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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027.	Application 22-05-002
And Related Matters.	Application 22-05-003 Application 22-05-004

ASSIGNED COMMISSIONER'S RULING DIRECTING RESPONSE TO QUESTIONS AND ENERGY DIVISION STAFF PROPOSALS RELATED TO APPLICATION 22-05-002 PHASE II ISSUES AND DIRECTING SOUTHERN CALIFORNIA EDISON COMPANY TO SUBMIT A CAPACITY BIDDING PROGRAM ELECT PROPOSAL FOR PROGRAM YEARS 2024-2027

Pursuant to the Amended Scoping Memo issued on December 19, 2022, this Ruling seeks party comments in response to questions specific to Phase II of this proceeding, as well as comments on the attached Energy Division staff proposals for Demand Response (DR) program changes.[1]

The Energy Division staff proposals are provided below in Appendix A of this Ruling.

To assist parties in responding to questions and staff proposals presented here that pertain to the Emergency Load Reduction Program (ELRP), this ruling also issues the *Statewide Residential Emergency Load Reduction Program Baseline*

[1] Assigned Commissioner's Amended Scoping Memo and Ruling, and Assigned Administrative Law Judges' Ruling on Two Motions at 10.

Evaluation report (the ELRP Report) prepared for the Utilities[2] by Demand Side Analytics. Because of file size limitations, the ELRP Report is hosted on the Commission website, and a link is provided in Appendix B.

This ruling also includes a directive to Southern California Edison Company (SCE) to submit a "Capacity Bidding Program (CBP) Elect" program proposal for 2024 to 2027 in their Supplemental Testimony, which, per the December 19, 2022, Assigned Commissioner's Amended Scoping Memo (Amended Scoping Memo) schedule, is due on March 3, 2023.

1. Procedural Background

DR programs encourage reductions, increases, or shifts in electricity consumption by customers in response to economic or reliability signals. Such programs can provide benefits to ratepayers by reducing the need for construction of new generation and the purchase of high-priced energy, among others. Commission Decision (D.) 17-12-003 directed Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and SCE (collectively, the Utilities) to file, by November 1, 2021, their 2023-2027 DR Portfolio Applications. A September 30, 2021 letter issued by the Commission's Executive Director extended the deadline to May 2, 2022.

On May 2, 2022, PG&E (Application (A.) 22-05-002), SDG&E (A.22-05-003), and SCE (A.22-05-004) filed their respective 2023-2027 DR Portfolio Applications. Pursuant to Rule 7.4, an Administrative Law Judge (ALJ) Ruling issued on May 25, 2022, consolidated these applications (A.22-05-002, *et al.*).

A July 5, 2022 Assigned Commissioner's Scoping Memo and Ruling divided this proceeding into two phases. Phase I addressed the Utilities' 2023

[2] The Utilities are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

Bridge Year funding requests. The Amended Scoping Memo established the scoping issues and procedural schedule for Phase II, which is currently undertaking the work to address the Utilities' Applications for the years 2024-2027.

2. The Statewide Residential Emergency Load Reduction Program Baseline Evaluation

Ordering Paragraph (OP) 39 of D.21-12-015 directed the Utilities to evaluate their Residential ELRP baseline methodology after the first year of the program and to submit a joint report of their findings to the Commission's Energy Division.

The Utilities submitted the Statewide Residential Emergency Load Reduction Program Baseline Evaluation report (the ELRP Report) prepared by Demand Side Analytics on January 17, 2023, to the Energy Division and members of the Rulemaking (R.) 20-11-003 and A.22-05-002 Service Lists. As mentioned, the ELRP Report is being issued in this ruling to aid parties in responding to the relevant questions and staff proposals herein.

The ELRP Report compares various residential baseline models that have been or could be used in the calculation of incremental load reduction (ILR) for residential ELRP sub-group A.6, also known as Power Saver Rewards (PSR). Baselines are mathematical models used to estimate the counterfactual electricity consumption that a customer would have exhibited, had they not been dispatched for a DR event.

3. Directive to SCE

In its protest to SCE's Application, the Joint DR Parties (JDRP) of CPower and Enel X North America, Inc. expressed "serious concerns about SCE's proposal relating to its [Capacity Bidding Program (CBP)] product, which SCE notes is a relatively small program."[3] JDRP further asserts that based on its experience with SCE's CBP program, "…SCE's proposed changes [to its CBP program] will continue to shrink, rather than expand, program enrollment and participation."[4] JDRP suggests that "to increase the program's desirability, SCE should be required to adopt a CBP Elect model, similar to PG&E or SDG&E's CBP Elect programs."[5] In its reply, SCE did not respond to this protest.[6]

To adequately consider JDRP's recommendation for growing DR via SCE's CBP program, the Commission needs the parties to fully debate the merits of a potential CBP Elect offering by SCE. To facilitate the discussion, SCE is directed to submit a "CBP Elect" program proposal for the PYs 2024 to 2027 in their Supplemental Testimony filing due March 3, 2023.

To allow parties to fully comment on the merits of a CBP Elect proposal to be filed by SCE, the proposal should include sufficient details regarding program design, schedule, budget, cost-effectiveness, and any other element that could be an important factor in a party's comment. In the interest of time, SCE is invited to model its proposal on the Elect products offered by PG&E and/or SDG&E. In the Supplemental filing, SCE can discuss its position on whether its CBP Elect proposal should be adopted or not, and why.

4. Demand Response Auction Mechanism

In the near future, a further Ruling will be issued to provide parties with a reduced-redaction Nexant Report and Demand Response Auction Mechanism (DRAM)-specific topics for party comment.

