

Energy Division Staff Concept Paper
Proposals for Summer 2022 and 2023 Reliability Enhancements

August 16, 2021

This document offers a variety of Energy Division Staff program and policy concepts that could be considered by the California Public Utilities Commission (CPUC or Commission) to address Summer 2022 and 2023 reliability needs at net peak. The document is organized by topic area. In many cases, these concepts are brief descriptions of key rule or program design elements, rather than detailed proposals. Parties are encouraged to provide comments on these concepts in their own testimony, and parties are encouraged to submit as part of their testimony their own proposed rule changes or program designs.

Party testimony may use all or parts of these concepts as starting points for their own more detailed proposals but should not be limited by the concepts in this document. In presenting proposals and responding to these concepts, parties are strongly encouraged to identify resource potentials (i.e., megawatt (MW) estimates) as well as elaborate the legal, technical, and practical pros and cons of these concepts.

The topic areas are based on the issues raised in the Order Instituting Rulemaking (OIR) (R.20-11-003) and revised Scoping Memo issued on August 10, 2021. When making use of these concepts to prepare testimony due on September 1, 2021, parties are encouraged to review the “Proposal Guidance to Parties” provided by Administrative Law Judge Stevens on August 11, 2021.

Parties should also be aware that the Commission has scoped possible demand-side program changes that would help reduce load at times of net peak into other proceedings that are specific focused on these program areas. This includes the Energy Efficiency (EE) proceeding (R.13-11-005) and the Microgrid and Resiliency proceeding (R.19-09-009).

Finally, some of the concepts described below overlap with demand response programs proposed by Pacific Gas & Electric Company (PG&E) and by California Environmental Justice Alliance (CEJA) that have already received a round of party testimony in this proceeding. We encourage parties to comment on how those programs could be integrated with the concepts in this document.

The topic areas are as follows:

A. Demand Reduction

1. Emergency Load Reduction Program (ELRP) Modifications
2. Demand Response Auction Mechanism (DRAM) Modifications
3. Third Party Demand Response Procured by Non-IOU Load Serving Entities
4. Agricultural Demand Flexibility Pilot

B. Smart Thermostats (SCT)

1. SCT Related Changes to Energy Efficiency Programs
2. SCT Related Changes to Energy Savings Assistance Programs

C. Utility-Scale Storage, Imports, and Generation

1. Introduce Penalties for Delays to D.19-11-016 Procurement
2. Increase Resource Adequacy Penalties
3. Accelerate Procurement Ordered in IRP Mid-Term Reliability Decisions
4. Emergency Procurement and Cost Recovery via a Non-Bypassable Charge
5. Bundled Procurement Rules Modifications

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A. Demand Reduction

1. Emergency Load Reduction Program (ELRP) Modifications

The ELRP was created by D.20-11-003 as a five-year pilot program designed to obtain additional load reduction beyond existing demand response (DR) programs at times when the California Independent System Operator (CAISO) has issued a Grid Alert, Warning or Emergency. The program pays customers \$1 for every kilowatt hour (kWh) of actual savings, defined as incremental load reduction (ILR). The program has two sets of customers.

- ELRP Group A participants are non-residential customers or virtual power plant (VPP) aggregators (aggregating non-residential or residential customers) that do not already participate in a CAISO market-integrated demand response program, except the Base Interruptible Program (BIP).

Customers can provide the load reduction by either reducing load or replacing their load with distributed energy resources that can generate energy (e.g., behind-the-meter solar plus storage, electric vehicles, cogeneration, etc.).

- ELRP Group B participants are third-party DR providers or investor-owned utilities (IOUs) operating CAISO market-integrated DR resources that aggregate residential or non-residential customers.

D.20-11-003 provided for a programmatic review of the pilot program in 2022 in a proceeding scheduled to be opened on November 1, 2021, to consider IOU applications for DR programs and budgets for 2023-2027. Based on Energy Division staff (“Staff”) understanding of experience to date, as well as responses from potential customers who have chosen to not participate in the program for the summer of 2021, Staff offers some proposal concepts some more immediate changes to the program to increase participation and program effectiveness in 2022.

