STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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November 6, 2023 **Agenda ID #22039**
**Ratesetting**

TO PARTIES OF RECORD IN APPLICATION 22-05-002, *et al.*:

This is the proposed decision of Administrative Law Judges Jason Jungreis and Garrett Toy. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 14, 2023 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Acting Chief Administrative Law Judge

MLC:jnf
Attachment

Decision **PROPOSED DECISION OF ALJs JUNGREIS AND TOY**
**(Mailed 11/6/23)**

**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<br>Application 22-05-004 |

# DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

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# DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

## Summary

In response to the separate Application requests of investor-owned utilities Pacific Gas and Electric Company (Application (A.) 22-05-002), San Diego Gas & Electric Company (A.22-05-003), and Southern California Edison Company (A.22-05-004) (collectively, the Utilities), this decision directs certain Demand Response (DR) programs, program modifications, and pilots, and approves respective Utilities' budgets for these Demand Response programs and pilots, for the years 2024-2027.

The proceeding remains open to address outstanding Demand Response Auction Mechanism issues.

## 1. Factual And Procedural Background

Demand Response (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[1] directed investor-owned utilities Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (collectively, the Utilities or IOUs) 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.

[1] D.17-12-003 approved the Utilities' 2018-2022 DR Programs.

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 of the Commission's Rules of Practice and Procedure (Rules), an Administrative Law Judge (ALJ) Ruling issued on May 25, 2022 consolidated these Applications (A.22-05-002 *et al*.,). On June 6, 2022, a Protest to the consolidated Applications was filed by the Public Advocates Office of the California Public Utilities Commission (Cal Advocates), and Responses to the consolidated Applications were filed by the Small Business Utility Advocates (SBUA), Leapfrog Power, Inc. (Leapfrog or LEAP), Google LLC, CPower and Enel X North America, Inc. (Enel X), California Efficiency + Demand Management Council (CEDMC), Polaris Energy Services (Polaris), Marin Clean Energy (MCE), Center for Energy Efficiency and Renewable Technologies (CEERT), California Energy Storage Alliance (CESA), California Large Energy Consumers Association (CLECA), and the Vehicle Grid Integration Council (VGIC). Per ALJ Ruling, replies were filed on June 13, 2022 by PG&E, SDG&E, and SCE.

A prehearing conference (PHC) was held on June 16, 2022, to discuss the scope, schedule, and other procedural matters. At the PHC, oral Rule 1.4(a)(3) Motions for Party Status were granted to OhmConnect, Inc., Weave Grid, Inc., and Voltus, Inc. In addition, the following entities have been granted party status in the proceeding: Enchanted Rock, LLC (Enchanted Rock) on September 26, 2022; Tesla, Inc. (Tesla) on December 19, 2022; the California Independent System Operator (CAISO) on April 21, 2023; EV Energy Corporation (EV Energy) on April 21, 2023; Industrial Pumping Customers (IPC) on April 21, 2023; Sierra Club on April 21, 2023; Silicon Valley Clean Energy (SVCE) on April 21, 2023; City of San Jose on April 25, 2023; East Bay

Community Energy on April 25, 2023; Peninsula Clean Energy on April 25, 2023; Sonoma Clean Energy on April 25, 2023; TeMix Inc. (TeMix) on April 25, 2023; and, Gridtractor, Inc. (Gridtractor) on June 8, 2023.

On July 5, 2022, the Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) was issued, detailing the scope and schedule of this proceeding. The Scoping Memo detailed a phased schedule for this proceeding, with Phase I focusing on the 2023 Bridge Year Funding as well as a Phase I 2024 funding for the Demand Response Auction Mechanism (DRAM) Pilot, and with DR Phase II to address the Utilities' 2024-2027 DR program proposals, and DRAM Phase II to address the future of the DRAM Pilot (and any issues remaining following the conclusion of each Phase I).

On December 6, 2022, the Commission issued Decision (D.) 22-12-009 regarding DR Phase I concerning the 2023 Bridge Year Funding. On January 13, 2023, the Commission issued Decision (D.) 23-01-006 regarding DRAM Phase I concerning funding for the year 2024.

On October 25, 2022, a second PHC was held to consider DR Phase II and DRAM Phase II aspects of this proceeding. On December 19, 2022, the Assigned Commissioner issued an Amended Scoping Ruling setting forth the issues and schedule concerning DR Phase II and DRAM Phase II (Phase II Scoping Ruling). The Phase II Scoping Ruling schedule included an opportunity to request an evidentiary hearing: no party availed itself of that opportunity.

On January 27, 2023, the Assigned Commissioner issued a Ruling seeking party comments in response to questions specific to DR Phase II and DRAM Phase II, and also seeking party comments in response to Commission Energy Division proposals regarding possible DR and DRAM program changes (January 27 Ruling). On March 2, 2023, a further ruling was issued directing the release of Emergency Load Reduction Program (ELRP) data to inform responses to the January 27 Ruling. On April 21, 2023, parties filed comments responsive to the questions and proposals in the Ruling, and on May 5, 2023, parties filed replies to other parties' comments. On July 14, 2023, parties filed DR Phase II Opening Briefs, and on August 11, 2023, parties filed DR Phase II Reply Briefs.

### 1.1. Submission Date

This matter was submitted on August 11, 2023, upon the filing of parties' DR Phase II Reply Briefs.

## 2. Demand Response (DR) Phase II Issues

Given the late filing of these Applications, the Commission granted the Utilities' request to initially consider their requests for 2023 Bridge Funding as Phase I, while leaving consideration of their sought 2024-2027 program year budgets as Phase II. Therefore, it was in the Phase II Scoping Ruling that the issues to be considered in this DR Phase II were identified. Those issues are as follows:

1. Do the applications of PG&E, SCE, and SDG&E requesting approval of Demand Response Programs and budgets for Years 2024 through 2027 advance the goals, principles, directives, and guidance adopted in D.16-09-056 and comply with the directives in D.16-09-056, D.17-12-003, and D.21-03-056, as well as other directives in Commission decisions and rulings under the DR, summer reliability, and other applicable proceedings?
2. Are PG&E's, SDG&E's, and SCE's proposed demand response programs and activities, including pilot recommendations, Emergency Load Reduction Program, and modifications to existing programs and policies, reasonable, and should they be adopted?
   a. Are parties' proposed changes, including those presented for the 2023 Bridge Year but not addressed by

the Commission in Phase I, to Utilities' programs reasonable?

b. Are PG&E's, SCE's, and SDG&E's proposed demand response activities and programs, including pilot recommendations and proposals presented for the 2023 Bridge Year but not addressed by the Commission in Phase 1, reasonable, and should they be adopted?

c. To improve program cost-effectiveness, usefulness, and system reliability, should the Commission consider design changes to RA-eligible emergency DR programs, such as (but not limited to) dispatch conditions and requirements, compensation & penalties, and performance measurement techniques?

d. Should the temporary increase in the DR reliability cap to 3 percent be extended?

3. Did PG&E, SCE, and SDG&E accurately follow the Commission's DR cost-effectiveness protocols to determine their programs' cost-effectiveness score, and are their programs cost-effective?

4. Are PG&E's, SCE's, and SDG&E's requested budgets to implement the proposed demand response and Rule 24/32 programs, including pilot recommendations, cost allocations, and related cost recovery requests, reasonable?

5. Should fund-shifting rules be revised to allow Utilities greater discretion?

6. What program reporting requirements and schedules should the Utilities be required to follow?

7. Do the demand response programs proposed by PG&E, SCE, and SDG&E adequately take into consideration the Commission's Environmental and Social Justice Action Plan? How should the programs be modified to better meet the needs of environmental justice communities?

8. 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)?

9. Should dual participation rules be modified or clarified?
10. Should ratepayers provide funding in 2024-2027 for continued modeling of DR potential and related research overseen by Energy Division?

Issues in the Phase II Scoping Ruling related to DRAM Phase II will be addressed in a later decision.

## 3. Admission of Testimony and Exhibits into Record

In order to fairly access the record, it is necessary to include all admitted party Exhibits. On August 3, 2023, parties filed a final Joint Motion For Admission of Evidence Regarding Phase II Demand Response Issues (Joint Motion). No objection to the Joint Motion was raised. Good cause being shown, and in the absence of party objection, the Joint Motion is granted. Those Joint Motion Exhibits are formally accepted into the record for consideration in this proceeding.[2]

## 4. Evaluating Program Cost Effectiveness

Evaluation of program cost-effectiveness ensures that ratepayer funding is being wisely spent. If a program is not cost-effective, it is not providing benefits to ratepayers at a level that matches their cost to ratepayers. D.10-12-024 adopted a method for estimating the cost-effectiveness of demand response activities and required the Utilities to use the protocols for all future cost-effectiveness analysis of demand response programs. The protocols require the Utilities to use the four cost-effectiveness tests defined in the Standard Practice Manual: Total Resource Cost (TRC), Program Administrator Cost (PAC), Ratepayer Impact Measure (RIM), and the Participant Test. These tests provide

[2] Attachment A to this Decision is the Joint Motion List of Exhibits.

the net present value of the costs and benefits, discounted over the lifetime of the relevant demand response resource. These protocols also define costs attributable to a demand response program and use the Avoided Cost Calculator (ACC) developed by the Commission to calculate the avoided costs of behind-the-meter (BTM) distributed energy resources.

In D.12-04-045 the Commission took a flexible approach while using the protocols. It took into account not just the outputs generated by the protocols, but also the changes DR programs were going through. The Commission also recognized that not all DR programs might be cost-effective in all tests. In the same decision, when making a determination on the budget of a specific program, the Commission looked at the cost-effectiveness of a program as well as the current market situation of the demand response market.[3] In order to allow for flexibility and recognize that transition, D.12-04-045 deemed programs with a TRC result of 1.0 to be cost-effective, but allowed for an error band of 10 percent, allowing programs with a TRC of at least 0.9 to be deemed cost-effective for the purposes of that proceeding.[4]

In D.17-12-003, the last DR Application Decision, the Commission determined that the IOUs would need to meet a TRC cost-effectiveness ratio of 1.0 for each program or a continuous progress report on a program with qualitative and quantitative indicators.

First, we will discuss the IOUs' reported Cost-Effectiveness calculations. We will then consider the ratios, their purpose, and how they will be applied in this Decision.

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[3] D.12-04-045 at 30.

[4] D.12-04-045 at Finding of Fact No. 12.

### 4.1. Utility Reported Cost-Effectiveness Results

Tables 20 through 22 show the TRC results with and without Auto Demand Response (Auto DR or ADR) costs, for each utility's demand response programs, as provided by the Utilities.[5] These calculations were conducted utilizing the 2021 ACC in the initial applications, with updates provided in supplemental testimony in 2023 utilizing the 2022 ACC.

**Table 1**
**PG&E Cost-Effectiveness Results with 2021 ACC[6]**

| Program | TRC w/ ADR | TRC w/o ADR |
|---|---|---|
| Base Interruptible Program | 0.82 | 0.84 |
| Capacity Bidding Program | 0.71 | 0.81 |
| SmartAC | 0.89 | 0.89 |
| Automated Response Technology Program | 1.43 | 1.43 |
| **Total DR Portfolio** | **0.77** | **0.79** |

**Table 2**

**PG&E Cost-Effectiveness Results with 2022 ACC[7]**

| Program | TRC w/ ADR | TRC w/o ADR |
|---|---|---|
| Base Interruptible Program | 2.65 | 2.69 |
| Capacity Bidding Program | 2.31 | 2.66 |
| SmartAC | 2.64 | 2.62 |
| ART Program | 4.48 | 4.45 |

5 PG&E-01 at 7-2; SCE-03 at 26; SDG&E Opening Brief, July 24, 2017, at 83.

6 PG&E-02A, at 9-2, Table 9-1. PG&E's original TRC calculations utilized incorrect budgets, which was corrected in errata testimony.

7 PG&E-7, at 12-9, Table 12-3, Table 12-4.

| | | |
|---|---|---|
| **Total DR Portfolio** | **2.48** | **2.54** |

**Table 3**
**SCE Cost-Effectiveness Results for CBP, BIP-15, and Portfolio with and without Auto-DR with 2021 ACC**

| Program | TRC w/ ADR | TRC w/o ADR |
|---|---|---|
| Base Interruptible Program-15 | 0.88 | 0.88 |
| Capacity Bidding Program – Day-Ahead | 0.71 | 0.91 |
| **Total DR Portfolio** | **1.09** | **1.1** |

**Table 4**
**SCE Cost-Effectiveness Results with 2021 ACC**[8]

| Program | TRC |
|---|---|
| Agricultural Pumping Interruptible | 1.76 |
| Base Interruptible Program 15 Minute | 0.88 |
| Base Interruptible Program 30 Minute | 1.04 |
| Optional Binding Mandatory Curtailment | 1,527.91 |
| Scheduled Load Reduction Program | - |
| Summer Discount Program Residential | 1.49 |
| Summer Discount Program Commercial | 0.93 |
| Capacity Bidding Program (CBP) Day-Ahead | 0.71 |
| Smart Energy Program (SEP) | 1.07 |
| **Portfolio** | **1.09** |

[8] SCE-04, at 31, Table IV-19.

**Table 5**
**SCE Cost-Effectiveness Results for CBP, BIP-15, and Portfolio with and without Auto-DR with 2022 ACC[9]**

| Program | TRC w/ ADR | TRC w/o ADR |
|---|---|---|
| Base Interruptible Program-15 | 2.76 | 2.78 |
| CBP – Day-Ahead | 0.75 | 1.19 |
| CBP Elect | 1.26 | 1.31 |
| CBP Elect+ | 1.89 | 1.97 |
| **Total DR Portfolio** | **2.76** | **2.77** |

**Table 6**
**SCE Cost-Effectiveness Results with 2022 ACC[10]**

| Program | TRC |
|---|---|
| Agricultural Pumping Interruptible | 1.62 |
| Base Interruptible Program 15 Minute | 2.76 |
| Base Interruptible Program 30 Minute | 3.32 |
| Optional Binding Mandatory Curtailment | 5,048.85 |
| Scheduled Load Reduction Program | - |
| Summer Discount Program Residential | 2.80 |
| Summer Discount Program Commercial | 1.75 |
| CBP – Day-Ahead | 0.75 |
| CBP Elect | 1.26 |
| CBP Elect+ | 1.89 |
| SEP | 3.46 |
| Portfolio | 2.76 |

**Table 7**
**SDG&E Cost-Effectiveness Results with 2021 ACC[11]**

| Program | TRC | PAC | RIM |
|---|---|---|---|
| Capacity Bidding Program Day-Ahead | 0.4 | 0.3 | 0.3 |
| Capacity Bidding Program Day-Of | 0.4 | 0.4 | 0.3 |
| Smart Energy Program | 0.3 | 0.2 | 0.2 |

| | | | |
|---|---|---|---|
| **Portfolio** | **0.2** | **0.2** | **0.2** |

**Table 8**
**SDG&E Cost-Effectiveness Results with 2022 ACC[12]**

| **Program** | **TRC** | **PAC** | **RIM** |
|---|---|---|---|
| Capacity Bidding Program Day-Ahead | 1.0 | 1.0 | 0.9 |
| Capacity Bidding Program Day-Of | 1.0 | 1.0 | 1.0 |
| Smart Energy Program | 0.7 | 0.6 | 0.6 |
| **Portfolio** | **0.7** | **0.6** | **0.6** |

The reported cost-effectiveness ratios utilizing the 2021 ACC are generally under a TRC of 1.0. However, as we will discuss in more detail below, the cost-effectiveness ratios are close to 1.0, and some significantly exceed 1.0 if utilizing the 2022 ACC. Utilizing the 2022 ACC shows that the majority of the demand response programs proposed by the Utilities for the 2024-2027 period are cost-effective or close to cost-effective. However, significant issues persist with SDG&E's portfolio that must be addressed.

### 4.2. Applying Total Resource Cost (TRC) Ratios to the Portfolios

As discussed above, D.17-12-003, the previous DR Application decision, stated that the IOUs must meet a minimum TRC ratio of 1.0. SDG&E's 2024-2027 DR Application has a portfolio TRC score of 0.2.[13] Cal Advocates therefore advocates for the wholesale denial of SDG&E's DR Application.[14] Alternatively,

[9] SCE-12, at 8, Table 12-7.

[10] SCE-12, at 10, Table 8.

[11] SDGE-5, at BG-1, Table BG-1. SDG&E does not include Auto DR calculations as it does not offer such incentives. SDGE-5, at BG-8:1-12.

[12] SDGE-8, at BG-11, Table BG-10.

[13] SDGE-5, at BG-1, Table BG-1.

[14] Cal Advocates Phase II Opening Brief, at 30.

Cal Advocates proposes that regional or statewide administration of DR programs would result in lower transaction costs and higher cost-effectiveness ratios.

PG&E recommends suspension of the cost-effectiveness requirements for the 2024-2027 cycle for a number of reasons:[15]

- D.17-12-003 noted that there may be circumstances that warrant approval of DR activities with a TRC below 1.0;
- The adoption of the 2022 ACC results in significant improvements to the TRC of IOU DR programs;
- The Commission is exploring updates to the cost-effectiveness protocols; and
- The Commission has increased the availability requirements for non-Reliability DR Resources (RDRRs) in the Resource Adequacy (RA) proceeding (R.21-10-002), which may reduce cost-effectiveness.

PG&E also notes that changes can be made to its programs to either bring its programs closer to a TRC of 1 or even above it.[16] SDG&E notes that with 2022 ACC inputs, its portfolio improves to a TRC ratio of 0.7, and that this reflects the reality that cost-effectiveness tools are subject to variability and that with updates to the DR protocols SDG&E's portfolio could continue to approach cost-effectiveness.[17] PG&E and SCE's portfolios' TRC ratios also show improvement utilizing the 2022 ACC inputs.[18] SDG&E states that the Commission may terminate any program or programs it finds to be not cost-effective. SDG&E also notes that third-party administration of DR programs is

[15] PG&E Phase II Opening Brief, at 76.

[16] PG&E-2, at 9-9:1-18.

[17] SDG&E Phase II Opening Brief, at 56.

[18] PG&E-2A, at 9-2. Table 9-1; SCE-12, at 8, Table 12-7.

unlikely to provide any cost savings, due to added administrative costs.[19] CEDMC and CESA support a waiving of cost-effectiveness requirements.[20]

D.17-12-003 required that programs achieve a TRC cost-effectiveness ratio of 1.0, or be required to provide continuous progress reports.[21] However, Commission DR decisions have noted that there exists some flexibility in how we apply cost-effectiveness requirements in this proceeding. In 2017 the Commission held that "we will continue to be cognizant of the current state of the demand response industry including new programs objectives that may be established for the Utilities, *e.g.* targeting demand response for disadvantaged communities."[22]

Since the implementation of D.17-12-003, the Commission has taken extraordinary steps to ensure that Californians have access to reliable electricity during the summer months, with the most obvious example of this being the establishment of the Emergency Load Reduction Program Pilot in 2021. Through measures such as this, the Commission has dictated a clear need to maximize the amount of grid flexibility available during the months when DR programs generally operate.

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19 *Id*. at 59.

20 Response of the California Efficiency + Demand Management Council to Applications of PG&E, San Diego Gas & Electric, and Southern California Edison Company for Approval of Their Demand Response Programs (June 6, 2022), at 5-6; Comments of the California Energy Storage Alliance to the 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 (April 21, 2023), at 17.

21 D.17-12-003, at 119.

22 *Id.*

At this time, we decline to enforce the TRC 1.0 ratio requirement, either onto SDG&E or the IOUs as an inflexible requirement, either on a portfolio or program basis. Given the continuing need to mitigate grid reliability issues during the summer, it would be unreasonable to remove DR options that may provide significant benefits to the CAISO.

For this decision, we continue to rely on cost-effectiveness analysis as a principal – but not the only – factor in determining whether specific programs should or should not be approved. SDG&E's pilot programs, for example, should be scrutinized with a heavier brush given the poor performance of SDG&E's portfolio in general. Where programs fail to show cost-effectiveness as measured by TRC ratios, modifications must be considered that can bring the program into compliance. We will utilize the TRC ratios to inform our review of the IOUs' DR portfolios but decline to implement strict requirements of cost-effectiveness based only on TRC ratios.

### 4.3. SCE Request to Exclude the Emerging Markets and Technology Program from Portfolio Cost Effectiveness Requirements

In its Application, SCE proposes to extend the DR Cost Effectiveness Protocols' exemption of Pilots from inclusion in the IOU-required cost effectiveness analysis to the Emerging Markets and Technology Program (EM&T)). It should be noted that the EM&T is what SCE calls its Demand Response Emerging Technologies (DRET) program (discussed in Section 10.2.2 of this document). SCE argues that the EM&T "serves a similar role to pilots, at an earlier stage of the DR program lifecycle, through long-term advocacy and research that provides a foundation for future innovation. Given that direct benefits are not explicit or measurable, and that this research program is *crucial for providing advanced technology support for other programs in the DR portfolio*, SCE proposes that the [EM&T] program be exempt from portfolio cost effectiveness going forward."[23]

Per Section 1.H of the DR Cost Effectiveness Protocols, "the only type of costs which [sic] can be excluded from the portfolio cost-effectiveness analysis are the costs associated with 'pilot' programs."[24] Per D.17-12-003, Pilots fall within DR budget category 5, but the EM&T (DRET) falls under DR budget category 4. Relatedly, per the Cost Effectiveness Protocols, "the IOUs' DR portfolio cost effectiveness analysis should "include costs associated with broader activities, including any DR-related activities…, which [support] or [promote] DR in general rather than any specific DR program."[25] In its application, as cited above in italics, SCE contends that EM&T provides support for programs in the DR portfolio *in general*, which contradicts SCE's claim that EM&T operates similarly to a DR pilot. SCE's request to remove the EM&T from the DR cost effectiveness analysis requirement is denied.

Furthermore, PG&E's Cost Effectiveness Report for its 2024-2027 DR programs shows PG&E did not include its DRET program costs in its DR portfolio cost effectiveness analysis.[26] As discussed above, in accordance with the 2016 Protocols, the three IOUs, including PG&E, shall include DRET in their portfolio cost effectiveness analysis, beginning with their applications submitted for the next DR cycle.

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[23] SCE-01, at 35-36 (italics added).

[24] 2016 DR Cost Effectiveness Protocols, at 18.

[25] *Id*. at 17.

[26] Link to PG&E's Cost Effectiveness Report can be found at PG&E-02A, at 11-1.

### 4.4. DR Cost Effectiveness Protocol Changes

Parties submitted comments on updating the DR Cost-effectiveness Protocols. In particular, the IOUs filed comments asking the Commission to update the "A factor" calculation methodology to resolve discrepancies with the updated ACC modeling.[27] To the extent that the IOUs believe this is an issue, they may submit a joint Tier 2 advice letter providing updates to the A factor calculation methodology.

Given time constraints, we decline at this time to consider other, less ministerial changes to the protocols, and leave these issues for other Commission proceedings for which these issues are properly scoped, which may include the cost-effectiveness track of the Customer Programs Rulemaking, R.22-11-013.

## 5. Overarching Issues

In the course of this proceeding, numerous policy issues unrelated to specific DR programs have been raised by the parties or the Commission. These are addressed below.

### 5.1. Dual Participation

Dual Participation rules allow customers to simultaneously participate in two DR programs while ensuring that customers do not receive two payments for the same load reduction.[28] These rules are: 1) duplicative payments for a single instance of load reduction or load drop is prohibited, 2) dual participation is permitted in two DR activities, if one provides an energy payment and the other provides capacity payments, and 3) dual participation in two Day-Ahead or two Day-Of programs is prohibited. Electric Rules 24/32 also prohibit

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[27] SCE Opening Comments to January 27 Ruling, at 18-19; SDG&E Opening Comments to January 27 Ruling, at 16; PG&E-8, at 12-8:12-19.

[28] D.12-04-045, at 47-48.

customers from simultaneously participating in a program provided by a third-party and bid into the CAISO market and an event-based utility-administered DR program.

PG&E proposes that the dual participation rules be revised and a workshop/working group process be scheduled to develop a common understanding of existing Commission and CAISO dual participation rules and policies and initiate the establishment of principles and goals for dual participation.[29] PG&E proposes to eliminate the rules categorizing programs as event-based and non-event-based, prohibit double payments for a single instance of load reduction or load shift across wholesale and retail settlement, ensure accurate load impact measurement and attribution for each program, and consideration of the expansion of dual participation rules to other load management solutions, among other topics.[30] PG&E states that the working group findings could inform a Phase III of this proceeding.

The Joint CCAs[31] support PG&E's proposed working group, and highlight five objectives that should be established in a dual participation working group process:[32]

- Develop a common understanding of existing DR programs and dual participation rules and policies;
- Establish updated principles and goals for dual participation;

[29] PG&E-7, at 12-14:9-15.

[30] *Id*. at 12-14:30-12-15:30.

[31] The Joint CCAs consist of East Bay Community Energy, Marin Clean Energy, City of San Jose, Sonoma Clean Power Authority, and Peninsula Clean Energy.

[32] Joint CCAs Phase II Opening Brief, at 5.

- Assess and establish modifications to the dual participation rules, considering, at a minimum, the growth of Community Choice Aggregator (CCA) and utility load-modifying programs, as well as California Energy Commission (CEC)-overseen DR programs;
- Develop and establish a bilateral customer participation data exchange process for load-modifying DR programs between IOUs and CCAs (and other entities as needed);
- Develop and establish an efficient and consistent customer unenrollment process where dual participation is identified.

The Joint CCAs note that load modifying DR programs currently lack a process to identify potential dual participation, leaving the CCAs without an effective mechanism to track customer enrollment in load-modifying DR programs across program administrators. The Joint CCAs also note that a bilateral data exchange process would both prevent dual participation and improve each load serving entity's (LSEs) knowledge of forecasted load reductions for their customer bases, allowing for more accurate bidding and scheduling decisions.[33] The Joint CCAs also highlight the lack of an established process to resolve enrollment conflicts.

Many parties, including Cal Advocates, CEDMC, CLECA, LEAP, SDG&E, and VGIC supported holding a workshop to discuss and revise the dual participation rules. At the outset, we reject any request to make changes to the dual participation rules at this time. The record has not been adequately developed, nor have parties sufficiently considered all the potential repercussions of changes. We also note that parties do not need Commission approval to conduct workshops and develop a proposal for changes to the dual

[33] *Id*. at 6.

participation rules. To the extent that parties believe changes are needed, relevant parties could work together to hold their own workshops and provide a proposal for changes at the next appropriate Commission venue. We decline at this time to direct additional workshops on this issue.

### 5.2. Prohibited Resources (PR) Policy

#### 5.2.1. Installation of Interval Metering Devices

Cal Advocates proposed in Opening Testimony that the Commission require the installation of interval metering devices for all on-site Prohibited Resources (PR) to conclusively determine compliance with the PR policy.[34] This issue has been decided in D.22-12-004, and is out of scope for this phase of this proceeding. We decline to adopt Cal Advocates' proposal.

#### 5.2.2. Fuel Eligibility for "Fuel-switching Pathway"

PG&E recommends that the Commission coordinate with other state agencies to determine what fuels should qualify for the fuel switching pathway described in Resolution (Res.) E-4906.

This issue is out of scope for this proceeding. It does not fall under any of the issues scoped in the Phase II Scoping Ruling. We therefore decline to make any changes pursuant to this recommendation.

#### 5.2.3. PR Verification Plan

D.22-12-004 modified the existing Prohibited Resources[35] Verification plan, directing the IOUs to procure logging devices and incorporate their use into the monitoring of PRs installed BTM by customers enrolled in certain DR programs. SCE noted that the cap of 60 loggers allowed in D.22-12-004 may be insufficient

[34] CalAdvocates-1, at 3-7:11-18.

[35] Prohibited Resources are resources that may not qualify as load reduction during demand response events. Generally, prohibited resources are generators that use fossil fuels.

to cover all sites, and that up to 90 loggers may be needed.[36] SCE therefore requests that the Commission modify Ordering Paragraph (OP) 1 of D.22-12-014 and authorize SCE to purchase up to its 40 percent share of 90 loggers (36 in total). SCE states that any budget overruns can be covered by charging incremental costs to the DR programs covered by the Verification Audit.

We find SCE's request to increase the total number of purchased loggers to 90 reasonable, and authorize each IOU to purchase up to its share of loggers in the same 40/40/20 (PG&E, SCE, SDG&E, respectively) proportion as has been allotted previously for PR Verification plan expenses. Any cost overruns may be attributed as incremental costs for the DR programs covered by the Verification Audit.

#### 5.2.4. Exemption of Energy Storage Resources

The DR Prohibited Resources Policy originally included an exemption for "storage and storage coupled with renewable generation that meet the relevant greenhouse gas emissions standards adopted for the Self Generation Incentive Program."[37] This exemption was later modified so as to not rely on a metric developed in the Self Generation Incentive Program. The revised text exempted "energy storage resources not coupled with fossil-fueled generation." The Decision ordering this modification also ordered the Commission to revisit the exemption in "either the proposed new rulemaking on new models of demand response or the 2023-2027 demand response program applications, whichever commences first."[38]

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[36] SCE-11, at 5:9-18.

[37] D.16-09-056, at OP 3.

[38] D.18-06-012, at OP 3.

The IOUs,[39] Cal Advocates,[40] CLECA,[41] and CESA[42] were supportive of keeping this exemption. It is reasonable to maintain the exemption.

### 5.3. Definition of "Qualified" DR Programs

D.22-04-036 established that customers receiving rebates for Heat Pump Water Heaters (HPWH) appliances via the Self Generation Incentive Program (SGIP) are required to enroll in a "qualified" DR program for a minimum of three years.[43] In order to facilitate similar requirements in other proceedings for customers to enroll in "qualified" DR programs, Commission staff prepared a definition that could be easily referenced. The January 27 Ruling asked parties to comment on the following Commission staff proposal:[44]

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 RA.
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).

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39 PG&E Opening Comments to January 27 Ruling, at 17; SCE Opening Comments to January 27 Ruling, at 17-18; SDG&E Opening Comments to January 27 Ruling, at 15.

40 Cal Advocates Opening Comments on January 27 Ruling, Attachment 1, at 8.

41 CLECA Opening Comments on January 27 Ruling, at 4.

42 CESA Opening Comments on January 27 Ruling, at 15.

43 D.22-04-036, at 105-108.

44 January 27 Ruling, Appendix A, at 11-12.

3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement.

Comments were generally supportive of the staff proposal. SDG&E agreed with the staff proposal, noting that customers enrolled with a CCA are not eligible for an SDG&E load-modifying commodity rate and may be left without a viable participation option.[45] SDG&E also noted that it cannot verify whether a customer who receives a technology incentive and enrolls in a third-party supply-side program is truly participating in the DR program.

SCE assertsthat the provided staff list of eligible programs is too limited and may impact customer adoption of technologies.[46] For example, SCE believes electric vehicle (EV) rates would not be eligible. SCE also states that the eligible definition for market-integrated programs might need to be adjusted given future changes in the RA proceeding or to DR bifurcation rules. Finally, SCE states that the eligibility list should reflect the four types of DR services identified by the Lawrence Berkeley National Laboratory.

PG&E supports the staff definition, and recommends that the IOUs be authorized to file a Tier 3 advice letter to update the definition of "qualified" DR programs in the future.[47] The Joint CCAs request that clarifications be made that the requirement applies whether the DR program administrator is an IOU, CCA, or third-party Demand Response Provider (DRP).[48]

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[45] SDG&E Opening Comments on January 27 Ruling, at 20.

[46] SCE Opening Comments on January 27 Ruling, at 21.

[47] PG&E Opening Comments on January 27 Ruling, at 7-11.

[48] Joint CCAs Opening Comments on January 27 Ruling, at 15.

No party disagreed with staff's proposal with respect to including RA-counted supply-side DR programs as a "qualified" DR program. With respect to load-modifying DR programs, party opinions vary as to what programs should be considered "qualified." We formulate the principle that for a load-modifying program to be "qualified," its contribution to reliability should be symmetric with RA-counted supply-side DR programs in both the planning and operational domains. An RA-counted supply-side DR program has the following characteristics: 1) The program is integrated with the CAISO energy market (the program's dispatch signal is determined by the energy prices in the day-ahead or real-time market) - operational domain; 2) the program's load impact is counted toward RA obligations directly or indirectly through a Commission approved process - planning domain. Hence, in line with the symmetry principle, we require a load-modifying DR program to satisfy the same two characteristics applicable to RA-counted supply-side DR programs in order for the program to be "qualified."

Leveraging the foregoing requirement and in response to party comment, the staff proposal is modified to the following:

The following DR programs are deemed as "qualified" to satisfy a potential DR enrollment requirement established by the Commission for an authorized program:

1. Supply-side market integrated DR programs counted for RA irrespective of whether the administrator is an IOU, CCA, or third-party DRP.
2. Load modifying DR programs that satisfy the following two requirements:
    a. The program is integrated with the CAISO energy market such that the program's dispatch signal is linked

to the energy prices in the Day-Ahead or real-time market – operational domain.

b. The program's load impact is counted towards RA obligations directly or indirectly through a Commission-approved process or planning domain.

3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program.
4. Critical Peak Pricing or Peak Day Pricing. These options shall be discontinued as a "qualified" DR program when the dynamic rate(s) under consideration in R.22-07-005 is (are) made available to customers that is (are) compliant with CEC adopted Load Management Standards (California Code of Regulations – Title 20, Article 5, §1623).

IOUs and LSEs may submit a Tier 2 advice letter to update the eligible program list on an as needed basis. The above language is adopted to define what is a "qualified" DR program for purposes of determining what DR programs customers should enroll in if the Commission requires such enrollment as an eligibility condition for a customer's participation in a non-DR program.

### 5.4. Heat Pump Water Heater (HPWH) Enrollment - SDG&E

SDG&E proposes to enroll customers that have received the SGIP Heat Pump Water Heater (HPWH) incentive into SDG&E's supply-side DR programs.[49] SDG&E does not seek additional funding for the technical costs at this time, but states that if additional funding is needed to bring the HPWH into DR programs, SDG&E should be allowed to seek additional funding via advice letter submission.

No party commented on this proposal. It is reasonable for SDG&E to incur some cost in order to accommodate HPWH, which is an area of large growth

[49] SDGE-1, at EBM-36:21-37:4.

given the goals of the SGIP program. SDG&E's request is approved. SDG&E is authorized to file a Tier 2 advice letter to fund-shift from other DR programs or Category 7 operational budget to support the participation of HPWHs in supply-side DR programs.

### 5.5. Fund-Shifting Rules

In the last DR Application proceeding, D.17-12-003 reiterated that the IOUs may shift up to 50 percent of a program's funds to another program within the same budget category, without notification to the Commission, but not between the seven budget categories adopted in that decision.[50] D.17-12-003 required that the IOUs submit Tier 2 advice letters to obtain Commission approval for shifting of more than 50 percent of a program's funds to a different program within the same budget category. SDG&E, PG&E, and SCE have all proposed modifications to this setup.

#### 5.5.1. SDG&E Proposal

SDG&E proposes that the previously approved fund shifting rules be adjusted to match D.20-05-009, which allowed the IOUs to submit a Tier 3 advice letter to shift funding between budget categories[51] for the 2018-2022 DR cycle. In applying for such fund shifting authority, D.20-05-009 required the IOUs to provide information regarding:[52]

- Justification for the dollar amount needed;
- What categories are impacted (source category and recipient category);

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[50] D.17-12-003, at 135.

[51] These categories are as dictated in D.17-12-003: 1) Supply-Side DR Programs; 2) Load Modifying DR Programs; 3) Rule 24/32 and DRAM; 4) Emerging and Enabling Technology Programs; 5) Pilots; 6) Marketing, Education, and Outreach; and 7) Portfolio Support.

[52] D.20-05-009, OP 6.

- Why the established rules are not adequate to accommodate the requested fund shift at that time;
- An accounting of the budget spent thus far on each DR program within each affected category;
- Explanation as to why the approved budget of the source category and programs will not be needed;
- How a budget shift will not cause a detrimental effect on any affected DR program;
- How an increase or decrease in budget aligns with or deviates from the Commission's determination of the cost-effectiveness of the recipient and source programs; and
- An updated program cost-effectiveness analysis.[53]

#### 5.5.2. SCE and PG&E Proposal

Current fund shifting rules allow the IOUs to shift up to 50 percent of a program's budget category to a program in the same budget category. SCE states that more budget flexibility is needed to respond to rapidly changing grid conditions. SCE's proposal is that for categories 1 (Supply-side DR) and 5 (Pilots), the IOUs be allowed to automatically fund shift up to 75 percent of a program's funds to another program within the same category, with a Tier 2 Advice Letter only required if the shift is above 75 percent. For other categories, SCE recommends changing the rules so that any fund shifts can be reported through monthly DR program and Interruptible Load Program (ILP) reports. For fund shifts between categories, SCE recommends requiring a Tier 2 Advice Letter. PG&E's proposal is similar, except that it is silent regarding the reporting of non-Category 1 and 5 shifts. SDG&E proposes that the IOUs be allowed to fund shift between categories via Tier 3 Advice Letter.

[53] D.20-05-009, OP 6, at 11.

#### 5.5.3. Discussion

No party commented on this issue. SCE and PG&E's proposal does not provide sufficient Commission oversight of spending. It is also not reasonable for the IOUs to be allowed to shift 75 percent of budget amongst pilot programs and supply-side DR programs without Commission approval, as reducing a program budget by 75 percent drastically limits the testing and knowledge that can be gained from running a program. SCE's recommendation that fund-shifts need only be reported in monthly reports is also not sufficient, as they do not provide adequate notice. The IOUs' arguments that some flexibility is needed are well taken, but the rules for the 2018-2022 cycle seem sufficient. It is reasonable to allow the IOUs to shift budget between categories during the 2024-2027 DR program cycle, as was previously authorized by D.20-05-009. SDG&E's proposal is affirmed, as was authorized in D.22-12-009.[54]

### 5.6. Statewide Flex Alert Media Campaign

The January 27, 2023, Assigned Commissioner Ruling included a Commission staff proposal to extend, for 2024 through 2027, the funding for a statewide third-party vendor public marketing, education, and outreach (ME&O) contract for Flex Alert (Flex Alert Campaign). That Flex Alert Campaign contract is managed by SCE. The proposal included maintaining the current annual Flex Alert Campaign contract budget of $22 million and preparing a new solicitation for a third-party vendor.

The Flex Alert Campaign promotes public awareness and responsiveness in the interest of grid reliability during grid stress events. D.21-12-015 continued the Flex Alert Campaign from January 1, 2022, through December 31, 2023, but

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[54] D.22-12-009, at 31.

increased the $12 million budget previously authorized in D.21-03-056. D.21-12-015 stated that the annual $22 million budget for 2020-2023 "represents the same budget as approved [in D.21-03-056] for 2021 ($12 million), plus $10 million in additional ratepayer funding that matches a $10 million one-time appropriation for the program from the State General Fund approved in the 2021 Budget Trailer Bill, Assembly Bill 128."[55]

Parties express reservations about the continuation of the Flex Alert Campaign, in particular that a program that may have a statewide benefit should not be solely funded by IOU ratepayers. SCE, the Flex Alert Campaign contract manager, stated in pertinent part as follows:

> SCE did not request funding for the Flex Alert paid media campaign in its Application. SCE does not recommend or support keeping the current annual budget of $22 million for a paid media campaign for the CAISO's Flex Alert program… as all beneficiaries of the Flex Alert program should fund the program, rather than only the IOUs' customers…
>
> Should the Commission consider extending funding for Flex Alert paid media beyond 2023, the Commission should address issues raised in prior Commission decisions. Specifically, how does authorizing IOU ratepayer funding in this proceeding for a Flex Alert marketing campaign comport with D.13-04-021, Finding of Fact 8, which states: "It is logical that the entity controlling the Flex Alert program also be responsible for administering and securing funding for the program, and that the funding is provided by all customers who benefit from the conservation and load reduction due to Flex Alerts, not just the ratepayers of the investor-owned utilities." [footnote: The "entity controlling the Flex Alert program" is the CAISO.] If a Flex Alert paid media campaign has greater benefit and value to CAISO and the State, then funding for this program should be recovered through CAISO's administrative fees

[55] D.21-12-015 at 71.

> or allocated from the State's General Fund similar to what the California State Legislature appropriated in Fiscal Year 2021-22.[56]

PG&E generally opposes the proposal, but would accept a more limited budget, stating in pertinent part as follows:

> PG&E recommends issuing a competitive solicitation with a reduced scope of work and reduced budget of $12 million annually for a statewide Flex Alert Campaign. PG&E also recommends that the CPUC work with CAISO and the CEC to add funding from all load serving entities who benefit from the grid stability that Flex Alerts provides.
>
> PG&E recommends that the scope of the statewide campaign should be conducted by CAISO at a local level…
> PG&E recommends that the campaign tactics used for Flex Alert should be evaluated to leverage earned media and text messages from CAISO as much as possible and minimize high-cost tactics. The Opinion Dynamics 2022 Flex Alert Marketing Evaluation demonstrates the $24 million for Flex Alerts in 2021 and 2022 spent thus far has resulted in limited increases and a lack of sustained awareness for Flex Alerts...
>
> The Flex Alert Evaluation showed that TV, text message, and emails from IOUs each contributed 30% of how customers heard about Flex Alert in November 2022. If each of those contributed 30% to the awareness of the Flex Alert and one of the tactics is significantly higher in cost, there should be a shift to put more of the funding into the methods that can produce equal results with less funding…
>
> PG&E requests that the Commission identify all the entities that fund Flex Alert campaigns as well as a mechanism and percentages for cost sharing among IOU and non-IOU parties. This will ensure that Flex Alert is funded by all customers who benefit

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[56] SCE's April 21, 2023, Response of SCE To Questions In The January 27, 2023, Assigned Commissioner's Ruling at 23-25.