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[3] JDRP Response to IOU Consolidated Applications, June 6, 2022, at 7.

[4] *Ibid*, at 7.

[5] *Ibid*, at 8.

[6] Reply of SCE Company to Party Responses and Protests, June 13, 2022.

5. Schedule

To give parties adequate time to respond to this this Ruling, the following revised schedule is adopted here (and may be further modified by the assigned Commissioner and/or Administrative Law Judges as required to promote the efficient and fair resolution of the Rulemaking). The due dates for Phase II DR Intervenor Testimony and Rebuttal Testimony regarding DR Program issues have been extended. For all parties, Opening Responses and Reply Responses pursuant to this Ruling shall be due concurrently with Phase II DR Intervenor Testimony and Rebuttal Testimony (as noted in the revised Schedule below).

The schedule below also advances the due dates for DR Opening Briefs to July 14, 2023, and Reply Briefs to August 11, 2023. Should Evidentiary Hearings be necessary, the original Briefing dates established in the Amended Scoping Memo will be restored.

2024-2027 Utilities' Demand Response Program Schedule

Applicants' File Supplemental Testimony with DR Cost Effectiveness Report as Required by 2016 DR Cost Effectiveness Protocols	February 3, 2023
Phase II DR Applicants' Supplemental Testimony Due	March 3, 2023
Phase II DR Intervenor Testimony Due and All Ruling Opening Responses	April 21, 2023
Phase II DR All Party Rebuttal Testimony Due and All Ruling Reply Responses	May 5, 2023
Meet and Confer to Determine Need for Evidentiary Hearings	June 2, 2023
Last Day to Request Evidentiary Hearing and Conduct Discovery	June 5, 2023
Evidentiary Hearings, if necessary	June 14-15, 2023

Concurrent Opening Briefs on Phase II DR	June 30, 2023
Concurrent Reply Briefs on Phase II DR	July 21, 2023
Last Day to Request Oral Argument	September 7, 2023
Oral Argument	September 14, 2023
Proposed Decision	October 2023

The DRAM schedule remains unchanged:

DRAM Schedule

Event	Date
Concurrent Opening Testimony Due on DRAM	May 31, 2023
Concurrent Reply Testimony Due on DRAM	July 14, 2023
Meet and Confer to Determine Need for Evidentiary Hearings on DRAM Issues	August 1, 2023
Last Day to Request Evidentiary Hearing and Conduct Discovery	August 11, 2023
Evidentiary Hearings	End of August 2023
Opening Briefs on DRAM	September 30, 2023
Concurrent Reply Briefs on DRAM	November 3, 2023
Proposed Decision	January 2024

6. Questions for Parties to Address

<u>TECHNOLOGY PROGRAMS</u>

1. In portfolio applications, PG&E proposes to end the residential thermostat incentives and instead have customers rely on incentives from energy efficiency, the Self Generation Incentive Program, and Integrated Demand-side Management to fund them.[7] SDG&E proposes to eliminate thermostat incentives and instead provide an enrollment incentive. SDG&E also cites

[7] PG&E-2 at 4-12

technical barriers to providing thermostat incentives.[8] Should ratepayers continue to fund incentives for smart communicating thermostats through the AutoDR program (Category 4 of IOU proposed budgets)? Why or why not? If yes, what should be the eligibility criteria for a customer to receive an incentive, what is the right thermostat incentive amount and why? Should it decline over time or be based on some other factors? What, if any, customer performance standards or requirements should be attached?

2. The utilities have proposed to spend $42 million over four years (2024 to 2027) on the Demand Response Emerging Technology program (DRET).[9] As described in D.17-12-003 at page 75, this program "enables research into new technology, equipment, processes and products." This program has operated since the 2009-2011 program cycle. Bi-annual reports filed by each utility describe a range of efforts including lab and field tests, demonstration projects, evaluations of capabilities and market and deployment barriers, often focused directly on emerging technologies including pre-commercial technologies. Reports on these projects can be found on the Emerging Technology Coordinating Council website.[10] Other studies[11] show a large gap between DR potential and realization.

    a. Has the DRET program been valuable in advancing DR goals? Is it delivering adequate "value for the money" to ratepayers?

    b. Is the DRET program duplicative of CEC's EPIC program?

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[8] SDG&E-1B EBM-50

[9] More information on the statewide DRET collaborative and bi-annual reports can be found at this link: About DRET – Emerging Markets & Technologies (dret-ca.com) (https://www.dret-ca.com/about-program/).

[10] https://www.etcc-ca.com/reports/search.

[11] https://buildings.lbl.gov/potential-studies

c. Is continued DRET program funding necessary in light of the various pilots proposed by IOUs that the Commission may adopt? If yes, how should the Commission differentiate the objectives of the DRET program from IOU pilots?

d. Should the Commission adopt new or revised guidelines to improve the DRET program; if so, what guidelines should the Commission consider? For instance, should DRET:

   - Refocus away from testing communication and control capabilities to dispatch new devices in response to signals?
   - Refocus toward testing new business models or approaches that could be scaled up or adopted by IOU or third-party program administrators to increase DR capacity?
   - The parties are invited to comment on the offered example and/or suggest other guidelines.