- a. Increase Compensation Rates: Based on feedback from potential customers in the ELRP program, the current payment of \$1/kWh may not be high enough to offset operational costs of reducing load during CAISO Grid Alerts, Warnings and Emergencies. Thus, to increase participation the ELRP program overall, the ELRP’s Compensation Rate (ECR) should be increased to \$2/kWh for Group A.1 non-residential customers and Group A.2 BIP aggregators. However, at the higher compensation rates commitment of load reduction should be more certain, thus the increased compensation values should be limited to customers who commit to providing a certain load reduction performance level.
- b. ELRP Group A Enhancements: Staff offers the following concepts as changes specific to Group A customers:
 - i. Currently, Group A.1 customers must meet specific Minimum Size Thresholds, which vary by IOU. This restriction limits the number of the customers that can participate. In order to increase total customer participation staff proposes reducing the A.1 customer minimum size thresholds.

- ii. Currently, to enroll in ELRP, Group A.1 customers must initially nominate a specific amount of load they can reduce during an ELRP event. This nomination amount defines a compensation collar that bounds the ELRP compensation for an event to between 50 percent and 200 percent of the pre-nominated quantity. This compensation collar may be overly complicated for customers and the CPUC could consider removing the compensation collar to simplify customer enrollment process and encourage additional enrollment.

- c. ELRP Group B Enhancements: Staff offers selected change concepts specific to Group B customers:
 - i. Add Day-Of (DO) trigger in response to CAISO Warning or Emergency declaration (in addition to the Day Ahead trigger already existent).
 - ii. To be eligible to participate in ELRP, proxy demand resource providers (PDRs) participating in CAISO real time market (RTM) must bid at or below \$900/MWh. This is to maintain some consistency with reliability-based Base Interruptible Program (BIP) resource which is triggered at RTM price reaching \$950/MWh.

- d. Expand Eligibility to Include Residential Customers: Currently, most residential customers do not participate in demand response programs that compensate them for load reductions, but the CAISO often depends on load reduction from residential customers through the Flex Alert program, which is a voluntary program that calls on social action to reduce demand but does not compensate individual customers. This raises questions of both equity and effectiveness given that the CPUC has developed numerous programs, including ELRP, that compensates non-residential customers for load reduction, but comparatively few programs for residential customers. Additionally, the voluntary Flex Alert program may have diminishing impacts over time as customer fatigue sets in. To address these possible concerns, Energy Division staff offers a proposal concept for consideration that all residential customers be considered

eligible to participate in ELRP by default (except customers participating in existing supply-side DR programs). To implement this policy, the following proposal concept details are offered for CPUC consideration:

- i. All residential customers would be automatically enrolled in ELRP (except customers currently enrolled in supply-side DR programs). There would be no required sign-up or acknowledgment process.
 - ii. The triggering requirements for these residential customers would be the CAISO calling a Flex Alert or Grid Alert in the day-ahead.
 - iii. The Flex Alert marketing would be modified to promote ELRP event and to utilize all available channels to reach and notify customers about the imminent event and the opportunity to reduce consumption and receive payment or bill credit.
 - iv. The payments for load reduction would be based on meter-verified incremental load reduction (ILR) relative to a “simple” baseline to be established by the IOUs.
 - v. Program would be administered through the IOUs.
 - vi. IOUs and third-party DR Providers would still be permitted to target Residential ELRP customers to enroll them into their respective supply-side DR program, in which case the customer is removed from ELRP.
- e. Electric Vehicle/Vehicle to Grid Integration (EV/VGI) Aggregation Pilot: Currently the ELRP pilot has at least one provision (Group A option A.3) to allow electric vehicles to support the grid at net peak through vehicle to grid export. Energy Division Staff believes there may be additional potential for VGI aggregation integration (V1G managed charging and/or V2G discharge) to support the grid at net peak and to increase the effectiveness of the ELRP. Aggregating and dispatching EV resources through the ELRP represents an opportunity to enable and demonstrate the technical capabilities and customer engagement strategies necessary to harness and deploy this nascent resource. These efforts could serve to establish a foundation for further deployment of VGI resources, which is a priority for the CPUC and EV stakeholders given the enormous potential of these resources. The pilot may require revisions to interconnection rules to enable streamlined and affordable access to the grid for EVs and EV Supply Equipment (EVSE) with bi-directional capabilities. Staff proposes:

- i. Allow aggregators to utilize networks of V1G or bi-directionally capable charging stations (EVSEs) to be eligible to participate in ELRP, providing the aggregation can contribute incremental load reduction (ILR) exceeding the Minimum VGI Aggregation Size Threshold of 25 kW within an IOU service territory.
- ii. The IOUs shall dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for the ILR delivered during the dispatched hours.
- iii. In case the EVSE is located on different meter (stand-alone EVSE) from the related host site meter (for example, Multi-Unit Dwellings), the aggregator is permitted to virtually aggregate the stand-alone EVSE meter(s) with the host site load on the different meter to partially bypass the V2G export restriction on the stand-alone EVSE meter(s). The virtual load aggregation of all stand-alone EVSEs and the related host site must not be negative at any time, even when the host site is participating in an event called by another DR program. V2G discharge is prohibited outside of the IOU dispatched hours.
- iv. The ILR settlement shall be based on the measurements at the EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter.

2. Demand Response Auction Mechanism (DRAM) Modifications

DRAM is a capacity auction mechanism through which the IOUs procure DR capacity aggregated by third-party DR Providers (DRPs), with DR resources directly integrated into the CAISO markets. The procured capacity is counted for Resource Adequacy and has an associated Must Offer Obligation that requires the DRP to bid the contracted capacity into the CAISO energy markets and dispatch the aggregated customers to deliver load reduction in response to the schedule awarded by the CAISO. The DRP invoices the IOU for monthly capacity payment based on the ex-post performance of its resource in the CAISO market.

DRAM is currently authorized through 2023. A solicitation for 2022 DRAM was conducted earlier this year, resulting in procurement of approximately 200 MW (August) in DR capacity, with the associated contracts approved by the CPUC last month.

- a. Additional Auctions for 2022: Energy Division staff proposes expanding DRAM capacity for 2022 by adding a partial year supplementary auction (for DR capacity to be delivered June – December 2022) to attempt to add additional MWs. Additionally, the CPUC could consider expanding the budget for 2023 DRAM for which the auction is expected to occur in 2022 (but likely before the 2023 DRAM budget as a policy issue is revisited here or in other proceedings).
- b. Additional Requirements for Future Auctions: Energy Divisions staff proposes that new requirements for the supplementary 2022 DRAM auction and the 2023 DRAM auction should be considered to continue to improve the utility and performance of third-party DR, including:
 - i. Offered capacity that is only able to participate in the CAISO Day-Ahead Market (DAM) would be assigned a lower value in the bid evaluation process than offered capacity that is able to participate in the CAISO Real Time Market (RTM), unless the Demand Response Provider (DRP) commits to bidding the offered capacity at or lower than \$500/MWh in the DAM at all times.
 - ii. Proxy Demand Resources (PDRs) participating in CAISO Real-Time Market (RTM) must bid at or below \$900/MWh to maintain some consistency with the triggering price for the reliability-based demand response programs, including the Base Interruptible Program (BIP), which are triggered at RTM price reaching \$950/MWh.
 - iii. Once a PDR Resource Identification (ID) is introduced on a supply plan, it must be maintained on the supply plan until it is removed; the PDR cannot be reintroduced into the supply plan during the remaining months of the contract. This requirement is in addition to the existing prohibitions on the customer and Resource ID movement within and across the contract.
 - iv. A shortfall in the DR capacity shown on the monthly supply plan relative to the contracted capacity is subject to a penalty based on the level of the capacity shortfall.
 - v. Capacity awarded in the 2022 supplementary auction and the 2023 DRAM should be counted toward the Qualifying Capacity limit

established for 2022 and 2023 through the 2021 and 2022 Load Impact Protocol (LIP) processes.