> from the load reductions in compliance with D.13-04-021 [and] reiterated in D.15-11-033. The Mid-August 2020 Heat Storm Preliminary Root Cause Analysis identified that the CEC, CAISO, and CPUC should coordinate to add funding from all LSEs to better target conservation messaging and utilize automated devices.
>
> PG&E recommends that a competitive solicitation be issued to select the administrator of the campaign that provides the most efficient and cost-effective plan to inform Californians of Flex Alerts. When reviewing the bids, PG&E believes that there should be consideration for diverse and California based agencies that have competitive rates similar to what the IOUs pay for their local campaigns.[57]

SDG&E stated in pertinent part as follows: "As a policy issue, Flex Alert statewide messaging should be handled at the state level through the statewide budget."[58]

The staff proposal noted that Flex Alert awareness has increased by 50 percent from June 2021 to October 2022, and the Power Saver Rewards program showed significant gains in awareness.[59] In addition, elsewhere in this decision, we authorize continued funding for Power Saver Rewards for program years 2024 and 2025. The Flex Alert paid media campaign is the key means of noticing enrolled customers that a Power Saver Rewards event has been called and is therefore integral to the design of that program.

Given the need to ensure grid reliability and the role played by Flex Alert paid media advertising in notifying customers when the Power Saver Rewards

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[57] PG&E's April 21, 2023, Opening Comments of PG&E In Response To The Assigned Commissioner's January 27, 2023 Ruling at 24-28 (footnotes omitted).

[58] SDG&E's April 21, 2023, Opening Response To Questions And Energy Division's Staff Proposals Present In Assigned Commissioner's Ruling Date January 27, 2023, at 23.

[59] Assigned Commissioner's Ruling (January 27, 2023), Appendix A (Staff Proposals) at 18.

program has been called, it is reasonable to continue Flex Alert funding for two years through 2025, to match the current end date of Power Saver Rewards as authorized in this decision. While the concerns of parties in the record of this proceeding regarding the appropriateness of ratepayer funding for statewide Flex Alert media campaigns and the effectiveness of past Flex Alert paid media campaigns are legitimate, the programmatic need for Flex Alert paid media campaigns through 2025 to support Power Saver Rewards is clear, immediate, and compelling.

In addition, as Power Saver Rewards is a ratepayer-funded program open only to customers of the IOUs, it is appropriate for ratepayers to also fund the mechanism, Flex Alert paid media advertising, that triggers and gives notice of a Power Saver Rewards event. While PG&E recommends that the budget for Flex Alert paid media campaigns be reduced to $12 million annually, it provides no justification. As such, we will continue to fund Flex Alert paid media campaigns at the same level as in recent years: $22 million.[60]

PG&E, SCE, and SDG&E shall share in the cost of the annual $22 million budget, at proportions based on each IOU's portion of Commission-jurisdictional share of CAISO peak load: 45 percent for SCE, 45 percent for PG&E, and 10 percent for SDG&E. Costs shall be tracked to Category 6 ME&O costs. As in D.21-12-015, SCE shall work with the current vendor to extend the contract currently set to expire in 2023 and set a new expiration date of December 31, 2025. If SHEE is not able to extend the contract, we direct SCE too issue a new solicitation for a vendor to administer Flex Alert and Power Saver Rewards

[60] In 2022, a portion of the $22 million annual total budget for Flex Alert was appropriated by the legislature, with ratepayers funding $12 million annually. There is no similar appropriation from the General Fund for Fiscal Year 2023-2024.

marketing, with a budget of $22 million per year for calendar years 2024 and 2025.

### 5.7. Mid-cycle Review

D.16-09-056 required the IOUs to submit Tier 3 advice letters in April of the third year of each DR application cycle, known as a mid-cycle review (MCR).[61] Although the IOUs submitted advice letters pursuant to this process during the previous DR budget cycle, they were unable to be approved by the Commission in time to implement them as had been envisioned. SDG&E and initially, PG&E, state that this process should not be continued, stating that the submittal of these Tier 3 advice letters was not an efficient use of IOU or Energy Division staff time and are duplicative of other, more agile methods by which the IOUs can propose changes to its DR programs.[62] PG&E also noted that the required monthly updates on DR program activity and spending provide sufficient reporting on DR program activities. PG&E proposed in the alternate that the IOUs be allowed to submit Tier 1 or Tier 2 advice letters at the end of each year wherein the utilities may propose changes to program design elements.[63]

CEDMC and SCE[64] support the MCR. SCE states that the review allows the opportunity to make timely portfolio or programmatic changes. PG&E has also since changed its position and is now in favor of a MCR but agrees with SCE that disposition must take no longer than 5 months after submission.[65] PG&E

[61] D.16-09-056, OP 9.

[62] PG&E-2, at 2-19; SDGE-1, at EBM-100:2-16.

[63] PG&E-2, at 2-20:8-12.

[64] Council-02, at 11:13-12:2, SCE-01, at 42:4-5.

[65] PG&E-8, at 1-12:27-1-13:9.

also proposes that the MCR filing be due by November 1, 2025, with Commission disposition targeted by April 1, 2026. This would allow for two years of program experience, but also for program changes to be implemented by the 2026 summer season. CEDMC proposes an April 1, 2026 submission date with resolution by September 1, 2026. Cal Advocates states that any new pilots should be subject to review during the MCR with possible termination considered if the pilot has not accomplished its goals.

Given that elsewhere we have declined to open a Phase III of this proceeding, it is reasonable to create a process by which the IOUs can refine their DR portfolios in the middle of the 2024-2027 DR application cycle. The MCR process discussed here shall also take the place of the ELRP Advice Letter process previously approved in Summer Reliability Decisions (D.21-03-056 and D.21-12-015) and the Auto DR process prescribed in D.18-11-029,[66] but with filing deadlines reflecting those in the past.

We adopt the following guidance:

1. The utilities may propose modifications to ELRP on a uniform statewide basis via a joint Tier 2 advice letter due on January 15, 2026, with limited deviations to accommodate utility specific implementations due to information technology and billing systems.[67]
2. The utilities may propose modifications to the design of CBP on a uniform statewide basis via a joint Tier 2 advice letter due November 1, 2025, with limited deviations as necessary for a utility to ensure cost-effectiveness.
3. PG&E may propose modifications to the design of PG&E's Automated Response Technology Program via a joint Tier

[66] D.18-11-029, at 56-57 and OP 8.

[67] D.21-12-015, OP 22 allowed these limited deviations.

2 Advice Letter due November 1, 2025, with limited deviations as necessary to ensure cost-effectiveness.

4. SCE may propose changes to SCE SDP & SEP via a Tier 2 advice letter due November 1, 2025.
5. The scope of changes that could be proposed by the utilities in the above advice letters is limited to: manage or increase program enrollment, improve program efficiency, increase potential load reduction available, improve program value, reduce costs, or bring the program in alignment or comply with Commission policies.[68] The types of modification permitted shall be limited to technical aspects of the program design.
6. The utilities shall provide status updates on, and may propose modifications to, authorized pilots on a utility-specific basis via Tier 2 advice letters due November 1, 2025. New pilots authorized in this proceeding shall be subject to termination if they are not affirmatively shown to be accomplishing their goals.[69]
7. The process to identify and mitigate issues with Auto DR as prescribed in D.18-11-029 may be conducted once during the current budgeting cycle, at the discretion of Utilities with Auto DR offerings, and with Energy Division concurrence. Any proposed changes may be submitted via Tier 2 advice letter, by November 1, 2025. Utilities may eliminate the stakeholder involvement and detailed schedule set in D.18-11-029 if flexibility is needed.

The MCR shall provide updates on new pilot programs, but all other proposed changes are discretionary.

[68] D.21-12-015, OP 22 establishes most of the same parameters for changes proposed in the annual ELRP Advice Letter.

[69] Cal Advocates-1, at 5-1:16-17.

### 5.8. PG&E Enrollment Requirement Proposal

PG&E proposes that the Commission require customers that receive technology incentives to automatically enroll in a DR program.[70] PG&E states that this requirement would improve cost-effectiveness by increasing DR capacity. PG&E points to requirements in the Auto DR as well as in SGIP.

Parties were generally opposed to the proposal. Cal Advocates notes that it could have negative bill impacts on low-income or medically vulnerable customers, or any others that do not understand how the DR programs operate.[71] Cal Advocates recommends holding a workshop to discuss. In response, PG&E agreed that the idea should be discussed at a workshop.[72] Accordingly, the request to implement this enrollment requirement proposal is denied.

### 5.9. Funding of DR Research

Proposal E of the January 27 Ruling asked parties to comment on whether to continue DR research funding to inform planning and policies that address the needs of the grid.[73] The staff proposal suggested continuing the current budget of $1 million per year, from 2024-2027. The staff proposal states that the funding has been used for research with the LBNL, which has recently completed a Phase 4 Potential Study forecasting the technical, economic, and achievable potential for shed, shift, and a dynamic rate-based shape service through 2050. Recent projects include the creation of a bill analysis tool for use in a working group and the study of elastic impacts on load, customer bills, and cost recovery. Currently there is an ongoing dynamic tariff benefits study.

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70 PG&E-2, at 2-11:1-14.

71 CalAdvocates-1, at 2-3:24-2-4:12

72 PG&E-8, at 1-8:21-26.

73 January 27 Ruling, Appendix A, at 13-16.

Parties were generally supportive of continuing the research. PG&E, SCE, and SDG&E proposed to continue funding at current levels of $1 million per year.[74] CLECA voiced concerns about the cost-effectiveness of the research, and suggests that future research should include topics regarding industrial customers.[75] PG&E asks that the Commission's Energy Division regularly provide updates regarding DR research through workshops and publication on the Commission's website.

It is reasonable to continue this research, given the benefits it has provided thus far. With regards to PG&E's request for more visibility, we note that the research is already made publicly available on the LBNL website. We authorize PG&E and SCE to each recover $400,000 per year, and SDG&E $200,000 per year from 2024-2027 for this DR research. It shall be added to the IOU's Category 7 budgets, although we note that SDG&E has already accounted for it in its application.

### 5.10. Competitive Parity Between Investor-Owned Utilities (IOUs) and Demand Response Providers (DRPs)

CEDMC proposes that the Commission take actions to ensure parity between IOUs and third-party DRPs. CEDMC recommends that the Commission allow DRPs to provide both RDRR and load-modifying DR capacity. CEDMC also noted that restricting technology incentives to IOU DR programs and DRAM customers provides the IOUs with an advantage. OhmConnect also recommends that the Commission review all proposals in this proceeding against DR principles adopted in D.16-09-056.

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[74] PG&E Opening Comments on January 27 Ruling, at 23; SCE Opening Comments on January 27 Ruling, at 23; SDG&E Opening Comments on January 27 Ruling, at 22.

[75] CLECA Opening Comments on January 27 Ruling, at 5.

Party comments were mixed. PG&E and Cal Advocates opposed these recommendations, noting that the Commission's policy goals do not include increasing emergency DR capacity or allowing third parties to operate emergency DR programs.[76] PG&E also notes that the Base Interruptible Program (BIP) is already open to third-party aggregators. Cal Advocates and SCE state that OhmConnect's proposal is out of scope of this proceeding, and should be addressed in the RA proceeding.[77]

We decline to adopt either CEDMC's or OhmConnect's proposals at this time. Neither has presented sufficient evidence to show that third-party DRPs are hamstrung from providing load modifying DR to non-IOU LSEs, nor have they shown that this is the appropriate venue to address their concerns.

### 5.11. Reliability Cap

In the January 27 Ruling, parties were asked to provide comment on whether the DR reliability cap should be kept at three percent if the ELRP pilot is extended, as was previously authorized in D.21-03-056. In D.10-06-034, the use of emergency DR to meet RA requirements was limited to two percent of all-time system peak load. To support summer reliability, this cap was increased to three percent for the duration of the ELRP pilot.[78]

Parties providing comments assert that the cap should be continued at three percent through 2027. SCE advocates for an extension, noting that the proposed removal of its Save Energy Program and Summer Discount Program from the Day-Ahead market would make them subject to the reliability cap. SDG&E states that the cap should be continued so long as ELRP remains a pilot

[76] PG&E-8, at 1-14:3-22; CalAdvocates-02, at 3-4.

[77] CalAdvocates-02, at 4-2:12-4-3:3; SCE-14, at 17:7-18:19.

[78] D.21-03-056, at 31.

and not a regular DR program. PG&E, Tesla, CLECA, and CalSSA also support the extension.

The Commission enacted the temporary increase of the cap to 3 percent of all time system peak load in order to increase available DR capacity at a time when the ability to meet system peak and net peak demand was uncertain.[79] However, there is no evidence in the record of this proceeding to suggest that any IOU has surpassed even its share of the 2 percent reliability cap. As stated by SCE, the removal of its Save Energy Program and Summer Discount Program from the Day-Ahead market would have made the RA QC associated with those programs subject to the reliability cap – thereby pushing that IOU above 2 percent. However, as this decision denies SCE's request to make the proposed change, we find that the temporary increase in the reliability cap has in fact not led to an increase of emergency DR capacity.

At this time, we decline to extend the temporary increase of the emergency DR cap beyond the initial duration as established in D.21-03-056.[80] The cap shall remain at 3 percent of all-time system peak load through 2025, and then shall revert to 2 percent as agreed in D.10-06-034.

If one of the parties to the settlement in D.10-06-034 finds that there is both a need for and a potential for development of emergency DR resources beyond 2 percent of all-time system peak load after 2025, the party may seek relief either through a petition for modification of this Decision or through another appropriate Commission venue. However, as stipulated in the settlement agreement, the party advocating for the change shall bear the burden of proof.

[79] D.21-03-056, Finding of Fact 37.

[80] D.21-03-056, at 19.

### 5.12. Demand Response and Interruptible Load Program Reporting

Currently, the DR Provider and ILP reports are submitted by the IOUs each month on the 21st day, for the month prior.[81] SCE states that 30 percent of reports for the 2023-2027 cycle will be filed late, due to the last data point being unavailable until the 15th day. This is due to a number of weekends and holidays occurring that can further compress an already tight schedule. SCE states that more time is needed to compile and check the data, resolve any issues, and conduct management review. SCE proposes that the due date be moved to the first business Day-Of the second month after the reporting month.[82]

SCE's request is reasonable and approved. PG&E and SDG&E are also directed to align their submissions with the same schedule.

### 5.13. Joint IOU Status Reports on Progress Towards Interim Goal

SCE proposes that the IOUs no longer be required to file Joint IOU Status Report on Progress Toward Interim Goal (Status Report) as required by D.14-12-024. A settlement agreement in that decision between the parties set a statewide DR goal of five percent of the sum of the peak demand of the IOUs by 2020. This goal would remain in effect until superseded by permanent DR goals, to be informed by a DR potential study.[83] SCE states that the purpose of the Status Report has been frustrated, due to various policy changes and delay in the release of the final phase of the DR potential study.[84] SCE therefore recommends the elimination of the annual filing of the Status Report.

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[81] SCE-01, at 42:13-43:18.

[82] *Id* at 43:15-18.

[83] D.14-12-024, Attachment A to Appendix 1, at 12-13.

[84] SCE-03, at 44:4-12.

SCE's proposal is reasonable and approved as to all IOUs. The IOUs need no longer file the Status Report.

### 5.14. Phase III – PG&E Proposal

PG&E proposes that the Commission consider opening a Phase III in this proceeding to consider and resolve a number of issues that have revealed themselves over the course of this proceeding.[85] PG&E states that a Phase III would ensure that the 2024-2027 DR programs are aligned with CEC and CAISO developments since these applications were filed in May of 2022. PG&E points to overlapping policy proposals regarding the ACC, DR availability requirements in the RA rulemaking (R.21-10-002), demand flexibility rate proposals in the Demand Flexibility Rulemaking (R.22-07-005), and the expansion of the CEC's Demand Side Grid Support (DSGS) program to IOU customers in 2023, and related modifications to ELRP.

CLECA supports PG&E's proposal to open a Phase III in this proceeding, noting that DR implementation requires coordination with other dockets, and a Phase III would allow the Commission to more quickly and thoroughly address issues that arise during the program cycle.[86]

SDG&E would like to see this proceeding close, noting that the next DR Application cycle will occur soon and that any Phase III is likely to overlap with that cycle.[87]

PG&E and CLECA have not sufficiently justified the need for a Phase III in this proceeding. None of the issues proposed to be addressed in Phase III need resolution to resolve the issues outstanding in the instant applications. Many of

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[85] PG&E Phase II Opening Brief, at 5-6.

[86] CLECA Phase II Opening Brief, at 32.

[87] SDG&E Phase II Reply Brief, at 14.

the issues raised would be better addressed in a singular DR rulemaking, as opposed to in an application process. We decline to open a Phase III in this proceeding.

## 6. Utilities' Applications, Intervenor Responses, and Commission Direction Regarding Demand Response Programs, Pilots, and Proposed Budgets for the Years 2024-2027

The Utilities each filed their respective Applications on May 2, 2022. Each Utility provided supporting testimony describing its proposed DR program and corresponding budget. Each Application provided a separate request for both the 2023 Bridge Year and for the combined 2024-2027 years. D. 22-12-009 addressed DR Phase I issues concerning the 2023 Bridge Year Funding. This Decision reviews and makes direction regarding DR Phase II issues concerning each Utility's DR programs, pilots, and proposed budget for the years 2024-2027.

This Decision will address each Utilities' Phase II DR program, pilot, and budget proposals. These will be addressed by subject. The subject discussions will include each Utility's relevant requests, party comments and suggested changes to the Utility's requests, and the Commission's directions regarding the Utility's requests. The IOUs have divided their budget requests into seven categories, as in the last DR application cycle. This decision will address the costs split by those categories.

### 6.1. Standard of Review

Where the IOUs have proposed specific programs and activities, they bear the burden of proof. Generally, all utility requests to recover costs from customers must comply with California Public Utilities (Pub. Util.) Code[88] (Code) Section 451, which requires that "[a]ll charges demanded or received by any

[88] All references to the "Code" are to the Public Utilities Code.

public utility … for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable." The IOUs must therefore show that their proposed costs and ratemaking mechanisms are fair, just, and reasonable.[89] The utility "has the burden of affirmatively establishing the reasonableness of all aspects of its application. Intervenors do not have the burden of proving the unreasonableness of the utility's showing. The standard of proof is that of a preponderance of the evidence, which is generally defined as 'in terms of probability of truth, e.g., such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[90] However, we also note that "any party contesting those costs has the burden of going forward to produce evidence to support its own position."[91] Additionally, other non-IOU parties presenting their own proposals must show by a preponderance of the evidence that the Commission should adopt their proposal.[92]

Where the IOUs are the only party to have introduced evidence on an issue, we do not necessarily conclude that they have met their burden to establish that a request is just and reasonable. However, as a general matter, where the IOUs have presented individual uncontested issues in this proceeding, we find that they have made a *prima facie* just and reasonable showing, and adopt

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89 D.04-06-018, Appendix at 5. "The application must be supported by testimony, with supporting analysis and documentation, describing the components of the utility's proposed increase. All significant changes from the last adopted and recorded amounts must be explained, and all forecasted amounts must include an explanation of the forecasting method." *See* D.18-12-021, at footnote 8.

90 D.08-12-058, at 19.

91 D.19-05-020, at 333.

92 D.18-10-019, at 32.

the proposal, unless otherwise stated in this opinion.[93] This is reasonable given the large number of parties and amount of attention dedicated to this proceeding.

### 6.2. PG&E Application

PG&E proposes to increase its DR portfolio from 495 megawatts (MW) in 2022 to more than 1,000 MW in 2027.[94] PG&E proposes changes to the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), SmartAC Program (SmartAC), and Auto DR programs to address future grid challenges from 2024-2027. It also proposes a new Automated Response Technology program to support the enablement of residential smart technologies, such as batteries and electric vehicles for use in DR and time-of-use (TOU) and/or load shifting. PG&E also proposes two new pilots, a residential Smart Panel Pilot and an Agricultural DR Pilot. PG&E also recommends continuation of the ELRP pilot through 2027.[95] PG&E seeks a budget of $783 million for DR programs in the 2024-2027 program cycle.[96]

### 6.3. SDG&E Application

SDG&E proposes a number of new pilots for consideration. SDG&E proposes to discontinue the AC Saver program, BIP, and some of its CBP products. SDG&E also proposes a number of new pilots. SDG&E projects 57.44

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[93] *Id.*, at 7.

[94] PG&E-2, at 1-2, Table 1-1.

[95] PG&E Phase II Opening Brief, at 5-6.

[96] *Id.* at 2.

MW of load impact from its portfolio for the August monthly peak day.[97] SDG&E seeks a budget of $156.6 million for its 2024-2027 DR programs.[98]

### 6.4. SCE Application

SCE's DR program includes the Agricultural and Pumping – Interruptible (AP-I) program, BIP, CBP, the Smart Energy Program (SEP), Summer Discount Plan (SDP), and load-modifying DR programs. SCE proposes to continue ELRP, and asks for approval for two new pilot programs. SCE projects load reduction of 819 MW capacity average peak. SCE initially requested $790 million for its 2024-2027 DR program budget.[99]

## 7. Supply-side Demand Response Programs

Supply-side DR (also known as dispatchable DR) programs are integrated into the wholesale energy markets of the CAISO. When such resources or programs are dispatched by the CAISO, they can be utilized to reduce demand when needed for economic or reliability reasons. The following sections discuss the IOUs' supply-side DR programs and any changes proposed by the parties. These programs include Base Interruptible, the Agricultural Pumping Interruptible, Capacity Bidding, A/C cycling and smart thermostat and other smart technologies programs.

### 7.1. Base Interruptible Program

The Base Interruptible Program is a day-of DR program designed to provide firm load reduction to maintain electric grid reliability. Participating customers are under contract to reduce their loads to their contracted firm service level (FSL) within 15 to 30 minutes of notification of the need to

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[97] SDGE-4, at LGR-4, Table LG-5.

[98] SDG&E Application, at 3.

[99] SCE Application, at 7.

implement load reductions. In return, the customers receive a monetary incentive either from the IOU, directly or via an aggregator. BIP-enrolled customers may opt out or revise their FSL once each year during the month of November, with changes becoming effective on January 1. Due to changes to the BIP and incentive rates implemented in this decision, as described later in the BIP section, we authorize an exceptional 30-day period for BIP participants to opt-out of the program or to revise their FSLs.

#### 7.1.1. SDG&E BIP

SDG&E's BIP offers a monthly capacity payment to commercial customers that can commit to curtailing at least 15 percent of Monthly Average Peak Demand, with a 20-minute notification. It is a supply resource bid into the CAISO. SDG&E proposes to allow BIP to end on December 31, 2023. SDG&E states that it has been unable to find large industrial customers or manufacturers in its service territory that can quickly reduce energy within 20 minutes and that are willing to enroll in BIP.[100] SDG&E notes no enrolled customers in 2021 and 2022,[101] despite substantial marketing efforts.[102] SDG&E notes that the TRC for BIP is 0.158.[103] With no customers and an extremely low cost-effectiveness value SDG&E proposes ending BIP.

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[100] SDGE-1, at EBM-8:13-21.

[101] SDGE-1, at EBM-10, Table EBM-1.

[102] *Id*., at EBM-10:8-EBM-13:5.

[103] *Id*. at EBM-15:4.

Cal Advocates supports SDG&E's proposal to end BIP, noting that the service area does not include sufficient industrial customers.[104] CLECA opposes the proposal and instead encourages increased marketing efforts.[105]

It is reasonable to end SDG&E's BIP. Given SDG&E's extensive marketing efforts have been unable to yield new participants for a number of years, the lack of large industrial customers in SDG&E territory, and the attrition of all formerly enrolled BIP customers, it does not make sense to continue to spend funds on a program that is not likely to yield any appreciable benefits to ratepayers. SDG&E's BIP shall be allowed to sunset at the end of 2023.

#### 7.1.2. PG&E BIP and Proposed Changes

PG&E proposes the following changes to its BIP to encourage participation and reduce attrition. PG&E notes that since 2020, a year in which BIP was called upon five days in a row in August and two days in September, the number of customers enrolled in BIP has almost halved and the amount of MWs available for dispatch in BIP has decreased by almost 30 percent.[106]

##### 7.1.2.1. Continue Year-Round Enrollment with Retention Requirement

PG&E proposes to continue through 2027 to allow year-round enrollment in BIP,[107] as currently required by D.21-03-056,[108] and that customers be required to enroll for a minimum of six months before unenrolling or raising their FSL. PG&E notes that customers may only unenroll from BIP during the November unenrollment window. PG&E's proposal therefore requires that any customer

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[104] CalAdvocates-01, at 2-9:13-22.

[105] CLECA-02, at 9:3-9.

[106] PG&E-2, at 3-7, Table 3-3.

[107] PG&E-2, at 3-7:16-19.

[108] D.21-03-056, at 30.

that enrolls after July 1 on a given year must stay enrolled through November of the following year, a maximum period of 17 months. This is a change from the current requirement, which requires that customers enrolling after April 30 on a given year must (effectively) stay enrolled through November the following year, a period of 20 months.[109] PG&E states these changes are needed to make program enrollment easier and less restrictive. No other parties commented on these proposed changes.

These changes are reasonable and may help increase customer enrollment. It is also reasonable to standardize these changes across all IOU BIP programs. They are approved with respect to PG&E's and SCE's BIP programs.

##### 7.1.2.2. End Lottery System

PG&E proposes to end the lottery process for the BIP. The lottery was instituted as a way to fairly determine which prospective BIP customers should be allowed to participate in the program, due to the IOUs approaching or exceeding the two percent DR reliability cap. The lottery currently runs once a year in April. PG&E states that with the increased cap, the lottery is no longer needed and only serves to restrict enrollment.[110] PG&E also states that the release of the annual load impact report in April is too late to provide aggregators and customers with clarity regarding the cap before participation elections must be made.

No parties commented on this proposal. Elsewhere in this decision, the reliability cap has been set at three percent through 2025. There is currently no evidence to suggest that the IOUs are overenrolled in BIP at this time. It is also

[109] PG&E-2, at 3-9:13-33.

[110] PG&E-2, at 3-8:10-26.

reasonable to remove barriers to BIP participation given potential grid stresses in the near future. It is therefore reasonable to suspend the lottery until 2025 while the temporary increase to the reliability cap has been extended. However, starting in 2026, with the currently planned return to a two percent reliability cap, the IOUs shall again utilize the lottery detailed in D.18-11-029[111] to determine BIP participation.

#### 7.1.2.3. Changes to Limits on Number of BIP Events

Currently, BIP is allowed to be deployed no more than 1) once per day, 2) no more than six hours per event, 3) no more than ten times per calendar month, and 4) no more than 180 total hours per calendar year.[112] BIP customers receive monthly incentives for their dispatchable capacity, but are not specifically compensated for the amount of energy delivered during a dispatch. BIP customers thus receive the same total payments whether they were dispatched for 180 hours or one hour in a year.

PG&E proposes to modify the monthly limit so that the program is limited to 10 dispatches in a rolling 30-day window, rather than 10 dispatches in a calendar month, and add a limit that the program can only be dispatched up to three days consecutively.[113] PG&E states that multi-day dispatches cause fatigue leading participants to unenroll from the program.

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[111] D.18-11-029, at 104.

[112] PG&E Electric Schedule E-BIP p. 9: CPUC Sheet No. 45778-E; SCE Schedule TOU-BIP, p. 14: CPUC Sheet No. 74149-E.

[113] PG&E-2, at 3-11:1-19.

Both the Joint DR Parties[114] and CLECA[115] support the proposal, noting that dispatches on consecutive days can lead to inventory shortages of important goods. The Joint DR Parties note that allowing businesses a day off after three days may allow them to participate in more events going forward, where they may otherwise be unable to perform for five consecutive days. Cal Advocates opposes, on the basis that imposing new limits on reliability resources is short-sighted because extreme heat events are likely to become more intense and more frequent in the future.[116] Cal Advocates also notes that events have only been called for a small fraction of the maximum ten events per month and 180 hours per year.

We decline to adopt PG&E's proposal. BIP is designed to help during critical grid conditions – conditions that can endure for periods (such as during an extended heat wave) that can last for longer than three days. Reducing the frequency with which BIP can be called will reduce the efficacy of the program. Additionally, as discussed below, we will increase incentive rates to make BIP more attractive in other ways to participants.

##### 7.1.2.4. Add 15-Minute Dispatch Option with Higher Incentive Level

PG&E's current BIP requires that customers reduce load within 30-minutes after an event notification is received. PG&E proposes to add a 15-minute option.[117] SCE already has both a 15-minute and 30-minute option. PG&E states that this option will allow for greater flexibility to respond to emergency grid

[114] JDRP-02, at 1:22-29, 8:1-26.

[115] Council-02, at 17.

[116] CalAdvocates-01, at 2-4:15-2-5:8.

[117] PG&E-2, at 3-11:20-30.

needs and local capacity requirements. PG&E proposes the following incentive rates:

**Table 9**

PG&E 15-Minute Notification Proposal[118]

| Potential load reduction (kW)[119] | Summer (proposed) | | | Winter (proposed) | | |
|---|---|---|---|---|---|---|
| | 30-minute | 15-minute | % difference | 30-minute | 15-minute | % difference |
| 1-500 | $12.50 | $13.60 | +8.8% | $9.50 | $10.60 | +11.6% |
| 501-1,000 | $13.00 | $14.20 | +9.2% | $10.00 | $11.20 | +12% |
| 1,000+ | $13.50 | $14.80 | +9.6% | $10.50 | $11.80 | +12.4% |

CLECA supports this proposal, noting that additional resources will improve grid reliability and that the higher incentive level may encourage new customer enrollments.[120]

PG&E's proposal will provide additional options to respond to grid needs and could encourage increased participation. PG&E is authorized to establish a 15-minute notification option at the incentive levels proposed.

#### 7.1.2.5. Proposed BIP-30 Incentive Changes

PG&E proposes to increase summer capacity incentive rates for its BIP 30-minute notification option (BIP-30) by $2/Kilowatt (kW) from May to October each year. PG&E notes that BIP incentives were increased twice before in the

[118] PG&E-2, at 3-12, Table 3-5.

[119] PG&E distinguishes BIP customer groups by potential load reduction. Customers that commit to shedding a high amount of load (in kW) during a dispatch are compensated at a higher rate than customers with lower commitments.

[120] CLECA-01, at 21:6-15.

summer reliability proceeding.[121] PG&E states that these increases are needed to combat attrition and stalled program growth.

Table 10

PG&E Historic and Proposed BIP-30 Incentive Levels

| Potential Load Reduction (kW) | (1) 2018-2020 | (2) 2021 | (3) 2022 & 2023 | | (4) 2024-2027 (Proposed) | |
|---|---|---|---|---|---|---|
| | All year | All year | November-April | May-October | November-April | May-October |
| 1-500 | $8/kW | $9.50/kW | $9.50/kW | $10.50/kW | $9.50/kW | $12.50/kW |
| 501-1,000 | $8.50/kW | $10/kW | $10/kW | $11/kW | $10/kW | $13/kW |
| 1,001+ | $9/kW | $10.50/kW | $10.50/kW | $11.50/kW | $10.50/kW | $13.50/kW |

Enchanted Rock and the Joint DR Parties[122] support the increases. Joint DR Parties suggest that an additional tier for customers over 5,000 kW be added.

CLECA suggests that the incentive level should be increased even higher.[123] CLECA proposes that an additional $1/kW incentive be applied to the average customer load, minus FSL for the aggregate period in any month that otherwise does not figure into the existing incentive calculation equation. CLECA states that this will reflect the reality that customers are expected to commit to curtailment at all hours of the day, and does not pose cost-effectiveness issues due to the much higher 2022 ACC TRC.[124] PG&E recommends its above proposal instead, noting that it is not clear that CLECA's proposed increase is necessary to incentivize participation nor is it clear that

[121] PG&E-2, at 3-10:2-18.

[122] JDRP-01, at 22:13-17.

[123] CLECA-01, at 18:3-14.

[124] *Id*. at 18:15-19:9.

CLECA's proposal won't cause inadvertent performance reduction during the peak periods.[125]

Alternatively, PG&E proposes to revert BIP incentives to 2020 levels and lower excess energy charges, to improve program cost-effectiveness. Cal Advocates supports this proposal instead, to increase cost-effectiveness.[126] As noted above, cost-effectiveness is a factor to consider but shall not be the final determining factor when judging whether to continue a DR program.

We adopt PG&E's proposed summer incentive level increases. We agree with PG&E and Cal Advocates that an iterative approach should be taken before implementing proposals such as CLECA's and the Joint DR Parties. If the increased incentives are not enough to encourage participation then we may consider additional modifications to the incentive structure in the future.

#### 7.1.2.6. Suspend Prohibited Resources Policy for BIP through 2027

PG&E proposes to suspend the Prohibited Resources Policy for BIP through 2027. This change would allow customers to use fossil fuel generators to meet their FSLs during a dispatch, but not during test and re-test events. PG&E states that this change could open up the potential for more participation. PG&E points out that waivers were issued via Executive Orders during system emergencies from 2020-2021.[127]

Cal Advocates, SBUA, and Sierra Club state that the proposal should be rejected, given that PG&E customers are likely to have large on-site backup

[125] PG&E-8 at 2-7:20-2-8:2.

[126] CalAdvocates-01, at 4-2:5-6.

[127] PG&E-2, at 2-16:10-32.

generators and that the negative public health impacts will lead to worse pollution in disadvantaged communities.[128]

PG&E's proposal is in contravention to the Commission's recent pronouncements that RA-qualifying DR resources (such as BIP) must be clean, regardless of whether such resources are procured by IOUs or non-IOU LSEs.[129] PG&E's proposal is therefore denied.

Enchanted Rock states that diesel generators are the most common Prohibited Resource, and that increases in particulate matter pollution caused by more frequent use of these resources can have serious consequences for nearby communities, including many Disadvantaged Communities. Enchanted Rock states that exempting only Prohibited Resources that meet their proposed emissions and fuel standards would improve grid reliability while producing lower levels of greenhouse gas and criteria pollutant emissions than using conventional diesel generation resources.

SBUA expresses opposition to PG&E's proposal to universally suspend the PR policy for BIP through 2027, yet supports the proposal by Enchanted Rock, stating that, "clean sources of backup generation should not be forced to compete with dirtier sources such as diesel backup generators."

Enchanted Rock's testimony is compelling. However, the consideration of any modification to the Prohibited Resources policy should purposefully engage stakeholders from communities impacted by pollution from backup generators. Furthermore, such modifications are out of scope for this proceeding. The

[128] CalAdvocates-01, at 3-7; SBUA-3, at 3:1-6.

[129] D.23-06-029, at 90-91.

proposal by Enchanted Rock is dismissed without prejudice and may be introduced at a suitable Commission venue in the future.

#### 7.1.2.7. PG&E BIP Budget

PG&E requests $175.359 million for BIP from 2024-2027, a 28 percent increase over the funding authorized for the 2018-2022 program cycle. PG&E notes that this is mainly driven by the increased incentive levels.[130] As discussed above, increased incentives may be necessary to ensure continued BIP participation. Utilizing the 2021 ACC, PG&E's BIP shows a TRC of .79 without ADR, and when utilizing the 2022 ACC, a TRC of 2.69 without ADR. We find that this sufficiently shows that PG&E's BIP is cost-effective or close to cost-effective. PG&E's proposed increases are therefore approved.

**Category 1 - 2024-2027 PG&E BIP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $0.583 | $0.604 | $0.625 | $0.647 | **$2.46** |
| | Incentives | $43.225 | $43.225 | $43.225 | $43.225 | **$172.9** |
| Authorized | Administrative | $0.583 | $0.604 | $0.625 | $0.647 | **$2.46** |
| | Incentives | $43.225 | $43.225 | $43.225 | $43.225 | **$172.9** |
| | Total | **$43.81** | **$43.83** | **$43.85** | **$43.87** | **$175.36** |

### 7.1.3. SCE BIP

#### 7.1.3.1. Proposed Change to Use of Event Days in BIP and AP-I Incentive Calculation

SCE proposes to modify incentive calculations for BIP and Agricultural Pumping - Interruptible customers to exclude event days from those calculations.[131] Specifically, SCE proposes to remove days on which a BIP or AP-

[130] PG&E-2, at 3-12, Table 3-6, 3-6:17-3-7:28.

[131] SCE-03, at 10:1-11:4.

I event gets triggered from the customer's respective incentive calculation. SCE states that this will fix a current oversight in which BIP and AP-I participants have their incentive amounts reduced due to events because the event reduces their monthly average load, which is used to calculate the monthly incentive payment. This could disincentivize program participation. This change would be in line with how SCE calculates Critical Peak Pricing incentives, as well as how PG&E calculates their BIP incentives.[132] SCE asks for $1.5 million total to implement this change, $750,000 allotted to each program.

Both CLECA and Cal Advocates were supportive of the change. Cal Advocates opposed the proposed cost, on grounds that the fix can be conducted by SCE's already supported billing or information technology (IT) staff.

It is reasonable to fix this unintended BIP/AP-I calculation consequence. SCE is authorized to make this change. However, we are unconvinced that SCE's proposed cost should be so high. We therefore reduce the allocated funding for SCE's BIP non-labor request by $500,000, but authorize SCE to seek up to an additional $500,000 via a Tier 2 fund-shifting Advice Letter submitted by December 31, 2024 that includes justification for the additional funds, if necessary.

#### 7.1.3.2. BIP Incentive Rates

SCE determines its BIP incentive levels based primarily on generation capacity marginal cost as calculated in its Phase 2 General Rate Case, and uses a variety of factors to calculate the incentive levels for the various BIP enrollment

[132] *Id*. at 15, footnote 27.

options, customer service voltages, and time-of-use periods.[133] SCE proposes revised BIP incentive rates, as shown below:

Table 11

Current and Proposed SCE BIP Incentive Rates

| | | Current ($) | | | Proposed ($) | | | % increase | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Summer On-Peak | Summer Mid-peak | Winter Mid-peak | Summer On-Peak | Summer Mid-peak | Winter Mid-peak | Summer On-Peak | Summer Mid-peak | Winter Mid-peak |
| BIP-15 | <2kV | 26.11 | 2.04 | 10.97 | 31.35 | 7.18 | 10.31 | 20% | 252% | -6% |
| | 2-50kV | 26.11 | 1.70 | 10.26 | 30.06 | 4.46 | 9.00 | 15% | 162% | -12% |
| | >50kV | 17.84 | 0.86 | 6.46 | 23.54 | 2.61 | 6.41 | 32% | 203% | -1% |
| BIP-30 | <2kV | 23.54 | 1.84 | 9.89 | 27.4 | 6.28 | 9.01 | 16% | 241% | -9% |
| | 2-50kV | 23.14 | 1.50 | 9.07 | 26.27 | 3.9 | 7.87 | 14% | 160% | -13% |
| | >50kV | 15.37 | 0.73 | 5.54 | 20.57 | 2.28 | 5.60 | 34% | 212% | 1% |

In order to account for distribution losses in front of the meter, SCE distinguishes incentive rates based upon the voltage at which a customer receives service from the utility. Customers receiving electric service at less than 2,000 volts are referred to as secondary voltage customers. Customers receiving electric service between 2,000 volts and 50,000 volts are referred to as primary voltage customers. Customers receiving electric service at higher than 50,000 volts are referred to as sub-transmission voltage customers.

Parties noted a number of concerns with the calculations. IPC highlighted the fact that the 2021 avoided cost of generation capacity for SCE's BIP has been updated using the 2022 ACC, yielding a value that is higher by 150 to 350 percent. IPC suggests that this increase in ACC values should result in significantly increased BIP incentive rates.[134] IPC recommends that SCE's

[133] SCE-04, at 3:8-15.

[134] IPC-01, at 5:19-20.

incentives be increased by proportionate amounts. In rebuttal testimony, SCE clarifies that outputs of the ACC do not factor into BIP incentive calculations. Rather, the avoided costs upon which BIP incentive rates are built is the Generation Capacity Marginal Cost (GCMC) as determined in the Phase 2 General Rate Case.[135] SCE notes that the GCMC is similarly used as an input to calculate retail rates and that its use in BIP incentive calculations ensures symmetry between avoided costs and recovered costs.[136]

IPC also raises issues with the incentive levels for sub-transmission voltage customers as compared to primary and secondary voltage customers. According to IPC: one would expect slight differences between incentive levels to account for greater avoided line losses associated with primary and secondary voltage customers, but not the magnitude of difference observed in SCE's proposed incentive rates. According to IPC's calculations, proposed Summer On Peak incentive rates for sub-transmission voltage customers are between 75 percent and 78 percent of the rates proposed for secondary voltage customers and primary voltage customers. [137]

IPC also notes concerns with what assumptions SCE is utilizing when determining how much interruptible MW is available from sub-transmission voltage customers, who tend to have higher load factors than primary and secondary voltage customers.[138]

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[135] SCE-14, at 11:13-16.

[136] *Id.*, at 12:4-8.

[137] IPC-01, at 7, Table 1.

[138] IPC Phase II Opening Brief, at X.

Many parties highlighted the need to further incentivize BIP participation given the program attrition seen in recent years.[139] Joint DR Parties, CLECA, and IPC both support higher BIP incentive rates for customers receiving service at greater than 50 kV levels.[140] CEDMC proposes higher incentives for all BIP customers. Cal Advocates recommends against incentive increases, stating that the 2021 ACC should be used and that there is no requirement to increase incentives just because programs are cost-effective.[141]

SCE states in response that BIP incentives have already been increased substantially by recent Summer Reliability Decisions, and that more caution is needed before larger increases are considered. SCE also notes that enrollment is down due to a number of factors, not just incentive levels, and that incentive levels are calculated utilizing GCMC, not outputs of the ACC.[142] SCE defends the use of its existing approach to calculating incentives and argues that BIP incentives overall should not be increased beyond the level calculated by their methodology.[143]

Parties are generally in favor of increased BIP incentive levels. However, as discussed above similarly in PG&E's BIP incentive section, it is unclear whether or how SCE's calculation methodology should be modified to further increase incentive rates. Additionally, SCE's response to IPC's data request[144] contains ambiguities and numbers that require additional analysis. We therefore

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[139] IPC-01, at 3:13-4:3.