<u>ELRP</u>

3. What factors should the Commission consider in deciding whether to extend ELRP to 2026 and 2027? Does the status of these factors justify the extension of the pilot program?
4. In D.21-12-015, the Commission provided a limited exemption from its Prohibited Resource (PR) policy in permitting customers to use PRs to participate in ELRP events subject to certain conditions and receive compensation for load reduction enabled by the use of the PR. D.21-12-015 also provided direction to the instant proceeding to consider minimizing the use of PRs.[12]

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[12] D.21-12-015, Att. 2 at 1:

"ELRP duration will be five years (2021-2025), with years 2023-2025 subject to review and revision in the Demand Response (DR) Applications proceeding expected to be initiated May 2022.

a. Should the existing PR policy as applied to ELRP be modified? Why or why not? If yes, how?

b. Should PRs be prohibited from participation in ELRP?

c. In the event the CEC offers a program[13] that accommodates and compensates the use of PRs during grid reliability events, are there any compelling reasons the Commission should not require the IOUs to facilitate participation by customers with PRs in CEC's offering, with compensation and utility expenses funded by the CEC? Why or why not? If yes, how should the Commission ensure that this option for enrolling in CEC's program does not lead to customer attrition from DR programs counted for RA under CPUC oversight?

5. Per D.21-12-015, the load reduction potential of ELRP is not counted for Resource Adequacy (RA) or considered by the CEC in forecasting peak demand.[14] ELRP is intended to be an insurance layer to supplement RA resources during emergency events and targeted for customers who do not see their situation fitting with the requirements of RA-counted DR programs. ELRP is not intended to offer competition to RA-counted DR programs such that customers are diverted away from enrolling in those DR programs.

"ELRP design aspects that are subject to review and revision include minimizing the use of diesel backup generators where there are safe, cost-effective, and feasible alternatives; consideration of local air pollution impacts on disadvantaged communities; and other modifications to make the program more effective and consistent with the state's decarbonization goals."

[13] CEC will host a workshop on January 27, 2023, to seek public comments on potential modifications to the Demand Side Grid Support (DSGS) program (workshop details are available at https://www.energy.ca.gov/event/workshop/2023-01/session-1-lead-commissioner-workshop-demand-side-grid-support-program-and.

[14] D.21-12-015, Att. 2 at 2.

a. Is the risk of ELRP competing with RA-counted DR programs a concern that should be addressed by the Commission?

b. What design changes or guardrails should the Commission consider (for example, guidelines for utility ELRP marketing) to mitigate this concern?

6. Should the compensation rate (applicable to the whole ELRP program or any specific sub-group option of ELRP) for incremental load reductions achieved during an ELRP event be reduced? Why (and to what level) or why not?

7. The Commission authorized ELRP to help mitigate grid emergencies. Per D.21-12-015, the dispatch trigger for the Power Saver Rewards (PSR) program (ELRP/A6 sub-group) is linked to CAISO issuing a Flex Alert notice (unlike the triggers for other ELRP sub-groups, which are generally[15] linked to an EEAx notice). Experience indicates that in some instances, the CAISO has issued Flex Alerts accompanied by an EEA Watch declaration at the same time; in other instances, CAISO has issued Flex Alert stand-alone without any accompanying EEAx notice.

   a. What is the reliability benefit of dispatching PSR (but not other ELRP sub-groups) in response to a stand-alone Flex Alert if the grid conditions are not serious enough to warrant an EEAx alert?

   b. To better align with the dispatch triggers of other ELRP sub-groups, should the PSR dispatch trigger be limited to a Flex Alert accompanied by an EEAx notice?

8. If the ELRP pilot is extended, should the temporary increase of the DR reliability cap to 3% (authorized in D.21-03-056) be also continued?

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[15] D.21-12-015 requires that certain ELRP sub-groups (A.2, A.4, A.5) be dispatched by the IOUs for a specified minimum number of hours per year. The Decision allows IOUs to use discretion in dispatching these sub-groups based on grid conditions, which could include Flex Alert.

MISCELLANEOUS

9. Should the Commission continue the exemption of energy storage resources not coupled with fossil-fueled generation from the Demand Response Prohibited Resources Policy (as established in D.18-06-012), or should the Commission develop a new metric to be met by energy storage resources in order to participate in demand response programs which are subject to the Demand Response Prohibited Resources Policy?
10. The current DR Cost Effectiveness Protocols were established in 2016. If the Protocols are to be updated, what specific areas of the Protocols should be considered for revision and why? Please limit comments to issues within the scope of and exclusive to the DR Cost Effectiveness requirements as described in D.15-11-042 and the 2016 DR Cost Effectiveness Protocols, and other directives in Commission decisions and rulings under previous DR proceedings. Please do not comment on general Distributed Energy Resources (DER) Cost Effectiveness issues within the scope of R.22-11-013, including those pertaining to the Avoided Cost Calculator (ACC) and cost-effectiveness evaluation of resources other than DR.
11. Currently, some aspects of Rule 24/32 are applicable only when DR providers aggregate bundled customers. Should these Rules be expanded to include DRPs' aggregation of unbundled customers? If so, how should these Rules be revised?

IT IS RULED that:

1. The amended schedule of this proceeding is adopted as set forth in Section 5. The assigned Commissioner and/or Administrative Law Judges may adjust the schedule of this proceeding, as needed, to promote efficient management of the case.

2. Southern California Edison Company shall submit a Capacity Bidding Program Elect program proposal for 2024-2027 in their Supplemental Testimony filing due March 3, 2023.

Dated January 27, 2023, at San Francisco, California.