3. Third Party Demand Response Procured by Non-IOU Load Serving Entities (LSEs)

To continue to improve the visibility, utility, and performance of third-party DR, and apply a consistent framework of applicable policies to DR capacity procured via DRAM vs. non-IOU LSE DR contracts, the CPUC could consider requiring all third-party Demand Response (DR) resources contracted with Community Choice Aggregators (CCAs) to adhere to certain DRAM requirements, such as those related to market bid price caps, capacity counting and showing (including customer and Resource ID movement), and minimum dispatch activity, starting in 2022.

4. Agricultural Demand Flexibility Pilot

In Phase 1 of this proceeding, Valley Clean Energy (VCE), noting that it has annual irrigation pumping usage of ~100,000 MWh/year (15% of total service area load), submitted in its opening testimony a proposal for an Agricultural Demand Flexibility Pilot, supported by Sonoma Clean Power Authority, to be made available to customers on irrigation pumping tariffs. Staff offers as a proposal concept that a modified version of VCE's proposal be considered by the CPUC to tap into the load reduction/ shift potential available in the pumping sector. VCE and other parties are encouraged to submit a more fleshed out proposal that includes the following elements:

- a. Incentivize automation of the pumping loads to receive an experimental rate that incorporates generation and delivery costs in hourly prices, with conventional monthly demand charges replaced by hourly, dynamic capacity charges. Design the experimental rate incorporating the ideas in the 6-step Distributed Energy Resource (DER) & Demand Flexibility roadmap described by ED Staff at the May 25, 2021, workshop on Advance DER and Demand Flexibility Management, specifically Steps 2 through 6. (See workshop materials here:

<https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der->

[and-demand-flexibility-management-workshop](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/slides-unide-workshop_gupta.pdf); and the specific presentation at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/slides-unide-workshop_gupta.pdf)

- b. Include a provision to hold PG&E harmless for any difference in cost recovery between the experimental rate's charges and the otherwise applicable tariff.
- c. Present the experimental rate to customers in a similar manner as the Step 1 of the above referenced 6-step roadmap.

B. Smart Thermostats

There are multiple Energy Efficiency (EE) and Demand Response (DR) programs that promote the use of smart controllable thermostats (Smart Thermostats or SCTs) for load reduction. There are also thousands of SCTs installed in California that are not enrolled in programs that would enable them to be used to promote targeted load reduction at net peak times. Energy Division staff offers a proposal concept that would involve the CPUC making changes to the existing programs, expanding the reach of these programs and coordinating better between the programs to best enable incentives for SCTs in Energy Efficiency, Energy Savings Assistance (ESA) and Demand Response budget to maximize net peak demand reductions during summer high heat events.

As shown in Tables 1-3 below, in 2020, 18 IOU administered EE programs offered smart thermostat measures for a total of 63,000 units installed. In 2020, ESA installed 22,000 units. There are a variety of non-IOU SCT programs.

The average rebate for smart thermostats across the IOU EE incentive programs was \$59 per thermostat (ranging from \$50–\$215 depending on the program). However, the average budget per thermostat installed was \$222 across all IOU EE programs. This budget includes the costs of the rebate, administration, and labor to implement the program. Slightly less than one third of EE smart thermostat measures were installed through direct install programs (in which a trained installer provides the installation at a customer's site).