[140] JDRP-01, at 20:1-3; CLECA-02, at 7, Table 2.

[141] CalAdvocates-02, at 2-2:4-14.

[142] SCE-14, at 11:9-12:21.

[143] SCE Phase II Reply Brief, at 17.

[144] CLECA/IPC-01-R.

approve SCE's proposed rates, which are a substantial increase over current BIP incentive levels, but decline additional changes requested by other parties until the effects of these increase have been given an opportunity to sufficiently play out. As discussed above in the section discussing PG&E's proposed BIP incentive levels, we also decline to implement CLECA's proposed $1/kW incentive level increase on similar grounds.

SCE is directed to submit updated Excess Energy Charges, via Tier 1 advice letter, as it has done in the past when updating BIP incentive rates.[145] SCE shall submit this advice letter by February 28, 2024.

#### 7.1.3.3. Third Party Independent Monitor

Joint DR Parties recommend that a third-party monitor be introduced to facilitate cooperation between SCE and the Joint DR Parties to resolve data quality and data access issues. We decline to take action on this issue at this time.

#### 7.1.3.4. SCE BIP Budget

SCE requests $278.441[146] million for its BIP from 2024-2027. As discussed above, this budget is reduced by $500,000 to account for the reduced amount granted to remove Event Days from incentive counting. SCE is therefore authorized to recover $276.975 million from 2024-2027 for BIP, as shown below:

**Category 1 - 2024-2027 SCE BIP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $1.675 | $1.176 | $1.629 | $1.683 | **$6.163** |

[145] SCE Advice Letter 4377-E-A, January 25, 2021.

[146] This number is inclusive of marketing and evaluation, measurement, and verification costs, but such costs will be addressed later in this decision.

| | | | | | | |
|---|---|---|---|---|---|---|
| | Incentives | $66.65 | $67.514 | $68.237 | $68.908 | **$271.31** |
| Authorized | Administrative | $1.175 | $1.176 | $1.629 | $1.683 | **$5.663** |
| | Incentives | $66.65 | $67.514 | $68.237 | $68.908 | **$271.31** |
| | Total | **$67.83** | **$68.69** | **$69.87** | **$70.59** | **$276.97** |

#### 7.1.4. Exceptional BIP Adjustment Period

Given the above implemented changes to BIP, it is reasonable to re-open the BIP adjustment period to allow potential customers to opt-in, opt-out, or make changes to their Firm Service Level. The IOUs are directed to allow customers to opt-in or opt-out of BIP, or to make changes to their Firm Service Level for the 30 days after the date of issuance of this decision.

### 7.2. SCE Agricultural and Pumping Interruptible Program

#### 7.2.1. Removal of Event Days from Incentive Calculation

As discussed above, SCE is authorized to remove event days from its calculation of AP-I incentives. SCE is allowed to recover $250,000 to implement this change from the AP-I program.

#### 7.2.2. Increased Incentive Levels

SCE's AP-I incentive rates are based on similar factors as described above for BIP.[147] SCE proposes slight decreases to its AP-I program incentive rates to the following:

Table 12

**Proposed SCE AP-I Incentive Rates**

| | Current | Proposed | % increase |
|---|---|---|---|

[147] SCE-04, at 7:3-7.

| | | | |
|---|---|---|---|
| Summer | 19.62 | 18.77 | -4% |
| Winter | 10.87 | 9.50 | -13% |

No party commented on this issue. It is reasonable to make these changes based on adjusted inputs as calculated by SCE. SCE's proposed AP-I incentive rate changes are approved.

#### 7.2.3. SCE AP-I Budget

SCE requests $22.324 million for its AP-I budget. No party commented on this request. As discussed above, $500,000 shall be removed from administrative budget for 2024 to account for the reduction related to implementing the removal of Event Days from the incentive calculations. SCE calculates a 1.76 TRC for the AP-I program when utilizing 2021 ACC values, showing that the program is cost-effective. SCE is therefore authorized to recover $21.25 million for its AP-I activities from 2024-2027.[148]

**Category 1 - 2024-2027 SCE AP-I Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $1.322 | $0.588 | $0.644 | $0.659 | **$3.213** |
| | Incentives | $4.585 | $4.611 | $4.651 | $4.691 | **$18.538** |
| Authorized | Administrative | $0.822 | $0.588 | $0.644 | $0.659 | **$2.71** |
| | Incentives | $4.585 | $4.611 | $4.651 | $4.691 | **$18.538** |
| | Total | **$5.41** | **$5.20** | **$5.30** | **$5.35** | **$21.25** |

148 Not inclusive of marketing and evaluation, measurement, and verification (EM&V) costs, which are discussed elsewhere in this decision.

### 7.3. PG&E SmartAC Program

PG&E's SmartAC program is an air conditioning direct load control program for residential customers, operated from May 1 through October 31. It consists of a residential component as well as a commercial component. PG&E proposes to discontinue the commercial SmartAC program, while continuing the residential portion but with no further marketing activities. PG&E recommends a slow sunset of the program due to low cost-effectiveness.[149] PG&E will allow current enrollees to remain on the program but will cease marketing efforts and new enrollments will not be allowed. As discussed below, PG&E recommends that new customers, including those participating in the Bring Your Own Thermostat (BYOT) program, be directed to the Automated Response Technology program instead, which is more cost-effective than the residential SmartAC program. PG&E also asks for the authority to close the Commercial SmartAC program, as there are no customers currently enrolled.

PG&E's proposed modifications are reasonable. As discussed below, PG&E's ART program is promising and has the potential to provide far greater return on ratepayer funds. We authorize PG&E to limit enrollments in the residential AC program. We note that Resolution E-5103 has already authorized PG&E to close the commercial component of the SmartAC program.

#### 7.3.1. SmartAC Budget

PG&E requests $5.697 million for the SmartAC program from 2024-2027. PG&E projects a TRC of 0.89 when using the 2021 ACC values, and 2.62 when utilizing the 2022 ACC values. These values when taken together suggest that

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[149] PG&E-2, at 3-33:1-7.

the SmartAC program is cost-effective. These costs are therefore reasonable and approved.

**Category 1 - 2024-2027 PG&E Smart AC Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $0.5105 | $0.5105 | $0.5105 | $0.5105 | **$2.042** |
| | Contracts | $0.914 | $0.914 | $0.914 | $0.914 | **$3.655** |
| Authorized | Administrative | $0.5105 | $0.5105 | $0.5105 | $0.5105 | **$2.042** |
| | Contracts | $0.914 | $0.914 | $0.914 | $0.914 | **$3.655** |
| | Total | $1.42 | $1.42 | $1.42 | $1.42 | **$5.697** |

### 7.4. PG&E Automated Response Technology Program Proposal

PG&E proposes to begin a new program in 2024, the ART program, to allow customers with smart home technologies to participate in DR and load shifting.[150] Technologies shall include, but are not limited to, smart thermostats, smart appliances, heat-pump water heaters (HPWH), EV chargers, and batteries. PG&E proposes that participating customers be allowed to shift or curtail use during high-cost TOU rate periods or possibly in response to future real time pricing rates. PG&E proposes that the program work on a pay for performance incentive structure for third-party implementers, to work around fees charged by smart home technology device manufacturers.

#### 7.4.1. Proposal Specifics

Program events can occur year-round, between the hours of 4:00 p.m. to 9:00 p.m. daily, starting on May 1, 2024. Triggers shall be Day-Ahead, based on

[150] PG&E-2, at 3-36-3-38.

CAISO market award dispatch or PG&E system emergencies or near-emergencies for distribution service. The program will be market integrated as Proxy Demand Resources (PDR). Customers may dually participate if they are not enrolled in any other PG&E or DRP supply-side DR program.

Customers must own technologies that support daily automatic load management functions for TOU or other varying price rate plans. Residential bundled and CCA customers with electric service shall be eligible. Customers will directly enroll. No incentives will be offered by this program; the program will leverage technology incentives provided by other sources, such as energy efficiency, SGIP, and EV initiatives. PG&E will market via e-mail, digital, and newsletters.

PG&E will conduct a Request for Proposal to search for a third-party implementer(s) to conduct technology integrations, customer management, workflows, and communications.

CEDMC notes that the proposal lacks detail on how customers participating in PDRs and supporting daily automatic load functions for a dynamic non-TOU rate will allow for accurate measurement of the CAISO market performance.[151] CEDMC also questions whether third-party aggregators can participate.

PG&E predicts that the program will provide 104 MW of load impact, based on recent impact assessments of smart technologies and BTM Distributed Energy Resources (DERs).[152] PG&E will report evaluations as part of the annual April 1 DR load impact filing. PG&E projects a TRC of 1.57 with Auto DR for the

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[151] Council-02, at 27-28.

[152] PG&E-2, at 3-41, Table 3-18.

ART program.[153] Cal Advocates notes that the calculations of load impacts are based on unreasonable kW savings for TOU-optimized smart thermostats, and that using more reasonable estimates produces a total load impact of 82 MWs.[154]

CEDMC also notes that the proposed incentive rates are far below those of PG&E's CBP.[155] Even utilizing the lower expected load impact, the average incentive is still far below CBP. PG&E agrees that the incentive rates may need to be increased but does not propose new incentive amounts.[156] SBUA recommends that PG&E expand program eligibility to small businesses in 2024.[157] PG&E states that it will consider adding commercial customers after it has successfully started the program with residential.[158]

The ART program provides a way for PG&E to leverage existing technology program incentives and bring them into the DR portfolio. However, as noted by parties above, PG&E's proposal lacks in many specifics. PG&E itself states that it will rely on the RFP process to guide much of the program design.[159] Given the breadth of outstanding details, PG&E is directed to submit a Tier 2 advice letter by February 28, 2024, detailing the program design, before it is able to proceed with the program.

#### 7.4.2. ART Budget Request

PG&E requests $23.8 million for the ART program.

[153] PG&E-2, at 9-2, Table 9-1.

[154] CalAdvocates-01, at 2-6:5-2-7:11.

[155] Council-02, at 28:6-15.

[156]

[157] SBUA-2, at 2.

[158] PG&E-8, at 2-22.

[159] PG&E-8, at 2-21:23-25.

**Category 1 - 2024-2027 PG&E ART Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $1.124 | $1.249 | $1.262 | $1.124 | **$4.759** |
| | Incentives | $4.495 | $4.998 | $5.048 | $4.497 | **$19.04** |
| Authorized | Administrative | $1.124 | $1.249 | $1.262 | $1.124 | **$4.759** |
| | Incentives | $4.495 | $4.998 | $5.048 | $4.497 | **$19.04** |
| | Total | **$5.62** | **$6.25** | **$6.31** | **$5.62** | **$23.80** |

Cal Advocates states that the administrative budget should be reduced by 10 percent, and that incentives should be reduced, for a total reduction of $7.3 million.[160] PG&E notes that a new system will need to be created to support ART, which utilizes half of the administrative budget.[161]

It is reasonable for PG&E to take advantage of technology incentives for other programs to create new programs for load curtailment or shifting. It is also reasonable to have an initially high administrative budget, due to the program getting started. It would be expected that the amount of administrative costs normalize as the program continues in future years. PG&E's ART program is approved at the budget requested.

### 7.5. SCE Smart Energy Program

SCE proposes changes to the SCE Smart Energy Program (SEP). The SEP is a direct load control residential program currently limited to specified Wi-Fi enabled smart thermostats. SCE requests $29.264 million from 2024-2027 for the SEP.[162]

160 CalAdvocates-2, at 2-5.

161 PG&E-8, at 2-19:21-30.

162 SCE-03, at 31, Table III-11.

#### 7.5.1. Dispatch Granularity

SCE requests authority to dispatch the SEP at levels below Sub-LAP. SCE states that this will enable it to provide local load relief to affected areas while mitigating impacts to customers in surrounding areas.[163] No party commented on this issue. SCE is authorized to implement this change but is reminded that if the SEP is dispatched in response to a CAISO Energy Emergency Alert (EEA) notice, the entire sub-LAP should be dispatched to correspond with CAISO expectations. Additionally, to bid economically into the CAISO market, the SEP must continue to use dispatches at the sub-LAP level.

#### 7.5.2. Eligible Non-Residential Customers

SCE proposes to expand the SEP to non-residential customers with less than 200 kW load, in order to counteract the fact that certain smart thermostats from certain manufacturers such as Google and ecobee are operationally restricted from complying with SCE's other DR program dispatch parameters, such as those under Critical Peak Pricing.[164] No party commented on this issue. SCE has not provided particulars on implementation of this, including customer targeting and incentive changes. However, it is reasonable to implement this change to expand DR program participation.

#### 7.5.3. CAISO Day-Ahead Market Integration

SCE proposes to modify SEP integration into the CAISO wholesale energy market by removing the Day-Ahead economic component, while remaining integrated as a RDRR in the real-time market. According to SCE, RDRRs participating as economic resources in the Day-Ahead market must register as continuous and have the flexibility to operate anywhere between its Pmin and

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[163] *Id.*, at 29:20-24.

[164] SCE-03, at 30:19-22, 31:1-7.

Pmax MW capability,[165] based on the awarded bid quantity. SCE states that SEP load groups when dispatched always deliver full capacity output, and are unable to operate as a continuous resource, as required by CAISO RDRR tariff rules.

SCE's changes would effectively convert the SEP into an emergency DR program, potentially limiting its benefits. Additionally, perhaps due to the complex nature of the underlying technical requirements of the CAISO market, we find the record to be insufficient to justify an apparent major change requested by SCE with potentially significant implications. The proposed change is denied without prejudice.

#### 7.5.4. Increase SEP Marketing Budget

SCE was last authorized $530,000 per year for the SEP marketing budget, an amount SCE claims limited it to digital marketing. SCE proposes a larger budget of approximately $1.44 million per year ($5.756 million total from 2024-2027) to expand the marketing activities to direct mail letters, which SCE states will allow it to reach potential enrollees that do not receive communications and lack awareness about SEP. No party commented on this increase.

SCE has not presented any evidence or data to support its belief that a larger marketing budget will provide substantial increases to the number of enrollees. Its proposed increase is significant and would amount to approximately 20 percent of the requested $29.3 million for the SEP program overall. SCE is therefore authorized a total budget of $2.350 million for the SEP marketing budget, representing almost 10 percent of the overall SEP budget from

[165] Pmax is the maximum normal capability of a generating unit, as measured at the point of interconnection or point of delivery; Pmin is the minimum load of a generating unit. *See* CAISO, Business Practice Manual for Definitions & Acronyms, Version 19, available at https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Definitions%20and%20Acronyms (last accessed October 26, 2023).

2024-2027. This amount will be removed from SCE's marketing budget, category six.

SCE calculated the SEP to have a 1.07 TRC when utilizing the 2021 ACC, showing that it is cost-effective. SCE is authorized to recover $23.28 million in SEP costs.[166]

**Category 1 - 2024-2027 SCE SEP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $2.15 | $0.657 | $0.712 | $0.739 | **$4.258** |
| | Incentives | $4.027 | $4.556 | $5.017 | $5.418 | **$19.02** |
| Authorized | Administrative | $2.15 | $0.657 | $0.712 | $0.739 | **$4.258** |
| | Incentives | $4.027 | $4.556 | $5.017 | $5.418 | **$19.02** |
| | Total | **$6.18** | **$5.21** | **$5.73** | **$6.16** | **$23.28** |

### 7.6. SCE Summer Discount Plan

SCE's Summer Discount Plan (SDP) uses radio frequency load switches to periodically turn off or cycle off a residential or commercial customer's air conditioner compressor during periods of peak energy demand, system emergencies, or times of high wholesale energy prices, in return for a bill credit from June 1 to October 1. SCE notes that the program has consistently provided fast and reliable load shed.[167] SCE proposes a number of changes to counteract high attrition losses of 79 MW from 2015 to 2021, which SCE blames on market integration that took place in 2018, which led to increased event hours.[168]

[166] Not inclusive of marketing and EM&V SEP costs.

[167] SCE-03, at 32:22.

[168] *Id*. at 33:19-34:2.

#### 7.6.1. Remove SDP From the CAISO Day-Ahead Market

SCE notes that in recognition of high attrition, the Commission authorized SCE to increase incentives, remove minimum economic dispatch requirements, and offer sign-up bonuses.[169] SCE proposes to continue this effort by removing SDP from the CAISO Day-Ahead Market, which will have the effect of decreasing unnecessary event hours and reducing attrition due to event fatigue. SCE also notes that SDP cannot meet CAISO requirements as a Day-Ahead economic resource, as it is a discrete resource limited to participation in the real-time market for emergency and reliability purposes.[170] SCE proposes that the SDP remain an RDRR resource, which means SDP will be subject to the statewide reliability cap, which may cause friction with the two percent cap in 2026.

The proposal would turn SDP into an emergency DR program driven by the real-time market, removing the reliability benefits of bidding economically into the Day-Ahead Market during high price conditions. The 20-hour cap serves as a sufficient limit to the amount of bidding into the Day-Ahead Market. We decline to implement this change to the SDP at this time.

#### 7.6.2. Create Incentive Adder for SDP-Commercial Customers

SCE proposes an increase in incentives for commercial SDP participants. Due to changes in the RA window as well as typical load patterns since the Covid-19 pandemic, SCE projects that its SDP commercial customers will see a decrease of 63 percent in incentives from current levels mostly due to reduced ex ante load impacts factored into the rate calculation.[171] Such a large decrease

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[169] SCE-03, at35, *citing* D.21-03-056, at 33.

[170] *Id*. at 38.

[171] SCE-03, at 40:5-16.

would greatly decrease program attractiveness and participation, states SCE. To combat this, SCE proposes adjusting the commercial incentive to match that of the residential incentive, such that the commercial incentive is reduced only 11 percent. SCE requests $14.9 million for this.[172]

Cal Advocates protests the incentive adder, stating that the commercial load shed is projected to be minimal and does not justify additional expense.[173] SCE notes in reply briefs that commercial SDP provides value outside of the RA window when emergency events occur.[174] SCE estimates losses of 14-16 MW of load reduction potential if the incentive adder is not implemented.

It is reasonable to align the incentive losses between residential and commercial SDP. Stemming SDP program attrition to keep the load reduction potential available was a stated goal in past Commission decisions, and no argument has been presented to suggest that has changed. Additionally, the cost-effectiveness of the commercial SDP program is 1.75, when calculated utilizing the 2022 ACC.[175] The incentive adder as proposed by SCE is approved.

#### 7.6.3. SDP Budget

SCE requests $153.173 million for the SDP program, a decrease from the $220 million approved for 2018-2022. SCE has continued to analyze program performance, removing non-compliant customers which has increased average load reduction.[176] Utilizing the 2021 ACC, SCE calculated a TRC of 1.49 and 0.93 for SDP Residential and Commercial, respectively, with significantly improved

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[172] *Id.* at 41:2.

[173] Cal Advocates Phase II Opening Brief.

[174] SCE Phase II Reply Brief, at 10-12.

[175] *Id.* at 12.

[176] SCE-03, at 36.

values utilizing the 2022 ACC. The programs are cost-effective. SCE's proposed SDP budget is reasonable and SCE is authorized to recover $145.39 million for its SDP program costs, less its marketing and EM&V costs.

**Category 1 - 2024-2027 SCE SDP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $6.811 | $6.917 | $7.082 | $7.144 | **$27.953** |
| | Incentives | $29.814 | $29.495 | $29.2 | $28.925 | **$117.435** |
| Authorized | Administrative | $6.811 | $6.917 | $7.082 | $7.144 | **$27.953** |
| | Incentives | $29.814 | $29.495 | $29.2 | $28.925 | **$117.435** |
| | Total | **$36.63** | **$36.41** | **$36.28** | **$36.07** | **$145.39** |

### 7.7. SDG&E Smart Energy Program – Formerly AC Saver

SDG&E proposes to rename its AC Saver program, to the Smart Energy Program (SEP). The SDG&E SEP currently utilizes direct load control switches to decrease load from residential and commercial customers' air conditioning units. SDG&E proposes a number of changes to expand the SEP to devices other than air-conditioners, as well as other changes to modernize the program.[177] These include:

- Retiring the air-conditioning switch portion of the SEP on December 31, 2023;
- Expanding the program to customers with devices which control end uses other than air-conditioning;
- Modifying the annual incentive structure to accommodate the addition of new devices;

[177] SDGE-1, at EBM-23.

- Adding commercial customer incentives;
- Adding an enrollment incentive of $200 per kW to the program; and
- Consolidating the program into a single Day-Of product.

SDG&E requests a total of $11.113 million for SEP activities from 2024-2027.[178]

### 7.7.1. SEP Cost-Effectiveness

Before addressing SDG&E's proposals to modify the SEP, we must first address the program's cost-effectiveness. SDG&E's initial application presented a TRC of 0.3 for the SEP.[179] Even utilizing the updated 2022 ACC values, SDG&E calculates a TRC of just 0.7 for the SEP.[180] SDG&E in its testimony and briefing has not discussed how the proposed changes to the SEP will remedy the low cost-effectiveness of these programs. Cal Advocates supports SDG&E's proposal to retire the switch portion of the SEP, but also states that the SEP should be closed entirely by the end of 2024.

The TRC ratios presented by SDG&E's SEP program are too low, and SDG&E has not presented any compelling evidence to suggest that the SEP program as designed will remedy this issue. Additionally, SDG&E's Ex-Ante Load Impact Analysis does not suggest that the SEP will provide meaningful load reduction, as SDG&E does not project load impacts more than 10 MW on an annual basis through 2027.[181] We therefore direct SDG&E to terminate the current AC Saver program at the end of 2023 and decline to fund the SEP for future years.

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[178] SDGE-1, at EBM-35, Table 7.

[179] SDGE-8, at 2, Table BG-1.

[180] *Id.*, at 11, Table BG-10.

[181] SDGE-4, at LGR-4, Table LG-5.

As noted above in section 4.2, the Commission is interested in further developing a record on potential DR program delivery streamlining and efficiency through regional and/or statewide program administration models. To that end, we note here that both PG&E and SCE have proven, cost-effective models for delivering similar programmatic interventions as SDG&E's SEP. This area may be a fruitful one for the Commission to explore regional and/or statewide program administration models that could cost-effectively deliver programmatic savings in SDG&E territory.

### 7.8. Capacity Bidding Program

The Capacity Bidding Program (CBP) is an economic supply-side program bid into the CAISO market by the IOUs as PDR. It is designed to offer both residential and non-residential customers a choice of compensation, commitment, and risk levels for their DR participation. CBP is a program that consists of Day-Ahead and Day-Of notification options. All three IOUs maintain a CBP. Depending on the IOU, participants can be either aggregators and/or customers directly enrolled with an IOU. Participants make nominations for an entire month in the month prior, which cannot be adjusted once the applicable month begins. Participants receive capacity payments based on the monthly capacity price and their nominated MW, adjusted for performance during events in that month. Aggregators can also receive energy payments for performance during market dispatches. Parties filed comments on CBP as a whole and with regard to each individual IOU's program.

#### 7.8.1. Statewide Administration of Capacity Bidding Program (CBP)

Cal Advocates proposes that the Commission adopt a statewide CBP, due to inadequate cost-effectiveness scores of the IOUs' CBP programs, expected efficiency gains due to statewide administration (as seen with energy efficiency), as well as statewide uniformity with regards to program and rules.[182]

PG&E, Joint DR Parties, SCE, SDG&E, and CEDMC all oppose this proposal,[183] noting that it would reduce program flexibility, is based on speculative cost reductions, and state that what works for energy efficiency does not necessarily work for the CBP program. For example, there is significant real-time data exchange with regards to CBP, which does not exist for energy efficiency.[184] Parties note that smaller changes can be made to improve program efficiency before a statewide administrator should be considered. Parties also note the improvement in cost-effectiveness above a TRC of 1.0 after application of the 2022 ACC.

We decline to adopt Cal Advocates' proposal at this time. Cal Advocates has not sufficiently shown the need for a statewide administrator for the CBP program. Cal Advocates' arguments that a statewide administrator will improve cost-effectiveness are also not sufficiently supported. However, it may in some cases make sense to align the design of the IOU's CBP programs, to reduce participant confusion and improve program efficacy. As currently designed, the program provides benefits administered by each IOU, and utilization of the 2022 ACC brings the TRC above 1.0.

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[182] CalAdvocates-02, at 1-1-1-3.

[183] PG&E Phase II Opening Brief, at 45-49; Joint DR Parties Phase II Opening Brief, at 26-30; SCE-14, at 17-17; SDGE-10, at EBM-10; Council-03, at 10:2-24

[184] PG&E Phase II Opening Brief, at 47-48.

#### 7.8.2. CBP Product Options

PG&E proposes to remove underused product options of CBP to simplify the program and reduce costs.[185] These include the CBP Prescribed (or CBP Traditional) and Elect+ products, and all various event time durations products except the one to four hour event product. PG&E states that the Prescribed option is less than one percent of the 2021 CBP Portfolio, but that its removal will necessitate the combination of <100 kW Prescribed resources in the same Sub-LAP to keep bid price for the combined resource consistent. The Elect+ option has never been selected by Aggregators. PG&E states that the two to six hour event duration in the Prescribed option composes less than one percent of the 2021 CBP portfolio, and that between 2018-2021 the one to eight hour and one to 24 hour event durations have not been selected. PG&E proposes that the one to four hour event product should be the only one offered going forward with CBP Elect.

SDG&E also proposes to retire its Prescribed CBP program and keep the CBP Elect, and also eliminate the 11 a.m. to 7 p.m. event window.[186] SDG&E states that the retirement is welcome and will encourage customers to transition to the new CBP Day-Ahead and Day-Of 1 p.m. to 9 p.m. Elect products.

SCE proposes to eliminate the current CBP products, CBP Day-Ahead (Prescribed) after 2024 and CBP Day-Of (Prescribed) after 2023 while creating a new CBP Elect and Elect+ product (discussed in the SCE section).[187] SCE states that the Elect and Elect+ options are likely to be more attractive than the current product, as they are with PG&E and SDG&E.

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[185] *Id*. at 3-18:16-3-19:23.

[186] SDGE-1, at EBM-17:5-12.

[187] SCE-03, at 21:23-22:9; SCE-10, at 10:3-6.

No other parties submitted comments on this issue. It is reasonable to remove the various underutilized CBP product options to save operational costs and reduce confusion amongst participants. PG&E and SDG&E are authorized to end their CBP Prescribed offerings as of 2023. PG&E is authorized to end CPB Elect+. SCE is authorized to end its CBP Prescribed options - the CBP Day-Of as of 2023 and the CBP Day-Ahead at the end of 2024.

Further, PG&E is authorized to end the two-six hour event duration option and offer only the one-four hour event duration for its CBP Elect offering. SDG&E is authorized to reduce the event window options to only the 1 p.m. to 9 p.m. for its CPB Elect offering. Authorizations for SCE Elect and Elect+ product options are addressed later (under SCE CBP Proposals).

### 7.8.3. Capacity Payment Schedules

PG&E proposes to update the CBP capacity payment schedules to lower the demonstrated capacity shortfall threshold at which the aggregator is subject to performance penalties and increase the penalty amount.[188]

**Current PG&E Capacity Payment Schedule**

| **Hourly Delivered Capacity Ratio** | **Adjusted Hourly Capacity Payment or Penalty** |
|---|---|
| Greater than or equal to 1.05 | Adjusted Hourly Capacity Payment = Unadjusted Hourly Capacity Payment * 1.05<br><br>Adjusted Hourly Capacity Penalty = 0 |
| Greater than 0.75 and Lower than 1.05 | Adjusted Hourly Capacity Payment = Unadjusted Hourly Capacity Payment * Hourly Delivered Capacity Ratio<br><br>Adjusted Hourly Capacity Penalty = 0 |

[188] PG&E-2, at 3-17:4-3-18:14.

| **Hourly Delivered Capacity Ratio** | **Adjusted Hourly Capacity Payment or Penalty** |
|---|---|
| Greater than 0.6 and Lower than 0.75 | Adjusted Hourly Capacity Payment = Unadjusted Hourly Capacity Payment * 0.5<br><br>Adjusted Hourly Capacity Penalty = 0 |
| Greater than 0 and Lower than 0.6 | Adjusted Hourly Capacity Payment =0<br>Adjusted Hourly Capacity Penalty = Unadjusted Hourly Capacity Payment * (0.6 – Hourly Delivered Capacity Ratio) |
| Lower than 0 | Adjusted Hourly Capacity Payment =0<br>Adjusted Hourly Capacity Penalty = Unadjusted Hourly Capacity Payment * 0.6 |

**Table 13**
**Proposed PG&E Capacity Payment Schedule**

| **Hourly Delivered Capacity Ratio** | **Adjusted Hourly Capacity Payment or Penalty** |
|---|---|
| Greater than or Equal to 0.5 and Lower than or Equal to 1.1 | Unadjusted Hourly Capacity Payment Hourly Delivered Capacity Ratio, capped at 1.10<br><br>Adjusted Hourly Capacity Penalty = 0 |
| Greater than 0 and Lower than 0.5 | No payments<br><br>Penalty = Unadjusted Hourly Capacity Payment (1 Hourly Delivered Capacity Ratio) |

PG&E states that this is needed to help overcome negative impacts of aligning CBP with RA supply plan requirements. The proposal also would increase the demonstrated capacity performance cap eligible for compensation from 105% to 110%. PG&E states that this would help mitigate the impact of the increased nomination window (rejected below) by easing the penalty terms, while allowing compensation for performance exceeding nominated capacity.

PG&E also proposes to simplify the capacity payment/penalty structure from the current five levels to two, to reduce confusion and barriers to entry.

SDG&E also proposes to update its CBP capacity payment schedule. SDG&E states that these changes are needed to increase participation, thereby increasing cost-effectiveness. SDG&E seeks to:[189]

- Raise its performance cap from 100% to 120%;
- Reduce the number of energy payment tiers from five to four to simplify the rules (and also eliminates the penalty tiers);
- Reduce the zero-payment threshold from 50 percent to 30 percent, to encourage continued recruitment.

**Current SDG&E Capacity Payment Schedule**

| **Actual Load Reduction Achieved** | **Adjusted Event Capacity Payment or Penalty** |
|---|---|
| Greater than or equal to 1.0 | Adjusted Event Capacity Payment = Unadjusted Event Capacity Payment * 1.0 |
| Greater than or Equal to 0.75 and Lower than 1.0 | Adjusted Event Capacity Payment = Unadjusted Event Capacity Payment * percent of nominated load reduction achieved |
| Greater than or equal to 0.5 and Lower than 0.75 | Adjusted Event Capacity Payment = 0<br><br>Adjusted Event Capacity Penalty = 0 |
| Lower than 0.5 | Adjusted Event Capacity Payment = 0<br><br>Adjusted Event Capacity Penalty = Unadjusted Event Capacity Payment * ((0.5 – Actual Load Reduction)/(nominated load reduction)) |

189 SDGE-1, at EBM-18, Table EBM-3.

**Table 14**
**Proposed SD&E Capacity Payment Schedule**

| Actual Load Reduction Achieved | Adjusted Event Capacity Payment or Penalty |
|---|---|
| Greater than 1.0 | Payment = Unadjusted Event Capacity Payment * 1.2 |
| Greater than or Equal to 0.3 and Lower than or Equal to 1.0 | Payment = Unadjusted Event Capacity Payment * percent of nominated load reduction achieved<br><br>Adjusted Hourly Capacity Penalty = 0 |
| Lower than 0.3 | No payments or penalties |

CEDMC and the Joint DR Parties support the idea of modifying payment/penalty structures.[190] Joint DR Parties state that PG&E's proposal to increase penalties would, however, decrease control and flexibility, reducing participation in the program. Accordingly, Joint DR Parties present a reduced penalty amount.[191] OhmConnect states that changes that reduce the penalty thresholds for aggregators while imposing harsher non-performance penalties is inequitable.[192]

PG&E agrees that a reduced penalty amount could be implemented, and instead presented a new payment/penalty structure where capacity payments for demonstrated capacity performance less than 110% is instead pro-rated in proportion to the demonstrated capacity ratio, and a reduced penalty.[193] SDG&E supports the lower penalty threshold proposal.[194]

190 Joint DR Parties Opening Brief, at 17-21; Council-2, at 26.

191 JDRP-01, at 12:25-13:7.

192 OhmConnect-4, at 6:9-26.

193 PG&E Phase II Opening Brief, at 38.

194 SDG&E Phase II Reply Brief, at 20.

At the outset, we note that a fundamental concept of the CBP is to provide bid-in capacity but with penalties or payments based on performance. The proposal by SDG&E to eliminate penalties would create a consequence-free environment for program participants that goes against program intent. As the Commission has not yet required CBP alignment with RA supply plan requirements, we decline to implement the changes proposed by SDG&E at this time.

We find that PG&E's proposed change from five tiers to two is too simplistic and does not sufficiently incentivize participation, as customers may attempt to game the incentive levels at the edges. We also see no need to increase the penalties implemented, with the rejection of the change in tiers. PG&E's proposal to adjust the payment/penalty structure for its CBP program is denied. PG&E shall maintain its current payment schedule.

We also find it reasonable to standardize the capacity payment structure across CBP programs, to ease participation and achieve program consistency. We direct SDG&E and SCE to change their CBP Elect option to match the adjusted hourly capacity ratios and adjusted hourly capacity payment multipliers of PG&E's current payment schedule.

#### 7.8.4. CBP Elect Bids Price Options

Currently, PG&E CBP Elect participants are allowed to select any price between the Net Benefit Test and bid cap for a resource. PG&E proposes that participants instead be allowed to select two bid levels, a low bid level and a high bid level.[195] This will allow PG&E to combine resources at the same bid level within a Sub-LAP, creating consistency and reducing operational issues.

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[195] PG&E-2, at 3-24:15-3-25:13.

PG&E also proposes that lower-level bid prices (which will be called more often) be paid at full capacity incentive rate while the higher bid prices be paid at 90 percent of capacity incentive rate, with no adjustments to penalties. PG&E states that additional analysis is needed to refine the total number of bid levels, bid price at the lower level, and the capacity incentive derates, and proposes that it be authorized to submit a Tier 2 Advice Letter to reevaluate and adjust the framework.

CEDMC and the Joint DR Parties disagree with PG&E's proposal. The Joint DR Parties note that in designing its new CBP Elect and Elect+ options, SCE should adopt capacity incentive structure similar to that of SDG&E, which allows participants to nominate monthly capacity amounts and select from three trigger prices.[196]

As proposed by the Joint DR Parties, adoption of SDG&E's current system of three bid price tiers across for SCE's proposed CBP program would improve consistency across the IOUs CBP offerings and also allow consistency with regard to varied capacity incentive structures. Adoption of SDG&E's incentive structure will improve participation options for SCE CBP participants. PG&E shall be allowed to retain its current capacity incentive structure. SCE shall incorporate this change into its new CBP Elect program that is approved in this decision.

#### 7.8.5. PG&E CBP Proposals

PG&E currently offers 3 CBP programs: Prescribed CBP, CBP Elect, and CBP Elect+. Elsewhere in this Decision, we authorize PG&E to end CBP Prescribed and Elect+ options.

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[196] JDRP-01, at 11:3-10.

#### 7.8.5.1. Capacity Incentive Payments

##### 7.8.5.1.1. Primary Proposal

PG&E proposes to increase capacity incentive payments as below (primary CBP proposal):

**Table 15**
**Monthly Capacity Incentives (Dollars per KW)**

| | May | June | July | August | September | October | Average |
|---|---|---|---|---|---|---|---|
| **Current** | $3.18 | $3.88 | $16.30 | $22.54 | $13.90 | $6.80 | $11.10 |
| **Proposed** | $5.64 | $6.44 | $17.67 | $23.82 | $14.92 | $7.79 | $12.71 |

PG&E states that in the interest of summer reliability, the program needs to stay competitive and provide sufficient incentives for participation. CEDMC supports the increase, stating it is needed as the rates were last set in 2018 and since then historic inflation has rendered the capacity incentive amounts too low jeopardizing participation and the success of the program.[197]

##### 7.8.5.1.2. Alternative Proposal

PG&E separately also proposes adjustments that improve the cost-effectiveness of the CBP program (alternative CBP proposal). PG&E states that CBP has a TRC of 0.71 (higher after application of the 2022 ACC) and is thus not cost-effective due to factors such as changes in the LIP ex-ante forecast methodology, increases in cost due to capacity incentive rate changes, and decreases in benefits due to load impacts reflecting four hours of DR and not five.[198] PG&E therefore proposes to:

- Slightly reduce the monthly capacity incentive rates per month;

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[197] CEDMC Phase I Reply Brief, at 3.

[198] PG&E-2, at 3-31:1-18.

- Adjust program hours to 4 p.m. to 11 p.m. and providing a program event hour option of one-five event hour option.

These changes would yield a savings of $2.2 million per year from 2024 to 2027, as compared to the Primary CBP Proposal.[199] There would be a corresponding estimated loss of five MW during the peak month of August, and a five percent decrease in load impacts caused by decreased incentives.

###### 7.8.5.1.3. Analysis

Cal Advocates states the primary proposal should not be approved, given the poor cost-effectiveness of the program. As noted by PG&E, the initial TRC of the program was poor, at 0.71. However, given the projected cost-effectiveness score of 2.31 for PG&E's CBP (using the 2022 ACC),[200] we find it reasonable to increase incentives to ensure continued program success. This will also ensure that the CBP program does not lose load reduction ability during peak energy usage months.

##### 7.8.5.2. Energy Payment Process

PG&E proposes to accelerate energy payments to CBP aggregators by replacing the current framework involving pass-through of CAISO settled energy payments with IOU estimated energy payments and penalties based on CAISO hourly energy prices.[201] The current settlement process often takes 70 days after a market dispatch and final settlement data could be available 11 months after dispatch. PG&E proposes to submit a Tier 2 advice letter detailing the proposed calculation method.

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[199] PG&E-2, at 3-31:19-3-32:2.

[200] PG&E-7, at 12-9, Table 12-3.

[201] PG&E -2, at 3-28:1-9.

CEDMC supports the proposal, recommending it be approved with the inclusion of a true-up mechanism via a Tier 2 advice letter. CEDMC states that this change would alleviate any issues with incorrect compensation due to the increased timeframe. Polaris believes a Tier 2 advice letter is not sufficient oversight for such an important change.[202]

The proposal will enable PG&E to align both capacity and energy payment processes, increasing administrative efficiency, expediting energy payments, and leading to better customer experience. PG&E is authorized to implement this change. We also direct SDG&E and SCE to implement this change. PG&E, SCE, and SDG&E shall submit a Joint Tier 2 advice letter for approval, no later than 60 days after the day of issuance of this decision, aligning their energy payment processes, and include a true-up mechanism. If any utility is unable to implement the change, it shall state its reasoning.

#### 7.8.5.3. Electronic Enrollment Pilot

In its Application, PG&E proposes to continue to allow enrollment through a utility approved electronic process.[203] PG&E states that it is researching options to streamline enrollment, including the creation of a PG&E Aggregator Portal, with potential collaboration with the ShareMyData processes. PG&E also asks that the pilot title be removed. CEDMC supports this change.

Improving participant experience will encourage program participation going forward. PG&E's request is reasonable and approved.

#### 7.8.5.4. Capacity Nomination Window

PG&E proposes to align CBP with potential future RA Supply Plan requirements by changing the nomination window from the 15th day (T-15) of the

[202] Polaris-1, at 3.

[203] PG&E-2, at 3-28-3-29.

month prior to the operating month to 70 days (T-70) prior to the operating month.[204] PG&E states that this change is needed so that monthly supply plans may be submitted T-45 to the CAISO as required. PG&E proposes that aggregators be allowed to wait until T-15 to provide a full list of participating customers, to allow for some flexibility.

Polaris, Joint DR Parties, and CEDMC disagree with the proposal. Polaris states that agricultural customers are unable to predict reduction amounts 70 days in advance, which will greatly reduce participation.[205] Joint DR parties believe this degree of advanced notification is unnecessary, and that the T-70 window will decrease flexibility too much.[206] In response, PG&E agrees that this proposal can be deferred, as there is still no requirement that the IOUs submit DR resources in RA supply plans.[207] PG&E recognizes that a June 2023 decision declined to adopt the supply plan requirement.

We decline to adopt the proposed change in the capacity nomination window at this time, given the lack of immediate need to address it.

#### 7.8.5.5. Bid Cap for CBP Elect Products

PG&E proposes to continue the bid cap at $650 per MWh for CBP Elect programs continuing past 2022 and 2023.[208] D.21-12-015 authorized a bid cap of $650/MWh for its CBP Elect and Elect+ programs for the years 2022 and 2023. Otherwise, the cap of $1000 per MWh will apply, and certain resources would not enter the market. PG&E states that the lower cap will ensure that CBP

[204] PG&E-2, at 3-22.

[205] Polaris-1, at 3:5-14.

[206] Joint DR Parties Phase II Opening Brief, at 6.

[207] PG&E Phase II Reply Brief, at 12-14.

[208] PG&E-2, at 3-24:1-14.

capacity is used. PG&E notes during an August 2020 heatwave, 45 percent of CBP resources were not dispatched during rotating blackouts due to the high bid prices.

No other parties provided comments on this issue. It is reasonable to approve a lower cap to ensure that bids are set at a level that will make dispatch of CBP resources realistic. PG&E's request to continue the $650 per MWh bid cap for CBP Elect through 2027 is approved.

