information and activities.[55]

Subsequently, the Commission recognized that additional transparency could beneficially contribute to the CPE framework. On March 3, 2022, the Commission directed CPEs to disclose additional information about the procurement process.[56] The CPEs were directed to disclose aggregated information about selected resources and the procurement of generation facilities located in Disadvantaged

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[52] "Decision on Central Procurement of the Resource Adequacy Program," June 11, 2020, OP 2 at 91.
[53] *Id*. OP 22 at 98.
[54] *Id*. OP 23 at 99.
[55] "Decision on Track 3.A Issues: Local Capacity Requirement Reduction Compensation Mechanism and Competitive Neutrality Rules," December 3, 2020, OP 9 at 49.
[56] "Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure," March 17, 2022, OP 17 at 77.

Communities. Beginning with the 2023 Annual Compliance Report, the Commission directed CPEs' filings to include the following new data:

1) Total local RA allocation for the CPE from the Commission;
2) Total local demand response (DR) resources allocated for the CPE by the Commission;
3) Total local CAM resources (non-DR) applied towards CPE requirements;
4) Total local resources procured by the CPE;
5) Total LSE self-shown local resources;
6) Net total position associated with the CPE;
7) Total capacity of preferred resources that were bid or shown to the CPE;
8) Total capacity of preferred resources selected and not selected by the CPE; and
9) Total capacity of MWs procured by the CPE from generation facilities located in Disadvantaged Communities.

Challenges

ED staff recognize that the effective functioning of a CPE structure requires the balancing of transparency while protecting critical, market-sensitive information. LSEs that are dependent on allocations from CPEs to assess their system and flexible RA positions may need more information to timely address deficiencies in their portfolios.

To address the need for more transparency in 2022, ED staff sent a data request to the CPEs in September 2022, following the annual distribution of CPE allocations from Energy Division. This led to ED staff posting aggregated CPE procurement information in mid-September. Thereafter and following the September 30th annual ACR filing, ED staff sent a request to the PG&E CPE asking for previously filed public information to be supplemented with additional information related to resources that did not participate in the CPE RFO or were not awarded a contract.

Proposal

ED staff propose that additional data is included in the mid-August compliance filings to allow LSEs to better manage their upfront system RA procurement and to assess the potential for backstop procurement. Given the continued tightness of system supply, the increased transparency could alleviate speculation regarding local capacity shortfalls and facilitate additional certainty in the CPE process.

The Commission's 2022 decision on this matter established reporting requirements on the total resources procured, bid, or shown and also requested reporting on resources that participated, but were not selected. [57] ED staff propose expanding the current public reporting requirement to include (a) aggregated resources that did not participate in the solicitation process altogether; (b) aggregated resources that were not contracted due to unreasonable prices; (c) aggregated resources that were offered but withdrawn; and (d) a summary of the results of outreach efforts made to resources in (a) and (c).

This information is to be provided by the CPE with its mid-August compliance filing to Energy Division. ED staff will make this information available on its website with aggregated information reported from the CPE compliance filings. This aggregated information will allow LSEs to achieve greater understanding about the inventory of available resources in the market and the nature of these resources, while providing additional time for LSEs to manage their positions. The CPEs should also provide this information in their public ACR filing due in late September.

Specifically, the ED staff proposes that IOU CPEs submit the following information in their September ACR filings *and* as part of the mid-August compliance filings, both of which are currently required by the 2022 Decision:[58]

(1) The following aggregated information (Table 6), which will be posted to the Commission's website.

Table 6

Monthly Procurement Summary Covering All CPE Procurement					
Total CPUC Local Allocation (Excluding DR)	Total CPUC-Allocated Local DR	Local CAM (non-DR)	Total Procured Resources	Total Self-Shown	Net Total

(2) In the mid-August compliance filing *and* the public CPE annual compliance filing submitted in mid-September, CPEs shall include:
   a. Monthly MW amounts of deferred procurement that were the result of unreasonable prices over the compliance period;
   b. Monthly MW amounts of procurement not offered to the CPE in deficient areas over the compliance period;

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[57] *Ibid*.
[58] "Decision on Phase 1 of the Implementation Track: Modifications to the Central Procurement Entity Structure," OP 13 at 75.

c. Monthly MW amounts of procurement offered in and then later withdrawn over the compliance period; and
d. Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

Proposal 5: Load Serving Entity Expansion Requirements

Summary and Background

The RA program is a key component of State efforts to ensure reliability of the grid. However, in recent years, the number of deficient LSEs has increased significantly. In 2021, seven LSEs received citations for uncured month ahead deficiencies and in 2022, five LSEs received citations for uncured month ahead deficiencies. In some cases, the deficiencies accounted for very large portions of the LSEs' total system RA requirements. Despite a demonstrated inability to procure sufficient RA capacity to meet their existing requirements, several LSEs have continued to increase load.

Challenges

ED staff is concerned that continued expansion by LSEs that have not met their RA obligations at current levels of load will jeopardize reliability if these LSEs fail to procure their full RA obligations in the future with increased levels of load. In addition, if LSEs fail to procure RA, this results in leaning on other LSEs that have procured their full RA obligations as well as leaning on the effective PRM procurement, if the effective PRM program continues. Persistent under-procurement of RA by some LSEs also undermines the stated purpose of the effective PRM, which is to have the IOUs procure above and beyond the required PRM to provide additional resources for unanticipated, climate-change related events – the purpose is not to backfill for those LSEs that do not fulfill their existing obligations.