Additionally, according to a 2018 SCT study, 24 percent of all SCTs offered through IOU EE programs have been installed in the three coolest regions that have relatively few “cooling days” when air conditioning is contributing to high net peak demand. Therefore, SCTs in these coastal areas may not be able to help reduce electric demand summertime net peaks. (See: Impact Evaluation of Smart thermostats - Residential Sector Program Year 2018, California Public Utilities Commission, March 2020, page 6. Available at <https://pda.energydataweb.com/#!/documents/2339/view.>)

Finally, the IOUs have not yet estimated the number of smart thermostats expected to be installed through EE programs in the upcoming program years. However, in ESA, the IOUs have forecasted that they expect to install an additional 100,000 thermostats between 2021 and 2023.

Table 1. 2020 EE Smart Thermostat Savings

IOU	Program Name	Units	Budget	First Year kWh Savings	First Year Therm Savings
Pacific Gas and Electric Company (PG&E)	Residential Energy Fitness Program	33	-303,457	3,435	355
PG&E	Residential Energy Efficiency	10,718	3,040,543	556,033	137,437
PG&E	Enhance Time Delay Relay	5,424	1,419,974	582,506	25,107
PG&E	Direct Install for Manufactured and Mobile Homes	1,391	768,493	266,937	14,198
Southern California Edison (SCE)	Plug Load and Appliances Program	15	1,671	1,775	179

IOU	Program Name	Units	Budget	First Year kWh Savings	First Year Therm Savings
SCE	Multifamily Energy Efficiency Rebate Program	404	210,435	36,792	6
SCE	Residential Direct Install Program	8,958	2,181,169	1,438,590	89,994
SCE	Comprehensive Manufactured Homes	1,844	350,487	459,777	10,777
Southern California Gas Company (SCG)	Residential Energy Efficiency Program	13,635	1,931,133	783,769	60,794
SCG	Plug Load and Appliances	39	3,820	3,630	164
SCG	Community Language Efficiency Outreach Program	130	104,840	9,937	678
SCG	Multifamily Direct Therm Savings	7,881	2,065,513	223,719	37,636
SCG	Manufactured Mobile Home	2,072	517,582	523,919	12,161
SCG	Residential Direct Install Program	1,954	266,180	13,965	16,089
SCG	Residential Joint Los Angeles Department of Water and	1,699	86,636	-	12,985

IOU	Program Name	Units	Budget	First Year kWh Savings	First Year Therm Savings
	Power (LADWP) Heating Ventilation and Air Conditioning (HVAC) Program				
SCG	Residential Single-Family Solicitation	343	144,861	31,259	2,177
San Diego Gas & Electric Company (SDG&E)	Plug Load and Appliances	5,913	989,407	383,200	26,414
SDG&E	Comprehensive Manufactured Mobile Home	1,259	347,277	228,476	5,404
<i>Sum</i>		<i>63,712</i>	<i>14,126,564</i>	<i>5,547,719</i>	<i>452,555</i>

Table 2. 2020 ESA Smart Thermostat Savings

	Units	Budget	First Year kWh Savings	First Year Therm Savings
ESA	22,142	6,343,828	3,614,921	341,930
ESA-Common Area Measures	16	7,036	915	133
<i>Sum</i>	<i>22,158</i>	<i>6,350,864</i>	<i>3,615,836</i>	<i>342,063</i>

1. SCT Related Modifications to Energy Efficiency Programs

Under this staff concept, Staff offers that several changes could be made to energy efficiency program rules to better target new installations of SCTs in 2021 and 2022 to the regions of the state and to the specific customer that will lead to greatest load reductions at net peak. Parties should be aware that a ruling was issued in the CPUC's energy efficiency proceeding (R.13-11-005) to consider measures and rule changes in energy efficiency programs that will help increase load reduction in 2021 and some of the staff proposals in this paper could also be part of proposals and changes in that proceeding.

- a. Targeting hot climate zones. SCT measures should only be installed in the hottest climate zones that have demonstrated the highest potential energy savings for smart thermostat measures.