##### 7.8.5.6. Recovery of RA-Related Market Penalties

PG&E asks in its application to allow recovery of RA-related market penalties via the DR Expenditure Balancing Account (DREBA).[209] PG&E submitted this change in expectation that the Commission will order DR resources to be shown in RA supply plans. As discussed above in the section regarding the T-70 nomination window, these changes have yet to be implemented by the Commission. We therefore decline to adopt PG&E's proposal.

##### 7.8.5.7. Weekend Option

PG&E proposes in 2024 to convert current weekend options to require Saturday participation, to comply with RA requirements described in D.21-06-029.[210] PG&E currently offers voluntary weekend participation on any day that experiences high Day-Ahead market prices, incentivized at 25 percent of the capacity rate, with no penalties and ability to lower capacity nomination for weekends. PG&E's proposal would require aggregators to nominate a MW amount for Saturdays, but may provide a lower capacity nomination, down to

[209] PG&E-2, at 3-25:16-26.

[210] PG&E-2, at 22.

zero. PG&E seeks to maintain the same incentive rate, and asks for authority to evaluate and adjust the payment and penalty framework for mandatory Saturdays via submission of a Tier 2 Advice Letter. CEDMC supports this change.[211]

D.21-06-029 requires that DR availability requirements be updated to include Monday through Saturday, starting with the 2022 RA compliance year. PG&E's proposal is therefore in compliance with a Commission directive. It is approved.

#### 7.8.5.8. CBP Testing Process

PG&E proposes to make changes to its CBP testing process, to increase transparency and improve testing efficacy.[212] Currently, one CBP test event is allowed per month, on the 20th day or later of the month if a resource has not yet been tested and if the prescribed price trigger is met. Payments and penalties are the same as a normal event.

PG&E proposes an initial four-hour test event for all resources with new customers during the first week of the first month in the calendar year that an aggregator is participating. This test will serve as a learning experience by ensuring systems and customers are prepared to respond to dispatch notifications. No payments or penalties will be counted. Additional test events will continue to be issued on a weekday after the 20th day of the month if the Day-Ahead market price exceeds $100/MWh with a maximum duration of four hours, but will also be contingent on:

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[211] Council-02, at 26:2-6.

[212] PG&E-2, at 3-19:25-3-20:26.

- Whether the resource has previously been called in the calendar year for real or test events, and whether performance was at or above 75 percent;
- The probability of the resource being dispatched in the remainder of the month for actual grid needs, dependent on PG&E's forecast Sub-LAP temperatures and/or outages; and
- CAISO alerts or notices issued.

Party comments initially opposed PG&E's proposed testing changes.[213] The Joint DR Parties note a number of issues with the proposed testing system, including:

- The initial four-hour test event will subject businesses to a four-hour shut down due to a new participant in their sub-LAP;
- The dispatch systems are set up to work on the sub-LAP level so the one site dispatch test is not aligned with existing systems;
- It is up to aggregators, not customers, to conduct training;
- Subjects customers to unnecessary and long testing conditions; and
- Lacks specificity with regards to how PG&&E will determine the likelihood that a resource will be dispatched later in the month.

The Joint DR Parties instead proposed a different testing regime, to which PG&E and the Joint DR Parties have continued to iterate on.[214] PG&E has eliminated the proposed initial test event, as well as extension of test events from

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[213] Council-02, at 26; JDRP-01, at 13:10-117:6.

[214] PG&E-8, at 2-9-2:10, 2-15:1-2-16:16; Joint DR Parties Phase II Opening Brief, at 21-26; PG&E Phase II Opening Brief, at 40-41; Joint DR Parties Phase II Reply Brief, at 13-14; PG&E Phase II Reply Brief, at 11-12.

two to four hours. PG&E now proposes the following changes, to which the Joint DR Parties agree:[215]

- Resources can be called for up to one, two-hour test event per month per program season if the following conditions are met:
  - It is a weekday during program hours after the 20th of the month;
  - If there has not been any form of dispatch in that given month;
  - If there has not been a test throughout the preceding month;
  - If previous event or test performance was below 75 percent of the presently nominated value;
  - There is not a state of emergency in California related to the grid; and
  - There are not forecasted capacity shortfalls.

The changes proposed help further define the conditions under which CBP testing shall occur without creating undue burden to CBP participants. These changes are reasonable and adopted. CEDMC also requests that the proposal be adopted across all IOUs, to provide consistency and simplify CBP participation for aggregators and customers participating across multiple IOU service areas.[216] It is reasonable to standardize testing conditions across all IOU CBP programs to reduce confusion. We direct PG&E, SCE, and SDG&E to incorporate the above changes into their respective CBP testing rules.

[215] PG&E Phase II Opening Brief, at 41; Joint DR Parties Phase II Reply Brief, at 14.

[216] Council-03, at 8.

#### 7.8.5.9. PG&E CBP Budget Request

PG&E requests $28.475 million for its 2024-2027 CBP budget.[217] Except as already discussed, no other party provided comments on this budget request. We find it reasonable to approve PG&E's CBP, given the higher TRC ratios seen with the 2022 ACC. PG&E is authorized to recover the CBP budget of $28.475 million for the 2024-2027 period.

**Category 1 - 2024-2027 PG&E CBP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $0.558 | $0.577 | $0.598 | $0.619 | **$2.35** |
| | Incentives | $5.479 | $6.201 | $6.863 | $7.586 | **$26.13** |
| Authorized | Administrative | $0.558 | $0.577 | $0.598 | $0.619 | **$2.35** |
| | Incentives | $5.479 | $6.201 | $6.863 | $7.586 | **$26.13** |
| | Total | **$6.04** | **$6.78** | **$7.46** | **$8.21** | **$28.475** |

### 7.8.6. SCE CBP Proposals

#### 7.8.6.1. Event Parameters (CBP Prescribed)

SCE proposes to increase the maximum number of program events per month for the CBP (Prescribed) from five to six and reduce the maximum event duration from six to five hours. SCE also proposes to reduce the 3 p.m. to 9 p.m. event window to 4 p.m. to 9 p.m. to align with CAISO Availability Assessment Hours.[218] This matches PG&E's current CBP Elect program design. As discussed above, SCE has been approved to sunset its CBP Prescribed program, so SCE's

[217] PG&E-2, at 3-30, Table 3-12.

[218] SCE-03, at 20:3-12.

proposal would apply only to 2024. CEDMC opposes the increase in maximum events per month, in the name of reducing program attrition.[219]

It is reasonable to make these changes to align with RA requirements. SCE's request is approved for the Prescribed CBP product in 2024.

#### 7.8.6.2. Other CBP Prescribed Changes

SCE proposes to end CBP (Prescribed) off-peak months, November through April, due to low participation. SCE then proposes to take that budget for off-peak months and allocate it towards the remaining May through October months to increase the incentive rate without increasing the budget.

**SCE CBP Program, Day-Ahead Option Capacity Incentives**
**Current and Proposed for 2024-2027**
**(Dollars per KW)**

| | January | February | March | April | May | June |
|---|---|---|---|---|---|---|
| **Current** | $1.98 | $1.66 | $1.66 | $1.66 | $3.96 | $5.94 |
| **Proposed** | - | - | - | - | $4.59 | $6.89 |

| | July | August | September | October | November | December |
|---|---|---|---|---|---|---|
| **Current** | $20.14 | $23.44 | $12.54 | $2.32 | $1.98 | $1.98 |
| **Proposed** | $23.36 | $27.19 | $14.54 | $2.69 | - | - |

CEDMC supports this change.[220] It is reasonable to eliminate months with low participation to fund the CBP program when it is most needed. SCE's changes to capacity payment rates for the CBP (Prescribed) Day-Ahead are approved. We note that these new payments will only be in effect through 2024,

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219 Council-02, at 24-26.

220 Council-02, at 24-26.

due to the replacement of the CBP (Prescribed) Day-Ahead program with CBP Elect as discussed below.

SCE also proposes to align how energy payments for CBP (Prescribed) market dispatches are made from SCE to aggregators to match how payments are made from the CAISO to SCE.[221] In order to do so, SCE proposes to:

- Issue energy payments to aggregators at the settled Locational Marginal Price (LMP) for a resource's sub-LAP, rather than the trigger price to determine event dispatch, and for the awarded energy quantity rather than the quantity dispatched;
- Change the penalty rate for the Day-Ahead program to be the average settled LMP in the real-time market at the SCE Default Load Aggregation Point (DLAP_SCE); and
- Change the payment cap from 150 percent of delivered kWh to 100 percent of awarded kWh.

CEDMC opposes the energy cap because the CAISO rules allow for additional energy payments for uninstructed energy when resources deliver more than their schedule.[222] It is reasonable to alter the current Prescribed CBP offerings to meet CAISO requirements. The request is adopted, with recognition that it will only apply to 2024, as discussed in the next section.

#### 7.8.6.3. Capacity Nomination

SCE proposes to replace the existing CBP Prescribed monthly capacity nomination schedule of at least five days prior to operating month with annual May-October capacity contracts executed by January 31 of each year.[223] SCE also proposes to replace the existing nomination system where aggregators have no

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[221] SCE-03, at 22.

[222] Council-02, at 26.

[223] SCE-03, at 21.

obligation to make a nomination on any given month with collateral requirements based on the maximum capacity nominated at $5/kW.

CEDMC, Polaris, and the Joint DR Parties oppose this proposal by SCE. They note that the proposal for SCE would not match the month-to-month capacity availability of CBP participants and would therefore eliminate one of the benefits of CBP.[224] CEDMC also states that SCE provides no evidence that a collateral requirement is needed.

SCE has not sufficiently justified its proposed changes to the CBP nomination window. We note that this CBP program will also be sunsetting in 2024, and it therefore does not provide any substantial ratepayer benefits to implement this change at this time. We decline to implement SCE's proposed nomination changes. However, to the extent that the current nomination process is providing operational difficulties to SCE,[225] we note that both SDG&E and PG&E utilize a T-15 nomination window. We therefore implement a T-15 nomination window for SCE going forward for all CBP programs, including the 2024 Prescribed CBP Day-Ahead program, and CBP Elect until 2027.

#### 7.8.6.4. CBP Elect and Elect+ Options

In its supplemental testimony, SCE presented a proposal to replace its current Prescribed Day-Ahead offering with new CBP Elect and Elect+ offerings, starting in 2025.[226] SCE proposes to operate these programs as load modifying programs dispatched system-wide rather than by Sub-LAP, due to concerns regarding the utilization of PG&E and SDG&E Elect options. The design would be as follows:

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224 Council-02, at 26; Polaris Response to Application; JDRP-01, at 6.

225 SCE-03, at 21:13-16.

226 SCE-10, at 5:2-11.

**Table 16**
**Summary of Proposed SCE CBP Elect and Elect+ Programs**

| | **Elect** | **Elect+** |
|---|---|---|
| **Notice** | Day-Ahead | |
| **Min-Max Duration Per Event** | 1-4 Hours | 2 Hours |
| **Trigger** | Anticipated high prices or high energy demand, CAISO Flex Alert, CAISO EERA Watch, or Governor's Emergency Order | |
| **Availability** | May-October<br>Monday-Friday<br>4-9 p.m. | May-October<br>Sunday-Saturday<br>6-8 p.m. |
| **Max Event Hours per Month** | 24 Hours | |
| **Max Events per Day** | 1 Event | |
| **Max Number of Consecutive Days** | No Max | |
| **Max Number of Events Per Month** | 6 Events | 12 Events |
| **Capacity Rate ($/kW-months)** | $72.08 | $43.25 |

SCE states that it proposes to make these changes based on options and issues as explained by PG&E and SDG&E with their CBP Elect and Elect+ programs.[227] SCE notes that aggregator participation has mainly been with PG&E's CBP Elect one-four hour option, which allows aggregators to choose their own energy bid price, and therefore proposed to eliminate other options. SCE proposes the same for its Elect option, but for its Elect+ proposes a shorter two-hour static option to incentivize BTM devices during super peak periods.

[227] SCE-10, at 5.

SCE also states that by making these load modifying resources it will mitigate concerns regarding DR resource availability as well as resolving SCE's concerns about market risks as a Scheduling Coordinator. It would also reduce administrative costs. SCE proposes that the Elect+ option only pay a capacity rate at 60 percent of the Elect option, due to low event duration.

**Table 17**
**Summary of Proposed SCE CBP Capacity Prices**

| | **May** | **June** | **July** | **August** | **September** | **October** | **Total ($/kW-6 Months)** |
|---|---|---|---|---|---|---|---|
| **Elect Capacity Rates ($/kW-month)** | $4.62 | $5.02 | $12.08 | $16.56 | $21.72 | $12.08 | **$72.08** |
| **Elect+ Capacity Rates ($/kW-month)** | $2.77 | $3.01 | $7.25 | $9.94 | $13.03 | $7.25 | **$43.25** |

SCE projects that the CBP Elect and Elect + options will provide 60 MW and 20 MW, respectively, of peak load reduction, as opposed to the 5.9 MW the Prescribed CBP Day-Ahead program currently provides.

SCE requests that the Commission authorize SCE to submit a Tier 2 advice letter, finalizing the operational detail, aggregator agreements, nomination process, and tariff changes for the Elect and Elect+ programs.[228] SCE states that it could implement the programs in twelve months.

228 SCE-10, at 7:2-6.

The Joint DR Parties support SCE's proposal to create Elect and Elect+ programs in-line with those of PG&E and SDG&E, but note significant design differences that it states hamper the program.[229] The Joint DR Parties note that in their experience the current SCE CBP lacks participants, mainly due to multiple daily dispatches in a row during summer months.[230] They state that PG&E and SDG&E's programs provide more comparative flexibility, and that SCE's new Elect and Elect+ options should match that flexibility. The Joint DR Parties however state that SCE's proposed CBP Elect and Elect+ designs seem to be set to provide SCE greater control over the program, including when events are triggered. The Joint DR Parties also note that the proposed options do not provide DR supply-side resources. Joint DR Parties state that SCE recognizes that PG&E's CBP Elect option has improved aggregator participation, due to greater flexibility in choosing an energy bid price.[231] The Joint DR Parties recommend that SCE adopt the bid options currently utilized by SDG&E, which allow aggregators to nominate monthly capacity amount at three trigger prices.[232]

SCE states that it did not seek to model its Elect and Elect+ programs after other IOU offerings, and instead proposed this in order to reduce summer net peak loads in a cost-effective manner. SCE states that a load modifying option is appropriate since SCE has always provided such an option.[233]

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[229] JDRP-01, at 7-8.

[230] JDRP-01, at 9:10-16.

[231] JDRP-01, at 10:18-23.

[232] *Id*. at 12:3-10.

[233] SCE-10, at 14.

As designed, SCE's proposed CBP Elect program is likely to provide more cost-effective benefits to ratepayers than SCE's current offerings. Should DRAM be eliminated, it would also be helpful to have other pathways for SCE to procure potentially available DR resources. We are not persuaded, however, that the programs should be approved as designed by SCE. Consistent with the Commission's DR bifurcation policy, event-based DR programs should be able to meet RA requirements as supply-side programs – we note that both SDG&E's and PG&E's CBP Elect programs are supply-side. SCE's proposal to make its CBP programs load-modifying DR resources is against precedent and is not adequately explained by SCE. We therefore direct SCE to implement CBP Elect as a supply-side resource in compliance with RA requirements, including market integration. This also means elimination of the proposed CBP Elect+ option since its proposed 2-hr event window does not meet RA requirements.

We therefore authorize SCE's CBP Elect program, but decline to authorize the CBP Elect+ option. SCE shall incorporate the changes discussed above and offer CBP Elect as a supply side program, along with the program design elements summarized in the table above (with the exception of the Trigger element). To further promote alignment between IOU programs, we direct SCE to incorporate SDG&E's CBP Elect three-tier bid price options, along with the relative capacity incentive rates, as well as change to a T-15 nomination window. Within six months of the date of issuance of this decision, SCE shall submit a Tier 2 advice letter, finalizing the operational detail, aggregator agreements, nomination process, and tariff changes for its CBP Elect offering.

#### 7.8.6.5. Elimination of Prescribed CBP Day-Of

Prior to CAISO market integration, SCE dispatched a Day-Ahead product based on actual or forecasted prices in the CAISO Day-Ahead market, and the

Day-Of product based on forecasted prices in the CAISO real-time market. However, since 2015, SCE has dispatched both the Day-Ahead and Day-Of products based on actual prices in the Day-Ahead market only because the operating parameters of the Day-Of product do not allow it to be dispatched in the real-time market. Because of this, Day-Of only earns system RA credit, and not local or flexible RA credit. SCE has determined that the programmatic and technical changes needed to the Day-Of product that would allow for participation in the CAISO Hour-Ahead Scheduling Process would not be worthwhile, and therefore proposes to eliminate this program.[234]

No other parties provided comments on this issue. Given SCE's proposal to begin a new CBP Elect program, it is reasonable to end the CBP Day-Of, where it does not provide significant load reduction. Doing so will simplify SCE's offerings and possibly ease the transition to the new CBP Elect offering, as customers will be required to migrate to continue with CBP. SCE's request to end the CBP Day-Of offering is approved. SCE shall end the program in the year prior to the start of the new CBP Elect program.

##### 7.8.6.6. SCE CBP Budget Request

SCE's budget request filed with its application requested $28.475 million for its CBP program from 2024-2027.

**Category 1 - 2024-2027 Original Application SCE CBP Budget (in $million)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $2.136 | $2.142 | $2.159 | $2.166 | **$8.603** |

[234] SCE-03, at 21:3-22:9.

SCE's CBP Elect and CBP Elect+ proposal, as filed in its supplemental testimony SCE-10, would eliminate SCE's other CBP offerings. To support the CBP Elect and Elect+ programs, SCE requests $42.703 million from 2024-2027.[235] The 2024 budget would consist of the current SCE Prescribed CBP Day-Ahead program:

**Category 1 - 2024-2027 SCE CBP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $0.982 | $0.276 | $0.354 | $0.362 | **$1.97** |
| | Incentives | $1.052 | $13.11 | $13.11 | $13.11 | **$40.38** |
| Authorized | Administrative | $0.982 | $0.276 | $0.354 | $0.362 | **$1.97** |
| | Incentives | $1.052 | $13.11 | $13.11 | $13.11 | **$40.38** |
| | Total | $2.03 | $13.39 | $13.46 | $13.47 | **$42.36** |

In terms of cost-effectiveness, SCE states that the CBP Elect option has a TRC of 1.26, while the CBP Elect+ option has a TRC of 1.89.[236]

After removing marketing and EM&V costs, we authorize SCE to recover $42.36 million for its CBP program activities from 2024-2027. We note that SCE's request to open a CBP Elect+ option was declined, but SCE did not provide a breakdown of budget costs for that option alone. We therefore direct SCE to submit a Tier 3 advice letter within 60 days of the date of issuance of this decision, updating its CBP budget to reflect the removal of the CBP Elect+ product option.

[235] SCE-10, at 8, Table 10-4.

[236] SCE-12, at 8, Table 10-7.

#### 7.8.7. SDG&E CBP Proposals

Except as already discussed in earlier sections, there are no significant proposed changes to SDG&E's CBP programs. We authorize SDG&E to retire its underutilized CBP products, reject SDG&E's proposed capacity payment schedule, and direct it to adopt PG&E's payment schedule approved in this decision.

##### 7.8.7.1. SDG&E CBP Budget Request

SDG&E seeks authority to recover $6.929 million for its CBP. SDG&E's calculated CBP TRCs are 0.4 utilizing the 2021 ACC and 1.0 utilizing the 2022 ACC. Given the proposed changes and the 1.0 TRC utilizing the 2022 ACC, it is reasonable to continue to approve SDG&E's CBP program for 2024-2027. SDG&E is authorized to recover $6.929 million for its CBP budget from 2024-2027.

**Category 1 - 2024-2027 SDG&E CBP Budget (in $million)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SDG&E Requested | $1.674 | $1.735 | $1.745 | $1.776 | **$6.929** |
| Authorized | $1.674 | $1.735 | $1.745 | $1.776 | **$6.929** |

## 8. Load Modifying DR

Load modifying programs are defined as resources that reshape or reduce the net load curve. Furthermore, a load modifying program is often embedded into the California Energy Commission's unmanaged/base case load forecast.

### 8.1. PG&E Load Modifying DR

PG&E maintains two Load Modifying Resource (LMR) DR programs: the Optional Binding Mandatory Curtailment (OBMC) Program, and the Scheduled Load Reduction Program (SLRP). PG&E proposes no changes to these programs.

PG&E notes that even though it has no participants in the SLRP, it is statutorily required to keep the program open.[237] For the other program, PG&E states it is prudent to keep the capacity available. No other parties made comments on this issue. It is reasonable for PG&E to continue to operate these LMR DR Programs. PG&E requests $34,902 for 2024-2027 for these activities.[238] This budget is approved.

**Category 2 - 2024-2027 PG&E Load Modifying DR Budget**

| | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| PG&E Requested | $8,273 | $8,565 | $8,886 | $9,178 | **$34,902** |
| Authorized | $8,273 | $8,565 | $8,886 | $9,178 | **$34,902** |

### 8.2. SCE Load Modifying DR

SCE also operates its own OMBC and SLRP programs. SCE proposes $3,000 to bridge the OMBC program to coverage through its next General Rate Case Application. SCE requests $20,000 for the SLRP program.

Similar to PG&E above, we authorize SCE to keep these programs open. SCE requests $23,000 for these programs through 2027.[239] This request is approved.

**Category 2 - 2024-2027 SCE Load Modifying DR Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $8,000 | $5,000 | $5,000 | $5,000 | **$23,000** |
| Authorized | $8,000 | $5,000 | $5,000 | $5,000 | **$23,000** |

[237] PG&E-2, at 3-41:1-3-42:9.

[238] *Id*. at 3-42, Table 3-19.

[239] SCE-03, at 43, Table IV-13, at 45, Table IV-14.

## 9. Rule 24 and Rule 32

PG&E and SCE Electric Rule 24 and SDG&E Electric Rule 32 (collectively, Rule 24) program activities support third-party DR operations, by providing the administrative and technical mechanisms by which third-party DR Providers (DRPs) may bid DR resources directly into the CAISO wholesale energy market. Rule 24 sets the terms and conditions for entities that seek to take part in Direct Participation DR Service. It also allows DRPs or retail customers to participate directly in the CAISO wholesale energy market for compensation by the CAISO in accordance with market awards and established dispatch instructions. DRAM sellers also aggregate load and bid that load into the CAISO market through Rule 24.

### 9.1. PG&E Rule 24 Budget Request

PG&E requests $13.92 million over four years for its Rule 24 operations and IT.[240] PG&E was previously authorized $12.931 million over five years for these costs.[241] PG&E proposes to increase the number of full-time employees from 5.5 to nine, for planned volume increases in Rule 24 data sharing authorizations. PG&E also proposes Click Through enhancements to support mass market participation for Rule 24 in the future, by transitioning the ShareMyData platform to a cloud-based service. PG&E states this will allow for processing of increased volumes of data sharing authorizations.[242] Based on an assumption of 2022 approval of its Click Through Application, PG&E states that it will take 24 months to completely implement these cloud services.[243] The

[240] PG&E-2, at 6-7, Table 6-3.

[241] D.17-12-003, Attachment 3, at 1.

[242] PG&E-2, at 6-8:8-15.

[243] *Id*. at 6-8:16-18.

decision approving PG&E's Click Through Application has only recently been approved.[244] It is therefore reasonable to assume that the 2024 cloud fees are unlikely to be needed, given the almost year long gap between PG&E's projected date of approval and the actual date of approval. PG&E's budget request is therefore reduced in 2024 by $210,000.

Cal Advocates, in opening testimony, stated that PG&E's request for increased funding for IT systems enhancement should be denied, as the potential ending of DRAM would counteract any rise in authorization requests.[245] However, PG&E notes that numerous new programs will increase requests, including OhmConnect's Resi-Station, a potential increase in activity by non-IOU LSEs, such as CCAs, and potential needs due to the decommissioning of Diablo Canyon Power Plant.[246] PG&E is authorized to recover $13.71 million for its Rule 24 Program from 2024-2027.

**Category 3 - 2024-2027 PG&E Rule 24 Budget (in $ millions)**

| **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|
| PG&E Requested | $3.36 | $3.47 | $3.59 | $3.5 | **$13.92** |
| Authorized | $3.15 | $3.47 | $3.59 | $3.5 | **$13.71** |

### 9.2. SCE Rule 24 Budget Request

SCE requests a budget of $3.855 million over four years to support Rule 24 operations. SCE expects that continued growth in CAISO registrations, due to DRP expansions of eligible DR technologies, including smart thermostats.[247] SCE

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[244] D.23-09-006.

[245] Cal Advocates-01, at 1-5:20-1-6:25.

[246] PG&E-01, at 2-4:11-2-6:23

[247] SCE-03, at 48:9-18,

proposes to increase the CAISO registration cap from 100,000 to 225,000, in order to meet expected demand increases observed since 2018.[248] SCE's Rule 24 budget request includes $3 million in labor costs to fund additional staff needed to support the expected higher demand for Rule 24 resources, and $0.852 million in non-labor costs to support specific IT and other system improvements.[249] Cal Advocates states that should SCE's expected registration increase fail to materialize by the end of 2024, then SCE should evaluate and reduce its Rule 24 IT budget accordingly for 2025-2027.[250] OhmConnect states that just because the goal is not met in 2024 does not mean that it will not be met by 2027, given lags in demand or delays for customers.[251] OhmConnect states that it would be prudent to stay ahead of the number of registrations, as opposed to being reactive. SCE states that its proposed Rule 24 IT costs are not volumetric and do not vary based on the number of registrations. Rather, the proposed Rule 24 IT costs would facilitate automation of tasks related to registration and data sharing authorizations, including migration away from manual data entry, to increase staff efficiency.[252]

It is reasonable for SCE to increase its capacity as requested for CAISO registrations and data-sharing authorizations, and automate these processes going forward. SCE is authorized to recover $3.855 million for Rule 24 operations from 2024-2027.

248 SCE-03, at 47:15-20.

249 SCE-03, at 51:1-52:3.

250 Cal Advocates-01, at 5-4:12-5-5:6.

251 OhmConnect-5, at 4:12-25.

252 SCE-14, at 20:3-25.

**Category 3 - 2024-2027 SCE Rule 24 Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $0.938 | $0.961 | $0.990 | $0.966 | **$3.855** |
| Authorized | $0.938 | $0.961 | $0.990 | $0.966 | **$3.855** |

### 9.3. SDG&E Rule 32 Budget Request

SDG&E requests a budget of $6.406 million to fund Rule 32 operations, IT, and M&E activities from 2024-2027.[253] This request is based on expected growth from 57,000 in 2022 to almost 260,000, with 120,000 enrollments by end of 2024.[254] Cal Advocates states that this growth seems extreme and SDG&E should be directed to file a Tier 2 advice letter requesting an adjusted budget, should SDG&E's CAISO registrations not reach expected levels by the end of 2024. SDG&E expects an almost five-fold increase in registrations from 2022 to 2027, significantly larger than the other IOUs.

Although SDG&E's expected increase in enrollments is potentially extreme, we are not convinced that the administrative time to resolve any potential overages necessitates an advice letter update, given that any overcollections will be returned to ratepayers, and the small amounts involved with this budget. SDG&E's request for $6.406 million for Rule 32 budget is approved.

**Category 3 - 2024-2027 SDG&E Rule 32 Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SDG&E Requested | $1.557 | $1.586 | $1.615 | $1.648 | **$6.406** |

253 SDGE-2, at EBM-88, Table EBM-18l; SDGE-2, at EK-1, Table EK-1; SDG&E 4, at LGR-14, Table LG-10.

254 Cal Advocates-01, at 5-6:6-19.

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| Authorized | $1.557 | $1.586 | $1.615 | $1.648 | **$6.406** |

### 9.4. Rule 24 and Rule 32 Applicability to Unbundled Customers

In the January 27 Ruling, parties were directed to file comments on the potential expansion of Rule 24/32 to unbundled customers participating in market-integrated DR programs, and if so, what revisions should be implemented. Rule 24 defines the obligations of the utility and other parties in facilitating customer participation in market integrated DR programs. Such parties currently include DRPs, LSEs, Utility distribution companies, meter data management agents, and meter service providers. However, Rule 24 currently does not apply to DRPs that aggregate only unbundled customers. Such situations can occur when a market integrated DR program is run by a CCA and only enrolls CCA customers, an RA-counted DR program is run by a third-party DRP that only enrolls unbundled customers, or large industrial customers served by Direct Access providers offer their own load shed into the market. In such situations, resources must still be registered with the CAISO in order to participate in and settle with energy markets, even though certain parties participating in such arrangements may not be bound by any IOU's Rule 24.

Parties commenting on this issue expressed some support for expansion. PG&E supports expansion, with specific tariff recommendations to be identified through a working group process. PG&E states that modification of Rule 24 should consider changes to dual participation rules, competitive neutrality firewalls, DRP obligations, and IT system changes.[255] SCE also recommends a

[255] PG&E Opening Comments in Response to the January 27 Ruling, April 21, 2023, at 20-22.

stakeholder process to determine what changes are needed, and highlighting dual participation issues.[256] The Joint CCAs also support a workshop to consider changes to that may be necessary to apply Rule 24 to unbundled customers.[257]

No changes to Rule 24/32 are to be considered at this time, given the lack of record in this proceeding. Parties have expressed support for the change, but we lack detail at this time for implementation. The Energy Division may host a stakeholder workshop at its discretion to determine whether changes or updates to Rule 24/32 are needed.

## 10. Emerging and Enabling Technologies

### 10.1. Auto DR

Within the Emerging and Enabling Technologies category, the Automated (Auto) Demand Response program (Auto DR or ADR) provides customers incentives to install automation technologies that allow automated response to a demand response event or price signal without the customer taking an action. Emerging and Enabling Technologies also provide for research into new technology, equipment, processes, and products. Utilities fund these efforts out of their budget Category 4.

Below, the discussion considers the Utilities' proposals for changes to specific Auto DR incentive offerings for residential, small and large commercial, and industrial customers, including elimination of one PG&E, and all SDG&E incentive programs. These proposals are generally accepted, with some modifications.

256 SCE Opening Comments in Response to the January 27 Ruling, April 21, 2023, at 19-20.

257 Joint CCAs Responses to Questions and Energy Division Staff Proposals Related to Phase II Issues, April 21, 2023, at 11-12.

#### 10.1.1. Controllable Thermostat Incentive Proposals

The premise of a controllable (also referred to as "smart") thermostat incentive is a lump-sum payment to induce customers to purchase and install a controllable thermostat and enroll in an eligible program enabling another party (whether a Utility or other third party) to remotely adjust the thermostat in response to a DR signal or event. The controllable thermostat can be adjusted remotely so that, during certain events as determined by CAISO, the customer's energy demand is reduced or shifted (without the customer needing to intervene manually).

As an example, SCE describes this scheme as follows:

> SCE has the capability to adjust the cooling temperature set point on participating thermostats by up to four degrees for Critical Peak pricing and Capacity Bidding Program-Residential customers during DR events to help reduce energy usage. Customers may opt-out of this automated service at any time without necessarily opting out of the DR program.[258]

We note that in regard to the Commission policy stated earlier, that Auto DR incentivizes customers to purchase a control so that they can participate in DR programs without manual intervention, several parties discussed how the technology incentives encourage enrollment. SDG&E and SCE both acknowledged that their thermostat incentives function as an enrollment incentive. Referring to the $50 thermostat incentive offered by its Technology Deployment (TD) program, SDG&E said, "[a]lthough in theory the TD program

[258] SCE-03, at 56.

is a separate technology program, in reality it is functioning as an enrollment payment."[259]

In arguing against PG&E's proposal to end its $50 thermostat incentive, CEDMC said, "[t]his also ignores the value of the [Smart Communicating Thermostat] Program to encourage DR enrollment by allowing DR providers to leverage these up-front incentives when recruiting customers."[260]

OhmConnect discussed maximizing enrollment of customers who already have a smart communicating thermostat. SCE says it recognizes the opportunity to motivate "both smart thermostat owners and non-smart thermostat owners to enroll in Smart Energy Program (or another qualifying DR program) by offering the DR thermostat rebate." SDG&E says the TD program it offers the $50 thermostat incentive through a "bring your own device" program.[261]

As such, it follows that SDG&E proposed to replace the $50 thermostat-specific incentive with an $80 enrollment incentive to promote participation in a proposed end-use agnostic program that would, if approved in this decision, replace the AC Saver program.[262] While neither PG&E nor SCE specifically proposed replacing thermostat-specific incentives with an enrollment incentive, including one that could be applied to more end uses, both PG&E and SCE did propose programs that go beyond harnessing just air conditioning, and would, if approved in this decision, allow other end uses to participate in DR events.[263]

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[259] SDGE-1, at 50; SCE-02, at 2.

[260] Council-02, at 22.

[261] SDG&E-1, at EBM-47.

[262] SDGE-1, at 33.

[263] PG&E-2, at 3-36; SCE-03, at 78.

We review these comments and proposals because they illustrate that some percentage of customers receiving thermostat incentives already own thermostats, and that incentives that encourage program enrollment could derive not just from a separate device incentive program such as Auto DR, but also from an enrollment incentive internal to the load modifying or supply-side DR program.

Each of the Utilities provides a distinct proposal, with distinct arguments. Parties voice some agreement and some opposition. We accept the basic proposals of each of the Utilities, with some modification.

##### 10.1.1.1.1. PG&E Thermostat Proposals

PG&E proposes to eliminate its $50 residential connected thermostat Deemed Incentive, asserting that there are authorized connected thermostat incentives through other existing programs.[264]

We note that PG&E funds a $75 smart thermostat rebate through the Statewide Energy Efficiency (EE) Plug Load and Appliance (PLA) program called Golden State Rebates.[265] Further, PG&E supplements the $75 EE PLA smart thermostat rebate with an additional $45 incentive from EE integrated demand side management funding (pursuant to D.18-05-041), and PG&E funds a $75 smart thermostat rebate for customers in hot climate zones who enroll in a market-integrated supply side DR program (pursuant to D.21-12-015).[266]

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[264] PG&E-2 ,at 12: "Other non-DR programs can be the source of residential ADR technology incentives in the future such as EE [Energy Efficiency], SGIP [Self-Generation Incentive Program], IDSM [Integrated Demand Side Management], etc."

[265] PG&E's April 21, 2023, Opening Comments In Response To The Assigned Commissioner's January 27, 2023 Ruling at 7.

[266] *Ibid.*

In response, CEDMC opposed PG&E's proposal, arguing that such incentives encourage customer enrollment, that DR providers use the incentives as recruitment tools, and that the incentives based in other proceedings may end.[267] By contrast, Cal Advocates agreed with PG&E because the proposal would reduce duplicative funding.[268]

In reply to CEDMC, PG&E contended that the purpose of the Auto DR program is not to increase the adoption of connected technologies but instead to increase the use of technologies that have OpenADR capability, which most current residential technologies already have.[269]

We agree with PG&E's proposal to eliminate its $50 residential connected thermostat Deemed Incentive for the reasons PG&E cites. There are existing PG&E customer programs that provide ample financial incentives to install connected thermostats.

Further, as discussed above, incentives that encourage enrollment in a demand response program can be offered by the program administrator through an incentive internal to that program and could incent technology neutral participation. As SDG&E points out below, PG&E already does this through its Smart AC program.

#### 10.1.1.2. SCE Thermostat Proposals

SCE proposes to maintain its $75 connected thermostat incentive offered through its Programmable Communicating Thermostat Incentive Program at a cost of $2.075 million annually for 2024-2027.[270] The incentive is available to

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[267] Council-02, at 19, 21, 22.

[268] Cal Advocates Response to Assigned Commissioner Questions Ruling at Attachment 1.

[269] PG&E-8, at 3-4 ("OpenADR" is a standard communication protocol).

[270] SCE-03 at 57-58.

customers (residential or small and medium businesses) in its existing Capacity Bidding Program, Critical Peak Pricing Program, and DRAM, if enrolled with a qualified DR program provider.[271] SCE also proposes to add an instant rebate at its Marketplace site with pre-enrollment in its Smart Energy Program (SEP).[272]

SCE asserts that the basis for continuing to offer the connected thermostat incentive is that it helps drive enrollments into DR programs, such as SEP, which SCE contends helps decrease loads during grid emergencies.[273] SCE also reports that at present, there are no connected thermostat incentives available to SCE customers through the SGIP or IDSM programs, and that the statewide EE connected thermostat rebate is currently only funded through 2024.[274]

SCE reports that a 2021 SEP process evaluation identified financial benefits as the most important motivator for enrollment: 77 percent of survey respondents said the one-time $75 thermostat incentive was "important" or "extremely important."[275] SCE estimates that it would provide 110,000 thermostat incentives between 2024 and 2027 if this program is approved.[276]

Further, as discussed above, SCE has described its capability to adjust the cooling temperature set point on participating thermostats by up to four degrees for DR program events. SCE also identifies its vendor contracting that allows for

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[271] *Id*., at 59.

[272] *Id*., at 57.

[273] SCE's April 21, 2023, Opening Comments In Response To The Assigned Commissioner's January 27, 2023 Ruling, at 2.

[274] *Ibid*.

[275] *Ibid*.

[276] SCE-03, at 58.

this thermostat management during events.[277] SCE also described an electronic rebate award process it spent years developing.[278] We see no need to disrupt this system at this time.

We agree with SCE's proposal to continue its $75 incentive for connected thermostats and therefore approve SCE's 2024-2027 budget request for that incentive. We note with approval that the connected thermostat incentive program for SCE customers mostly requires enrollment in a market-integrated supply side DR program. We do not presently adopt but are mindful of the need to move toward mandating that all connected thermostat incentives funded through DR budgets must require enrollment in a "qualified" DR program, as defined in this decision.

#### 10.1.1.3. SDG&E Thermostat Proposals

SDG&E proposes to retire its Technology Deployment program, which offers a $50 connected thermostat incentive when the customer is enrolled in the Capacity Bidding Program, AC Saver, a rate with events, or DRAM. According to SDG&E, in 2020, 92 percent of the customers receiving this incentive were enrolled in SDG&E's AC Saver program, four percent were enrolled in a rate with events, four percent were enrolled in DRAM, while none were enrolled in Capacity Bidding Program.[279] Instead, SDG&E proposes to offer only an $80 enrollment incentive that is end use agnostic, in its AC Saver program, while it proposes to replace AC Saver with a new program that accommodates end uses

[277] SCE-03, at 114.

[278] SCE-03, at 58.

[279] SDG&E's April 21, 2023, Opening Comments In Response To The Assigned Commissioner's January 27, 2023 Ruling at 3.

beyond air-conditioning.[280] SDG&E asserts its proposal is supported by a customer survey preferring an $80 program enrollment incentive to a $50 connected thermostat incentive.[281] SDG&E says this enrollment incentive proposal reflects PG&E's SmartAC program, which SDG&E says also offers an up-front enrollment payment, though SDG&E acknowledges that the control switch capability in the PG&E program is provided by PG&E at no cost to the customer.[282]

SDG&E also asserts that there are connected thermostat incentives authorized through other existing programs.[283]

Further, SDG&E identifies technical challenges it faces related to thermostat incentives and the fact that thermostat settings can for the most part only be adjusted by the manufacturer. SDG&E also discusses what it considers technical challenges offering the incentive to participants of multiple programs, which requires two enrollment portals, one for participants of IOU programs and another for third-party program participants. Relatedly, SDG&E says it cannot verify that a third-party program customer thermostat is online.[284]

In response, CEDMC argued against eliminating the connected thermostat incentive for DRAM.[285]

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[280] SDGE-1, at 33, 50.

[281] SDGE-1, at 33.

[282] SDG&E's April 21, 2023, Opening Comments In Response To The Assigned Commissioner's January 27, 2023 Ruling at 2.

[283] SDGE-9, at 26.

[284] SDGE-1, at 51; SDG&E's April 21, 2023, Opening Comments In Response To The Assigned Commissioner's January 27, 2023 Ruling at 3-5.

[285] Council-01, at 21-22.

We approve SDG&E's proposal to eliminate its Technology Deployment program due to the technical challenges SDG&E complains of. SDG&E has also made the case for incentivizing enrollment through the demand response program instead of through a device incentive external to it, though due to action in this decision that will not be possible via SDG&E's proposed Smart Energy Program. We also deny SDG&E's request to establish an $80 program enrollment incentive.

#### 10.1.2. Auto DR Customized Incentive Programs

The Utilities each have a customized incentive program. Their respective programs have been operating since before the 2018-2022 program cycle, with an alternative incentive design approved for 2022 and 2023 only in D.21-12-015. Each Utility provides certain commercial and industrial customers with custom software and hardware controls to enable them to shed substantial electrical loads. Here we approve the continuation of the programs at PG&E and SCE, as well as the alternate incentive design. We approve SDG&E's closure of its program.

##### 10.1.2.1. PG&E's Custom Incentive Program

PG&E proposes to continue its custom Auto DR incentive program and offer the standard incentive design as well as an alternate version approved through 2023 in D.21-12-015.

D. 21-12-015 (Ordering Paragraph 42) approved for 2022 and 2023 only a PG&E custom incentive design option of 100% payment of the technology costs, to be reimbursed after installation, with an agreement in place requiring that the customer remain in an eligible program for five years.

PG&E also has what it refers to as a standard option customer incentive, which pays for 60% of eligible costs, reimbursed after installation, with the remaining 40% of eligible costs (capped at 75% of total project costs) to be paid after one year upon confirmation that the customer was shedding the load total that had been estimated in the engineering test that served as to the premise for the incentive. With this standard option customer incentive, the customer is required to remain in an eligible program for three years.[286] PG&E cites support for these non-residential custom incentive designs based on a 2022 study by Energy Solutions that was commissioned by the Utilities: that study was asserted to demonstrate a large drop in customer enrollment, which the 100% upfront reimbursement is intended to alleviate.[287]

We note no relevant party comment regarding PG&E's custom design incentive proposal.