/s/ JOHN REYNOLDS
John Reynolds
Assigned Commissioner

APPENDIX A

Appendix A

A.22-05-002 Phase II

Demand Response Staff Proposals

Energy Division

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1. A.22-05-002 Phase 2 Staff Proposals

1.1 Proposal A: Modify Day-Ahead Trigger for ELRP

1.1.1 Proposal

AWE "Alert" should be mapped to EEA Watch instead of EEA 1 since EEA 1 can only be issued day-of. The correction to the AWE-EEA mapping table in D.21-12--015 Attachment 2 is highlighted below in green:

Table. Alert Warning Event Levels

AWE Levels	**NERC EEA Levels**	**Comments**
Restricted Maintenance Operations		Issued in real time or in advance
Transmission Emergency		Issued in real time
Notifications of forecasted reserve deficiencies		
Alert	EEA Watch	Issued in advance – day ahead by 15:00
Warning	EEA 1	Issued in real time
Warning – triggering DR programs	EEA 2	Issued in real time
Stage 1	EEA 2	Issued in real time
Stage 2	EEA 3	Issued in real time
Stage 3	EEA 3	Issued in real time

This change to the AWE-EEA mapping table would effectively result in replacing all references to DA Alert in D.21-12-015 with EEA Watch.

1.1.2 Background

Decision (D.) 21-03-056 established the day-ahead (DA) and day-of (DO) triggers for the Emergency Load Reduction Program (ELRP) in Attachment 1. In defining these triggers, the Decision referenced CAISO issued grid alerts per the "Alert, Warning, Emergency" (AWE) process as defined in CAISO's Operational Procedure 4420. Per CAISO's input indicating a planned transition from AWE alert system to the North American Electric Reliability Corporation (NERC) Energy Emergency Alert (EEA) alert system, the Decision also included a table to show equivalent alert levels between the AWE and EEA alert systems. The table mapped the DA Alert to EEA 1 and noted that EEA 1 would be "issued in advance – day ahead by 1500".[1] This table was later repeated in the D.21-12-015 Attachment 2.

In between the two Decisions, the CAISO completed its transition from the AWE process to the EEA standard. In the May 1, 2022 update to CAISO Operating Procedure 4420, the CAISO clarified that EEA Watch replaced the AWE's "Alert" notice and EEA 1 replaced the AWE's "Warning" notice. Furthermore, it established that EEA Watch would be issued "by 15:00 PPT the day before [day-ahead] when the Day-Ahead analysis is forecasting that one or more hours may be energy deficient" (unless if a sudden onset event occurs, in which case EEA Watch may be issued after 15:00) whereas the EEA 1 notice would be issued in the day-of if "real-time analysis reflects that during one or more hours all available resources are in use and/or are committed to be in use".[2]

To summarize, the AWE-EEA mapping tables in D.21-03-056 and D.21-12-015 are outdated and internally inconsistent. It is illogical to use EEA 1 as the DA trigger for ELRP per the current mapping table since EEA 1 notices, by definition, cannot be issued a day in advance. Now that CAISO has completed its transition to the EEA standard, it is clear that the DA Alert from the legacy AWE process should be mapped to EEA Watch instead of EEA 1, per the CAISO Operational Procedure 4420.

[1] D.21-03-056 Attachment 1 at 9.

[2] California ISO Operating Procedure 4420, Version No. 14.0 at 7-9.

1.2 Proposal B: Clarify Calculation of ELRP Group A Compensation

1.2.1 Proposal

The Commission should direct the IOUs to implement Method 2 (described below) for determining the event ILR to be used as the basis for compensating ELRP Group A customers, starting in 2024. Additionally, the IOUs should voluntarily switch to implementing Method 2 in 2023 and file ALs as needed to document this change.

1.2.2 Background

ELRP Compensation Policy

D.21-12-015 (Decision) defines Incremental Load Reduction (ILR) as the basis for compensation under the Emergency Load Reduction Program (ELRP). More specifically, the Decision directs:

> "Incremental Load Reduction (ILR) is defined as the load reduction achieved *during an ELRP event* (emphasis added) incremental to the non-event applicable baseline and any other existing commitment. Only ILR is eligible for compensation under ELRP."[3]

Per the Decision, "There are no penalties for non- or under-performance."[4]

IOU Advice Letter Filings

The IOUs submitted joint Tier 1 Advice Letters (ALs) describing ELRP terms and conditions, which were approved by Energy Division (ED)[5]. The ALs did not explicitly describe the methodology for determining the ILR "achieved during an ELRP event." (defined as "event ILR" in this proposal).

The IOUs submitted program parameters for the ELRP sub-group A.6 in Tier 2 ALs on February 4, 2022.[6] SCE submitted two additional ALs related to ELRP sub-group A.6.[7] These ALs, which were approved by ED, generally defined ILR

[3] D.21-12-015, Att. 2 at 12.

[4] D.21-12-015, Att. 2 at 13.

[5] Joint AL 6485E (PG&E), 3939E (SDG&E), 4708E (SCE).

[6] AL 6496E (PG&E); AL 3950E (SDG&E), and AL4709E (SCE).

[7] AL 4774E was submitted April 28, 2022, and approved June 13, 2022. It revised the terms and conditions, only for sub-group A.6. AL 4801E was submitted May 26, 2022, and approved July 12, 2022. It withdrew the proposed ELRP tariff and aligned the program structure with that of PG&E.

using similar language as in the Decision but also did not explicitly describe the methodology for determining the ILR "achieved during an ELRP event."