As shown in Table 3, in 2018 climate zones 10, 11, 13, 14, and 15 had significantly higher Cooling Degree Days (CDD) and electric consumption than most other California climate zones. It was found in the 2018 smart thermostat study that smart thermostats installed in these climate zones also showed the largest energy savings. (See: Impact Evaluation of Smart thermostats - Residential Sector Program Year 2018, California Public Utilities Commission, March 2020, <https://pda.energydataweb.com/#!/documents/2339/view>)

Table 3. CA Climate Zones and Cooling Degree Days

Climate Zone	Cooling Degree Days	Total number of 2018 residential customers	Average 2018 annual electric consumption (kWh)
2	414	335,819	6,380
3	299	1,339,683	4,527
4	294	626,998	5,567
5	375	244,403	4,631

Climate Zone	Cooling Degree Days	Total number of 2018 residential customers	Average 2018 annual electric consumption (kWh)
6	866	1,536,725	5,745
7	889	717,178	4,587
8	982	2,116,032	5,883
9	1,402	2,439,293	7,083
10	1,822	1,880,786	7,452
11	1,873	373,864	7,483
12	1,360	1,495,654	6,753
13	2,308	922,882	7,566
14	3,109	381,822	8,091
15	4,945	324,021	10,336
16	1,771	251,134	5,951

Along with targeting Climate Zones with the highest CDD needs, the IOUs should also consider targeted SCT installation and DR enrollment in climate zones within their service territories that include customers with high AC usage. The IOUs and other EE program administrators could leverage load disaggregation tools to facilitate this customer targeting. The IOUs could also work with manufacturers to determine the installed base of SCT (rebate, non-rebated, etc.).

- b. Require enrollment in a demand response program with any smart thermostat incentive. For EE programs, smart thermostats have been shown to provide limited energy efficiency savings in most climate zones in

California. EE program administrators do not currently claim demand savings for smart thermostat measures. However, these programs have the potential to provide significant demand savings when paired with existing demand response programs. By focusing smart thermostat installations to climate zones that have demonstrated the highest energy savings and pairing them with a DR program, a higher amount of savings and reliability is expected. To satisfy the DR enrollment requirement, the customer could choose to enroll in Residential ELRP option (assuming this program is authorized) or any of the existing supply-side DR programs offered by the IOUs or third-party DR Providers or other designated pilot programs offered by IOUs.

- c. Consider either a new statewide program to encompass these changes, or direct the IOUs and other EE program administrators to, at a minimum, maintain the budgets for their current programs. Due to the limited energy efficiency savings of smart thermostat measures, IOUs, at least, if not other EE program administrators have been scaling down the installation of smart thermostats through their energy efficiency programs. This may limit the effectiveness of the proposal as there will be fewer smart thermostat measures installed going forward. ED recommends considering directing the IOUs and other EE program administrators to develop a statewide program following the suggestions above. The program should make recommendations on the most effective delivery channel and program design to maximize smart thermostat adoption and DR program enrollment.
- d. Utilize Combine EE-DR Cost Effectiveness Tests to increase the Cost Effectiveness of Smart thermostats for Energy Efficiency Programs. At this time smart thermostat measures are not cost effective in the Energy Efficiency portfolio leading to the IOUs removing smart thermostat measures from the portfolio. CPUC Energy Division is in the process of developing a Cost Effectiveness tool for EE-DR that encompasses the load shapes for the dual EE-DR programs. Including energy savings from this dual cost effectiveness test will increase the cost effectiveness of these measures, making it more likely for the IOUs and other EE program administrators to offer these measures.

2. SCT Modifications to Energy Savings Assistance (ESA) Programs

- a. Continue to allow smart thermostats in all climate zones with potential voluntary participation in the DR program. ESA makes smart thermostats available to all eligible customers across all climate zones for PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) service territory. Due to the program design, it is recommended that this be allowed to continue.
- b. For hotter climate zones that currently allow central Air Conditioning (AC) measures (and potentially paired with insulation measures) as well as smart thermostats, include voluntary participation in the DR program. ESA delineates certain hot climate zones that can receive Central AC measures in order to increase cost-effectiveness and minimize use of ratepayer funds. These climate zones overlap with the five top climate zones identified in the EE proposal. Energy Division offers for consideration a program concept that customers who have SCT installed in these climate zones either in conjunction with central AC measures or separately be set up to automatically participate in the ELRP program.