We approve PG&E's custom design incentive proposal. PG&E's testimony supports its efficacy.[288]

#### 10.1.2.2. PG&E's FastTrack Auto DR Incentive Program Study

PG&E requests $250,000 to cover its portion of an intended joint study (along with SCE) to identify additional customers and additional means to apply Auto DR in its FastTrack Application process. PG&E seeks to identify additional large commercial and industrial customer segments amenable to its FastTrack Application Auto DR program. PG&E also seeks to further develop the FastTrack calculator to enable expansion of those controllable features that shed

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[286] PG&E-02, at 4-6.

[287] *Id.*, at 4-8.

[288] *Id.*, at 4-7 – 4-10.

power demand: presently, FastTrack only has pre-approved measures to calculate kW shed for commonly used HVAC and lighting.[289]

PG&E contends that expansion of the FastTrack Application program could increase cost effectiveness of the Auto DR program, because savings would result if large commercial and industrial customers choose FastTrack instead of the custom Auto DR program incentives.[290]

We note that no relevant party comment was received regarding PG&E's proposed FastTrack Auto DR incentive program expansion study.

We approve PG&E's proposed budget of $250,000 for its share of a study to expand the FastTrack Auto DR incentive program. We agree with the contention that more streamlined programs that reach more customers with more standardized methodologies to apply for Auto DR incentives should result in more cost-effective DR savings.

#### 10.1.3. PG&E's Auto DR Budget

PG&E's budget request for its entire Auto DR program is $9,523,497.[291] A determination as to continuation, modification, or discontinuation of the 2024-2025 DRAM program will be determined later in this proceeding in the DRAM Phase II decision. We note PG&E's assertion that this Auto DR budget total is significantly less than its correlating $20.4 million budget request for 2018-2022, primarily due to the termination of PG&E's residential connected thermostat incentive program.[292] PG&E's requested budget is approved, but we note that due to the discussion below denying SCE's and PG&E's request to provide Auto

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[289] PG&E-2, at 4-9 – 4-10.

[290] *Ibid.*

[291] PG&E-8, at 3-5.

[292] PG&E 2, at 4-12.

DR incentives to RDRR (including BIP), actual expenditures in this budget category should be less than authorized. We therefore direct PG&E to file a Tier 3 advice letter within 60 days after the date of issuance of this decision, setting a new budget minus any incentives for RDRR.

**Category 4 - 2024-2027 PG&E Auto DR Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| PG&E Requested | $2.38 | $2.38 | $2.38 | $2.38 | **$9.523** |
| Authorized | $2.38 | $2.38 | $2.38 | $2.38 | **$9.523** |

#### 10.1.4. SCE's FastTrack Auto DR Incentive Program Study

SCE requests $250,000 to cover its portion of an intended joint study (along with PG&E) to identify additional customers and additional means to apply Auto DR in its FastTrack Application process. SCE seeks to identify additional large commercial and industrial customer segments amenable to its FastTrack Application Auto DR program. SCE also seeks further develop the FastTrack calculator to enable expansion of those controllable features that shed power demand: presently, FastTrack only has pre-approved measures to calculate kW shed for commonly used HVAC and lighting.[293]

SCE contends that expansion of the FastTrack Application program could increase cost effectiveness of the Auto DR program, because savings would result if large commercial and industrial customers choose FastTrack instead of the custom Auto DR program incentives.[294]

[293] PG&E-2, at 4-9 – 4-10.

[294] SCE-03, at 58-60.

We note that no relevant party comment was received regarding SCE's proposed FastTrack Auto DR incentive program expansion study.

We approve SCE's proposed budget of $250,000 for its share of a study to expand the FastTrack Auto DR incentive program. We agree with the contention that more streamlined programs that reach more customers with more standardized methodologies to apply for Auto DR incentives should result in more cost-effective DR savings.

Two requests, one from SCE and one from CEDMC, impact SCE's budget request. CEDMC proposes that SCE clarify that DRAM customers will be eligible for Auto DR incentives if the pilot is extended, due to the fact that in its application, SCE says it is not currently anticipating that DRAM will be a qualifying program option after 2023.[295] We do not have a budget figure for this cost, and defer this to the DRAM decision.

SCE also proposes to make BIP-15 eligible as a qualifying program for Auto DR incentives. SCE states that this change will provide another option for customers enrolled or planning to enroll in DRAM, if it is not continued. D.16-06-029 declined to grant eligibility for Auto DR incentives to all reliability programs, due to the infrequent dispatch of reliability programs. SCE and PG&E both state that the eight BIP dispatches in 2020 is evidence that dispatch is frequent enough to justify Auto DR incentives.

We do not find that one year of evidence is sufficient to stray from the previously set Commission policy at this time. Reliability programs shall remain ineligible for Auto DR incentives.

[295] Council-02, at 20-21.

### 10.1.5. SCE's Auto DR Budget

SCE's budget request for its entire Auto DR program is $22,142,000: this amount includes $8,300,000 for SCE's connected thermostat incentive program and $9,600,000 for Auto DR incentives, which would include the custom calculated and streamlined nonresidential deemed subprograms, plus labor and marketing.[296] We authorize $21,517,000 which reflects SCE's budget request net of the BIP-15 costs.

**Category 4 - 2024-2027 SCE Auto DR Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $6.153 | $5.291 | $5.338 | $5.361 | **$22.142** |
| Authorized | $5.997 | $5.135 | $5.182 | $5.205 | **$21.517** |

### 10.1.6. SDG&E's Technology Incentive Program

SDG&E's Technology Incentive Program is a calculated incentive requiring a load shed test.[297] SDG&E proposes to eliminate its Technology Incentive Program, which, in conjunction with eliminating its connected thermostat incentive program, would close SDG&E's Auto DR incentive program. It asserts that its Technology Incentive Program has not approved any new projects since 2019.[298]

CEDMC argued that rather than close its Auto DR incentive program, SDG&E should align its programs with PG&E and SCE.[299]

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[296] SCE-03, at 63.

[297] SDGE-1, at EBM-50.

[298] SDGE-10, at 25.

[299] CEDMC's Opening Comment at 20-21.

We find that SDG&E has demonstrated that for several years its Technology Incentive Program has been failing, due to a lack of customer interest, poor performance of those customers who received incentives, and lack of interest by contractors. Between 2017 and 2021, the Program paid out only $6,300 in incentives, while incurring $1.3 million in administrative costs, and no customers stayed on the Program beyond the mandatory three-year enrollment participation requirement.[300]

#### 10.1.7. SDG&E Auto DR Budget

As this decision declines to fund either SDG&E's Technology Incentive Program or its Auto DR incentive program, SDG&E is allotted no budget for Auto DR activities during the 2024-2027 program cycle.

### 10.2. Demand Response Emerging Technologies (DRET)

#### 10.2.1. PG&E DRET Proposal

PG&E proposes to continue its DRET program, with a focus on studying and evaluating technologies that benefit customers on dynamic rates and researching ways to leverage batteries, EVs, and flexible appliances.[301] PG&E also hopes to provide support to, and look for ways to leverage, its ADR and Integrated Demand Side Management programs, as well as look for synergies with other Emerging Technology Programs as discussed in D.20-12-029.[302]

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[300] SDGE-9, at 54-60.

[301] PG&E-2, at 4-14-4-15.

[302] D.20-12-029, at 34-37.

#### 10.2.1.1. Joint IOU Market Integration Efficacy Study

PG&E also proposes to conduct a Joint IOU Market Integration Efficacy Study, to inform future program DR design.[303] PG&E states that the study would be utilized to determine whether DR market integration is a more effective mechanism to support California's clean energy policy, and what action can be taken to increase DR's effectiveness.[304] The study would be conducted by an independent consultant with an Advisory Committee providing input. PG&E requests $1.2 million for its proposed share of the $3 million cost.

SDG&E suggested that the study should focus instead on the efficacy of DR in general and whether the Commission should continue to pursue market integration, but supported PG&E's timeline and budget.[305] CEDMC suggests that the Advisory Committee include representatives of residential and non-residential DR participants as well as third-party DR providers.[306] Both CEDMC and LEAP suggest that regardless of the study's results, the Commission should accommodate both supply-side and load-modifying DR, with equal opportunity between the IOUs and third-party DRPs.[307]

PG&E has not provided sufficient detail regarding the deliverables of the project, and has not clearly delineated the need. The Commission has not pronounced goals by which to determine whether DR goals have been achieved. Other proceedings at the Commission are already looking into related issues,

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303 PG&E-2, at 7-17.

304 PG&E-2, at 2-7:24-2-8:5.

305 SDG&E Phase II Opening Brief, at 40.

306 Council-02, at 5:14-24.

307 *Ibid.*; Leap Phase II Opening Brief, at 7.

such as the RA proceeding (R.23-10-011), and other issues are more appropriately considered through the CAISO stakeholder process, including those related to PDR and RDRR. PG&E's request for $1.2 million for this program is denied, and its DRET budget is reduced. SDG&E's request for funding for this study is also removed; $300,000 shall be removed from its 2024 and 2025 Measurement and Evaluation Budget (Category 7).[308] SCE's request for funding for this study is also removed; $1.2 million shall be removed from its EM&V Budget (Category 7).[309]

##### 10.2.1.2. Joint IOU Bottom-Up Potential/Load Flexibility Study

PG&E proposes that the IOUs collaborate on a statewide load flexibility study, at a cost of $3 million total (shared in a 40 percent PG&E and SCE, and 20 percent SDG&E proportion).[310] PG&E states that the objectives of the study would be to study customer elasticity based on end use, by comparing disaggregated load data to relative changes in price, as a function of customer sector, locations, hour of day, and other factors, using PG&E pilots including those proposed in its application. PG&E states that the findings will inform program design and operational insights. PG&E notes that this study overlaps with research already completed by the LBNL utilizing DR Potential study finding. PG&E states that the work will build upon LBNL work.

Cal Advocates states that should the Commission approve this work, it should require PG&E to provide results that quantify in dollars what is required

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[308] SDGE-4, at LGR-12, Table LG-8.

[309] SCE-03, at 108:21-22.

[310] PG&E-2, at 1-15:3-33.

to incentivize customers to participate in DR.[311] Cal Advocates states that this should help create a framework toward understanding whether DR programs should be pursued based on the required cost of incentives, and aid in determining whether current incentives are too high.

The research provided by the IOUs regarding incentive amounts could provide significant savings, if it is able to determine the optimal amount of incentives for DR programs. However, the IOUs have not sufficiently justified the cost for the research. PG&E notes that the research overlaps with LBNL research. Given that, the proposal requires additional specifics to fully describe how it would exactly build upon LBNL research. Further, PG&E pilots to be used in the study were not approved here. The proposed study is denied. PG&E's DRET budget shall be reduced as described below, SCE's EM&V budget reduced by $1.2 million, and SDG&E's Measurement and Evaluation Budget by $600,000.[312]

#### 10.2.1.3. PG&E DRET Budget

PG&E proposes to increase its program budget to $5 million annually, from $1.446 million,[313] to perform larger scale studies and increase the overall number of technologies and processes the program can cover. PG&E has not sufficiently justified the proposed budget increase. We also decline to fund the additional studies proposed by PG&E. We approve PG&E's budget at the previous average annual value, $1.446 million.

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[311] CalAdvocates-1, at 2-2:4-2-3:3.

[312] SDGE-4, at LGR-12, Table LG-8.

[313] PG&E-2, at 4-16:10-13.

**Category 4 - 2024-2027 PG&E DRET Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| PG&E Requested | $5.0 | $5.0 | $5.0 | $5.0 | **$20.0** |
| Authorized | $1.446 | $1.446 | $1.446 | $1.446 | **$5.784** |

#### 10.2.2. SCE Emerging Markets and Technologies Proposal

SCE's Emerging Markets and Technologies (EMT) activities fund research and testing services, product demonstrations, market studies, assessments of advanced communications protocols, and field deployments. SCE states that its EMT activities in the 2024-2027 cycle will focus on:

- Assessment and advocacy for signal-responsive and interoperable technologies that can be utilized as flexible DR resources with real-time pricing models;
- Testing the performance and cost of emerging DR enabling technologies;
- Sharing technical knowledge with DR and DER stakeholders;
- Demonstrating advanced technologies and operational strategies that have mass-market demand flexibility potential;
- Pursuit of new models of dynamic rate design and real-time subscription tariff elements.

##### 10.2.2.1. SCE EMT Budget

SCE was previously authorized to recover $14.61 million, or $2.922 million per year, for its EMT activities. SCE requests a total of $16.915 million for EMT activities from 2024-2027.[314] This includes an additional $1.25 million to expand

[314] SCE-03, at 71, Table VI-19.

a dynamic rate pilot authorized by D.21-12-015.[315] This is to cover study of residential, commercial, and industrial customers with smart-enabling price response end uses (such as EV charging, BTM batteries, and controllable loads). SCE's proposed EMT activities are reasonable. The proposed study will build upon activities SCE has already undertaken.

We decline to authorize funding for the expansion of the dynamic rate pilot in this proceeding, as there is an outstanding staff proposal on the potential expansion of the dynamic rate pilot in R.22-07-005, the Demand Flexibility Rulemaking.[316] Parties have already filed multiple rounds of comment on the proposal in that proceeding, and it is more reasonable to consider funding for the pilot in the proceeding in which the pilot design is under consideration. SCE's other EMT budget requests are approved, for a total of $15.665 million. SCE has also not sufficiently justified the more than 33 percent increase over previous annual authorizations for this category. SCE is authorized to recover $15.66 million from 2024-2027 for EMT activities.

**Category 4 - 2024-2027 SCE EMT Budget (in $ millions)**

| **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|
| SCE Requested | $3.935 | $3.850 | $3.932 | $3.946 | **$16.915** |
| Authorized | $2.922 | $2.922 | $2.922 | $2.922 | **$11.69** |

[315] D.21-12-015, at 96.

[316] *See* R.22-07-005, Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots, August 15, 2023, at 4 and Attachment A.

### 10.2.3. SDG&E Emerging Technologies Proposal

SDG&E's 2018-2022 Emerging Technologies DR (ET-DR) activities included research on:[317]

- Smart Voice Assistant devices;
- Time-Of-Use messaging applications;
- DER data analytics Tools;
- EV charging impacts;
- Thermal storage for refrigeration; and
- Whole Home DR.

SDG&E's planned ET-DR activities for the 2024-2027 DR cycle would focus on expanding its studies to more complex and technical technologies.[318] SDG&E plans to conduct studies on Integrated Distributed Energy Resources, Microgrids, Virtual Power Plants, and whole home/facility controls that can be utilized with dynamic or real-time pricing. SDG&E requests a budget of $1.25 million per year for ET-DR from 2024-2027.[319] SDG&E was previously authorized to recover $774,000 per year for these costs from 2018-2022. SDG&E projects that its proposed funding level will support up to four to six projects per year.

SDG&E has not sufficiently justified the increased budget for ET-DR. Additionally, this decision declines to approve most of SDG&E's DR portfolio, bringing into question the need for this research. SDG&E's budget is therefore reduced to the funding level previously approved, $774,000 per year. SDG&E is authorized to recover $3.096 million for ET-DR costs from 2024-2027.

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[317] SDGE-1, at EBM-62.

[318] SDGE-1, at EBM-63-EBM-64.

[319] *Id.*, at EBM-63:20.

**Category 4 - 2024-2027 SDG&E ET-DR Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SDG&E Requested | $1.25 | $1.25 | $1.25 | $1.25 | **$5.0** |
| Authorized | $0.774 | $0.774 | $0.774 | $0.774 | **$3.096** |

## 11. Pilots

### 11.1. ELRP

The Emergency Load Reduction Program, or ELRP, is a pilot program launched in 2021 as a voluntary, emergency DR program to supplement RA supplies in case of extreme grid stress. It is a pay-for-performance program that compensates voluntary incremental load reductions provided by customers during an event triggered in response to CAISO-declared EEAs. The goal of the program is to help avoid rotating outages during peak summer electricity usage periods from May to October. The program is maintained by the IOUs.

ELRP participants consist of two groups, and eight sub-groups, as follows:

- Group A: Customers and Aggregators not participating in DR Programs:
  - A.1: Non-Residential Customers (includes dual-participating BIP)
  - A.2: Non-Residential Aggregators
  - A.3: Rule 21 Exporting DERs
  - A.4: Virtual Power Plant Aggregators
  - A.5: Vehicle-Grid Integration (VGI) Aggregators
  - A.6: Power Saver Rewards (PSR) – Residential Customers
- Group B: RA Demand Response Program Participants (PDRs)
  - B.1: Third-Party DR Providers

- B.2: IOU Capacity Bidding Programs

Most Group A ELRP events are triggered or called by the IOUs after declaration of an Energy Emergency Alert (EEAx) by the CAISO, or a CAISO-issued Flex Alert. When ELRP is triggered, enrolled customers may choose not to participate and there is no penalty for non-participation, nor is there any requirement to reduce load by a particular amount during the event. However, ELRP payment is calculated based on the load reduction measured on the customer's meter, either individually or via aggregation depending on the ELRP option.

Participants are compensated after-the-fact at a prefixed compensation rate of $2/kilowatt-hour for every kilowatt-hour of electricity consumption the customer reduces voluntarily during an ELRP event. The reduction in consumption during an ELRP event is measured relative to a baseline of how much energy the customer used on similar days preceding the event day during the hours corresponding to the event hours. The measured reduction in consumption is also known as the Incremental Load Reduction (ILR). There are no penalties for not reducing energy consumption, or for increasing consumption, during an ELRP event.

ELRP can be called for an event from May through October, during the hours of 4 p.m. to 9 p.m., seven days a week. An ELRP event can last for a minimum of one hour, and a maximum of five hours per day. ELRP can be used up to 60 hours per year, and there is no limitation to calling the program on consecutive days. ELRP is not counted towards RA or peak forecast adjustment.

The January 27 Ruling asked the parties to provide comments on questions related to ELRP related to compensation, whether the program should be extended, the eligibility of Backup Generators (BUGs), competition with RA-eligible programs, and staff proposals for consideration. Parties also provided proposals to ELRP as scoped in the Phase II Scoping Memo. This section will discuss party comments and staff proposals related to ELRP.

#### 11.1.1. ELRP Extension

ELRP has been authorized and funded through 2025. Question 3 of the January 27 Ruling asked parties to comment on what factors to consider when determining whether to extend ELRP to 2026 and 2027.[320] Parties brought up many, factors including:

- Grid reliability needs;[321]
- Cost-effectiveness;
- Whether Group B participants have a level playing field with Group A aggregators;
- Whether ELRP is being extended as a pilot or full program; and
- Whether ELRP is able to provide otherwise unavailable emergency capacity.

The IOUs have all proposed to continue ELRP through 2027 in their applications. SDG&E states that extending the ELRP is prudent, given the potential for extreme weather in the near future.[322] SCE states that it similarly sees ELRP as a key resource to support grid reliability.[323]

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[320] January 27, 2023 Ruling at 8.

[321] Cal Advocates Phase II Opening Brief, at 35-36; CESA Opening Comments on January 27 Ruling, at 6-8; SDG&E Opening Comments on January 27 Ruling, at 10-11; PG&E Opening Comments on January 27 Ruling, at 11-12; SCE Opening Comments on January 27 Ruling, at 10-11; Tesla/CalSSA Opening Comments on January 27 Ruling, at 1-3.

[322] SDGE-1, at EBM-47.

[323] SCE-01, at 30:11-21.

In comments, parties mostly agreed that ELRP should be extended through 2027. CESA states that it should be extended as it is still in its infancy and is not taking up MW that would otherwise be in RA—eligible programs due to the unique program parameters of ELRP.[324] CESA also states that ELRP also uniquely provides capacity backed by BTM generation and storage devices and uniquely compensates for exports and uniquely allows for submetering.[325] VGIC notes that extension would provide greater certainty for participants.[326]

Cal Advocates and the Joint CCAs state that the program should not be extended through 2027 if it is found to be not cost-effective, or only extend cost-effective sub-groups.[327]

At the outset, we note that ELRP was designed to be another tool to relieve grid reliability stress. Parties note that mid-term grid reliability remains an outstanding question, and that even if ELRP ends up being superfluous, its role in avoiding rolling blackouts in September 2022 leans in favor of approving it through 2027.

We also recognize arguments that the cost-effectiveness of ELRP is an open question. Joint CCAs note that ELRP will constitute more than half of PG&E's DR budget in program years 2024-2027 if it is approved.[328] However, to the extent that ELRP is still considered a pilot, it is not yet subject to cost-effectiveness considerations. In later sections we discuss changes made to

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[324] CESA Opening Comments on January 27 Ruling, at 4.

[325] *Id*. at 8-9.

[326] VGIC Phase II Opening Comments, at 5.

[327] CalAdvocates-2, at 3-1:18-22; Joint CCAs Opening Comments on January 27 Ruling, at 10-11.

[328] Joint CCAs Opening Comments on January 27 Ruling, at 10-11.

improve cost-effectiveness, including consideration of elimination of specific ELRP options.

At this time, we approve ELRP Group A (excluding sub-group A.6 PSR) and Group B to continue through 2027. As a relatively new pilot, the cost-effectiveness of ELRP should be a secondary concern. Additional pilot years may increase cost-effectiveness as the program continues to grow. Authorized budgets are discussed in a later section. Further refinements to the ELRP are discussed in the remainder of this section.

#### 11.1.2. Residential ELRP Extension

Parties have presented a number of issues with ELRP sub-group A.6 (PSR). D.21-12-015 authorized PG&E to recover $94 million, SCE $76.6 million, and SDG&E $30.8 million for incentives for all ELRP.[329] PG&E's ELRP incentive budget total amounts to over half the total DR program budget. Parties have proposed a number of changes to increase sub-group A.6 cost-effectiveness, which we discuss below.

Ultimately, we determine that sub-group A.6, also known as residential ELRP or PSR, should be allowed to sunset following the 2025 program year as currently designed by D.21-12-015.

##### 11.1.2.1. A.6 Dispatch Window

SCE proposes to reduce the sub-group A.6 dispatch window to two hours, from 6-8 p.m., in 2026-2027. CESA and Cal Advocates support the proposal, stating that it highlights load reduction when it is most needed, and will make it easier for customers by only requiring them to reduce usage over a smaller set of hours.[330] PG&E, and SDG&E disagree, stating the proposal will cause customer

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[329] D.21-12-015, at 46.

[330] CalAdvocates-01, at 5-3:16-5-4:7.

confusion and lead to precooling and snapback effects that reduce overall ELRP effectiveness.[331]

As discussed above, we are concerned with the outsized cost ELRP incentive payments. However, at this time we decline to reduce the dispatch window for sub-group A.6 only. This could lead to large amounts of confusion amongst program participants and could have unintended consequences. The dispatch window for sub-group A.6 shall remain 4:00 p.m. to 9:00 p.m. for 2024-2025.

#### 11.1.2.2. A.6 Auto-Enrollment of Customers

CEDMC proposes that residential ELRP A.6 (or PSR) customers should be able to opt-in only due to widespread free-ridership in opt-out programs, and that PSR should unenroll existing auto-enrolled customers to eliminate that issue.[332] Auto-enrolled customers deliver significantly less ILR than opt-in customers. PG&E and SDG&E agree that PSR should be made an opt-in program to mitigate free-ridership.[333] However, they disagree with unenrollment of auto-enrolled customers, citing to the need to draft a plan to do so and loss of load shed potential. The Joint CCAs also agree that PSR should be made opt-in, claiming auto-enrollment has not translated to increased ILR.[334]

It is reasonable to transition sub-group A.6 off of auto-enrollment procedures. The customer base currently is sufficiently large. However, disenrollment of already enrolled customers presents significant issues related to equity, messaging, and load savings reduction. In the near term, it would be

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[331] SDGE-10, at EBM-17-18; PG&E-8, at 3-14-3-14.

[332] Council-02, at 15:13-25-16:3.

[333] PG&E-8, at 3-14-3-15; SDG*E-10, at EBM-18.

[334] Joint CCAs Opening Brief, at 13-16.

prudent to keep the substantial customer count already built. We therefore decline to automatically disenroll any customers. Starting in 2024, sub-group A.6 shall be opt-in enrollment only, in preparation for the sunsetting of the program.

#### 11.1.2.3. Sub-Group A.6 Dispatch Trigger

Question 7 of the January 27 ruling[335] stated that "[t]he Commission authorized ELRP to help mitigate grid emergencies. Per D.21-12-015, the dispatch trigger for the Power Saver Rewards (PSR) program (ELRP/A.6 subgroup) is linked to CAISO issuing a Flex Alert notice (unlike the triggers for other ELRP sub-groups, which are generally linked to an CAISO 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." Question 7 then asked:

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

CEDMC states that Flex Alerts should not be the program trigger, as many customers already conserve in response to Flex Alerts without compensation through ELRP.[336] This creates a free-ridership problem in the view of CEDMC.

[335] January 27 Ruling, at 10.

[336] Council-02, at 16:18-21.

PG&E and SDG&E oppose, stating that customer confusion may ensue if the trigger becomes only a Flex Alert with an EEA, as then PSR will not be called on all occasions that a Flex Alert is called.[337]

We decline to make this change at this time for the 2026-2027 ELRP years, given the sunsetting of PSR after 2025 discussed below. Additionally, customer marketing and engagement thus far has focused on saving energy during Flex Alerts. Changing the residential ELRP trigger away from Flex Alert will likely create confusion amongst customers, and attempts to market the change will likely lead to detrimental repercussions with regards to participant load reduction. If customers become accustomed to Flex Alerts not triggering the program, then when an EEAx is actually called it is likely customers will not recognize the difference and will simply be confused.

#### 11.1.2.4. Sunsetting of ELRP Sub-Group A.6

As discussed above, parties have suggested many chances to improve the cost-effectiveness of sub-group A.6. Although we have not adopted all of the changes proposed by parties for residential ELRP, in totality the number of proposed changes suggests that the program is not cost-effective. Residential ELRP carries significant free-ridership problems due to a lack of minimum participation standards, the impact of payment errors as described in the Residential ELRP Baseline Evaluation Report, and payment of incentives when participants would have already otherwise reduced load. In the very near term however, before the program sunsets, it is reasonable to keep the program running as designed to ensure grid reliability. A reduction in incentives in 2024, as discussed in Section 11.1.10 below, may provide additional information

[337] PG&E Opening Comments to January 27 Ruling, at 15; SDG&E Opening Comments to January 27 Ruling, at 14.

regarding participant sensitivity to incentive levels. Ultimately, the high cost of the program is difficult to justify. SCE notes that in 2022 PSR (sub-group A.6) accounted for $110 million in incentive costs, far beyond the incentive cap set for all ELRP sub-groups in aggregate by the Phase 2 Summer Reliability Decision.[338] SCE now requests $144 million for ELRP incentive budgets in both 2024 and 2025 based on current program parameters.[339] We therefore will allow residential ELRP to sunset in 2025.

#### 11.1.3. Competition with RA-Counted DR Programs

Question 5 of the January 27 Ruling stated that ELRP is meant to be an insurance layer to supplement RA resources during emergencies and is not intended to offer competition to RA-counted DR programs such that customers are diverted away from enrolling in those programs. The ruling then asked:

- Is the risk of ELRP competing with RA-counted DR programs a concern that should be addressed by the Commission; and
- What design changes or guardrails should the Commission consider (for example, guidelines for utility ELRP marketing) to mitigate this concern?

CESA, PG&E, and Tesla/CalSSA agreed there is currently no cause for concern and or no evidence suggesting that there is a risk of ELRP competing with RA-counted DR programs, and therefore no changes are needed at this time.[340] These parties highlighted the fact that making changes could cause new issues or lead to customers dropping out. SCE and Cal Advocates agreed that

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[338] SCE-13, at 3:23-4:3.

[339] SCE-13, at 5:6.

[340] PG&E Opening Comments to January 27 Ruling, at 14-15; Tesla/CalSSA Opening Comments to January 27 Ruling, at 4,7; CESA Comments to January 27 Opening Ruling at 10.

there is currently no reason to believe ELRP is competing with RA-counted DR programs but expressed some support for lowering the incentive rate to $1/kWh.[341]

CLECA argued there is some risk of ELRP competing, especially if dispatch frequency or penalties for RA-counted DR programs become excessive.[342]

We find no evidence that ELRP is competing with RA-counted DR programs at this time. We decline to make any changes to ELRP incentive levels based on this factor.

#### 11.1.4. Group B Settlement

In Staff Proposal C[343] of the January 27 Ruling, Energy Division staff laid out modifications to the current "ELRP Settlement for Group B" guidelines. Staff laid out these changes because they had identified that the existing Group B compensation methodology contained erroneous phrases and incomplete instructions, which could disincentive an aggregator from participation in the CAISO market in certain scenarios.

SCE and SDG&E expressed support for the changes.[344] No party disagreed with the changes. The changes to the language for the ELRP Settlement for Group B guidelines, as laid out in Attachment 2 to this decision, are adopted. These changes also moot both CEDMC's proposal to settle Group B resources at

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341 SCE Opening Comments to January 27 Ruling, at 14;-15 Cal Advocates Phase II Opening Comments at 36-37.

342 CLECA Opening Comments to January 27 Ruling, at 2-3.

343 January 27 Ruling, Appendix A, at 7-10.

344 SCE Opening Comments to January 27 Ruling, at 21.

the individual level instead of the Resource ID level[345] and Joint CCA's request for Group B ILR and Compensation calculation clarification.[346]

#### 11.1.5. ELRP Trigger

OhmConnect proposes to change the triggering mechanism to the day-ahead Flex Alert for all ELRP subgroups. Currently, the day-ahead Flex Alert only triggers the ELRP sub-group A.6. OhmConnect states that this change is needed because when a Flex Alert is issued, the IOUs have the discretion to dispatch sub-groups A.2, A.4, and A.5 in order to reach the annual minimum dispatch hour requirements, thereby creating a situation where customers may perceive it to be more valuable to participate in the ELRP through an IOU-administered ELRP sub-group rather than via third-party providers.[347]

PG&E states that this change should not be made, and OhmConnect's justification of inequities between ELRP sub-groups is not sufficient justification for changing program triggers. PG&E notes that it only triggered other sub-groups in response to a Flex Alert in order to satisfy minimum dispatch requirements.[348]

OhmConnect has not sufficiently justified its proposal. Flex Alert is designed to remedy emergency grid situations, and the choice of trigger is not based on ensuring equity amongst sub-groups. The proposed change is denied.

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345 Council-02, at 13-14.

346 JCCA-01, at 8-10.

347 OhmConnect-4, at 18:24-19:8.

348 PG&E-8, at 3:21:11-22.

### 11.1.6. Compensation for BIP Customers During ELRP Events

CLECA proposes that BIP customers that are dual-enrolled in ELRP be compensated through ELRP during non-overlapping ELRP only events (that do not overlap with BIP events) for the amount of incremental load reduction achieved by the BIP customer.[349] CLECA states that this change would encourage incremental load reduction during standalone ELRP events.[350]

BIP is designed such that customers will quickly reduce onsite load to their chosen Firm Service Level (FSL) during a grid emergency as required by their contractual commitment under the BIP tariff. In exchange for the potential load reduction (PLR) available from BIP customers during an emergency per their contract, BIP customers receive a monthly monetary benefit whether or not a BIP event occurs in that month. The PLR available from BIP customers is routinely accounted for in the RA supply stack that is required by the Commission to ensure grid reliability.

ELRP is designed to provide "compensation for energy (or load reduction) beyond what is provided by RA resources. In other words, ELRP should be viewed principally as an insurance policy made available during emergency conditions to supplement the reliability already provided by the RA program."[351]

Noting the above design intent of BIP and ELRP, compensating BIP customers for any portion of the already compensated (via the RA program) PLR delivered during an ELRP only event is equivalent to compensating them twice. CLECA's proposal is denied.

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[349] CLECA-01, at 29-30.

[350] *Ibid.*

[351] D.21-12-003, at 20.

#### 11.1.7. ELRP Option A.2, A.4, A.5, and Group B

SCE proposes that ELRP Options A.2, A.4, A.5, and Group B be eliminated as pilot options from 2026-2027. SCE offers no justification for this change, and it is denied.

#### 11.1.8. Annual Dispatch Limit

SCE proposes to reduce the annual dispatch limit from 60 to 30 hours for 2026 and 2027 ELRP.[352] SCE states that this can be done due to expected transitioning customers off ELRP to other DR programs. SCE does not explain what purpose a reduction in the annual dispatch limit would serve. Presumably if customers are called for more than 30 hours, there will be grid reliability needs that are the cause. The proposal is rejected, and the annual dispatch limit shall remain 60 hours.

#### 11.1.9. Minimum Dispatch Hours

##### 11.1.9.1. Minimum Dispatch Hours for Sub-groups A.2, A.4, and A.5

SCE and PG&E propose to remove minimum dispatch requirements for the A.2, A.4, and A.5 sub-groups. These sub-groups consist of non-residential aggregators, virtual power plant aggregators, and vehicle-grid-integration aggregators. Minimum dispatch hours were instituted for these sub-groups to provide revenue via ELRP in order to encourage development of new resources that do not yet participate in DR in California.[353] Arguments in favor of removing the minimum dispatch requirements have been made by SCE, Cal Advocates and PG&E, who state that as it currently stands the minimum

[352] SCE-03, at 76:2-10.

[353] D.21-12-015, at 40, noting that "We adopt minimum VGI dispatch hours of 30 hours per season as an incentive for customers to participate in the program since they would otherwise have no assurance of receiving compensation."

dispatch hours only serve to provide revenue to the DR aggregators and they have not encouraged new aggregator participation. PG&E and SCE support removal of the dispatch requirements starting in 2026-2027, while Cal Advocates states it should be removed immediately.[354]

CEDMC and CESA[355] oppose removal of the minimum dispatch hours for all sub-groups, while VGIC opposes it for sub-group A.5, claiming Vehicle Grid Integration market development is still a new industry and that the aggregators rely on minimum dispatch hours for revenue to exist. VGIC in particular notes that sub-group A.5 was only instituted in late 2022 and has only one year's worth of lessons.[356]

With ELRP sub-groups A.2, A.4, and A.5, the Commission sought to encourage the growth of new aggregators and resources that do not participate in other forms of DR. Some success has already been realized with the joining of aggregators in sub-groups A.4 and A.5. However, two years is not yet sufficient time to allow the industry to grow and to determine the effectiveness of these programs. We therefore keep the minimum total dispatch hours the same for sub-group A.2, but lower the minimum total dispatch hours for sub-groups A.4 and A.5 to 15 and 20 hours, respectively. In order to incentivize participation, we also adopt a more targeted dispatch window of three hours for sub-groups A.4 and A.5, through 2027. This change should aid in determining whether the lack of incentives is causing low participation, or whether there is simply insufficient market for these sub-groups.

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354 PG&E Opening Brief, at 56; CalAdvocates-02, at 3-2:16-3-3:4; SCE-13, at 4.

355 CEDMC Phase II Opening Brief, at 10.

356 VGIC Phase II Opening Brief, at 6.

#### 11.1.9.2. Minimum Dispatch Hours for Group B

CEDMC proposes that minimum dispatch hours be instituted for all of Group B and states that this is a question of equity. The CEDMC states that minimum dispatch requirements are needed to provide revenue certainty for customers in group B to invest and commit to the program.[357] SCE states that such revenue is unnecessary, as Group B participants have other options available for participation in the CAISO wholesale energy market.[358] PG&E agrees with SCE, stating that the IOUs do not carry the same discretion to dispatch Group B as they do with Group A.[359]

We decline to adopt CEDMC's proposal. We note that Group A aggregators are out of market and therefore do not count for RA and may not participate in CAISO energy markets, unlike Group B participants. Minimum dispatch requirements in Group B will not create new resources or increase enrollment.

#### 11.1.10. ELRP Compensation Rate

As discussed earlier, SCE and Cal Advocates recommend reducing the ELRP compensation rate of $2/kWh to $1/kWh.[360] The initial ELRP compensation rate was set at $1/kWh in D.21-03-056, and was subsequently adjusted to $2/kWh by D.21-12-015. Cal Advocates states that DRPs did not increase bids in the CAISO market when the cap was raised in 2022, which shows that the $1,000/MWh price is sufficient to encourage load reduction. Consequential savings in 2022 would have amounted to over $134 million. SCE

[357] *Id.*

[358] SCE-14, at 4:18-5:13.

[359] PG&E-14, at 3-16:6-15.

[360] Cal Advocates Phase II Opening Brief, at 36-37.

notes that it has no data showing that a reduction in incentive levels will materially diminish load reduction during ELRP events.[361] SCE states that the large ELRP incentive payment jump is partially due to the increase in ELRP incentives.

PG&E, OhmConnect, SDG&E, CEDMC, CESA, Tesla/CalSSA, and VGIC all disagree with the proposed reduction. OhmConnect notes that the proposed incentive reduction will cause participants to leave ELRP, possibly for the CEC's Demand Side Grid Support program which offers a $2/kWh incentive rate.[362] PG&E states there is insufficient data to reduce the incentive level at this time,[363] and that incentive levels during a pilot would be inappropriate.[364] SDG&E and VGIC state that Cal Advocates reference to CAISO market bidding is insufficient justification, as ELRP is not in the market and doesn't follow prices but CAISO need.[365] VGIC also proposes to increase the incentive rate for A.5 participants.[366]

At this time, it is not reasonable to reduce the compensation rates for all ELRP sub-groups. The program is still a pilot, and having had only two years of data there is insufficient record to suggest that a reduction is needed for all sub-groups. However, with regards to sub-group A.6, PSR, we are convinced that the cost of this program in 2022 exceeded expectations so much that changes must be made to reduce cost. ELRP as a program takes up approximately 50 percent of PG&E and SCE's total IOU budget requests in this application, with

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361 SCE-14, at 3:11-13.

362 OhmConnect-5, at 3-4.

363 PG&E-8, at 3-11.

364 *Id*. at 3-11:21-23.

365 SDGE-10, at EBM-16:3-EBM-17:9; VGIC-1, at 3-4.

366 VGIC-01, at 23:4-6.

much of this being due to incentives.[367] SCE notes that in 2022 PSR (sub-group A.6) accounted for $110 million in incentive costs, far beyond the incentive cap set in the Phase 2 Reliability Decision.[368] The incentive rate for only sub-group A.6 is therefore reduced to $1/kWh, starting in 2024.

#### 11.1.11. Minimum Performance Thresholds for Compensation

The Joint CCAs ask that the Commission establish a participation floor (expressed as a percentage reduction from baseline) tied to compensation for sub-groups A.1 and A.2 and compensate only those customers whose participation levels surpass that floor.[369] SDG&E states that this will only confuse customers and places arbitrary barriers for customers to participate.[370]

We lack adequate record to determine what, if any, performance thresholds should be set at this time, and decline to adopt this proposal.

#### 11.1.12. Telematics-Based Submetering for A.5

VGIC recommends that telematics, which are measurement devices available within vehicles installed by the manufacturer, be allowed to participate in ELRP on an interim basis until a new Plug-In Electric Vehicle telematics submetering protocol is adopted.[371] VGIC states that the ELRP was designed to aggregate and dispatch EV resources and that extending this to telematics would be a logical next step.[372]

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[367] PG&EE-2, Chapter 10, Attachment A; SCE-02, at 5, Table II-1; SCE-13, at 7, Table 13-2.

[368] SCE-13, at 3:23-4:3.

[369] Joint CCAs Opening Brief, at 16-17.

[370] SDG&E January 27, 2023 Ruling Reply Comments, at 12.

[371] VGIC Phase II Opening Brief, at 8-9.

[372] *Id*. at 9.

Both PG&E and SCE state there is insufficient record in this proceeding and that the issue is already being addressed in R.18-12-006. They also state that ELRP is not the appropriate program to test or advance new approaches to EV participation.[373]

There is insufficient record in this proceeding to determine how telematics would be introduced to ELRP. Additionally, it is not an efficient use of Commission resources to consider the same issue in multiple proceedings. We therefore decline to address this issue here.

#### 11.1.13. Back-up Generator Participation in ELRP

ELRP is the only DR program or pilot with an exception to the Prohibited Resources policy and allows the use of back-up generators (BUGs) to be compensated. However, as noted by SDG&E, the use of BUGs in ELRP is subject to confusing restrictions and qualifications. [374] Therefore, SDG&E proposes that the Commission determine whether BTM resources, including prohibited fossil-fueled resources, can be utilized. SDG&E also asks that the Commission work with other state agencies such as the Air Resources Board and the CEC to implement a set of changes.

At this time, we lack adequate record to proceed with the proposed changes by SDG&E. Additionally, the Commission does not have the ability to make pronouncements on all of the issues related to BUGs, given that regulatory authority may lie with other state agencies. We therefore decline to take any action on BUG participation in ELRP at this time.

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[373] PG&E-8, at 3-25:1-13; SCE-14, at 2-4.

[374] SDG&E Phase II Opening Brief, at 15-16.

### 11.1.14. PG&E ELRP Budget

PG&E requests $425.617 million for ELRP budget for 2024-2027, an average of $106,404,250 over four years. D.21-12-015, OP 21 authorized PG&E $94 million per year for all ELRP compensation. PG&E requests the same in this decision.[375] Cal Advocates notes that ELRP accounts for over half of PG&E's budget in the upcoming cycle.

PG&E's ELRP budget is authorized. With changes to incentive levels in this decision, it can be expected that the actual spent money on ELRP will be reduced in 2024, and it is unlikely that the full amount will be spent each year. Any underspending will be returned to ratepayers. PG&E's 2026 and 2027 budget should also be reduced to account for the sunsetting of sub-group A.6. To account for the reduced incentives in 2026 and 2027, we reduce PG&E's incentives authorization in 2026 and 2027 by a total of $158 million, commensurate with the 85 percent percentage reduction to SCE's proposed ELRP incentive budget after the ending of sub-group A.6. PG&E is authorized to recover a total of $267.62 million for ELRP from 2024-2027.