IOU Methodology to Determine Compensation

Recently, ED became aware of the specific details of the methodology implemented by the IOUs for determining the event ILR delivered by customers in various ELRP A sub-groups (with one exception).[8]

The IOU chosen methodology (Method 1) for determining event ILR of a customer involves 1) sub-dividing an event window into hourly intervals for measuring hourly ILR relative to the non-event baseline in that hour, 2) summing all positive hourly ILRs occurring in the event (that is, excluding or zeroing out all negative hourly ILRs in the event).

ED recommends adopting a different methodology (Method 2) for determining event ILR of a customer, which involves 1) summing (netting) all hourly ILRs, positive *and* negative, and 2) retaining for compensation only those event ILRs that are positive overall, consistent with the "no penalties for non- or under-performance" aspect of ELRP.

Analysis of Compensation Methodologies

A simple example illustrates the difference between the two methods for a hypothetical 3-hour ELRP event, with measured hourly ILRs in each hour as shown in the table below:

Event	Measured Hourly ILR	ILR Method 1 (IOUs)	ILR Method 2 (ED)
Hour 1:	+2	+2	+2
Hour 2	+2	+2	+2
Hour 3	-3	0	-3
Event ILR		+4	+1

[8] SDG&E used the methodology described as Method 2 in this proposal to determine event ILR for ELRP Power Savers Rewards customers. For all other ELRP A sub-groups, SDG&E used Method 1. PG&E and SCE used Method 1 for all ELRP A sub-groups.

Several potential concerns are associated with IOUs' chosen Method 1. These include:

1. The approach appears inconsistent with the Decision's concept of ILR achieved "during an event" (event ILR) – nowhere does the Decision language suggest that the event window be sub-divided in hourly intervals with certain intervals *excluded* entirely (note that Method 2 does not exclude any measurement interval within the event).

   A potential counterargument that the "no penalties" aspect of ELRP implies exclusion of negative hourly ILRs should be dismissed as in the context of the relevant section of the Decision, the "no penalties" is reasonably interpreted as referring to a customer's overall performance in an ELRP event. It is not reasonable to interpret the statement as giving permission to exclude negative ILR in an administratively selected measurement interval (such as, hourly) within an event.

2. The approach is internally inconsistent – the measurement of ILR for any chosen interval (such as, hourly) necessarily involves netting of load increases and reduction in sub-intervals within the chosen interval.

3. The event ILR is dependent on the measurement interval size (if the chosen measurement interval was 15 min, the resulting event ILR could be substantially higher; note that under Method 2, the resulting event ILR is independent of the measurement interval size).

4. Under this approach, statistical noise involving non-participating customers could result in non-zero compensation, leading to substantially higher than warranted program payout without commensurate benefit to the ratepayers. While statistical noise could also be an issue with Method 2, the higher level of aggregation should reduce error and better align payments with overall performance.[9]

[9] Statewide Emergency Load Reduction Program Baseline Evaluation, at 11: "The level of aggregation of baseline reductions has a large effect on the amount of settlement error: aggregating noise from the hourly or event level will improve the ability of baseline methods to detect true reductions. Instead of paying participants for reductions on an event hour by event hour basis, *providing compensation at the event level* (emphasis added) or the monthly level will minimize payment error and ensure participants are fairly compensated for real reductions."

5. Excluding negative hourly ILRs could encourage unintended behavior involving customers increasing load during the later hours of ELRP events.
6. The approach could be perceived as unfair: customers with higher overall load reduction can receive same compensation as customers contributing lower overall load reduction.
7. The resulting event ILR could be misinterpreted as higher "performance" than that actually achieved by the customer.

ED believes that Method 2 is superior in either avoiding or mitigating above concerns compared to Method 1. ED recommends that Method 2 be adopted consistently as a basis of compensation across all ELRP sub-groups in Group A, as summarized earlier in the "Proposal" section.

1.3. Proposal C: Modify ELRP Settlement for Group B

1.3.1. Proposal

Energy Division (ED) proposes to clarify and modify the current settlement guidelines for ELRP Group B (market integrated DR resources, aka PDRs) to eliminate an unintended perverse incentive that may arise in certain scenarios.

The modification involves eliminating any ELRP Event Compensation where the energy quantity delivered by a PDR during an ELRP event that is below the PDR's QC value. However, DR providers could still earn the full ELRP Compensation Rate for the portion of energy quantity delivered by a PDR during an ELRP event that exceeds the PDR's QC value.

The specific changes to the settlement methodology are shown as markup to the current guidelines described in D.21-12-015, Attachment 2 in the "Proposed Modifications" section below.

1.3.2. Background

In D.21-03-056, the Commission adopted a framework for the ELRP pilot that contained elements of those party proposals, including the separation of ELRP into two distinct customer groups: (1) Group A comprised of select non-residential customers and aggregators not participating in DR programs, and (2) Group B comprised of market-integrated Proxy Demand Resources (PDR) . Attachment 1 of D.21-03-056 outlined the compensation and settlement methodologies for both Groups A and B.

D.21-12-015 made several modifications to the ELRP pilot, including incorporating minor revisions to the Group B compensation methodology in Attachment 2.

ED staff have identified that the existing Group B compensation methodology contains erroneous phrases and incomplete instructions, which could disincentivize an aggregator from participating in the CAISO market in certain scenarios. Proposed Corrections to Group B Settlement Guidelines

1.3.3. Proposed Modifications

The Commission should adopt changes to the current "ELRP Settlement for Group B" guidelines (quoted verbatim below) under D.21-12-015 Attachment 2, Section 6, as marked below (underlined text for insertions, strikethrough text as deletions).