C. Utility-Scale Storage, Import, and Generation

Staff makes the following observations and proposals regarding opportunities to bring new battery and generation resources online by summer 2022.

1. Introduce Penalties for Delays to D.19-11-016 Procurement

CPUC could apply penalties to Load Serving Entities (LSEs) for not bringing ordered procurement resources online in accordance with Integrated Resource Planning (IRP) decision D.19-11-016. D.19-11-016 required Tranche 1 resources by August 1, 2021 and Tranche 2 resources by August 1, 2022, and Tranche 3 resources by August 1, 2023. There are no penalties imposed on LSEs for failure to meet online dates with new resources per D.19-11-016; however, as detailed in D.20-12-044, the CPUC intends to consider whether to order backstop procurement and allocate the cost of that backstop procurement to one or more LSEs.

The CPUC could consider putting all LSEs on notice that it intends to impose fixed penalties (for instance, potentially \$50,000 per incident) or capacity-based

(potentially \$10/kW by Month for each month delay) for any LSE that fails to achieve commercial online dates consistent with the order. The CPUC may consider a grace period of up to six months from the expected online dates. Although collectively, LSEs contracted for sufficient Tranche 1 resources, some Tranche 1 projects were delayed for a variety of reasons. Penalties (with or without a grace period) may ensure that the delayed Tranche 1 resources materialize prior to June 2022. Penalties (with or without a grace period) may ensure that Tranche 2 and 3 resources materialize with minimum delays in 2022 and 2023. Any procurement delayed Penalties would be incremental to any penalties associated with Resource Adequacy deficiencies, and LSEs would not be exempt from penalties even if they were otherwise fully resourced for Resource Adequacy.

2. Increase Resource Adequacy Penalties

Pursuant to D.20-06-031, the RA penalty structure is currently \$8.88 kW/month for LSEs who fail to meet summer system RA obligations in the month ahead. The CPUC could consider doubling the penalties for LSEs who may be short in August 2022 and September 2022.

3. Accelerate Procurement Ordered in IRP Mid-Term Reliability Decisions

All LSEs were ordered to procure new resources beginning in June 2023 in IRP decision D.21-06-035, the IRP's Mid-Term Reliability (MTR) Procurement Decision. To the extent that these 2023 resources could be brought online by summer 2022, the CPUC could provide an incentive to LSEs for early compliance with D.21-06-035.

4. Emergency Procurement and Cost Recovery via a Non-Bypassable Charge

The CPUC could establish a new non-bypassable charge (NBC) for cost recovery of costs associated with emergency procurement that adds additional reserve margin and does not already fit into an existing cost recovery mechanism.

Although there is an existing Cost Allocation Mechanism (CAM) charge frequently used for IOU cost recovery associated with eligible capacity costs, the

CAM charge does not usually allow for cost recovery for emergency procurement that adds to reserve margins or for resources that do not provide firm resource adequacy.

There are a variety of procurement options for new, accelerated, re-contracted, or non-traditional resources that could provide additional reserve margin for Summer 2022. If a resource can provide both mutual benefit to all ratepayers and additional reserve margin above the resource adequacy requirements of individual LSEs, then it could be eligible for cost recovery under a new charge (if one was created). The CPUC could establish the charge and limit the eligibility for cost recovery to specifically approved projects via Advice Letter.