**Category 5 - 2024-2027 PG&E ELRP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $12.012 | $12.268 | $12.532 | $12.805 | **$49.617** |
| | Incentives | $94 | $94 | $94 | $94 | **$376** |
| Authorized | Administrative | $12.012 | $12.268 | $12.532 | $12.805 | **$49.617** |
| | Incentives | $94 | $94 | $15 | $15 | **$218** |
| | Total | $106.1 | $106.27 | $27.53 | $27.81 | **$267.62** |

375 PG&E-2, at 4-32, Table 4-5.

#### 11.1.15. SCE ELRP Budget

SCE initially requested $194.415 million over four years for the ELRP program.[376] SCE has subsequently increased its request to $418.618 million, mostly due to increases in expected amounts of PSR payouts.[377] No parties provided specific comments on SCE's ELRP budget. We note that SCE's original request did not include funding for PSR in the 2026 and 2027 ELRP years, but did include a normal budgeting amount for PSR incentives. The initially proposed PSR and ELRP budget amount should be sufficient to cover the program going forward, given the reduced PSR incentive levels discussed in this decision. We will also utilize the newly proposed 2026 and 2027 ELRP budget amounts requested by SCE, for automating ELRP processes and expected increases in other ELRP program incentive payouts.

As discussed above, we are sunsetting sub-group A.6 after 2025, making SCE's increased budget request for 2026 and 2027 unnecessary. We are also reducing incentive levels for sub-group A.6 beginning in 2024. SCE has also not presented sufficient evidence to show that an increased incentive balancing account cap above what was authorized in the Summer Reliability decision D.21-12-015 is necessary. We therefore authorize SCE to recover $177.77 million for ELRP costs.

**Category 5 - 2024-2027 SCE ELRP Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $12.584 | $12.809 | $6.823 | $6.952 | **$39.168** |
| | Incentives | $60 | $60 | $9.3 | $9.3 | **$138.60** |
| Authorized | Administrative | $12.584 | $12.809 | $6.823 | $6.952 | **$39.168** |

[376] SCE-03, at 77, Table VII-20.

[377] SCE-13, at 7, Table 13-2.

| | | | | | | |
|---|---|---|---|---|---|---|
| | Incentives | $60 | $60 | $9.3 | $9.3 | **$138.60** |
| | Total | $72.580 | $72.81 | $16.12 | $16.25 | **$177.77** |

SCE also requests authority to eliminate the Emergency Load Reduction Program Balancing Account (ELRPBA), in which the IOUs track ELRP costs, in 2024.[378] Any costs above the cap authorized in D.21-12-015 must be recovered only after Commission reasonableness review in the Energy Resource Recovery Account (ERRA) proceedings. SCE proposes to eliminate the ELRPBA and track ELRP payments in the Demand Response Balancing Accounts, which will allow for less administrative costs.

We decline to authorize this change at this time. Approval would limit Commission oversight of ELRP costs and allow SCE to shift ELRP funds to other DR programs.

#### 11.1.16. SDG&E ELRP Budget

SDG&E requests $140.2 million over four years for the ELRP program.[379] No other party provided significant comment. The ELRP budgets for 2026 and 2027 are reduced to account for the ending of Sub-group A.6 in 2026. We preliminarily remove $3 million[380] worth of administrative costs for each of 2026 and 2027. We also reduce SDG&E's ELRP incentive budget requests for 2026 and 2027 by 85 percent, as done for PG&E and SCE above. SDG&E is authorized to recover $81.64 million for ELRP program costs from 2024-2027.

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[378] SCE-04, at 34:5-35:3.

[379] SDGE-1, at 45-46.

[380] SDG&E notes that it requires $3 million for A-6 admin costs in 2023 and 2024. *See* SDGE-9, at EBM 45, Table EBM-7.

**Category 5 - 2024-2027 SDG&E ELRP Budget (in $ millions)**

| | ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|---|
| Requested | Administrative | $3 | $3 | $4.9 | $4.9 | **$15.8** |
| | Incentives | $31.1 | $31.1 | $31.1 | $31.1 | **$124.4** |
| Authorized | Administrative | $3 | $3 | $1.9 | $1.9 | **$9.8** |
| | Incentives | $31.1 | $31.1 | $4.82 | $4.821 | **$71.84** |
| | Total | $34.1 | $34.1 | $6.72 | $6.72 | **$81.64** |

### 11.2. PG&E Smart Panel Pilot

PG&E proposes to test a Smart Panel pilot to evaluate the potential of residential smart electrical panels, which have the ability to control entire home electric usage.[381] Customers would be allowed to enter an amount they would like to pay over a specific interval through a mobile application. PG&E states that by allowing customers to set their own level of participation in DR programs, it may solve predictability, availability, and firmness issues for customers participating in DR.[382] During or before a CAISO emergency or distribution event call, the Smart Panel program can be used to determine maximum likely uncontrolled peak demand above baseload for customers, pause or time-shift larger electric loads, and reduce demand limit threshold. Participants would be able to opt-out of events, and doing so will reduce incentives. Incentives shall depend on effective participation. The pilot would be available 24 hours a day, every day, with events being triggered by Day-Ahead Market and Real-Time Market price triggers, including CAISO EEA-1 to EEA-3 calls, along with a potential distribution trigger. PG&E proposes that

[381] PG&E-2, at 4-19:4-28.

[382] *Id*. at 4-20:4-26.

potential design elements could include events that last one to eight hours, with up to five events being called per month.

PG&E will market to customers that have plans to install or upgrade their current electrical panel, including those receiving incentives. PG&E plans to recruit up to 500 low income and disadvantaged households to the pilot, and seek feedback from the Commission's Disadvantaged Communities Advisory Group and community-based organizations (CBOs).[383] PG&E requests $11.2 million over four years for the pilot. Of this amount, $8.025 million is dedicated to incentives.

Metrics will include customer satisfaction, achieved bill savings and resiliency, ability to delivery multiple grid services, customer response and performance, and incentive payments. PG&E states that cost-effectiveness should not be the primary concern at this time, but that it will conduct evaluation of the efficiency of demand/amperage limiting, customer satisfaction in achieving their energy goals, and effects on customers' overall energy usage. No other parties substantively commented on the proposal.

PG&E has not provided sufficient information on the likelihood that this program will provide cost-effective ratepayer benefits. For example, many existing technologies are able to shift demand earlier or later, while smart panels are only able to shift demand later by temporarily interrupting power to an end use when dispatched. Many of the functions of this program would be duplicative to another PG&E program, the Automated Response Technology Program (ART), discussed above. PG&E does not provide sufficient detail regarding how the incentive budget will be divided between up-front and

[383] *Id*. at 4-23:6-21.

performance-based incentives. Many incentives already exist to support electrical panel upgrades, including the SGIP Heat Pump Water Heater program.[384] PG&E's request for funding for this Smart Panel program is therefore denied. PG&E should encourage smart panel manufacturers to participate in the ART program and leverage the software platforms being developed by PG&E. PG&E should then be able to collect some data to determine whether Smart Panels may provide an additional beneficial effect for load control on top of technologies already discussed in the ART.

### 11.3. PG&E Agricultural DR Pilot

PG&E proposes to develop a program to increase DR participation and load reduction among agricultural customers.[385] PG&E states that the agricultural sector represents about 1.6 gigawatts of use during the summer peak hours, or 9 percent of net system load on peak days. PG&E states that the objectives of the pilot are to 1) determine if agricultural DR participation and load reduction during peak hours can be achieved; 2) test design parameters to optimize peak load drop and net benefits; 3) determine reliability of load reduction by comparing forecasted versus actual load reduction provided; and 4) assess if the program designs would be cost effective.

Based on surveys, PG&E proposes to offer two options for participation: one performance only design with no penalties, and one with capacity payments and penalties. Payments will be evaluated based on ability to remain at or below a predetermined FSL, with testing over the pilot period to determine the optimal incentive rates and incentive amounts. Events shall be four hours in duration,

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[384] D.22-04-036, at 43.

[385] PG&E-2, at 4-34:6-15.

with Day-Ahead notification. Customers must be on an agricultural TOU rate schedule. Customers shall be eligible for Auto DR incentives.

PG&E estimates potential reduction of 17.5 MW during peak hours.[386] PG&E will contract with third-party vendors to implement the pilot. PG&E requests $4.79 million over four years for the pilot. PG&E plans to evaluate the DR incentive structures, trigger events, forecasting and event measurement tools, and satisfaction of participating customers.

Polaris supports the program, as due to changes to the CBP program most irrigation pumping loads will be unable to participate in the CBP going forward, if the nomination deadline is advanced by 70 days as proposed.[387] However, Polaris proposes changes, including that incentives should be raised to match those of the CBP.

PG&E has not sufficiently justified the potential savings of this program. It is concerning that most potential participants surveyed preferred the penalty free option,[388] bringing into question the efficacy of the program. Additionally, other programs such as the Agricultural Demand Flexibility pilot program[389] are producing significant load shifting already, potentially lessening the need for this program.[390] PG&E is denied funding for this Agricultural DR program at this time.

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386 PG&E-2, at 4-39:5-7.

387 Polaris Phase II Opening Brief, at 3-5.

388 PG&E-02, at 4-35:23-28.

389 D.21-12-015, at 87-88.

390 Polaris-01, at 4:4-12.

### 11.4. SCE Mass Market DR Pilot

SCE proposes a pilot to determine design elements for an SCE mass market DR program (MMDR) to be launched in the next DR cycle. SCE notes planned continued electrification of end uses, which will require new programs to provide new DR solutions.[391] SCE proposes that this pilot review the viability of customer various retail payment and technology rebate schemes, determine the load reduction capabilities of a singular DR program comprised of multiple end use devices, and conduct EM&V. SCE also plans to test vendor and technology capabilities with the goal of designing a technology agnostic DR program under one tariff.[392] SCE will mainly track basic customer performance information and customer feedback. SCE plans to begin the pilot in 2024. SCE proposes a budget of $1.461 million for this pilot.[393]

CEDMC expresses concern that the MMDR program lacks sufficient detail and is redundant with SCE's SEP.[394] CEDMC notes that both programs target mass market customers using a broad array of technologies. CEDMC recommends that SCE test the pilot for two years and perform an assessment following the end of the second year.

CEDMC's argument that the pilot is not well-defined, and possibly duplicative of the SEP, is persuasive. SCE has not provided sufficient detail such that this pilot can be authorized at this time. SCE's proposed MMDR pilot is denied.

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[391] SCE-03, at 79:7-9.

[392] *Id*. at 81:1-4.

[393] *Id*. at 83, Table VII-22.

[394] Council-02, at 29.

### 11.5. SCE Flexible DR Pilot

SCE proposes to conduct a pilot testing the potential for water and wastewater utilities to provide flexible DR through their energy storage capacity during periods of excess renewable energy, and discharging during periods of peak demand.[395] SCE states that its water customers (receiving SCE electric service) can provide price-responsive reliability demand-side resources that both help mitigate renewables curtailment and meet local grid supply needs. Water customers would integrate DR into their long-term capital planning and day to day operations.

SCE states that the pilot will have the following objectives:

- Demonstrate technical viability and economic value of the pilot;
- Determine optimal design of a cost-effective Flexible Demand Response (Flex DR) pilot going forward;
- Gather information about how to optimize distribution planning and capital investment to take advantage of potential water sector DR capabilities; and
- Enable water sector customers to provide demand flexibility of four MW to eight MW of peak load shift.

SCE points out that the Overgeneration Pilot supports the likelihood of success of the Flex DR pilot.[396] SCE also notes that unlocking this potential use of the water system may encourage further water resiliency benefits in California. SCE notes that the water sector could shift loads by up to 1,000 MWh in the summer, and can reduce its contributions to daily peak demand by greater than

[395] SCE-03, at 83:2-94:2.

[396] SCE-03, at 86-88.

300 MW.[397] SCE did not propose standards or metrics to judge the pilot by, nor does it provide any cost-effectiveness metrics. Most measurement and verification will be conducted via participant feedback. SCE proposes *ex post* assessment as well as a process evaluation. SCE seeks $5.86 million over four years for this pilot.

SCE's proposal is novel, with little precedence in DR programming. The research has the potential to provide significant insight into the use of the water sector for load shifting and to solve grid resiliency issues. However, SCE provides little in terms of pilot details – including what load shifting amounts will be required of participations, what incentives will be offered, to whom, and when and how events will be called. SCE has also not provided an EM&V plan. SCE is directed to submit a Tier 2 advice letter no later than March 15, 2024 with the above program specifics, and any others necessary to fully flesh out this pilot. The pilot may begin after the advice letter is made effective. SCE is authorized a budget of $5.856 million for the years 2024-2027. SCE shall also conduct a performance evaluation of the pilot by the end of 2026, to be submitted with its 2028-2032 DR application.

**Category 5 - 2024-2027 SCE Flexible DR Budget (in $ millions)**

| | **($ in millions)** | **2024** | **2025** | **2026** | **2027** | **Total** |
|---|---|---|---|---|---|---|
| Requested | Administrative | $1.139 | $1.393 | $1.478 | $1.046 | **$5.056** |
| | Incentives | $0.125 | $0.250 | $0.250 | $0.175 | **$0.800** |
| Authorized | Administrative | $1.139 | $1.393 | $1.478 | $1.046 | **$5.056** |
| | Incentives | $0.125 | $0.250 | $0.250 | $0.175 | **$0.800** |
| | Total | $1.26 | $1.64 | $1.73 | $1.22 | **$5.86** |

[397] *Id*. at 90:12-17.

### 11.6. SDG&E Electric Vehicle DR Pilot

SDG&E proposes to develop an EV DR pilot that enables SDG&E to manage charging times for EVs that have not signed up for EV TOU rates. Specifically, SDG&E proposes to test the use of direct communication with vehicle computers, to gather information on EV charging, vehicle miles driven, location of charge, speed and timing of charge, and other details. SDG&E will utilize these data to produce EV load profiles and analyze charging patterns with and without load management, in order to design optimization strategies. SDG&E plans to offer customers the option of SDG&E control of their vehicle charging either with the vehicle or the charger. SDG&E plans to issue a Request for Proposal (RFP) for aggregators to handle enrollment, event signaling, and to optimize charging.

Program Events will mainly occur during the Summer DR season, from May 1 to October 31. SDG&E plans to call 30-60 events per season, with events lasting two to three hours during the 4 p.m. to 9 p.m. period.[398] A spring DR season would also be offered. SDG&E plans to offer three incentive options, including monthly and annual incentives either as a bill credit or incentive rebate, with no opt-out penalty other than incentive forfeiture. SDG&E requests $3.333 million for funding for this program from 2024-2026. SDG&E plans to monitor and evaluate customer sign ups, participation, and drop-off rates.

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398 SDGE-1, at EBM-70:18-22.

Other parties generally supported SDG&E's EV DR Program, and recommended expansion of the pilot's duration and budget.[399] Cal Advocates recommended limiting the scope of the pilot.

SDG&E has not adequately explained the need for a pilot on these issues. SCE's Charge Ready DR pilot and other efforts by CCAs have provided ample amounts of similar data, and SDG&E has not sufficiently explained what more should be learned or how its pilot is different. Additionally, given the poor cost-effectiveness of SDG&E's portfolio, it is difficult to justify additional pilots which will produce further cost burdens on SDG&E's ratepayers. SDG&E's request for funding for this pilot is denied.

### 11.7. SDG&E Battery Storage DR Pilot

SDG&E proposes a battery storage DR pilot to determine how residential and small commercial customers use their batteries, and whether they can be successfully dispatched for DR events or to respond to Day-Ahead market prices. It will also test various incentive levels and attempt to determine what settlement baselines should be utilized to capture the value of battery resources. The program will be available to residential and small commercial customers, enabling them to use their existing battery technology to participate in DR events and respond to CAISO Day-Ahead prices. SDG&E hopes to gather data on customer usage patterns, load impacts, and settlement baselines. Eligible customers will already have a battery installed, and will be offered differing incentive structures. Participants' batteries will be discharged during DR events, anywhere from two to six hours in duration, from June to October.

399 EVE-1, at 3-6; WG-01, at 3-6; VGIC-01, at 26-28.

SDG&E will contract with battery and inverter vendors and build out the necessary Information Technology (IT) systems. SDG&E will conduct a load impact analysis at the end of the pilot. SDG&E requests $4,549,826 for the program, from 2024-2026.

We note that substantial experience has already been accumulated with BTM batteries through programs and efforts such as SCE LCR contracts for market-integrated BTM storage VPPs,[400] SCE VPP pilot, ELRP A.4 aggregations, and SGIP program evaluation. In light of this background, SDG&E has not adequately explained the need for the proposed pilot and the data it hopes to gather. Additionally, given the poor cost-effectiveness of SDG&E's portfolio, it is difficult to justify additional pilots which will produce further cost burdens on SDG&E's ratepayers. SDG&E's request for funding for this pilot is denied.

### 11.8. SDG&E Grid Isolation Controls Pilot

SDG&E proposes a Grid Isolation Controls Pilot, whereby a customer's premise is isolated from the grid in response to a public safety power shutoff (PSPS) event, outage, DR event, or other emergency. SDG&E states that the pilot will aid in determining whether new isolation technologies work appropriately and can safely isolate homes or business with solar and/or battery storage or other devices from the grid. SDG&E plans to issue an RFP seeking a third-party implementer to provide and install the approved grid isolation technology. SDG&E will attempt to enroll 50-100 locations for participation, with initial attempts taking place in low-income or disadvantaged communities.

SDG&E seeks authority to submit a Tier 2 advice letter to either 1) update and finalize the pilot after three years or 2) advise of next steps after an

[400] Virtual Power Plants are aggregations of distributed energy resources.

evaluation and measurement period. SDG&E requests a budget of $3.101 million for three years for the pilot.[401]

Cal Advocates notes that the testing of this technology has already been authorized in D.21-01-018, in the microgrids proceeding.[402] Cal Advocates states that $3 million has been allocated towards developing a pilot program that includes the use of integral remote disconnect switches, as well as other approaches to provide disconnection of a premises' entire electrical service. SDG&E states that the pilot would go beyond what has already been authorized, and would include the examination of future DR uses and customer acceptance of the technology, including potential DR load reduction strategies.[403]

SDG&E should await the results of the microgrids proceeding pilot. Further information may be gleaned from that program, after which time SDG&E can determine whether further research is needed. SDG&E's request for funding for this program is denied.

### 11.9. SDG&E Direct Dispatch Pilot

SDG&E proposes a three year Direct Dispatch Pilot (DDP) for commercial and industrial customers that already own qualifying Auto DR enabled equipment (excluding smart thermostats) that have controls and can directly curtail their energy usage when signaled and dispatched directly by the utility for DR events.[404] The pilot would pay participants $1/kilowatt-hour (kWh) for Day-Ahead or Day-Of participation of verified load shed per event, with no penalties for non-performance. SDG&E would determine when to dispatch

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[401] SDGE-1, at EBM-85:18.

[402] Cal Advocates Phase II Opening Brief, at 41.

[403] SDG&E Phase II Reply Brief, at 12-13.

[404] SDGE-1, at EBM-79:5-8.

events, which would take place between 4 p.m. and 9 p.m. Load shed would not be bid into the CAISO market.

SDG&E will contract with a third-party for customer enrollments in the pilot but will be responsible for calling of events and providing customer settlements. SDG&E believes that this pilot will allow it to test whether a pay-for-performance pilot with no penalties utilizing Auto DR systems dispatched by the utility will provide incremental load drop, market strategies, and higher incentive structures.

SDG&E will issue an RFP for customer outreach and recruitment. SDG&E seeks approval to file an advice letter to update and finalize the pilot after three years, or determine whether the program should be continued. SDG&E will conduct a load impact analysis at the end of the pilot. SDG&E seeks $4.797 million over three years for this pilot.[405]

SDG&E has not sufficiently shown that the pilot will provide ratepayer benefits to justify its cost. As noted, the Commission's goal is to have DR resources that may be bid into the CAISO market or that involve aggregators. This program does neither. Lastly, we are again mindful of the poor cost-effectiveness of SDG&E's DR portfolio and expect a high threshold to be met to justify additional pilots which will produce further cost burdens on SDG&E's ratepayers. SDG&E's request is denied.

### 11.10. SDG&E Capacity Bidding Program Residential Pilot

SDG&E launched the CBP Residential Pilot Proposal in the summer of 2022, following approval in D.21-12-015.[406] SDG&E has funding to operate the

[405] *Id*. at EBM-81:15-16.

[406] D.21-12-015, Attachment 2, at 6.

program through 2023. SDG&E in this Application seeks authority to submit a Tier 2 advice letter seeking approval of the CBP Residential Pilot to become a full program if it determines that the program is effective. The program would be added to the Capacity Bidding Program, and would be covered by the currently requested CBP budget. No other parties commented on this proposal. It is reasonable to authorize SDG&E to submit a Tier 2 advice letter to convert the CBP Residential Pilot to a full program and add it to SDG&E's CBP portfolio, if there is evidence that the TRC of the program is at least 1.0. No later than December 31, 2024, SDG&E shall submit a Tier 2 advice letter that 1) shows if the CBP Residential Pilot has a TRC of 1.0 or greater, and 2) if there is a TRC of 1.0 or greater, a request to have the CBP Residential Pilot added to SDG&E's CPB portfolio. For the sake of clarity, no increase to the overall CPB portfolio budget of SDG&E is authorized by this Tier 2 advice letter process. If SDG&E believes that additional authorized funds are required for its CPB portfolio as a result of the addition of the CBP Residential Pilot, then SDG&E must file a Tier 3 advice letter seeking that increase no later than December 31, 2024.

## 12. Evaluation, Measurement, and Validation

Evaluation, measurement, and validation (EM&V) activities assess demand response program attributes, allowing the Commission to evaluate program effectiveness. One major activity under this category is the consideration of Load Impact Protocols.

### 12.1. PG&E Requested Budget

During the 2024-2027 period PG&E proposes to support DR with measurement and evaluation studies in the following areas:[407]

[407] PG&E-2, at 7-1-7-4.

- IOU-administered DR programs – PG&E will continue to conduct impact evaluations of PG&E DR programs (including ART, BIP, CBP, and SmartAC) to determine load reduction capacity, customer acceptance, and DR program attributes, which will provide recommendations for RA, Integrated Resource Planning (IRP), and DR cost-effectiveness analyses.
- Verification of Prohibited Resources Compliance;
- DR Bid Forecasting – PG&E will continue to refine its bid forecasting methodology to accurately bid into the CAISO markets;
- Evolving Grid Needs and Grid-Responsive Loads – PG&E will study the effects of new BTM technologies and their changes on load, and work on refining how to account for their performance;
- Market Potential Study – PG&E will conduct a market potential study to determine how to identify DR capacity potential in areas where distribution and transmission are constrained, to increase DR enrollment;
- Load Impact Analyses - PG&E will also continue to refine and conduct Load Impact analyses, for both Ex Post findings and Ex Ante estimates. PG&E expects additional funding will be needed during this cycle to determine how DR should be evaluated in resource planning, due to changes in the long-term Qualifying Capacity (QC) Methodology at the CEC.

PG&E does not provide significant detail regarding the Market Potential Study. It states that the study would identify capacity potential in transmission and distribution constrained areas, but provides neither deliverables nor a budget. We deny PG&E's request for this study, and since no budget figure is given, direct PG&E to submit a Tier 3 advice letter filing within 60 days of the date of issuance of this decision updating its EM&V budget to reflect the denial of the study.

PG&E requests a total of $9.188 million for its DR Measurement and Evaluation.[408] No other party commented on this request. PG&E was previously authorized to recover $11.777 million for these costs from 2018-2022. We find PG&E's EM&V budget reasonable, and approve a budget figure of $9.188 million.

**Category 7 - 2024-2027 PG&E EM&V Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| PG&E Requested | $2.297 | $2.297 | $2.297 | $2.297 | **$9.188** |
| Authorized | $2.297 | $2.297 | $2.297 | $2.297 | **$9.188** |

### 12.1.1. Other PG&E Requests

PG&E asks that the Commission update the list of dockets in which the Annual Load Impact Reports and the monthly Interruptible Load Program Reports are served. PG&E proposes the following updates:[409]

- The Annual Load Impact Report filings and service will be in the current DR cycle application and the most current RA Dockets, as of the date of filing;
- The draft Annual Load Impact Reports would be served, but not filed, on parties on the service list for the current DR cycle application and the most current RA dockets, as of the date of service;
- The monthly ILP reports would be served, but not filed, on parties on the service list for the current DR cycle application, as of the date of service.

These changes are reasonable and approved.

[408] PG&E-2, at 8-8, Table 8-2

[409] PG&E-3, at 7-14:22-7-15:22.

### 12.2. SDG&E Requested EM&V Budget

SDG&E's requested EM&V budget includes funding for evaluation and measurement of load impact evaluations for DR pilots and customer research. SDG&E's Rule 32 EM&V budget is authorized elsewhere in this decision.

SDG&E was previously authorized to recover $5.795 million for these costs from 2018-2022. No other party provided comments on these costs. As this decision denies all of SDG&E's pilot proposals, we reduce the total by the amounts[410] set aside for EM&V of those pilots. This decision also denies $600,000 in 2024 and 2025 for denied studies. SDG&E is authorized to recover $4.62 million from 2024-2027 for its EM&V budget:

**Category 7 - 2024-2027 SDG&E EM&V Budget (in $ millions)**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SDG&E Requested | $2.137 | $2.349 | $1.961 | $1.804 | **$8.552** |
| Authorized | $1.14 | $1.03 | $1.21 | $1.24 | **$4.62** |

### 12.3. SCE Requested EM&V Budget

SCE's activities in this section are composed of a number of analyses and evaluations. One includes load impact evaluations of its DR programs (BIP, CBP, AP-I, SEP, and SDP), including Ex Post findings and Ex Ante estimations. SCE also plans to conduct process evaluations of its DR programs to document and assess the impacts of program changes. Activities of the EM&V team also support SCE pilots, prohibited resources audits as ordered in D.22-12-004, and the CAISO Market Integration Study. SCE was previously authorized to recover $6.09 million for these costs from 2018-2022. SCE requests $8.624 million for these activities from 2024-2027. No other party questioned these costs. We

[410] SDGE-4, at LGR-14, Table LG-9.

reduce SCE's budget to account for the denial of the Joint IOU studies as well as the denied MMDR Pilot. SCE is authorized to recover a total of $5.817 million.

**Category 7 - 2024-2027 SCE EM&V Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $3.935 | $1.53 | $1.564 | $1.595 | **$8.624** |
| Authorized | $1.435 | $1.429 | $1.462 | $1.491 | **$5.817** |

## 13. Marketing, Education, and Outreach

### 13.1. PG&E Requested ME&O Budget

PG&E proposes to leverage past outreach efforts, customer feedback, and operational experiences to inform ME&O strategies going forward. Specifically, PG&E plans to:

- Develop a framework to inform targeted ME&O efforts based on customer or technology segmentation;
- Coordinate DR outreach with other relevant customer programs and other integrated customer channels, such as through digital newsletters or through programs focused on low-income customers or disadvantaged communities;
- Conduct DR campaigns prior to the summer season, to maximize customer engagement prior to the period of highest need; and
- Further leverage partnerships, such as its customer relationship managers, CBOs, and third-party DRPs.

Of most interest, PG&E plans to develop an online platform for residential customers, by which customers can review all of the available PG&E offerings available to them, including DR programs, after entering some data. This can include ELRP, and the ART Program. PG&E believes the platform will lead to higher adoption rates of automated technologies and enrollment into DR programs. PG&E requests $14.711 million for ME&O activities from 2024-2027.

Of this total, $12.316 million is dedicated to DR Core Marketing & Outreach, $0.348 million is dedicated to SmartAC Market, and $2.047 million is dedicated to education and training.[411] This compares to an authorization of $13.571 million for 2018-2022.

No party opposed this request. Given the growth in programs and need to develop more tailored messaging methods, it is reasonable to increase the ME&O budget. It is also reasonable for PG&E to develop a platform for showing a list of participating aggregator residential programs, which will become of increasing importance as electric vehicles, batteries, and other distributed energy technologies. We also add in here the annual $9.9 million in 2024 and 2025 for the Flex Alert Media Campaign approved in Section 5.6 of this decision. PG&E is authorized to recover $34.51 million from 2024-2027 for DR ME&O activities. However, because PG&E did not provide marketing budgets for each program, PG&E is directed to submit a Tier 3 Advice Letter within 60 days of the date of issuance of this decision, modifying the DR ME&O budget to account for the denied Smart Panel Pilot and Agricultural DR Pilot marketing budgets.

**Category 6 - 2024-2027 PG&E ME&O Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| PG&E Requested | $3.677 | $3.677 | $3.677 | $3.677 | **$14.711** |
| Authorized | **$13.58** | **$13.58** | **$3.677** | **$3.677** | **$34.51** |

### 13.2. SDG&E Requested ME&O Budget

SDG&E seeks a total budget of $5.904 million for ME&O activities from 2024-2027.[412] SDG&E states that this budget is needed to support customer-

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[411] PG&E-2A, at 8-6, Table 8-1.

[412] SDGE-3B, at AB-1:8.

centric DR proposals going forward, which will target the right customers for the right program. This compares to an approved budget of $4.502 million for 2018-2022.

As discussed above, funding has been denied for the Smart Energy Program, EV DR Pilot, Battery Storage Pilot, Grid Isolation Pilot, ELRP sub-group A.6 for 2026 and 2027, and DDP. We therefore reduce SDG&E's request by $1,275,000 to account for denial of ME&O budget for those programs, or $425,000 per year from 2024-2026.[413] We also add in here the $2.2 million for the 2024 and 2025 Flex Alert Media Campaigns approved in Section 5.6 of this decision. SDG&E is authorized to collect $6.46 million for its ME&O budget from 2024-2027.

**Category 6 - 2024-2027 SDG&E ME&O Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SDG&E Requested | $1.715 | $1.608 | $1.508 | $1.073 | $5.904 |
| Authorized | $3 | $2.89 | $0.29 | $0.28 | $6.46 |

### 13.3. SCE Requested ME&O Budget

SCE seeks $17.55 million for 2024-2027 ME&O activities.[414] SCE plans to target customer groups who can most benefit from DR programs, including low-income customers and residents of disadvantaged communities. Specifically, SCE will:

- Implement targeted communications to cross-promote DR programs and incentives, by using customer segmentation and predictive modeling;
- Create customer profiles that allow for matching to other DR programs and encouragement towards joining others;

[413] *Id*. at AB-1-AB-13.

[414] SCE-03, at 100, Table VIII-24.

- Improvement of the SCE digital customer experience online and on the MySCE mobile application; and
- Tactical implementation of ME&O amongst difficult to reach populations, through CBO outreach, direct mail, social media, and personalized communications.

SCE was authorized to recover $14.277 million from 2018-2022 for ME&O activities. As noted above, the budget is reduced by $352,000 due to the denial of the MMDR pilot, as well as by $3.406 million for reduced SEP marketing budget. We also account here for the annual $9.9 million approved in Section 5.6 of this decision for the 2024 and 2025 Flex Alert Media Campaigns. The remaining requested marketing budgets are reasonable and approved, and SCE is authorized to recover $33.59 million for DR ME&O activities from 2024-2027.

**Category 6 - 2024-2027 SCE ME&O Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $3.956 | $4.043 | $4.716 | $4.835 | **$17.55** |
| Authorized | $12.88 | $13.03 | $3.78 | $3.9 | **$33.59** |

### 13.4. OhmConnect Proposal for Marketing SSDR Programs

OhmConnect proposes that the ELRP administrator should be required to utilize existing ME&O funding to provide customers with information about all DR offerings in California annually in the Spring.[415] OhmConnect states that the targeting of PSR customers will lower free-ridership in an attempt to solve ongoing issues resulting from the auto-enrollment of some ELRP sub-group A.6 “residential ELRP” participants. OhmConnect states that this auto-enrolled portion of residential ELRP participants have yielded limited actual impact due

[415] OhmConnect-4, at 7:1-12:15.

to lack of participation. OhmConnect points to SCE data showing that the auto-enrolled residential ELRP subgroups show virtually zero contribution to load reduction, whereas the self-enrolled group was positive and substantial.[416] OhmConnect states that $180 million was spent for minimal gains on residential ELRP, whereas IOU and third-party DRP providers delivered significantly more load reduction and at a more cost-effective price.

OhmConnect therefore proposes that ELRP administrators be required to provide customers with unbiased information regarding the available DR programs administered by all entities, including a description of the DR program, eligibility rules, number of events per year, and a link to enroll. OhmConnect states that current residential ELRP budget could be used, and no additional IT requirements should be necessary as the campaign is purely marketing and education.

Parties generally disapproved of the proposal. Cal Advocates noted that the Commission should not authorize the use of ratepayer funds to subsidize private business interests, and that OhmConnect has not shown that the cost of the plan would be cost-effective.[417] PG&E states that use of ELRP as an "on-ramp" as proposed by OhmConnect would likely lead to customer confusion and runs counter to the purpose of ELRP. Diverting money from ELRP would also reduce self-enrollments and event awareness, further decreasing ELRP's effectiveness.[418] SDG&E notes that ELRP was designed to mitigate emergencies, not funnel customers into other DR programs.[419]

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[416] *Id*. at 9:3-10.

[417] Cal Advocates Phase II Opening Brief, at 25.

[418] PG&E Phase II Opening Brief, at 63.

[419] SDGE-7A, at EBM-5:1-5.

ELRP is designed to be an emergency program when summer reliability issues occur. Its purpose is defeated if the high-performing customers are stripped from the program. Additionally, the budget originally approved for ELRP should be spent on improving program efficacy, rather than promoting potential competitors. We therefore deny OhmConnect's on-ramp proposal.

### 13.5. OhmConnect DR Market Awareness Campaign

OhmConnect states that the IOUs are not adequately highlighting third-party DRP options on their websites. OhmConnect states that PG&E and SCE do not fairly present Third Party DRP programs, oftentimes obscuring them at the bottom of a list, only presenting IOU-contracted programs (like DRAM/CBP), and removing DRPs from the web pages when the DRPs terminate contracts with that IOU (but are still participating in DR in the state).[420] OhmConnect notes that similar efforts have taken place in New York. OhmConnect proposes a DR market awareness campaign[421] that would require the IOUs to:

- Maintain and improve their current IOU DR web pages;
- Direct customers to the main DR web pages at regular intervals via e-mail campaigns; and
- Provide a pathway for customers to express interest in specific DR programs, including e-mail options where customers can opt-in for more information.

CEDMC supports the proposal, stating that it will help solve the free-ridership issue in ELRP A.6 and is a responsible way to capture real demand flexibility with little to no incremental funding required.[422] PG&E, Cal Advocates, and SCE disagree with the proposals. Cal Advocates states that IOU

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[420] OhmConnect-4, at 13:22-14:8.

[421] OhmConnect-4, at 12:16-17:19.

[422] Council-03, at 4:19-5:19.

DR websites should not have to advertise all DRPs in the state, regardless of contract status with the IOU.[423] Cal Advocates also notes that the second mass e-mail proposal would incur costs to ratepayers, and no analysis has been done on the cost-effectiveness of such actions. PG&E and SCE state that they are fully compliant with D.17-12-003 (negating the need for proposal 1), and their process has already previously been approved via the Commission's advice letter process. PG&E and SCE also state that the use of ratepayer funds to encourage marketing and acquisition activities for for-profit entities, which could result in ratepayers receiving e-mails, phone calls, and mailers from multiple providers, should not be approved.[424]

We agree with the position of the IOUs and Cal Advocates. It is not the business of the IOUs or ratepayers to support marketing activities for third-party DRPs. OhmConnect also has not provided any evidence regarding the cost of these activities. OhmConnect's proposal is denied.

## 14. DR System Support and Operations

The IOUs use this category of funding to support improvements in the IT systems, software and infrastructure, and other system maintenance.

### 14.1. PG&E

PG&E includes in this section Portfolio Support activities such as DR Integration Policy and planning, DR Operations, and Load Management Support.[425] This section does not include Rule 24 costs, which have been discussed above. PG&E breaks its DR Operations into activities in support of retail and customer facing activities, such as customer and aggregator

[423] CalAdvocates-02, at 4-4:21-4-5:13.

[424] PG&E-8, at 3-18:21-3-20:23; SCE-14, at 21:4-22:19.

[425] PG&E-2, at 6-2:1-6-3:16.

enrollments, event forecasting and dispatch, and settlement calculations; and activities in support of market activities. These costs include IT system operations, maintenance, enhancements, and service contracts as well as labor. PG&E states that $14.9 million in labor costs is needed to operate its Demand Response Market Integration (DRMI) platform, which allows it to easily integrate customers into the CAISO markets. An additional $8.9 million is also sought to enhance the DRMI system.

PG&E does not see a need to modify its billing systems to implement any DR proposals for this cycle. PG&E also requests authority to submit Tier 3 advice letters to address new system enhancements as needed.[426] PG&E requests a total of $48.716 million for DR Integration and planning, DR Operations, and Load Management Support activities. PG&E was previously authorized to recover $43.838 million for these costs from 2018-2022. No party challenged these costs. PG&E, in supplemental testimony, notes that it now reduces its budget request for this category by $8 million, as it will seek these costs in the Demand Flexibility rulemaking.[427] We find the proposed costs reasonable and approve PG&E to recover its Category 7 costs of $40.716 million, minus the separately discussed EM&V. We do not approve PG&E's request to seek system enhancements via Tier 3 advice letter, given the lack of detail given for what types of enhancements may be sought.

**Category 7 - 2024-2027 PG&E DR Portfolio Support Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| PG&E Requested | $12.179 | $12.179 | $12.179 | $12.179 | **$48.716** |

[426] PG&E-2, at 6-3:17-20.

[427] PG&E-7, 12-16:12-12-17:8.

| | | | | | |
|---|---|---|---|---|---|
| Authorized | $10.179 | $10.179 | $10.179 | $10.179 | **$40.716** |

### 14.2. SCE

SCE states that DR systems and technology support is needed to ensure that its DR systems stay up to date with security standards, ensure smooth customer participation, and are able to display accurate information, and calculate wholesale and retail settlements accurately.[428] Going forward, SCE states that this funding will be used to evaluate and enhance CAISO wholesale market integration efforts, to ensure accurate dispatches and settlements, as well as enabling cost-effectiveness improvements such as dispatch at more granular levels. SCE's DR systems allow for customer enrollment and management, load control and event dispatch, DR bidding, and billing and settlement systems. SCE notes that it partners with many vendors to support its DR portfolio, but continuously analyzes whether services may be combined, enhanced, or eliminated to ensure cost competitiveness.[429]

SCE was previously authorized to recover $31.211 million for these costs from 2018-2022. SCE seeks $43.75 million for these activities in 2024-2027. SCE states that this increase is due to vendor hosting and device fees being moved from the SEP budget to this budget (to reflect their use with multiple programs), transition of CAISO registration, bidding and settlements to a new vendor, increased system vendor fees, and use of more cloud-based solutions.

SCE, in supplemental testimony, requests an additional $2.739 million for improvements to cybersecurity, CAISO Interoperability, and settlement

[428] SCE-03, at 110:2-17.

[429] *Id*. at 113:2-6.

processing.[430] Specifically, SCE asks that for $312,000 for cybersecurity improvements, almost $1 million to perform quality control work for calculations by its third-party vendors, and $1.39 million for other internal resources to improve efficiency, related to CAISO integration, retail meter data flow, DR-billing system enhancements, and DR-vendor contract management. We approve the one-time costs related to cybersecurity improvements and quality control, but SCE has not sufficiently justified the additional labor needs for its other internal resources. We therefore authorize SCE to recover $1.309 million for these costs, or $327,000 per year.

No other parties commented on these costs. SCE has not sufficiently justified the almost $4.7 million (75 percent) increase in average annual cost for DR systems support initially asked for in its application. Although some increase is to be expected, it is not adequately explained by SCE, given that the large increase could not have only come from budget shifting. We therefore reduce SCE's initial recovery in this category by $1 million for each year. However, when accounting for the additional $0.327 million per year requested in supplemental testimony, SCE is authorized to recover a total of $41.06 million.

**Category 7 - 2024-2027 SCE DR Portfolio Support Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SCE Requested | $10.429 | $10.745 | $11.12 | $11.456 | **$43.75** |
| Authorized | $9.756 | $10.072 | $10.447 | $10.783 | **$41.06** |

### 14.3. SDG&E

SDG&E's activities in this category include regulatory policy and program support, IT infrastructure and systems support, and Commission directed

430 SCE-11, at 3-4.

research. Regulatory policy and financial support costs include those related to staff that respond to DR data requests and filings, as well as staff who track DR budgets and expenses.[431] System support and maintenance expenses include those related to supporting SDG&E's DR team and customers. SDG&E's IT costs include work to integrate and maintain the DR programs with other SDG&E and CAISO Applications, conduct quality assurance testing, and process application change requests.[432]

SDG&E was previously authorized to recover $13.042 million for these costs from 2018-2022. No other party disputed these costs. A large number of SDG&E's pilot proposals were denied funding above. We therefore authorize SDG&E's DR Portfolio Support budget at the same annual level as in the previous DR decision. SDG&E is authorized to recover $10.404 million for DR Portfolio Support costs.

**Category 7 - 2024-2027 SDG&E DR Portfolio Support Budget**

| ($ in millions) | 2024 | 2025 | 2026 | 2027 | Total |
|---|---|---|---|---|---|
| SDG&E Requested | $3.710 | $4.180 | $4.164 | $4.444 | $16.497 |
| Authorized | $2.601 | $2.601 | $2.601 | $2.601 | $10.404 |

## 15. Non-IOU Specific Issues

### 15.1. Two-Hour Super Peak DR Pilot

Leap and CEDMC propose in their Phase II Opening Briefs to create a two-hour dispatch product during the 6:00 p.m. to 8:00 p.m. period, the so called "super-peak."[433] They state that certain dispatchable DR technologies, such as

[431] SDGE-1, at EBM-99:8-18

[432] SDGE-2, at EK-1:10-2:20.