Proposal

To address the potential reliability issues that arise with continued expansion of LSEs that are failing to meet their current summer RA obligations, ED staff propose that a community choice aggregator (CCA) or electric service provider (ESP) must be in good standing in meeting its RA requirements in order to take on new customers. Specifically, ED staff proposes that any CCA or ESP with a deficiency of greater than 2.5% of its system RA requirement on a month ahead RA filing during the previous two calendar years should not be able to expand and take on new any new customer load for the following year. For example, any LSE with RA requirement deficiencies in 2021 or 2022, would not be eligible to expand to serve new load in 2023 for service in 2024.

Proposal 6: Using Annual Load Forecast for Resource Adequacy Requirements

Summary and Background

The current RA program requires load serving entities to submit binding load forecasts in order for the Commission to determine year-ahead requirements, but also allows updates to the monthly load forecasts to account for small amounts of load migration that occur throughout the year.

Challenges

The monthly load forecast updates increase the administrative complexity of the entire RA program, as any updates to load forecasts changes the monthly RA requirements. In addition, it calls into question what the purpose of a binding load forecast is, if it can be changed in the month-ahead timeframe. The frequency of load forecast updates requires extensive staff time, and it provides an opportunity for load migration to insert reliability risk. There is a benefit afforded to LSEs that have lost load during the calendar year that their RA obligations are reduced, but it is not clear that LSEs are able to engage in microtransactions to true-up their RA portfolio with their load on a monthly basis.

There are several options for program simplification and improvement that could be considered. First, the RA program could lock in the LSEs load forecast annually, and not allow monthly RA forecast adjustments. The RA program could allow for only quarterly changes, or one mid-year change. If the program allowed for one mid-year change (e.g. 6 months after the original forecast), then effectively there would be an update of the load forecast that applied for the summer months' RA requirements.

Proposal

ED staff request that the Commission and parties consider whether it would be appropriate to lock in year-ahead load forecasts to use for the RA program. This would obviate the need for LSE submittals of any monthly load forecast updates and CEC and CPUC staff consideration of forecast updates (and associated administrative processes). Under this proposal, system and local RA requirements would vary by month, but be locked in for the entirety of the year, which would provide parties and the Commission more certainty regarding which entity is responsible for the RA obligation. The local RA requirements are already unchanged throughout the year due to the recognition that the resources need to be known to be available for the full year. This proposal aligns with many yearly RA constructs implemented in other states and regions. Since this proposal could substantially reduce the administrative burden for ED staff, the adoption of this proposal would allow ED staff to redirect efforts to address the complexities and implementation details of slice of day, and introduction of other new program features, many of which parties have complained are too complex – this simplification could reduce the complexity considerably.

Proposal 7: Requirements for Load Serving Entities Using Non-Specific Imports

Summary and Background

The CPUC clarified its RA import rules for non-resource specific imports in D.20-06-028. That decision, among numerous other provisions, required that the contract be for energy. In addition, the Commission did not require load serving entities to be the scheduling coordinator for the non-resource specific RA imports but allowed load serving entities to designate another scheduling coordinator for the resource.

Challenges

The CPUC intended that non-resource specific RA imports be energy delivered to the load serving entity, but a number of load serving entities are structuring these non-resource specific imports as RA capacity contracts, not energy contracts, with the resource being bid into the CAISO, rather than delivered to meet the energy needs of the load serving entity. Further, given that load serving entity is not the scheduling coordinator for the resource, it makes it more difficult to assess penalty to the load serving entity for failure to meet the requirements of the previous decision.

Proposal

ED staff propose that the load serving entity must be the scheduling coordinator for the non-resource specific RA imports. This ensures that the load serving entity is responsible for meeting CPUC-jurisdictional requirements. Further, ED staff requests that the Commission consider whether the self-schedule or bid at $0 to negative -$150/MWh be replaced by an energy must-flow requirement, to ensure that the energy contracts are not speculative and, thus, to ensure that the reliability of the grid is maintained.

Proposal 8: Granting Resource Adequacy Capacity Based on Available Transfer Capability or Maximum Import Capability

Summary and Background

The CAISO is in the process of developing rules for wheeling transactions in its Transmission Service and Market Scheduling Priorities (TSMSP) stakeholder process.[59] In its draft final proposal, CAISO proposes to allow external entities (non-CAISO LSEs) to reserve available transmission capability (ATC) across the CAISO system based on historical RA usage in the 13-month time horizon and based on actual usage in the monthly and daily timeframe at each particular intertie location (e.g., COB/Malin or NOB).[60]

These high priority wheels across the CAISO system would be provided priority equal to CAISO load, in the event that CAISO is unable to serve its own load and allow for wheeling across its transmission system. CAISO does not propose that CAISO load serving entities could buy the ATC in the 13-month ahead timeframe or in the monthly timeframe but proposes to allow those with the high priority wheeling rights to sell those rights to others.[61]

Challenges

Some parties in CAISO's stakeholder process have argued that CAISO load serving entities should have the right to procure the ATC, similar to external parties. Further, if CAISO allows the resale of the ATC, conceivably this could be sold to a CAISO load serving entity. However, current Commission rules only allow Commission-jurisdictional entities to pair RA imports with maximum import capability (MIC) allocations and, thus, RA imports paired with ATC would not, at this point, count towards CPUC-jurisdictional RA obligations.

Proposal

ED staff propose that if CPUC jurisdictional load serving entities are able to procure ATC or acquire it through the resale process, that the CPUC-jurisdictional entities be allowed to pair that ATC with RA imports to meet RA requirements. In the alternate, the Commission could consider removing the MIC requirement for RA imports, which

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[59] CAISO Initiative "Transmission Service and Market Scheduling Priorities," formerly "External Load Forward Scheduling Rights Process."

[60] "CAISO Draft Final Proposal: Transmission Service and Market Scheduling Priorities – Phase 2," December 9, 2022 at 4.

[61] *Id*. at 14.

restricts the RA imports that entities are able to buy at each of the interties, since the MIC does not currently convey deliverability in any case.

END APPENDIX A