Examples of Potential Emergency Procurement Resources that may be considered eligible (these descriptions may not be mutually exclusive):

- a. Resources that could achieve accelerated online dates in advance of system RA requirements or otherwise applicable IRP Procurement Orders. These resources would have to be subject to a Must-Offer Obligation, and be in excess of any single LSE's individual RA requirement.
- b. Resources that IOUs could procure in excess of those resources needed to meet their bundled procurement RA obligations. In addition to the IRP-ordered resources they are responsible for procuring on behalf of their bundled customers, D.21-02-028 and D.21-03-056 in this proceeding previously authorized IOUs to procure new storage, imports, and/or generation resources from efficiency improvements for contracts of five years or less on behalf of all customers for 2022, up to the hard cap of 1,500 MW (across all three IOUs) that was set in that decision for supply-side generation and in-front-of-meter storage resources. This authority and CPUC directive remains in place, although the cap could be increased to meet a higher target if the CPUC determines that there is a greater need in 2022 than identified in the previous phase of the proceeding. In addition, the IOU procurement in excess of bundled procurement obligations directive could be expanded to include deliveries for 2023 (or beyond).
- c. New storage at IOU properties. Staff expects that there will be significant challenges associated with LSEs successfully accelerating the online dates of significant quantities of IRP resources by summer 2022. Given that IOU

properties – and in particular IOU substations -- can often avoid or expedite many of the challenges associated with bringing new projects online (e.g., site control, interconnection, deliverability, permitting, etc.), this concept would be for IOUs to be directed to submit project proposals via Tier 3 Advice Letters for Utility owned storage on utility-owned (or controlled) properties that could demonstrated to be brought online by June 2022.

- d. New Resources that can be depended upon to provide energy dispatch in response to alerts, warnings, and any stage of emergency. Resources could be use limited and would not necessarily have to be subject to a must-offer obligation. Resources could be under contract to an IOU or a non-IOU entity, but the IOU would need to submit the contract to the CPUC via Advice Letter in order for the resource to be eligible for cost recovery through the Emergency procurement non-bypassable charge. These resources must be additive to the existing 15% resource adequacy planning reserve margin. To the extent that there are ways for such resources to be procured and paid for by all CAISO-wide entities (and not limited to CPUC-jurisdictional entities), the CPUC should seek cost-recovery through alternative mechanisms.
- e. Re-contracting with Existing Resources that may retire in 2022. The CAISO's Capacity Procurement Mechanism (CPM) allows for a capacity payment to a resource that announces retirement. The CPUC could authorize procurement of such resources in advance of the CAISO CPM process with the expectation that such leeway may achieve a net cost savings for ratepayers and provide for earlier certainty to potentially retiring resources. These re-contracted resources would have to be in excess of RA requirements.
- f. Additional firm imports above Resource Adequacy limits.
- g. IOUs could be authorized to coordinate with the State to determine whether arrangements for any temporary generation resources that are procured or leased in 2021 – or whether similar and additional resources of this type – should be replicated for 2022. Similarly, staff proposes that IOUs be authorized to use (and obtain cost-recovery for fuel, operation and maintenance, etc.) existing or planned PSPS-purposed temporary generation that is used for CAISO systemwide reliability purposes so long

as it can meet dispatch requirements during alerts, warnings, and grid emergencies.

- h. IOUs could be directed to pursue long-term contracts for gas generation resources on behalf of all benefiting customers, provided that any gas contracts of greater than 5 years in length must require the resource, beginning in a certain future year of the contract, be capable of being fueled with hydrogen manufactured through carbon-free process or utilize another means to offset air quality and greenhouse gas emissions (such as sequestration) if fueled with natural gas.
- i. Firm supply resources that can be available for dispatch to meet the net peak but that do not otherwise meet Resource Adequacy capacity obligations.

5. Bundled Procurement Rules Modifications

Under existing bundled procurement rules, the IOUs are required to schedule and bid their hydro resources to achieve least cost procurement. The CPUC could adjust these rules to allow IOUs to preserve hydro generation for maximum availability during strained grid conditions, instead of using hydro at all times when it appears to be economically efficient. This policy change would effectively allow IOUs to plan for hydro resources to count for a higher RA value in August and September, during hours when it is most critically needed.