[433] CEDMC Phase II Opening Brief, at 12-13; Leap Phase II Opening Brief, at 12-14.

smart HVAC systems, may perform better over a two-hour window when the grid is most stressed, as opposed to over a four-hour window. Leap suggests that they see better performance across two-hour dispatches than four-hour. Both cite to SCE rebuttal testimony pointing out a need for a two-hour dispatch product.[434] Leap also alternatively encourages the Commission to establish a working group to develop a two-hour super peak pilot.

PG&E in its Phase II Reply Brief states that the proposal must be rejected, as it is first being proposed in briefs, and not in testimony, and that it also fails to meet the pilot requirements set out in D.12-05-045.[435]

Leap and CEDMC's proposal for a two-hour super peak DR pilot is not supported in the record at this time. There is insufficient testimony on which to base either the design of such a program or even the need for creation of a working group to consider its design. The proposal is denied.

### 15.2. CCA Proposal to Require Process for Data Sharing

The Joint CCAs propose that the Commission direct the development of a process for the CCAs and PG&E to regularly exchange program participation data for DR programs that are not integrated into the CAISO energy market, so as to mitigate the risk of customers being compensated twice for the same load reduction by participating in both ELRP and a CCA load-modifying DR program.[436] They note that similar programs exist for market-integrated DR programs. This would help prevent double counting of customer load reductions. The Joint CCAs note multiple programs that are similar to one or

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[434] SCE-14, at 19:2-3.

[435] PG&E Phase II Reply Brief, at 18-19.

[436] JCCA-01, at 5-6.

more ELRP sub-groups, which pose a risk for double compensation.[437] The exchange would also allow the Joint CCAs to plan and anticipate load reductions by their customers in response to DR events.

The Joint CCAs ask that that:[438]

- The Commission in this decision direct PG&E and the CCAs to bilaterally exchange monthly or quarterly load-modifying DR program enrollment data, including basic customer information, to facilitate dual participation verifications;
- PG&E be directed to unenroll customers already participating in a CCA load-modifying DR program from the ELRP or other PG&E load-modifying DR program within five days of receiving program participation data from the CCA; and
- Direct the parties to develop a streamlined process through a workshop in which PG&E and the CCAs can develop processes for customer enrollment data sharing for load-modifying Demand Response Resource programs as well as unenrollment processes for customers found to be improperly dual-enrolled.

CEDMC supports the proposal, but suggests more frequent than monthly or quarterly. CEDMC also asks that third-party DRPs be allowed to access any system so they can monitor eligibility of customers seeking enrollment.[439]

PG&E disagrees with the proposal, noting that although the exchange of program participation data may prevent double counting, the proposal does not

[437] *Id*. at Attachment A to Attachment D.

[438] *Id*. at 6-8.

[439] Council-03, at 7:6-22.

address numerous questions related to customer consent and data privacy, competitive neutrality, and program choice.[440] PG&E recommends instead a dual participation workshop to further develop the Joint CCA's proposals.

The Joint CCAs have presented compelling evidence that they face issues with dual enrollment of customers in ELRP and their own load-modifying DR programs, and that such problem should be remedied when compared to existing Commission policy. However we are not convinced that customers should be automatically unenrolled from PG&E programs without proper notice and an appropriate amount of time to consider their options.[441] PG&E is therefore directed to share enrollment information of CCA customers directly enrolled in PG&E's ELRP sub-groups A.1 and A.6 with the CCAs requesting such information for their customers, for the purposes of CCA load forecasting and resolving potential dual enrollment issues between ELRP and programs managed by the CCAs. PG&E shall share with the requesting CCA, at the minimum, on a monthly basis, basic customer information including service agreement identification number, customer name and site address. We decline at this time to instruct a workshop process.

## 16. Authorized Budget and Rate Recovery

### 16.1. PG&E

PG&E requests $799 million for its 2024-2027 DR program budget, inclusive of $8.5 million for its Revenue, Fees, and Uncollectibles.[442] For cost recovery, PG&E proposes to continue using the Annual Electric True-Up (AET) Advice Letter process to recover its costs through distribution rates using the

[440] PG&E-8, at 1-6:19-1-7:27.

[441] PG&E-8, at 1-7:9-14.

[442] PG&E-2, at 10-3, Table 10-1.

Distribution Revenue Adjustment Mechanism.[443] It also asks to continue using the DREBA and its existing subaccounts to track the program expenses and authorized budget. These are the same cost recovery methods as approved in D.17-12-003.[444] PG&E also seeks continued authority to carry over operations funds unused in one year to offset the revenue requirement for subsequent years.[445] Any unspent and uncommitted funds for the 2024-2027 funding cycle will be returned to ratepayers after the funding cycle ends with the AET.[446]

No other party addressed PG&E's cost recovery methods. It is reasonable to allow PG&E and the other Utilities to utilize unspent and uncommitted funds from previous DR program cycles to pay for ongoing 2024-2027 cycle costs. PG&E's cost recovery proposal is approved. We authorize PG&E to submit a Tier 2 advice letter by February 28, 2024, implementing changes to program tariffs and implementation procedures that have been approved in this decision, unless otherwise directed.

As depicted in Attachment 3, after taking into account all budget authorizations and denials in this decision, PG&E is authorized to recover $616.01 million for its 2024-2027 DR program activities.

### 16.2. SCE

SCE's total initial proposed DR budget was $790.648 million.[447] SCE proposed to recover non-ELRP revenue requirements of $596.233 million,[448]

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[443] PG&E-2, at 10-4-10-5.

[444] D.17-12-003, at 138.

[445] PG&E-2, at 8-5:4-5.

[446] *Id*. at 10-7:2-4.

[447] SCE-03, at 5, Table II-1.

[448] SCE-04, at 33.

including Franchise Fee and Uncollectibles (FF&U), for the period from January 1, 2024 to December 31, 2027, utilizing the Demand Response Program Balancing Account (DRPBA), for recovery in distribution rates. No party contested this rate recovery proposal. In D.17-12-003, the Commission authorized SCE to record the difference between DR program annualized funding (tracked in the Base Revenue Requirement Balancing Account, or BRRBA) and incurred DR program expenses in the DRPBA. D.17-12-003 also required SCE to track incentives to the DRPBA, and then record the balances in the BRRBA, because its 2018-2022 DR program budget proposal did not explicitly include customer incentives as budget line items.[449] SCE's proposed 2024-2027 DR budget includes incentives as line items.[450] SCE requests approval to continue this practice.

SCE initially proposed to collect $194.415 million in ELRP costs. All ELRP costs are currently tracked in the ELRPBA. As noted above, we declined SCE's request to eliminate the ELRPBA. SCE shall continue to track administrative costs and incentives related to ELRP to the ELRPBA, for recovery in the BRRBA, with any costs exceeding the adopted cap amounts tracked in the Summer Reliability Demand Response Program Memorandum Account.

Any overcollections remaining the DRPBA at the end of 2027 will be returned to ratepayers at the end of 2027 in the Energy Resource Recovery Account (ERRA) review proceeding.[451]

SCE's proposed cost recovery method is in line with what has been approved in past Commission decisions, is reasonable, and is approved.

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[449] D.17-12-003, at 28.

[450] SCE-04, at 33, Table V-21.

[451] *Id*. at 36:3-7.

As depicted in Attachment 3, after taking into account all budget authorizations and denials in this decision, SCE is authorized to recover $812.02 million for its 2024-2027 DR program activities. We authorize SCE to submit a Tier 2 advice letter by February 28, 2024, implementing changes to program tariffs and implementation procedures that have been approved in this decision, unless otherwise directed.

### 16.3. SDG&E

SDG&E originally requested $156.584 million for its 2024-2027 DR program cycle.[452] SDG&E proposes to recover DR program costs by recording them into the Advanced Metering and Demand Response Memorandum Account (AMDRMA), as was authorized for 2022.[453] Costs are divided into subaccounts based on the type of cost. For example, costs related to support for programs available to all customers are recorded into the Distribution AMDRMA subaccount for recovery in electric distribution rates the following year,[454] whereas costs related to programs available only to electric bundled customers are recorded in the Generation subaccount, for recovery from bundled customers through electric commodity rates or via the Energy Resource Recovery Account.[455]

SDG&E seeks authorization to recover its Electric Rule 32 costs in the Direct Participation Demand Response Memorandum Account, for recovery through distribution rates after transfer to the Rewards and Penalties Balancing

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[452] SDGE-6, at KCP-2, Table A-1.

[453] SDGE-6A, at 3:2-9, D.17-12-003, at 140.

[454] SDGE-6A, at 3:16-20.

[455] SDGE-6, at KCP-4:2-10.

Account.[456] SDG&E also seeks to recover its electric revenues and incremental costs, up to SDG&E's annual administration cap authorized to be incurred in D.21-03-056 and D.21-12-015, in the Emergency Load Reduction Balancing Account, for recovery through distribution rates after transfer to the Rewards and Penalties Balancing Account.

SDG&E currently recovers ELRP costs up to the administration and incentive caps authorized in D.21-12-015 and D.21-03-056 into the Emergency Load Reduction Balancing Account (ELRBA).

No other party addressed SDG&E's cost recovery proposal. It is reasonable for SDG&E to continue the current cost recovery method for DR programs and activities. As depicted in Attachment 3, after taking into account all budget authorizations and denials in this decision, SDG&E is authorized to recover $120.35 million for its 2024-2027 DR program activities. SDG&E is authorized to submit a Tier 2 advice letter by February 28, 2024, implementing changes to program tariffs and implementation procedures that have been approved in this decision, unless otherwise directed.

SDG&E also requests permanent authorization to fund-shift between DR program budget categories by filing a Tier 3 advice letter as approved in D.20-05-009.[457] SDG&E states that fund-shifting allows flexibility to meet needs going forward. A Tier 3 advice letter process ensures sufficient Commission oversight for fund-shifting requests, to verify that the requested flexibility is justified. This request is reasonable and approved.

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[456] Approved via D.15-03-042, at 67-78, Ordering Paragraph 14; SDGE-6 at KCp-6:9-12.

[457] SDGE-6A, at 7:2-1

## 17. Filing Date of Next Demand Response Applications

The previous DR decision approving a full cycle of programs set a date of November 1, 2021 for the submittal of applications for this cycle. We adopt the same deadline for the next DR application cycle. PG&E, SDG&E, and SCE shall file by November 1, 2026 their DR portfolio applications for 2028-2032.

## 18. Comments on Proposed Decision

The proposed decision of ALJs Jason Jungreis and Garrett Toy in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, 2023 and reply comments were filed on ___________, 2023.

## 19. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Jason Jungreis and Garrett Toy are the assigned ALJs.

## Findings of Fact

1. Utilizing the 2021 ACC to calculate the TRC shows that most IOU DR programs are not cost-effective.
2. Most IOU DR programs' TRCs improve when utilizing the 2022 ACC.
3. Cost-effectiveness can be improved with modifications to programs and alterations in what inputs and assumptions are used to calculate it.
4. PG&E's and SCE's DR Portfolios and programs are generally cost-effective when calculated using the 2022 ACC.
5. PG&E's DR Portfolio's TRC ratio is 2.54 when calculated utilizing the 2022 ACC.
6. SCE's DR Portfolio's TRC ratio is 2.76 when calculated utilizing the 2022 ACC.

7. SDG&E's DR Portfolio's TRC ratio is 0.2 when calculated utilizing the 2021 ACC.

8. SDG&E's DR Portfolio's TRC ratio is 0.7 when calculated utilizing the 2022 ACC.

9. SDG&E's DR Portfolio is not cost-effective.

10. The IOUs are currently authorized to recover funding for 60 loggers to complete the PR Verification Plan.

11. The IOUs may require up to 90 loggers to complete the PR Verification Plan.

12. The number of loggers authorized for PR Verification in D.22-12-004 may be insufficient.

13. The DR Prohibited Resources Policy exempts energy storage resources not coupled with fossil-fuel generation.

14. D.22-04-036 requires customers that receive a HPWH rebate to enroll in a qualified DR program.

15. D.22-04-036 does not define what a qualified DR program is.

16. In order to allow customers to receive SGIP rebates, it must be determined what DR programs are qualified DR programs.

17. The HPWH incentive will lead to increased growth in SDG&E's supply-side DR programs.

18. SDG&E will incur administrative and technical costs in order to accommodate HPWH into its supply-side DR programs.

19. Current fund shifting rules allow IOUs to shift up to 50 percent of a program's budget category to a program in the same budget category.

20. Allowing fund shifting of 75 percent of program budget with no Commission oversight does not provide sufficient guarding of ratepayer money.

21. Flex Alert awareness has increased by 50 percent from June 2021 to October 2022, and the Power Saver Rewards program showed significant gains in awareness.

22. The Flex Alert paid media campaign is the key means of noticing enrolled customers that a Power Saver Rewards event has been called and is therefore integral to the design of that program.

23. Mid-cycle reviews allow the IOU and Commission to consider potential changes or terminations to programs.

24. Without an MCR, DR programs may run inefficiently for years given the four or five year timeframe.

25. Status updates on authorized pilots will help ensure Commission oversight of pilot performance.

26. Allowing for MCR on November 1, 2025 for most programs and January 15, 2026 for ELRP provides time to consider program performance while also leaving sufficient time to implement changes.

27. The Energy Division's contracted DR research has led to the production of numerous DR potential studies, leading to the development of a supply curve modeling framework which is used by various California agencies.

28. Further Energy Division-overseen DR research will provide benefits to ratepayers.

29. The Commission does not have a stated goal of supporting third party emergency DR programs.

30. Other programs exist for third-party DRPs to participate in DR besides emergency DR programs.

31. The use of DR resources to meet RA requirements cap is currently set at three percent of peak load.

32. A three percent cap through 2025 will allow for continued growth in emergency DR resources, should it be needed.

33. The current dates set for the filing of DR Provider and IL program reports cause scheduling issues.

34. Moving the filing dates of the DR and IL program reports to the first business day of the second month after the reporting month will resolve scheduling issues.

35. The Joint IOU Status Report required by D.14-12-024 requires the IOUs to report progress towards a goal of DR comprising five percent of the sum of peak demand.

36. SDG&E's BIP has no customers and low cost-effectiveness.

37. Allowing year-round BIP enrollment increases participation.

38. PG&E's proposed BIP enrollment duration changes will make enrollment easier and less restrictive.

39. The BIP lottery is not needed while the reliability cap is temporarily increased to three percent.

40. SCE currently offers a 15-minute BIP dispatch option.

41. PG&E's proposed 15-minute BIP dispatch option will allow greater flexibility and responsiveness to grid needs.

42. PG&E's proposed incentive increase for its BIP 30-minute notification option will increase program attractiveness.

43. An iterative approach to increase in incentives for PG&E's BIP 30-minute notification option will help determine what incentive level is optimal.

44. PG&E proposes to exempt BIP from the PR policy through 2027.

45. D.23-06-029 requires that RA-qualifying DR resources (such as BIP) must be clean, regardless of whether such resources are procured by IOUs or non-IOU LSEs.

46. PG&E's BIP has a TRC of 2.69 using 2022 ACC calculations.

47. SCE's Critical Peak Pricing incentives exclude event days from those calculations.

48. SCE's proposed change to exclude event days from BIP and AP-I incentive calculations would increase program attractiveness.

49. SCE's BIP has seen program attrition in recent years.

50. Increased incentives will increase the attractiveness of SCE's BIP.

51. SCE's BIP show a TRC of 0.88 (BIP 15-Minute) and 1.04 (BIP 30-Minute) when utilizing the 2021 ACC, and 2.76 and 3.32 utilizing the 2022 ACC.

52. SCE's BIP is cost-effective.

53. Changes made to BIP in this decision may alter participants' decisions with regards to FSL or program participation.

54. SCE's proposed increased AP-I incentive rates are based on standard inputs.

55. SCE's AP-I program has a TRC of 1.76 utilizing the 2021 ACC, and 1.62 utilizing the 2022 ACC.

56. SCE's AP-I program is cost-effective.

57. PG&E's SmartAC program has a 2021 ACC TRC of 0.89, and a 2022 ACC TRC of 2.62.

58. PG&E proposes to replace the SmartAC program with the ART program.

59. There are no customers enrolled in PG&E's Commercial SmartAC program.

60. PG&E's ART program allows PG&E to leverage existing technology program incentives with DR capabilities.

61. PG&E's ART program will increase DR participation.

62. PG&E projects a TRC of 1.57 for the ART program with AutoDR incentives.

63. PG&E's ART proposal lacks specifics.

64. Dispatching the SEP at levels below Sub-LAP allows SCE to better target events.

65. Expanding the SEP to non-residential customers with less than 200kW load will allow SCE to reach new customers.

66. SCE's SEP program is cost-effective.

67. SDP commercial incentives will decrease by up to 63 percent if not increased, due to changes in the RA window and load pattern changes.

68. Large decreases in SDP incentives could cause program attrition.

69. SCE requests $145.39 million for SDP budget, less marketing and EM&V costs.

70. SCE's SDP program is cost-effective.

71. SDG&E calculated a 2021 ACC TRC of 0.3 and 2022 ACC TRC of 0.7 for its Smart Energy Program.

72. SDG&E has not disclosed how its proposed changes to its SEP will improve cost-effectiveness.

73. SDG&E's SEP is not cost-effective.

74. The CBP requires significant data exchange between the IOUs and program participants.

75. When utilizing the 2022 ACC, the TRC of PG&E's CBP and SCE's CBP are above 1.0.

76. The CBP Prescribed product comprises a *de minimis* portion of the IOUs' CBP portfolio.

77. PG&E's CBP Elect+ product has never been selected.

78. Standardizing CBP capacity payment schedules between SCE and SDG&E would reduce confusion and could lead to increases in program participation.

79. PG&E's current CBP capacity payment schedule provides the most flexibility between the IOUs and increases payment and penalty granularity.

80. Standardizing CBP bidding across all three IOUs would reduce confusion and could lead to increases in program participation.

81. SDG&E's current CBP bidding method provides increased flexibility and clarity versus that of SCE.

82. PG&E's proposed increases to capacity payment incentives are likely to improve CBP participation.

83. PG&E's proposed changes to the CBP energy payment methods will increase administrative efficiency and customer experience.

84. PG&E's Electronic Enrollment Pilot improves CBP customer experience.

85. Increasing the CBP capacity nomination window from T-15 to T-70 days will reduce participant flexibility.

86. Decreased CBP participant flexibility will lead to decreased CBP participation.

87. Changing SCE's CBP nomination window to T-15 would increase CBP cohesion between the IOUs, reducing confusion.

88. A CBP bid cap of $650 per MWh helps ensure that bids are likely to lead to dispatch during emergency events.

89. PG&E's proposal to require CBP weekend option participants to require Saturday participation is in compliance with RA requirements described in D.21-06-029.

90. PG&E's proposed CBP testing process will better define when CBP testing occurs.

91. PG&E's proposal to change the CBP testing process, as amended, will decrease burdens on customer CBP participation.

92. PG&E's CBP offering is cost-effective.

93. SCE's proposal to change the maximum number of CBP events per month will match PG&E's current CBP Elect offering and will align its program with RA requirements.

94. SCE's November to April CBP program offerings are rarely utilized and do not provide significant benefits to ratepayers.

95. Utilization of SCE's November to April CBP program budget from May to October will increase incentives to participate in the more important summer months.

96. Alignment between energy payments from SCE to aggregators and CAISO to SCE will allow for participation in CAISO markets.

97. CBP participation in the CAISO improves program effectiveness.

98. Both PG&E and SDG&E's CBP offerings are supply-side DR resources.

99. SCE's current CBP offerings are poorly utilized.

100. SCE's proposed CBP Elect and Elect+ program options are similar to the CBP offerings of PG&E and SDG&E.

101. SCE's CBP Elect proposal is likely to provide more cost-effective benefits than SCE's current CBP offerings.

102. SCE's CBP Elect+ option is unable to be offered as a supply-side DR resource.

103. SCE's CBP Day-Of option only earns RA credit and not local or flexible RA credit.

104. SCE's proposal to begin a CBP Elect option eliminates the need for the CBP Day-Of option.

105. SCE's CBP Elect option was not approved, and its budget should be removed from SCE's CBP budget.

106. SCE's CBP proposal is cost-effective.

107. SDG&E's CBP proposal provides SDG&E with operational flexibility.

108. SDG&E's CBP proposal continues most program parameters.

109. PG&E proposes no changes to its PLS-Thermal Energy Storage, OBMC, and SLRP programs.

110. PG&E's load-modifying DR programs provide options for PG&E to modify capacity.

111. SCE's load-modifying DR programs provide SCE with options to modify capacity.

112. PG&E's Rule 24 budget includes increases in the number of employees for projected increases in data sharing authorizations.

113. SCE expects growth of more than 100 percent in CAISO registrations, to meet consistent demand increases.

114. SCE's Rule 24 budget includes funding for continued growth in CAISO registrations.

115. SDG&E projects growth of almost 500 percent in CAISO registrations from 2024-2027.

116. SDG&E should be required to submit an advice letter updating the Commission on CAISO registrations in 2025.

117. PG&E currently offers a $50 residential connected thermostat Deemed Incentive.

118. PG&E offers thermostat incentives through a number of other methods.

119. The statewide EE thermostat incentive budget is presently only funded through 2024.

120. There is risk of no smart thermostat incentives existing starting in 2024.

121. Smart thermostat incentives drive customer technology purchases that lead to increased SEP enrollment.

122. SDG&E's Technology Deployment Program faces issues with offering smart thermostat incentives to participants of multiple programs.

123. PG&E's Custom Incentive Program reduces the risk of customer attrition in DR programs.

124. Additional study of FastTrack Auto DR incentives can provide insight into untapped commercial and industrial customer markets, improving overall Auto DR cost-effectiveness.

125. Previous Commission decisions have made RDRR programs ineligible for Auto DR incentives.

126. PG&E and SCE have not sufficiently shown evidence that RDRR resources should be eligible for Auto DR incentives.

127. SDG&E's Technology Incentive Program lacks customers and has shown poor performance.

128. SDG&E's only two Auto DR programs are the Technology Deployment and Technology Incentive Programs.

129. PG&E DRET activities provide research to help integrate future technologies into DR.

130. SCE EMT activities research smart-enabling price response applications for end users.

131. SDG&E ET-DR activities will focus on distributed energy resources, microgrids, and virtual power plants.

132. SDG&E's proposed pilots in this application have all been denied, reducing the need for research.

133. ELRP provides important grid reliability support.

134. ELRP provides unique capacity supported by BTM generation and storage devices.

135. Mid-term grid reliability remains in question.

136. An extension of ELRP to 2027 would aid grid reliability.

137. ELRP incentive costs have thus far exceeded the projected incentive costs.

138. It is not clear that ELRP sub-group A.6 provides benefits above those that would occur naturally during a Flex Alert.

139. Changes to the ELRP sub-group A.6 dispatch window may cause significant confusion across participants.

140. The dispatch trigger for ELRP is currently a CAISO Flex Alert.

141. The Commission staff proposal to alter the "ELRP Settlement for Group B" guidelines will remedy erroneous phrases and incomplete instructions.

142. Long minimum dispatch hour periods can depress ELRP program participation by causing hardships for participants.

143. Adopting a more targeted dispatch window will incentivize more participation in ELRP sub-groups A.4 and A.5.

144. ELRP is still a pilot program.

145. Reducing the ELRP Sub-group A.6 incentive rate will reduce the cost to ratepayers of ELRP.

146. SCE's PSR incentives will be decreased for 2024 and 2025.

147. SDG&E's ELRP budget request should be reduced.

148. SCE's proposed Flex DR Pilot is based on SCE experiences with the Overgeneration Pilot.

149. SCE's proposed Flex DR Pilot tests a new group of customers that can provide load reduction and capacity that has not been studied.

150. The Flex DR Pilot could provide insights into a program that could provide grid resiliency.

151. The Flex DR Pilot is not yet fully developed.

152. SDG&E requests that the CBP Residential Pilot proposal be added to its portfolio permanently.

153. PG&E's Market Potential Study lacks sufficient detail and does not adequately discuss deliverables or a budget.

154. PG&E's EM&V budget should be reduced due to denial of the Market Potential Study.

155. Updating the dockets in which the Annual Load Impact Reports and monthly Interruptible Load Program Reports are submitted will ensure that updates are received by active energy participants at the Commission.

156. The DR Interim Goal report does not provide significant research.

157. SCE EM&V activities will provide significant DR program research.

158. PG&E's, SCE's, and SDG&E's ME&O activities increase participation in DR programs.

159. SDG&E's ME&O budget request includes funding for pilot programs not approved in this decision.

160. SCE's ME&O budget includes costs related to SEP marketing and the MMDR pilot, denied elsewhere in this decision.

161. PG&E's, SCE's, and SDG&E's DR planning and operations activities help ensure that its DR programs operate smoothly.

162. Allowing the IOUs to submit a Tier 3 advice letter to implement DR operations systems enhancements allows for improved IT flexibility.

163. Improved IT flexibility increases DR program participant service and interactions.

164. SCE has not justified the increase in costs for DR systems support.

## Conclusions of Law

1. Cost-effectiveness should not be the only consideration when determining whether a DR program should be approved.

2. DR Programs and Portfolios can be approved without a TRC of 1.0 or higher, but should be scrutinized for potential improvements.

3. It is reasonable to allow the IOUs to purchase additional loggers, up to 90 total, in order to complete the DR Prohibited Resources Verification Plan.

4. The exemption in the DR Prohibited Resources Policy for "energy storage resources not coupled with fossil-fueled generation" should be retained.

5. The definition of a qualified DR program in Attachment 1 is reasonable.

6. It is reasonable to adopt the definition of "qualified" DR programs in Attachment 1.

7. SDG&E should be authorized to submit a Tier 2 advice letter to incorporate HPWH technology into its supply-side DR programs.

8. The IOUs should continue to utilize the fund shifting rules authorized in D.22-12-009.

9. It is reasonable to utilize the current fund shifting rules going forward.

10. Given the need to ensure grid reliability and the role played by Flex Alert paid media advertising in notifying customers when the Power Saver Rewards program has been called, it is reasonable to continue Flex Alert funding for two years through 2025, to match the current end date of Power Saver Rewards as authorized in this decision.

11. As Power Saver Rewards is a ratepayer-funded program open only to customers of the IOUs, it is appropriate for ratepayers to also fund the mechanism, Flex Alert paid media advertising, that triggers and gives notice of a Power Saver Rewards event.

12. IOUs should be allowed to propose mid-cycle changes to their DR programs.

13. It is reasonable to limit the scope of the MCR.

14. It is reasonable to require that the IOUs submit status updates on authorized pilots on an IOU specific basis via Tier 2 advice letter by November 1, 2025.

15. The MCR, as adopted, is reasonable.

16. It is reasonable for the IOUs to continue to fund DR research overseen by the Commission's Energy Division, in the amount of $1 million per year.

17. It is reasonable to maintain a three percent ELRP reliability cap through 2025.

18. It is reasonable for the IOUs to move their DR Provider and IL Program reporting date to the first business day of the second month after the reporting month.

19. The Joint Motion for Admission of Evidence Regarding Phase II Demand Response Issues should be granted.

20. It is no longer necessary to have the IOUs submit the Status Report on their progress toward a statewide DR goal of five percent.

21. It is reasonable to end SDG&E's BIP due to poor participation and low cost-effectiveness.

22. PG&E and SCE should adopt a BIP minimum enrollment period requirement of six months, with unenrollment and increases in FSL only allowed during the November unenrollment window.

23. It is reasonable to suspend the BIP lottery through the end of 2025 while thee reliability cap remains temporarily raised to three percent.

24. PG&E should be authorized to offer a 15-minute BIP notification option.

25. PG&E's proposed changes to incentive levels for its BIP 30-minute notification option are reasonable.

26. PG&E's proposed BIP PR policy exemption is against Commission directive, and should be denied.

27. Enchanted Rock's proposed change to the PR policy is out of scope.

28. The changes adopted by this decision to PG&E's BIP are reasonable.

29. PG&E's BIP should be continued.

30. PG&E's BIP should be approved, as amended, and PG&E should be authorized to recover $175.359 million for BIP from 2024-2027.

31. SCE's proposed budget of $1.5 million to remove event days from calculations is not sufficiently justified.

32. SCE should be authorized to recover $500,000 each in its BIP and AP-I budgets, or a total of $1 million, to remove Event Days from BIP and AP-I incentive calculations. SCE should be authorized to submit a Tier 2 advice letter seeking fund-shifting of an additional $500,000 total to implement this change.

33. SCE's proposed incentive increases are a reasonable balance as compared to higher incentive levels proposed by intervenors.

34. SCE's proposed BIP incentive level increases are reasonable and should be approved.

35. SCE's BIP should be approved, as amended, and SCE should be authorized to recover $276.97 million for BIP Category 1 costs.

36. BIP participants should be allowed to re-consider their BIP FSL or participation following approval of this decision.

37. SCE's proposed AP-I incentive rates are reasonable.

38. SCE should be authorized to recover $21.25 million for AP-I program Category 1 costs for 2024-2027.

39. It is reasonable for PG&E to sunset the SmartAC program, given the start of the ART program.

40. It is reasonable to end PG&E's Commercial SmartAC program, given the lack of customers.

41. PG&E's proposed SmartAC program changes are reasonable.

42. PG&E's SmartAC program should be approved, as amended, and PG&E should be authorized to recover $5.697 million for its SmartAC program from 2024-2027.

43. PG&E 's ART program is reasonable, as amended, and PG&E should be authorized to recover $23.8 million for the ART program.

44. SCE should be allowed to dispatch the SEP at levels below Sub-LAP.

45. SCE should be allowed to expand the SEP to non-residential customers with less than 200 kW load.

46. SCE has not sufficiently justified an increase to the SEP marketing budget.

47. SCE's SEP is reasonable, as amended, and should be authorized to recover $23.28 million for its SEP Category 1 costs from 2024-2027.

48. It is reasonable to increase SDP commercial incentives to match the reduction to SDP residential incentives, in order to reduce program attrition.

49. SCE's SDP is reasonable, as amended, and SCE is authorized to recover $145.39 million for its SDP Category 1 costs.

50. It is reasonable to end SDG&E's SEP, due to cost-effectiveness concerns.

51. It is not reasonable to require statewide administration of the CBP.

52. It is reasonable for the IOUs to retire underused CBP product options.

53. PG&E should be authorized to end its CBP Elect+ option.

54. It is reasonable to standardize CBP bidding processes across all IOUs.

55. SCE and SDG&E should adopt CBP capacity payment schedules (i.e., adjusted hourly capacity ratios and adjusted hourly capacity payment multipliers) that are structurally similar to those of PG&E.

56. PG&E's increased CBP capacity payments incentives are reasonable.

57. It is reasonable for the IOUs to align their CBP energy payment frameworks to match each other.

58. PG&E's proposal to accelerate CBP energy payments is reasonable.

59. PG&E's CBP Electronic Enrollment Pilot should be changed to a permanent program.

60. It is not reasonable to extend the CBP capacity nomination window to T-70 days, due to the likely reduced participant participation in CBP.

61. It is reasonable for all IOUs to utilize a T-15 days nomination window for their CBP offerings.

62. It is reasonable for PG&E to continue to utilize a $650 per MWh bid cap for CBP Elect and Elect+.

63. It is reasonable to require participants in CBP weekend option offerings to participate on Saturdays.

64. It is reasonable to adopt similar CBP testing requirements across all IOUs to improve consistency and simplify CBP participation.

65. PG&E's CBP program should be approved, as amended, and PG&E should be authorized to recover $28.475 million.

66. It is reasonable for SCE to offer its CBP (Prescribed) from May through October.

67. SCE's proposed incentive increases to its CBP (Prescribed) are reasonable.

68. It is reasonable to alter SCE's current CBP offerings to match CAISO requirements.

69. SCE's CBP options should be offered as supply-side DR resources.

70. SCE's CBP Elect proposal is reasonable and should be approved, as amended.

71. SCE's CBP Elect+ proposal should be denied.

72. SCE should be authorized to end its CBP Day-Ahead (after 2024) and CBP Day-Of (after 2023) product options.

73. SCE's CBP program should be approved, as amended.

74. SCE's CBP budget proposal should be reduced, as the CBP Elect+ option was not approved.

75. SCE should be authorized to recover $42.36 million for its 2024-2027 CBP activities.

76. SDG&E's CBP program, as amended, is approved.

77. SDG&E should be authorized to recover $6.929 million for its CBP activities from 2024-2027.

78. PG&E's OBMC and SLRP programs should be approved.

79. PG&E should be authorized to recover $34,902 for its load-modifying DR programs.

80. SCE's OMBC and SLRP programs should be approved.

81. SCE should be authorized to recover $23,000 for its load-modifying DR programs.

82. PG&E's requested Rule 24 budget should be reduced by $210,000 for unneeded IT fees.

83. PG&E's Rule 24 budget is reasonable and should be approved.

84. SCE's Rule 24 budget is reasonable and should be approved.

85. SDG&E's Rule 32 budget is reasonable and should be approved.

86. SDG&E should be required to submit a Tier 2 advice letter to the Commission in 2025, updating the actual number of CAISO DRRS registrations and data-sharing authorizations through the end of 2024.

87. It is reasonable to end PG&E's connected thermostat Deemed Incentive, due to the existence of other smart thermostat incentives.

88. It is reasonable to continue SCE's $75 connected thermostat incentive, to ensure customers continue to enroll in SCE DR programs like SEP.

89. It is reasonable to end SDG&E's Technology Deployment Program.

90. PG&E's Custom Incentive Program is reasonable and should be approved.

91. The PG&E and SCE Joint FastTrack Auto DR Incentive Program Study is reasonable.

92. PG&E and SCE should be authorized to recover $250,000 each for the Joint FastTrack Auto DR Incentive Program Study.

93. PG&E should be authorized to recover $9.523 million for Auto DR activities.

94. PG&E should update its Auto DR budget to account for denial of RDRR incentives.

95. SCE's request for $625,000 to provide Auto DR incentives to BIP-15 customers is denied.

96. SCE should be authorized to recover $21.517 million for its Auto DR budget from 2024-2027.

97. SDG&E's Technology Incentive Program should be eliminated.

98. The Joint IOU Market Integration Efficacy Study should be denied.

99. PG&E and SCE shall each have their budgets reduced by $1.2 million for denial of the Joint IOU Market Integration Efficacy Study.

100. The Joint IOU Bottom-Up Potential Study should be denied.

101. PG&E and SCE shall each have their budgets reduced by $1.2 million, and SDG&E $600,000, for denial of the Joint IOU Bottom-Up Potential Study.

102. Given the denial of the Joint IOU bottom-up potential studies, PG&E's proposed DRET budget increase is unreasonable.

103. PG&E should be authorized to recover $5.784 million for 2024-2027 DRET activities.

104. SCE's EMT activities are reasonable.

105. SCE should be authorized to recover $11.69 million for EMT activities from 2024-2027.

106. SDG&E's proposed increase to its ET-DR budget is unreasonable.

107. SDG&E should be authorized to recover $3.096 million for its 2024-2027 ET-DR budget.

108. ELRP should be extended in some form through 2027.

109. Disenrollment of customers in ELRP sub-group A.6 with only two years left of program operation is not reasonable.

110. It is reasonable to end sub-group A.6 auto-enrollment procedures.

111. It is not reasonable to continue ELRP sub-group A.6, given the significant incentive increases above what was expected in D.21-06-015.

112. ELRP sub-group A.6 should be allowed to sunset in 2025.

113. It would be unreasonable to change the sub-group A.6 dispatch trigger, given the low number of years remaining.

114. The proposed changes by Commission staff to the "ELRP Settlement for Group B" guidelines should be approved.

115. The minimum dispatch hours for ELRP sub-groups A.4 and A5 should be reduced to 15 and 20 hours, respectively.

116. The dispatch window for ELRP sub-groups A.4 and A.5 should be three hours, through 2027.

117. It is unreasonable to reduce a pilot program's subsidy amount during the pilot phase, absent a compelling reason.

118. It is reasonable to reduce PG&E's requested ELRP budget to account for the sunsetting of Sub-group A.6 in 2025.

119. It is reasonable to reduce SCE's requested ELRP budget to account for the reduction in PSR incentives

120. PG&E should be authorized to recover $267.62 million for ELRP activities from 2024-2027.

121. SCE should be authorized to recover $177.77 million for Category 1 ELRP costs.

122. It is reasonable to reduce SDG&E's ELRP budget request for 2024-2027 to account for the sunsetting of Sub-group A.6 in 2025.

123. SDG&E should be authorized to recover $81.64 million for ELRP costs from 2024-2027.

124. SCE's Flex DR Pilot is reasonable and has the potential to provide information regarding untapped capacity.

125. SCE should be authorized to recover $5.86 million for its Flex DR Pilot.

126. SDG&E should provide evidence that the CBP Residential pilot is cost-effective before the program is converted to permanent.

127. SDG&E's request that the CBP Residential Pilot be approved permanently should be granted, if SDG&E can show that the program is cost-effective.

128. SDG&E should submit a Tier 2 advice letter showing that the CBP Residential Pilot is cost-effective before converting the program to a permanent program.

129. SDG&E should be authorized to submit a Tier 3 advice letter if additional funding is necessary for its CBP Residential Pilot.

130. PG&E's EM&V activities are reasonable.

131. PG&E is authorized to recover $9.188 million for EM&V costs from 2024-2027.

132. PG&E's proposed updates to the list of dockets in which the Annual Load Impact Reports and monthly Interruptible Load Program reports are filed are reasonable.

133. The Commission's Energy Division should update the list of dockets in which the Annual Load Impact Reports and the monthly Interruptible Load Program Reports are served.

134. SDG&E's EM&V activities are reasonable.

135. SDG&E's EM&V budget should be reduced to account for denied proposed studies.

136. SDG&E's EM&V request should be reduced, due to denial of SDG&E's pilot proposals.

137. SDG&E should be authorized to recover $4.62 million for DR EM&V activities from 2024-2027.

138. SCE's EM&V budget should be reduced to account for denied proposed studies.

139. SCE's EM&V budget should be reduced to account for denied studies.

140. SCE's proposed EM&V activities are reasonable and approved.

141. SCE requests $8.624 million for EM&V costs from 2024-2027.

142. SCE should be authorized to recover $5.82 million for DR EM&V costs from 2024-2027.

143. SDG&E's proposed DR ME&O costs should be reduced to account for costs related to denied pilots programs.

144. SDG&E 's proposed DR ME&O activities are reasonable, and SDG&E should be authorized to recover $6.46 million for ME&O costs from 2024-2027.

145. PG&E's ME&O budget request should be approved.

146. PG&E should be authorized to recover $34.51 million for ME&O costs from 2024-2027.

147. SCE's ME&O budget request should be approved.

148. SCE is authorized to recover $33.59 million for ME&O costs from 2024-2027.

149. It is not reasonable to approve PG&E's request to submit a Tier 3 advice letter to propose DR system enhancements.

150. It is reasonable to approve PG&E's DR systems and technology costs.

151. PG&E should be authorized to recover $40.716 million for DR Portfolio Support costs.

152. It is reasonable to approve SCE's DR systems and technology costs, as amended.

153. SCE's recovery for DR Portfolio Support Budget should be reduced by $1 million per year from 2024-2027.

154. SCE should be authorized to recover $41.06 million for DR Portfolio Support costs.

155. It is reasonable to reduce SDG&E's proposed budget for DR systems support, given the denial of SDG&E's pilot programs.

156. It is reasonable to approve SDG&E's DR systems and technology costs, as amended.

157. SDG&E should be authorized to recover $10.404 million for DR Portfolio costs.

158. PG&E should be authorized to recover a 2024-2027 DR Portfolio budget of $616.01 million.

159. SCE should be authorized to recover a total authorized 2024-2027 DR Portfolio budget of $812.02 million.

160. SDG&E should be authorized to recover a total authorized 2024-2027 DR Portfolio budget of $120.35 million.

## O R D E R

**IT IS ORDERED** that:

1. Pacific Gas and Electric Company shall recover its cumulative 2024-2027 Demand Response revenue requirement of $616.01 million through distribution rates using the Distribution Revenue Adjustment Mechanism by filing Annual Electric True-up Advice Letters. Pacific Gas and Electric Company shall continue using the Demand Response Expenditure Balancing Account to track Demand Response program expenses and authorized budget.

2. Pacific Gas and Electric Company shall record all demand response incentives in the Demand Response Expenditures Balancing Account distribution or generation sub-accounts depending on whether the program is available to all customers or bundled customers only. The balances shall be recorded in the Base Revenue Requirement Balancing Account, which will record differences between the forecasted amounts and the actual incentives paid.

3. Southern California Edison Company shall recover its non-Emergency Load Reduction Program cumulative 2024-2027 Demand Response Application's revenue requirement of $634.25 million through the Demand Response Program Balancing Account, for recovery in distribution rates.

4. Southern California Edison Company shall recover its Emergency Load Reduction Program cumulative 2024-2027 revenue requirement of $177.77 million through the Emergency Load Reduction Program Balancing Account, up to the adopted cap amounts authorized in Decision 21-03-056 and Decision 21-12-015. Costs shall be transferred to the Base Revenue Requirement Balancing Account for recovery in distribution rates. Any amounts that exceed the adopted cap amounts shall be tracked in the Summer Reliability Demand Response Program Memorandum Account.

5. Southern California Edison Company shall record all demand response incentives in the Demand Response Program Balancing Account distribution or generation sub-accounts depending on whether the program is available to all customers or bundled customers only. The balances shall be recorded in the Base Revenue Requirement Balancing Account, which will record differences between the forecasted amounts and the actual incentives paid.

6. San Diego Gas & Electric Company shall recover its cumulative 2024-2027 Demand Response Program Portfolio budget of $120.35 million, and shall

recover its Demand Response program costs (except those related to the Emergency Load Reduction Pilot and Electric Rule 32) as requested in its Advanced Metering and Demand Response Memorandum Account for recovery in distribution rates.