For participation in ELRP under Group B, a DRP must construct a PDR Portfolio consisting of only 1) PDRs with RA assignment or PDRs without RA assignment (but not both) and 2) PDRs limited to the service area of one IOU (thus, a DRP may have up to six PDR portfolios participating in ELRP).

The CAISO settled aggregated load during an ELRP event is modified to count net energy exported to the distribution grid by any customer location within the PDR aggregation.

Following an ELRP event, the DRP's scheduling coordinator is responsible for determining the following:

1. ELRP Event Performance (total load reduction during the ELRP event) of each PDR in the DRP's PDR Portfolio by applying the applicable ELRP modified baseline to the PDR's modified aggregated load settled during the ELRP event.

2. ILR of each PDR by subtracting the CAISO scheduled award quantities, inclusive of da-ahead market (DAM) and real-time market (RTM), from the PDR's ELRP Event Performance. If the total market award for the PDR during the ELRP event is zero, then ILR of the PDR equals the ELRP Event Performance.

3. The ELRP Event Compensation due for each PDR by adding all interval-specific ELRP Compensations across all applicable intervals of the ELRP event, subject to the following:

    a. The interval-specific ELRP Compensation in each applicable interval of the ELRP event is obtained by subtracting 1) any CAISO market payments for any portion of the load reduction counted in the interval-specific ILR <u>exceeding Market Eligible Capacity (MEC), defined below,</u> and 2) the interval-specific CAISO Opportunistic Revenue (COR), defined below, from 3) the interval-specific Product of the ELRP Compensation Rate and the interval-specific ILR (see illustration below).

       If the interval-specific ILR is negative, then the interval-specific ELRP Compensation is set to zero in that interval.

If the interval-specific COR is greater than the interval-specific Product, then the interval-specific ELRP Compensation is set to zero in that interval.

b. The interval-specific COR is the product of the interval-specific Market Eligible Capacity (MEC), defined below based on the interval-specific CAISO Market Event Performance (MEP) determined under the applicable CAISO market baseline, and the interval-specific CAISO Opportunistic Price (COP) ~~Clearing Price Delta (CCPD)~~, defined below (see illustration below).

i. MEC:

If the total CAISO scheduled award quantity in an interval is non-zero:

1. And if the interval-specific MEP is less than or equal to the total CAISO scheduled award quantity in the interval, then the interval-specific MEC is set to zero.
2. And if the interval-specific MEP is greater than the total CAISO scheduled award quantity in the interval and less than or equal to the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific MEP minus the interval-specific total CAISO scheduled award quantity.
3. And if the interval-specific MEP is greater than the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific QC of the PDR minus the interval-specific total CAISO scheduled award quantity.

If the total CAISO scheduled award quantity in an interval is zero, then the interval-specific ~~MEP in the above cases is set to the interval-specific ILR~~ MEC is set equal to the QC of the PDR in that interval.

If the PDR has no assigned QC in the above cases, then the QC is replaced by the PDR's "PMin" parameter on record in the CAISO Master File applicable to the interval. Additionally, if the PMin value is less than the total CAISO scheduled award quantity in an interval, then the interval-specific MEC is set to zero.

ii. CAISO Opportunistic Price (COP) ~~Clearing Price Delta (CCPD)~~:

COP is set equal to the ELRP Compensation Rate.

~~For a PDR participating in the DAM only (that is, "long-start" PDR), the interval-specific CCPD is the DAM clearing price in that interval.~~
~~For a PDR participating in the RTM, the interval-specific CCPD is equal to the higher of the DAM or RTM clearing price in that interval minus the lower of the DAM or RTM clearing price in that interval.~~

iii. Portfolio Level Net Event Compensation across all PDRs in the third-party DRP's Portfolio.

To receive ELRP compensation, the third-party DRP shall submit an aggregate invoice for the Cumulative Portfolio Level Net Event Compensation of each PDR Portfolio for May-June-July (First Quarter) period by September 30 and for August-September-October (Second Quarter) by December 31 of the program year for each of its PDR Portfolio to the applicable IOU's team administering Demand Response Auction Mechanism invoices. The Cumulative Portfolio Level Net Event Compensation of a PDR Portfolio over one Quarter is determined by summing the Portfolio Level Net Event Compensation across all ELRP events in that Quarter.

The invoice shall be accompanied with the supporting data for each event, including but not limited to PDR-specific ELRP Event Performance, ILR, applicable market awards during the event, applicable CAISO market payments for load reductions counted in the ILR, and ELRP Event Compensation. The IOU may audit and verify the invoice as needed. The aggregate invoice amount must be equal to or larger than the ELRP Minimum Invoice Threshold to be eligible for compensation by the IOUs. The IOU shall settle the invoice within 60 days of the invoice date.

The ELRP Minimum Invoice Threshold is set at zero at this time.

1.4. Proposal D: Define "Qualified" DR Programs for DR Enrollment

1.4.1 Proposal

The Commission should define "qualified" DR programs eligible to meet a DR program enrollment requirement as condition of a customer receiving an incentive or rebate as any of the following:

1. Supply-side market-integrated DR programs counted for Resource Adequacy.
2. Load modifying DR programs integrated with CEC's peak demand forecasting process (such as Critical Peak Pricing rates offered by the IOUs, and potentially marginal-cost-based dynamic pricing rates should the Commission adopt such rates in the future and establish a process to integrate those rates with CEC's forecasting process).
3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement.

1.4.2 Background

PG&E proposes the Commission develop DR enrollment requirements for customers receiving ratepayer-funded technology incentives, such as those available in Energy Efficiency, Clean Energy Transportation and Distributed Generation. PG&E believes this approach may improve overall cost-effectiveness, unlock flexible demand, and grow megawatts.[10]

The Commission established a policy in this regard in R.20-05-012. Per D.22-04-036, customers receiving rebates for Heat Pump Water Heater (HPWH) appliances via the Self Generation Incentive Program (SGIP) are required to enroll in a "qualified" DR program for a minimum of three years.[11] That Decision went on to specify DR programs considered qualified for meeting the enrollment requirement.

Additionally in R.20-05-012, an assigned commissioner ruling was issued on October 26, 2022, seeking comments to improve SGIP equity outcomes and implement AB 209. The ruling requested party comments on whether customers installing solar photovoltaic systems paired with energy storage systems or new energy storage systems should be required to participate in demand response or peak load reduction programs.

[10] PG&E-2 at 2-11.

[11] D.22-04-036 at 105-108.

It is anticipated that the Commission may consider or establish similar requirements in other DER proceedings for customers to enroll in "qualified" DR programs as a condition of receiving ratepayer-funded incentives or rebates. It is desirable to establish a standardized definition of "qualified" DR programs in the instant proceeding, where the relevant stakeholder expertise is readily accessible. This would enable the Commission to efficiently reference the potential DR enrollment requirement consistently in these other DER proceedings as appropriate to maximize the ratepayer benefit provided by the incentivized DER (in the form of improving grid reliability, reducing emissions, and reducing cost of service). For demand side DERs, a key mechanism for capturing these benefits is to require the potential grid contribution of the DER to be counted for Resource Adequacy by the CPUC on the supply side or counted by CEC in its peak demand forecast process, which in turn sets the RA procurement obligations. This forms the basis for ED's recommendation summarized in the "Proposal" section.

1.5 Proposal E: Extend DR Research Funding for 2024-2027

1.5.1 Proposal

Energy Division staff propose to continue ratepayer-funded Demand Response (DR) research to inform planning and policies that address the needs of the evolving California grid. Staff propose $1 million per year as a DR research budget for 2024-2027, or $4 million in total.

These funds would pay for the potential study and related research beginning in 2024 (once the state Department of General Services approves the contract post-decision.) Current and recent research performed through the current contract illustrates how the potential study and related DR research supports evolving grid needs and Commission policy making:

Recently Completed Study

- Phase 4 Potential Study: forecasting the technical, economic and achievable potential for shed, shift and a dynamic rate-based shape service through 2050, using hourly 2018 and 2019 interval meter data from more than 400,000 utility customers. The potential is forecasted for 29 additional end uses and many new building types, as well as other advanced treatments and sensitivities compared to past studies. (Cost: $2 million) (Study under review at the time of writing and public release subject to determination on confidentiality of data.)

Underway

- Bill analysis tool for stakeholder use in Working Group #2 of R. 22-07-005: Spreadsheet or web-based tool to calculate expected customer bill impacts for a representative set of customers under various user-selectable scenarios for the structure of a dynamic electricity tariff, to compare with customer bills on present-day tariffs. Features based on stakeholder input. (Cost: $150,000) Due spring 2023
- Study of elastic impacts on load, customer bills, and cost recovery of an illustrative dynamic rate tariff. (Cost: $570,000) Due spring 2023
- Dynamic tariff benefits study: Bottom-up dynamic tariff study of potential at the end-use and technology level with estimates of system benefits, and customer bill impacts. This modeling will be based on a suite of possible end-

use-specific response strategies and algorithms in addition to, or in place of, price elasticity estimates. (Cost: $900,000) Due end of 2023

1.5.2 Background

Since 2015, Commission staff have overseen Lawrence Berkeley National Laboratory's (LBNL's) production of three Demand Response Potential Studies, and related research, with the Phase 4 study complete and under Energy Division review. Through this body of research, LBNL developed a supply curve modeling framework to represent the availability of system-level grid services from distributed resources in the three large investor-owned utilities (IOU) territories, built from large samples of individual customer smart meter load shape data. The studies assess the cost, and value, created from having a diverse set of flexible loads. Highlights include the 2025 California Demand Response Potential Study released in March 2017 which created a new DR services taxonomy of Shape, Shift, Shed and Shimmy, and a July 2020 report that forecasted the size and cost of the expected resource-base of a load shift service through 2030. (The first three studies can be found at https://buildings.lbl.gov/potential-studies). Development of the potential study methodology and approach as well as early review of outputs is guided by a technical advisory group made up of about 30 representatives of market actors including third-parties and IOUs.

Data and findings from the potential studies have been widely used by Commission decision-makers, market actors, and incorporated into studies by the California Energy Commission (CEC). For example in 2022 and early 2023, the CEC used data from the Phase 4 potential study DR-Load and DR-Path models in the following efforts:

- Developing a Demand Response – Load Flexibility Modeling Tool to add DR as a load modifier to the 2023 IEPR CA Demand Forecast (Nov 2023)

The CEC's IEPR Demand Forecasts are utilized for statewide energy planning and procurement purposes. Demand response potential will be included once this tool is developed. When demand-side DR is included in the IEPR demand forecast framework it can be valued and programs can be developed and supported. The tool incorporates the LBNL Phase 4 study 8760 aggregated load shapes.

- Setting a Load Shift Goal as required by SB 846 (March 2023)

SB 846 requires the CEC to adopt a goal for load shifting to reduce net peak electrical demand and adjust this target in each biennial IEPR thereafter. This goal could be used to develop demand-side programs to incentivize load shifting to support decarbonization while maintaining grid reliability. LBNL Phase 4 study potential by end use, at various costs, per year, will be used pending CPUC release of the data.

- EPIC-funded CalFlexHub Project

LBNL Phase 4 study aggregated load shapes are supporting evaluation of the costs and benefits of optimization algorithms which can be used by technology manufactures to send control signals to their devices to maximize end-use load flexibility.

In addition, the Commission's Integrated Resource Planning proceeding regularly incorporates model data findings of these potential studies. In late 2022, Senate Bill (SB) 846, which amends the Public Resources Code to potentially extend operation of the Diablo Canyon Powerplant, specifically cited the LBNL Phase 3, July 2020 study when it directed the CEC in consultation with the Commission and California Independent System Operator to adopt a goal for load shifting to reduce net peak electrical demand based on the findings of the study.[12]

While the funding proposed predominantly supports potential studies, it also supports other DR research and technical assistance. For example, DR research funding supported LBNL's contributions to the Load Shift Working Group in 2018, where LBNL developed the Pay for Load Shape concept, performed technical analysis of the correlation between wholesale market prices and greenhouse gas emissions, and other contributions.

CPUC Procedural History

Decision (D.) 12-04-045 first directed Commission staff to oversee DR research and authorized $3 million for the contracted work.[13] D.14-12-024, which adopted a settlement agreement involving demand response goals, first directed Energy Division staff to conduct a DR potential study. D.14-12-024 reasoned that: "[t]he Commission considers the DR potential, market assessment and technology studies, and the policy and planning support studies important to the success of DR programs. Because these studies (frequently referred to as research studies)

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[12] Public Resources Code Section 25302.7.

[13] D.12-04-045 at 168-169.

informed Commission policies on DR programs, we direct that these studies be overseen directly by Commission staff."[14]

D.17-12-003 authorized $1 million per year for 2018-2022, or $5 million total, for DR research, including the DR potential study and its integration with the Energy Efficiency Potential & Goals study. The decision noted that, "[t]he 2017 potential study was a successful exercise and provided valuable information to the Commission as well as the industry."[15] (The integration with the Energy Efficiency Potential & Goals study was proposed in 2017 by the "Energy Division Staff Proposal on Limited Integration of Energy Efficiency and Demand Response Activities." D.17-12-003 supported the staff proposal, elements of which were approved by D.18-05-041.

[14] D.14-12-024 at 20

[15] D. 17-12-003 at 163-164

1.6. Proposal F: Extend Flex Alert Funding to 2024-2028

1.6.1 Proposal

The Commission should extend funding for the Flex Alert and Power Saver Rewards paid media campaign ("marketing") for 2024 through 2028. The program is currently funded by the large electric utilities, PG&E, SCE and SDG&E. The current contract, which expires at the end of 2023, is managed by SCE, and the vendor is Doyle Dane Bernbach Communications Group "DDB." The proposal is to keep the current annual budget of $22 million and open a new solicitation for a vendor to administer Flex Alert and Power Saver Rewards marketing from 2024 through 2027. Power Saver Rewards is also called the Emergency Load Reduction Program (ELRP), sub-group A.6.

Additional questions related to the above proposal that parties are requested to address include:

- If the Commission authorizes continued funding for a Flex Alert and Power Saver Reward Paid Media Campaign after 2023, as proposed above, what proportion of the campaign funding should go to Flex Alert awareness and education and what proportion for Power Saver Rewards awareness and education?
- Are there alternative approaches to Flex Alert and Power Saver Rewards messaging that the Commission should consider?

1.6.2 Background

The most recent reauthorization of the Flex Alert paid media campaign was approved in D.21-12-015 as a part of the Summer Reliability Rulemaking, R.20-11-003. This Rulemaking noted the advantages of coordinated Flex Alert messaging through a centralized organization structure with a paid media campaign to complement CAISO's earned media efforts to help ensure grid reliability during summer heat waves. The campaign was extended through 2023 in D.21-12-015 and the budget was increased from $12 million to $22 million. The Decision also directed the Flex Alert marketing to include messaging for the ELRP Power Saver Rewards initiative. ELRP campaign messaging was included in over half of marketing assets for 2022.

In the two years since the paid Statewide Flex Alert Marketing, Education, and Outreach (ME&O) began, it has been found to be highly effective. Highlights from the Opinion Dynamics 2022 Flex Alert Marketing Evaluation[16] include:

1. Awareness of Flex Alerts increased from 41% at the beginning of the campaigns (June 2021) to 63% by the end of the year 2 campaign (October 2022).
2. 65 percent of Californians surveyed correctly identified what Power Saver Rewards are after only 4 months of Power Saver Rewards paid media.
3. Over half (52%) of Californians surveyed who were not already enrolled in Power Saver rewards responded that they were very likely or extremely likely to enroll in the program after just four months of Power Saver Rewards messaging.
4. Community-based organization outreach effectively supported vulnerable populations that IOUs often don't reach.
5. California was able to navigate through the record-breaking heatwaves in 2022 without any major outage events.

[16] *Opinion Dynamics 2022 Flex Alert Marketing Evaluation, Summary of Baseline Survey Results*, December 13, 2022. See Also: CAISO Summer Market Performance Report September 2022, http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf (at 14-15) .

APPENDIX B

Appendix B

<u>Statewide Residential Emergency Load Reduction Program Baseline Evaluation</u>

Available online:
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/emergency-load-reduction-program/statewide_a6_elrp_baseline_evaluation_report_01172023.pdf