7. San Diego Gas & Electric Company shall recover its Electric Rule 32 costs through the Direct Participation Demand Response Memorandum Account, for recovery through distribution rates after transfer to the Rewards and Penalties Balancing Account.

8. San Diego Gas & Electric Company shall recover its Emergency Load Reduction Pilot electric revenues and incremental costs, up to its annual administration cap authorized to be incurred in Decision 21-03-056 and Decision 21-12-015, in the Emergency Load Reduction Balancing Account, for recovery through distribution rates after transfer to the Rewards and Penalties Balancing Account.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are each authorized to recover their proportional share of costs, 40 percent, 40 percent and 20 percent, respectively, for up to 90 loggers in order to complete the Prohibited Resources Verification Plan. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may each attribute such costs as incremental costs to any DR programs covered by the Verification Audit.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are each directed to submit Tier 2 advice letters within 60 days of the issuance date of this decision to establish and update the eligible program lists for purposes of determining what a "qualified" Demand Response (DR) program is in order to satisfy DR incentive conditions.

11. San Diego Gas & Electric Company is authorized to submit a Tier 2 advice letter by December 31, 2024, seeking authority to fund-shift from other Demand Response programs or Category 7 costs for administrative or technical costs for allowing Heat Pump Water Heaters to participate in supply-side Demand Response programs.

12. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall share in the cost of the annual $22 million budget for Flex Alert paid media promotions, at the following proportions: 45 percent for SCE, 45 percent for PG&E, and 10 percent for SDG&E. SCE shall work with the current Flex Alert paid media promotions vendor to extend the contract currently set to expire in 2023 so that it expires at the end of 2027. Should this Decision become effective after the expiration of the current contract, SCE shall conduct a new solicitation for a vendor to administer Flex Alert and Power Saver Rewards paid media promotions, with an annual budget of $22 million for calendar years 2024 and 2025.

13. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are each authorized to submit Mid-Cycle Review proposed changes to their Demand Response Portfolio Programs in the following manner:

(a) Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may propose modifications to the Emergency Load Reduction Pilot on a uniform statewide basis via a joint Tier 2 advice letter due no later than January 15, 2026, with limited deviations to accommodate utility specific implementations due to information technology and billing systems.

(b) Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may propose modifications to the design of the Capacity Bidding Program on a uniform statewide basis via a joint Tier 2 advice letter due no later than November 1, 2025, with limited deviations as necessary for a utility to ensure cost-effectiveness.

(c) Pacific Gas and Electric Company may propose modifications to the design of Pacific Gas and Electric Company's Automated Response Technology Program via a Tier 2 advice letter due no later than November 1, 2025, with limited deviations as necessary to ensure cost-effectiveness.

(d) SCE may propose changes to SCE's Summer Discount Plan program and Smart Energy Program via a Tier 2 advice letter due no later than November 1, 2025.

(e) The scope of changes that could be proposed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company in the above advice letters is limited to those that: manage or increase program enrollment, improve program efficiency, increase potential load reduction available, improve program value, reduce costs, or bring the program in alignment or comply with Commission policies. The types of modification permitted shall be limited to technical aspects of the program design.

(f) Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each provide status updates on, and may propose modifications to, authorized pilots on a utility-specific basis via Tier 2 advice letters due no later than

November 1, 2025. In its disposition of these advice letters, the Commission's Energy Division is authorized, in its sole discretion, to terminate new pilots approved in this decision if they are not affirmatively shown to be accomplishing the pilot's goals.

14. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) shall each recover up to $400,000 per year, and San Diego Gas & Electric Company (SDG&E) up to $200,000 per year, to fund 2024-2027 Energy Division contracted Demand Response (DR) modeling and research. PG&E shall track these costs in its DR Expenditures Balancing Account, for recovery in distribution rates. SCE shall track these costs in its Base Revenue Requirement Balancing Account, for recovery in distribution rates. SDG&E shall track these costs in its Advanced Metering and Demand Response Memorandum Account, for recovery in distribution rates.

15. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall each submit their Demand Response Provider and Interruptible Load Programing reports on the first business day of the second month after the reporting month.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall immediately cease filing the Joint Investor-Owned Utilities Status Report on Progress Toward Interim Goal, which was originally ordered via settlement agreement in D.14-12-024, Attachment A, at 15.

17. Pacific Gas and Electric Company (PG&E) shall conduct its Base Interruptible Program (BIP), as amended in this decision. PG&E is authorized to cumulatively recover $175.36 million in calendar years 2024-2027 for its BIP.

18. Southern California Edison Company (SCE) shall recover $250,000 each in its Base Interruptible Program (BIP) and Agricultural Pumping, Interruptible (AP-I) budgets, or a total of $0.5 million, to remove Event Days from BIP and AP-I incentive calculations. If additional funding is needed, SCE shall submit a Tier 2 advice letter no later than December 31, 2024, seeking fund-shifting of an additional $1,000,000 total to implement this change.

19. Southern California Edison Company (SCE) is ordered to submit updated Excess Energy Charges via Tier 1 advice letter by February 28, 2024 to update its Base Interruptible Program incentive rates.

20. Southern California Edison Company (SCE) shall conduct its Base Interruptible Program (BIP), as amended in this decision. SCE is authorized to recover $276.97 million for its BIP Category 1 costs in calendar years 2024-2027.

21. Pacific Gas and Electric Company and Southern California Edison Company are directed to allow Base Interruptible Program participants to re-consider their Firm Service Level and/or program participation for 30 days following the issuance date of this decision.

22. Southern California Edison Company's (SCE's) Agricultural Pumping, Interruptible Program (AP-I) shall be implemented by SCE, as modified by this decision. SCE is authorized to cumulatively recover $21.25 million for its AP-I program Category 1 costs in calendar years 2024-2027.

23. Pacific Gas and Electric Company (PG&E) shall conduct its SmartAC program, as amended in this decision. PG&E is authorized to cumulatively recover $5.697 million for its Smart AC program budget in calendar years 2024-2027.

24. Pacific Gas and Electric Company (PG&E) shall conduct its Automated Response Technology (ART) program, as amended in this decision. PG&E is

authorized to cumulatively recover $23.8 million for its ART program budget from 2024-2027. PG&E shall submit a Tier 2 advice letter no later than February 28, 2024 detailing full program characteristics, and may not begin the program until the advice letter has been disposed of by the Commission's Energy Division.

25. Southern California Edison Company (SCE) shall implement its Smart Energy Program, as modified by this decision. SCE is authorized to cumulatively recover $23.28 million for its Smart Energy Program Category 1 costs during calendar years 2024-2027.

26. Southern California Edison Company (SCE) shall implement its Summer Discount Program, as amended by this decision. SCE is authorized to cumulatively recover $145.39 million for its Summer Discount Program Category 1 costs during calendar years 2024-2027.

27. San Diego Gas & Electric Company is directed to terminate its Smart Energy Program no later than December 31, 2023.

28. Pacific Gas and Electric Company shall eliminate its Capacity Bidding Program (CBP) Prescribed and CBP Elect + product options within 60 days of the date of issuance of this decision.

29. Southern California Edison Company shall eliminate its Capacity Bidding Program (CBP) Day-Ahead product option no later than January 1, 2025, and its CBP Day-Of product option no later than January 1, 2024.

30. San Diego Gas & Electric Company shall eliminate its Capacity Bidding Program Prescribed product option within 60 days of the date of issuance of this decision.

31. Pacific Gas & Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are directed to submit a Joint Tier 2

Advice Letter implementing changes to its Capacity Bidding Program energy payment process no later than 60 days after the date of issuance of this decision.

32. Pacific Gas and Electric Company (PG&E) shall conduct its Capacity Bidding Program (CBP), as amended in this decision. PG&E is authorized to cumulatively recover $28.475 million during calendar years 2024-2027 for its CBP program.

33. Southern California Edison Company (SCE) shall conduct its Capacity Bidding Program (CBP), as amended in this decision. SCE is authorized to cumulatively recover Category 1 costs of $42.36 million during calendar years 2024-2027 for its CBP program. SCE shall submit a Tier 3 Advice Letter within 60 days of the date of issuance of this decision updating its budget to reflect the denial of the proposed CBP Elect+ product option.

34. San Diego Gas & Electric Company (SDG&E) shall conduct its Capacity Bidding Program (CBP), as amended in this decision. SDG&E is authorized to cumulatively recover $6.973 million during calendar years 2024-2027 for its CBP program. SDG&E is authorized to submit a Tier 2 advice letter seeking to make its CBP Residential Pilot permanent, contingent upon a showing of cost-effectiveness. SDG&E is authorized to submit a Tier 3 advice letter by December 31, 2024, seeking additional budget for its CBP Residential Pilot, if necessary.

35. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall adopt the Capacity Bidding Program testing process described in this decision.

36. Pacific Gas and Electric Company (PG&E) shall operate its Optional Binding Mandatory Curtailment Program and the Scheduled Load Reduction Program. PG&E is authorized to cumulatively recover $34,902 during calendar years 2024-2027 for these programs.

37. Southern California Edison Company (SCE) shall conduct its the Optional Binding Mandatory Curtailment Program, and the Scheduled Load Reduction Program. SCE is authorized to cumulatively recover $23,000 during calendar years 2024-2027 for its these programs.

38. Pacific Gas and Electric Company (PG&E) shall conduct its Rule 24 activities, as amended by this decision. PG&E is authorized to cumulatively recover $13.71 million during calendar years 2024-2027 for its Rule 24 program activities.

39. Southern California Edison Company (SCE) shall conduct its Rule 24 activities, as amended by this decision. SCE is authorized to cumulatively recover $3.855 million during calendar years 2024-2027 for its Rule 24 program activities.

40. San Diego Gas & Electric Company (SDG&E) shall conduct its Rule 32 activities, as amended by this decision. SDG&E is authorized to cumulatively recover $6.406 million during calendar years 2024-2027 for its Rule 24 program activities.

41. Pacific Gas and Electric Company (PG&E) shall conduct its Auto Demand Response activities, as amended by this decision. PG&E is authorized to cumulatively recover $9.523 million during calendar years 2024-2027 for its program.

42. Southern California Edison (SCE) shall conduct its Auto Demand Response activities, as amended by this decision. SCE is authorized to cumulatively recover $21.517 million during calendar years 2024-2027 for its Auto Demand Response activities.

43. Pacific Gas and Electric Company (PG&E) shall conduct its Demand Response Emerging Technology (DRET) activities, as amended by this decision.

PG&E is authorized to cumulatively recover $5.784 million during calendar years 2024-2027 for its DRET activities.

44. Southern California Edison Company (SCE) shall conduct its Emerging Markets and Technologies (EMT) activities, as amended by this decision. SCE is authorized to cumulatively recover $11.69 million during calendar years 2024-2027 for its EMT activities.

45. San Diego Gas & Electric Company (SDG&E) shall conduct its Emerging Technologies (ET-DR) activities, as amended by this decision. SDG&E is authorized to cumulatively recover $3.096 million during calendar years 2024-2027 for its ET-DR activities.

46. Pacific Gas and Electric Company (PG&E) shall implement its Emergency Load Reduction Program (ELRP) activities, as amended by this decision. PG&E is authorized to cumulatively recover $267.62 million in calendar years 2024-2027 for its ELRP activities.

47. Southern California Edison Company (SCE) shall implement its Emergency Load Reduction Program (ELRP) activities, as amended by this decision. SCE is authorized to cumulatively recover $177.77 million during calendar years 2024-2027 for its Category 1 ELRP activities.

48. San Diego Gas & Electric Company (SDG&E) shall implement its Emergency Load Reduction Program (ELRP) activities, as amended by this decision. SDG&E is authorized to cumulatively recover $81.64 million during calendar years 2024-2027 to fund its ELRP activities.

49. Southern California Edison Company (SCE) is authorized to cumulatively recover $5.856 million from 2024-2027 to fund its Flexible Demand Response Pilot. SCE shall file a Tier 2 Advice Letter detailing Flexible Demand Response Pilot specifics and implementation by March 15, 2024.

50. Pacific Gas and Electric Company is authorized to cumulatively recover $9.188 million during calendar years 2024-2027 for its Evaluation, Measurement and Verification Budget.

51. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to end the filing of the Demand Response Interim Goal Report at the end of 2023.

52. San Diego Gas & Electric Company is authorized to cumulatively recover $4.62 million during calendar years 2024-2027 for its Evaluation, Measurement and Verification Budget.

53. Southern California Edison Company is authorized to cumulatively recover $5.82 million during calendar years 2024-2027 for its Evaluation, Measurement and Verification Budget.

54. Pacific Gas and Electric Company is authorized to cumulatively recover $34.51 million during calendar years 2024-2027 for its Marketing, Education & Outreach Budget.

55. San Diego Gas & Electric Company is authorized to cumulatively recover $6.4 million during calendar years 2024-2027 for its Marketing, Education & Outreach Budget.

56. Southern California Edison Company is authorized to cumulatively recover $33.59 million during calendar years 2024-2027 for its Marketing, Education & Outreach Budget.

57. Pacific Gas and Electric Company is authorized to cumulatively recover $54.31 million during calendar years 2024-2027 for its Marketing, Education & Outreach Budget.

58. Pacific Gas and Electric Company is authorized to cumulatively recover $48.716 million during calendar years 2024 – 2027 for its Demand Response System Support and Operations Budget.

59. Southern California Edison Company is authorized to cumulatively recover $41.06 million during calendar years 2024 – 2027 for its Demand Response System Support and Operations budget.

60. San Diego Gas & Electric Company is authorized to cumulatively recover $10.404 million during calendar years 2024-2027 for its Demand Response System Support and Operations budget.

61. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are each directed to submit Tier 2 advice letters by February 28, 2024, implementing tariff changes and implementation procedures authorized by this decision, unless otherwise noted.

62. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) are directed to submit Tier 3 advice letters within 60 days after the date of issuance of this decision, updating the following budgets for denied costs:

(a) PG&E's Auto Demand Response Budget (Section 10.1.3);

(b) PG&E's Marketing, Education, and Outreach Budget (Section 13.1); and

(c) PG&E's Evaluation, Measurement, and Validation Budget (Section 12.1);

(d) SCE's Capacity Bidding Program Budget (Section 7.8.6.6).

63. Pacific Gas and Electric Company, Southern California Edison Company, and Southern California Gas Company shall submit their 2028-2032 Demand Response Portfolio Applications by November 1, 2026.

64. Applications (A.) 22-05-002, A.22-05-003, A.22-05-004 remain open.

This order is effective today.

Dated ________________, at Sacramento, California.

## GLOSSARY OF TERMS

AC: Air Conditioning

ACC - Avoided Cost Calculator: Commission tool used to determine the value of distributed energy resources by calculating the counterfactual cost to procure alternative resources providing similar attributes

AutoDR or ADR - Automated Demand Response: IOU-managed program that provides incentives to automate the customer response to a demand response dispatch

ALJ: Administrative Law Judge

AMDRMA - Advanced Metering and Demand Response Memorandum Account: SDG&E account to record and recover the incremental, one-time set-up and on-going operating, maintenance, administrative, and general expenses incurred to develop and implement its demand response programs

AP-I - Agricultural Pumping-Interruptible: SCE emergency demand response program to reduce load during supply shortfalls by interrupting water pumping equipment for agriculture

ART - Automated Response Technology: Proposed PG&E program to incentivize customers with smart home technologies to participate in demand response and load shifting

BIP - Base Interruptible Program: IOU managed emergency demand response program requiring enrolled customers to quickly curtail load to no more than a contracted firm service level. Customers are paid monthly for their interruptible load, whether or not they are dispatched

BRRBA - Base Revenue Requirement Balancing Account: SCE account to track the authorized budget for providing electricity service compared to actual amounts collected for service from customers

BTM - Behind the Meter: Any resource, generation, or consumption that takes place on a customer premise, downstream from a utility electric meter

BUG - Back-up Generator: A type of behind-the-meter generation resource designed to operate only when grid power is interrupted. Colloquially, this term is sometimes used to refer to all Prohibited Resources

BYOT - Bring Your Own Thermostat: Part of PG&E SmartAC program to remotely activate SmartAC devices to reduce demand on the electricity grid

CalFUSE - California Flexible Unified Signal for Energy: Demand flexibility framework proposed by CPUC staff to provide real time and capacity pricing specific to each customer through a statewide portal

CalSSA: California Solar and Storage Association

CAISO: California Independent System Operator

CBP - Capacity Bidding Program: IOU managed program where customers and aggregators can earn monthly capacity and energy incentive payments based on a percentage of nominated reductions in energy consumptions when called upon during a qualifying event

CCA - Community Choice Aggregator: Load serving entities established by local governments to aggregate electricity demand within their jurisdictions and procure sufficient resources to meet that demand

CEC: California Energy Commission

CEDMC: California Efficiency + Demand Management Council

CEERT: Center for Energy Efficiency and Renewable Technologies

CESA: California Energy Storage Alliance

CLECA: California Large Energy Consumers Association

CPP - Critical Peak Pricing: Tariff which offers a discount on summer electricity rates in exchange for higher prices during a select number of peak event days in the year

CPUC: California Public Utilities Commission

DAM - Day-Ahead Market: A series of processes conducted in the Day-Ahead that includes the Market Power Mitigation, the Integrated Forward Market, and the Residual Unit Commitment

DDP - Direct Dispatch Pilot: SDG&E proposed pilot for commercial and industrial customers with AutoDR equipment to curtail energy usage with no penalties for non-performance

DER - Distributed Energy Resource: De-centralized resources that connect to the distribution grid. Examples include behind-the-meter generation and storage, interruptible end uses such as electric vehicle service equipment, and customers participating in conventional demand response programs

DR - Demand Response: Reductions, increases, or shifts in consumption by customers in response to economic or reliability signals in the form of electricity prices or financial incentives

DRAM - Demand Response Auction Mechanism: An IOU-administered demand response program that allows IOUs to acquire supply-side DR capacity from third parties through an open solicitation

DREBA - Demand Response Expenditure Balancing Account: The balancing account used by PG&E to track costs and revenues associated with its demand response programs

DRET - Demand Response Emerging Technologies: Program that allows IOUs to conduct small studies, pilots and demonstrations on emerging technologies and processes on an ad hoc and rolling basis without the need for Commission review or approval of individual projects

DRP - Demand Response Provider: Any entity which designs and operates demand response programs, mostly used in reference to third party aggregators

DRPBA - Demand Response Program Balancing Account: The balancing account used by SCE to track costs and revenues associated with its demand response programs

DRRS - Demand Response Registration System: Computer system maintained by CAISO to track the enrollment of customer service accounts in supply-side demand response programs

DSGS - Demand-Side Grid Support: CEC Program which offers incentives to electricity customers who provide load reduction and behind the meter generation to support the electricity grid during emergencies

EE - Energy Efficiency: The quality of using less energy to perform tasks or produce results than would otherwise be used. EE is typically the result of advances in technology such as LED lights and variable speed motors

EEA - Energy Emergency Alert: A system of alerts used when a balancing authority expects to not have sufficient supply to meet both demand and planning reserve margins. Alert levels range from EEA Watch to EEA3

EEC - Excess Energy Charge: Penalties imposed on customers that fail to achieve their contracted firm service level in certain DR programs

ELRP - Emergency Load Reduction Program: IOU managed program in which customers and aggregators are provided a financial incentive for reducing their energy consumption during electricity grid emergencies

ELRPBA - ELRP Balancing Account : Account used by IOUs to track costs of the Emergency Load Reduction Program

EM&V - Evaluation, Management and Validation: Activities used to assess attributes of demand response programs

EMT - Emerging Markets and Technology: SCE's Demand Response Emerging Technology program

ERRA - Energy Resource Recovery Account: CPUC proceedings used to determine fuel and purchased power costs which can be recovered in rates

EV: Electric Vehicle

FSL - Firm Service Level: The maximum load (in kW) that a customer enrolled in certain demand response programs is permitted to draw from the grid during a demand response event. Enrolled customers that exceed their FSL are subject to penalties

GCMC - Generation Capacity Marginal Cost: The marginal cost of a unit (e.g., kW) of generating capacity to be procured by a load-serving entity. The GCMC for IOUs is determined in a Phase 2 General Rate Case proceeding, and is used as an input to calculate retail rates

HPWH: Heat Pump Water Heater

HVAC: Heating, Ventilation, and Air Conditioning

IDSM - Integrated Demand Side Management: The incorporation of demand side management into long-range integrated planning by considering energy efficiency, demand response, and distributed generation

ILP - Interruptible Load Program: Compliance report filed by each major IOU with the CPUC each month describing demand response available resources and activities

ILR - Incremental Load Reduction: The energy or capacity made available by customers reducing demand from what it otherwise would be

IOU: Investor-Owned Utility

IPC: Industrial Pumping Customers

IRP - Integrated Resource Plan: A comprehensive planning document wherein a utility forecasts long-term supply and demand to demonstrate that it is prepared to fulfill customer load throughout a planning horizon. An IRP also demonstrates compliance with evolving energy policy by incorporating preferred resources as required

IT: Information Technology

JCCA: Joint Community Choice Aggregators

kW: Kilo-watt

LBNL: Lawrence Berkeley National Laboratory

LCR - Local Capacity Resource: A resource capable of contributing toward meeting demand within a defined, transmission constrained local capacity area

LIP - Load Impact Protocols: CPUC set of guidelines to estimate the impact on load from demand response activities

LMP - Locational Marginal Price: Marginal cost of serving next increment of wholesale demand at a pricing node

LSE - Load Serving Entity: Any entity serving retail electricity load to end users including investor-owned utilities, electric service providers, and community choice aggregators

MCE: Marin Clean Energy

MCR - Mid-Cycle Review: During a multi-year demand response budget cycle, the submission by Advice Letter to update the Commission on the status of utility demand response programs, and to propose specific improvements to those programs

ME&O - Marketing, Education, and Outreach: Activities used to promote demand response programs

MMDR - Mass Market Demand Response: SCE proposed pilot program intended to be technology-agnostic, allowing for participation by diverse end uses

MW: Mega-watt

OBMC - Optional Binding Mandatory Curtailment: IOU managed load modifying demand response program to reduce stress on the grid by reducing electricity load from very large electricity customers during system emergencies

OP - Ordering Paragraph: Language within a formal decision to direct a regulating entity to act

PAC - Program Administrator Cost: Cost-effectiveness test to determine administration costs of a program

PDR - Proxy Demand Resource: A CAISO market participation model for supply-side demand response resources. PDRs are dispatched economically and can be offered as energy, spinning reserve, or non-spinning reserve

PEV: Plug-in Electric Vehicle

PG&E: Pacific Gas & Electric Company

PHC - Prehearing Conference: Meeting held early in the process of a proceeding to discuss the proceeding scope and other matters

PLR - Potential Load Reduction: The capacity available to be dispatched by a demand response program. May refer to dispatchable capacity of one customer, or an aggregation of customers in a program

PR - Prohibited Resource: CPUC policy which prohibits use of fossil-fuel generation resources to simulate load reduction in response to a demand response dispatch

PSPS - Public Safety Power Shutoff: Temporary, targeted de-energization of transmission and distribution resources by an IOU to mitigate wildfire risk

PSR - Power Saver Rewards: ELRP Sub-group A.6, comprised of residential customers directly enrolled with an IOU

QC - Qualifying (or Qualified) Capacity: The maximum resource adequacy capacity that a resource adequacy resource may be eligible to provide

RA - Resource Adequacy: The CPUC program that ensures that adequate capacity is available to meet (i) the load requirements under peak demand, and (ii) the planning and operating reserves necessary to maintain reliability for a one-to-three-year time horizon

RDRR - Reliability Demand Response Resource: A CAISO market participation model for supply-side demand response resources. RDRRs must be able to respond quickly and are typically dispatched for reliability purposes

RFP - Request for Proposals: Document proposing a project and soliciting bids to complete it

RIM - Ratepayer Impact Measure: Cost-effectiveness test to determine impacts on ratepayers from changes in utility revenues and program operating costs

RTM - Real Time Market: The CAISO spot market series conducted in Real-Time that includes the Hour-Ahead schedule processing, Fifteen-minute market, Short-term Unit Commitment, and Real-time Daily market for unit commitment, ancillary service procurement, congestion management, and energy procurement

SBUA: Small Business Utility Advocates

SCE: Southern California Edison

SCT - Smart Communicating Thermostat: Internet-connected thermostat that can be remotely adjusted, including by the manufacturer or by a demand response provider

SDGE or SDG&E: San Diego Gas & Electric

SDP - Summer Discount Plan: SCE program to periodically turn off or cycle the customer's air conditioner compressor when called upon in return for a financial incentive

SGIP - Self-Generation Incentive Program: CPUC program which provides incentives to support existing, new, and emerging distributed energy resources

SLRP - Scheduled Load Reduction Program: IOU managed program which pays customers to reduce electricity load during pre-selected times in advance

SSDR - Supply-Side Demand Response: Demand response resources that are integrated into the wholesale energy market operated by CAISO

SubLAP - Sub-Load Aggregation Point: Set of geographically grouped pricing nodes specified by CAISO that are used for the submission of bids and settlement of electricity demand

SVCE: Silicon Valley Clean Energy

TD - Technology Deployment : SDG&E program to offer a connected thermostat incentive when a customer enrolls in the capacity bidding program

TOU - Time-Of-Use: Electricity rate plan which charges a customer based on time of electricity consumption

TRC - Total Resource Cost: Cost-effectiveness test to determine net costs of a program based on total costs for a participant and the utility

VGI - Vehicle-Grid Integration: Coordination amongst electric vehicles, electric vehicle service equipment, demand response providers, and balancing authorities which support grid needs and facilitate widespread adoption of EVs by allowing for flexible charging and discharging

VGIC: Vehicle Grid Integration Council

VPP - Virtual Power Plant: Aggregation of dispatchable distributed energy resources

# ATTACHMENT 1

Definition of “Qualified” Demand Response Program for
Purposes of Satisfaction of Demand Response Enrollment Requirements

## Attachment 1

## Definition of "Qualified" Demand Response Program for Purposes of Satisfaction of Demand Response Enrollment Requirements

The following DR programs are deemed as "qualified" to satisfy a potential DR enrollment requirement established by the Commission for a CPUC authorized program:

1. Supply-side market integrated DR programs counted for RA irrespective of whether the administrator is an IOU, CCA or third-party DRP.
2. Load modifying DR programs that satisfy the following two requirements:
   a. The program is indirectly integrated with the CAISO energy market such that the program's dispatch signal is linked to the energy prices in the Day-Ahead or real-time market – operational domain.
   b. The program's load impact is counted towards RA obligations directly or indirectly through an approved process (such as, via a process for reducing RA obligations by integrating the program's load impact with CEC's peak forecasts) – planning domain.
3. Any DR pilot authorized and designated by the Commission as a "qualified" DR program eligible to meet the DR enrollment requirement.
4. Critical Peak Pricing or Peak Day Pricing. These options shall be discontinued as a "qualified" DR program when the dynamic rate(s) under consideration in R.22-07-005 is(are) made available to customers and compliant with CEC adopted Load Management Standards (California Code of Regulations – Title 20, Article 5, §1623).

**(END OF ATTACHMENT 1)**

# ATTACHMENT 2

Emergency Load Reduction Program
Settlement for Group B Guidelines

Attachment 2

Emergency Load Reduction Program

Settlement for Group B Guidelines

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.

**(END OF ATTACHMENT 2)**

# ATTACHMENT 3

2024 – 2027 Demand Response Program Budgets

| **PG&E 2024-2027 Authorized Demand Response Budget** | | | | | |
|---|---|---|---|---|---|
| (in thousands) | **2024** | **2025** | **2026** | **2027** | **Total** |
| AC Cycling: Smart AC | $ 510 | $ 510 | $ 510 | $ 510 | $ 2.042 |
| *Smart AC Incentives* | *$ 914* | *$ 914* | *$ 914* | *$ 914* | *$ 3,655* |
| Base Interruptible Program (BIP) | $ 583 | $ 604 | $ 625 | $ 647 | $ 2,460 |
| *BIP Incentives* | *$ 43,225* | *$ 43,225* | *$ 43,225* | *$ 43,225* | *$ 172,900* |
| Capacity Bidding Program (CBP) | $ 558 | $ 577 | $ 598 | $ 619 | $ 2,350 |
| *CBP Incentives* | *$ 5,479* | *$ 6,201* | *$ 6,863* | *$ 7,586* | *$ 26,130* |
| Automated Response Technology (ART) Program | $ 1,124 | $ 1,249 | $ 1,262 | $ 1,124 | $ 4,759 |
| *ART Incentives* | *$ 4,495* | *$ 4,998* | *$ 5,048* | *$ 4,497* | *$ 19,040* |
| **Category 1 Total** | **$ 55,890** | **$ 58,280** | **$ 58,050** | **$ 59,120** | **$ 233,330** |
| Optional Binding Mandatory Curtailment (OBMC) and Scheduled Load Reduction Program (SLRP) | $ 8 | $ 9 | $ 9 | $ 9 | $ 35 |
| **Category 2 Total** | **$ 8** | **$ 19** | **$ 9** | **$ 9** | **$ 35** |
| DRAM | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| Direct Participation Electric Rule 24 Operation & Maintenance | $ 3,150 | $ 3,470 | $ 3,590 | $ 3,500 | $, 13,710 |
| **Category 3 Total** | **$ 2,439** | **$ 2,511** | **$ 2,584** | **$ 2,659** | **$ 12,931** |
| Auto DR | $ 2,380 | $ 2,380 | $2,380 | $ 2,380 | $9,523 |
| DR Emerging Technology | $ 1,446 | $ 1,446 | $ 1,446 | $ 1,446 | $ 5,784 |
| **Category 4 Total** | **$ 3,826** | **$ 3,826** | **$ 3,826** | **$ 3,826** | **$ 15,304** |
| Emergency Load Reduction Pilot (ELRP) | $12,012 | $12,268 | $12,532 | $12,805 | $ 49,617 |
| *ELRP Incentives* | $94,000 | $94,000 | $15,000 | $15,000 | $ 218,000 |
| **Category 5 Total** | **$106,012** | **$106,268** | **$27,532** | **$27,805** | **$267,617** |
| DR Core Marketing & Outreach | $ 3,079 | $ 3,079 | $ 3,079 | $ 3,079 | $ 12,316 |
| Smart AC Market | $ 87 | $ 87 | $ 87 | $ 87 | $ 348 |
| Education and Training | $ 512 | $ 512 | $ 512 | $ 512 | $ 2,047 |
| Flex Alert Media Campaign | $ 9,900 | $ 9,900 | $ 0 | $ 0 | $ 19,800 |
| **Category 6 Total** | **$ 13,580** | **$ 13,580** | **$3,677** | **$3,677** | **$ 34,510** |
| Evaluation, Measurement, and Verification | $ 2,297 | $ 2,297 | 2,297 | $ 2,297 | $ 9,188 |

| | | | | | |
|---|---|---|---|---|---|
| DR Portfolio Support | $ 10,179 | $ 10,179 | $10,179 | $10,179 | $ 40,716 |
| DR Potential Study | $ 400 | $ 400 | $ 400 | $ 400 | $ 1,600 |
| | | | | | |
| **Category 7 Total** | **$ 12,875** | **$ 12,875** | **$ 12,875** | **$ 12,875** | **$ 51,500** |
| **Total Authorized in 2024-2027 Portfolio for PG&E (in thousands)** | **$ 195,260** | **$ 198,230** | **$109,480** | **$110,740** | **$616,010** |

| **SCE 2024-2027 Authorized Demand Response Budget** | | | | | |
|---|---|---|---|---|---|
| (in thousands) | **2024** | **2025** | **2026** | **2027** | **Total** |
| Agricultural & Pumping Interruptible (AP-I) | $ 822 | $ 588 | $ 644 | $ 659 | $ 2,713 |
| *AP-I Incentives* | *$ 4,585* | *$ 4,611* | *$ 4,651* | *$ 4,691* | *$ 18,538* |
| Base Interruptible Program (BIP) | $ 1,175 | $ 1,176 | $ 1,629 | $ 1,683 | $ 5,663 |
| *BIP Incentives* | *$ 66,650* | *$ 67,514* | *$ 68,237* | *$ 68,908* | *$ 271,310* |
| Capacity Bidding Program (CBP) | $ 982 | $ 276 | $ 354 | $ 362 | $ 1,970 |
| *CBP Incentives* | *$ 1,052* | *$ 13,110* | *$ 13,110* | *$ 13,110* | *$ 40,380* |
| Smart Energy Program (SEP) | $ 2,150 | $ 657 | $ 712 | $ 739 | $ 4,258 |
| *SEP Contracts* | *$ 4,027* | *$ 4,556* | *$ 5,017* | *$ 5,418* | *$ 19,020* |
| Summer Discount Plan (SDP) | $ 6,811 | $ 6,917 | $ 7,082 | $ 7,144 | $ 27,953 |
| *SDP Incentives* | *$ 29,814* | *$ 29,495* | *$ 29,200* | *$ 28,925* | *$ 117,435* |
| **Category 1 Total** | **$ 118,070** | **$ 128,900** | **$ 130,640** | **$ 131,640** | **$ 509,240** |
| Optional Binding Mandatory Curtailment and Scheduled Load Reduction Program | $ 8 | $ 5 | $ 5 | $ 5 | $ 23 |
| **Category 2 Total** | **$ 8** | **$ 5** | **$ 5** | **$ 5** | **$ 23** |

| | | | | | |
|---|---|---|---|---|---|
| Rule 24 | $ 940 | $ 960 | $ 990 | $ 970 | $, 3,860 |
| Demand Response Auction Mechanism (DRAM) | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| **Category 3 Total** | **$ 940** | **$ 960** | **$ 990** | **$ 970** | **$ 3,860** |
| Emerging Markets and Technology | $ 2,922 | $ 2,922 | $ 2,922 | $ 2,922 | $ 11,688 |
| *Technology Incentives* | *$ 5,997* | *$ 5,135* | *$ 5,182* | *$ 5,206* | *$ 21,517* |
| **Category 4 Total** | **$ 8,919** | **$ 8,057** | **$ 8,104** | **$ 8,128** | **$ 33,205** |
| **Category 5 – Pilots** | | | | | |
| Emergency Load Reduction Pilot | $ 12,584 | $ 12,809 | $ 6,823 | $ 6,952 | $ 39,168 |
| *ELRP Incentives* | *$ 60,000* | *$ 60,000* | *$ 9,300* | *$ 9,300* | *$ 138,600* |
| Flexible Demand Response (DR) Pilot | $ 1,139 | $ 1,393 | $ 1,478 | $ 1,046 | $ 5,056 |
| *Flexible DR Incentives* | *$ 125* | *$ 250* | *$ 250* | *$ 175* | *$ 800* |
| **Category 5 Total** | **$ 73,850** | **$ 74,450** | **$ 17,850** | **$ 17,470** | **$ 183,620** |
| Marketing, Education, and Outreach | $ 2,980 | $ 3,983 | $ 3,780 | $ 3,900 | $ 17,200 |
| Flex Alert Media Campaign | $ 9,900 | $ 9,900 | $ 0 | $ 0 | $ 19,800 |
| **Category 6 Total** | **$ 12,880** | **$ 13,030** | **$ 3,780** | **$ 3,900** | **$ 33,590** |
| DR Systems & Technology Support Total including (a) - (e) | $ 9,756 | $ 10,072 | $ 10,447 | $10,783 | $41,060 |
| Evaluation, Measurement & Verification (EM&V) | $ 1,435 | $ 1,429 | $ 1,462 | $ 1,491 | $ 5,817 |
| DR Potential Study | $ 400 | $400 | $ 400 | $ 400 | $ 1,600 |
| **Category 7 Total** | **$ 11,590** | **$ 11,900** | **$ 12,310** | **$ 12,670** | **$ 48,480** |
| **Total Authorized in 2024-2027 Portfolio for SCE** | **$ 226,250** | **$ 237,310** | **$ 173,680** | **$ 174,790** | **$ 812,020** |

| **SDG&E 2024-2027 Authorized Demand Response Budget** | | | | | |
|---|---|---|---|---|---|
| (in thousands) | **2024** | **2025** | **2026** | **2027** | **Total** |
| Capacity Bidding Program (CBP) | $ 1,674 | $ 1,735 | $ 1,745 | $ 1,776 | $ 6,929 |
| **Category 1 Total** | **$ 1,674** | **$ 1,735** | **$ 1,745** | **$ 1,776** | **$ 6,929** |
| Optional Binding Mandatory Curtailment (OBMC) and Scheduled Load Reduction Program (SLRP) | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| PLS *Eliminated* | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| **Category 2 Total** | **$ 0** | **$ 0** | **$ 0** | **$ 0** | **$ 0** |
| DRAM, Including IT | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| SDG&E Electric Rule 32, Including IT | $ 1,557 | $ 1,586 | $ 1,615 | $ 1,648 | $ 6,406 |
| **Category 3 Total** | **$ 561** | **$ 578** | **$ 596** | **$ 614** | **$ 2,981** |
| DR Emerging Technology | $ 774 | $ 774 | $ 774 | $ 774 | $ 3,096 |
| Technology Deployment | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| Technology Incentives | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 |
| **Category 4 Total** | **$ 774** | **$ 774** | **$ 774** | **$ 774** | **$ 3,096** |
| Emergency Load Reduction Pilot (ELRP) | $ 3,000 | $ 3,000 | $ 1,900 | $ 1,900 | $ 9,800 |
| *ELRP Incentives* | $31,100 | $31,100 | $4,820 | $ 4,820 | $71,840 |
| **Category 5 Total** | **$ 34,100** | **$ 34,100** | **$ 6,720** | **$ 6,720** | **$ 81,640** |
| Marketing, Education and Outreach | $ 799 | $ 692 | $ 292 | $282 | $ 2,170 |
| Flex Alert Media Campaign | $ 2,200 | $ 2,200 | $ 0 | $ 0 | $ 4,400 |

| | | | | | |
|---|---|---|---|---|---|
| **Category 6 Total** | **$ 2,999** | **$ 2,890** | **$ 292** | **$ 282** | **$ 6,450** |
| Portfolio and Policy Support | $ 2,601 | $ 2,601 | $ 2,601 | $ 2,601 | $ 10,404 |
| Evaluation, Measurement & Verification (EM&V) | $ 1.14 | $ 1,030 | $ 1,210 | $ 1,240 | $4,620 |
| DR Potential Study | $ 200 | $ 200 | $ 200 | $ 200 | $ 800 |
| **Category 7 Total** | $ 3,940 | $ 3,830 | $ 4,010 | $ 4,040 | $ 15,820 |
| **Total Authorized in 2024-2027 Portfolio for SDG&E** | **$ 45,040** | **$ 44,920** | **$ 15,160** | **$ 15,240** | **$ 120,350** |

**(END OF ATTACHMENT 3)**

# ATTACHMENT 4

List of Exhibits from Joint Motion

| Proceeding No. | ALJ |
|---|---|
| A.22-05-002, -003, and -004 | Garrett Toy<br>Jason Jungreis |

# Exhibit List

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| PG&E-1 | | 2023-2027 Demand Response Programs, Pilots, and Budgets 2023 Bridge Funding | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/4854/473872959.pdf |
| | Jomo Thorne | Ch. 1, 2023 Program and Pilot Proposals | | |
| | Brad Wetstone | Ch. 2, Electric Rule 24 Activities for Third-Party Demand Response | | |
| | Jomo Thorne | Ch. 3, 2023 Budget and Cost Recovery | | |
| | | | | |
| PG&E-2 | | 2023-2027 Demand Response Programs, Pilots, and Budgets -- 2024-2027 Full Proposal | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/4857/474109675.pdf |
| | Neda Oreizy<br>Jomo Thorne | Ch. 1, The Landscape of Demand Response and Summary of Proposals | | |
| | Sebastien Csapo<br>John C. Hernandez<br>Neda Oreizy<br>Jomo Thorne | Ch. 2, Program Policy Enhancements | | |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| | Anurooba Balakrishnan<br>Wendy Brummer<br>Aaron Kendall<br>Nancy Lee<br>Jomo Thorne | Ch. 3, 2024-2027 Demand Response Program Proposals | | |
| | Albert K. Chiu<br>John C. Hernandez<br>Randy Chiu | Ch. 4, 2024-2027 Demand Response Technology Programs, Pilots and Load Management Proposal | | |
| | Sebastien Csapo | Ch. 5, Third-Party Demand Response | | |
| | Jomo Thorne<br>Brad Wetstone | Ch. 6, Demand Response Operations | | |
| | Gil Wong | Ch. 7, Load Impacts, Measurement, and Evaluation | | |
| | Jomo Thorne | Ch. 8, Proposed and Alternative Demand Response Budget Request | | |
| | Jomo Thorne<br>Candace Potter | Ch. 9, Cost-Effectiveness Evaluation | | |
| | Eunice LI | Ch. 10, Cost Recovery and Revenue Requirements | | |

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|---|---|---|---|---|
| PG&E-2A | Anurooba Balakrishnan<br>Wendy Brummer<br>Jomo Thorne<br>Gil Wong<br>Candice Potter<br>Eunice Li<br>Albert Chiu<br>Randy Chiu | 2023-2027 Demand Response Programs, Pilots, and Budgets 2024-2027 Full Proposal Supplemental Testimony (Chapter 11)<br>Errata Testimony (Chapters 3, 7, 8, 9, and 10) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5788/501872335.pdf |
| | Anurooba Balakrishnan<br>Wendy Brummer<br>Aaron Kendall<br>Jomo Thorne | Ch. 3, 2024-2027 Demand Response Programs Proposals (CLEAN VERSION) | | |
| | Gil Wong | Ch. 7, Load Impacts, Measurement, and Evaluation (CLEAN VERSION) | | |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| | Jomo Thorne | Ch. 8, Proposed and Alternative Demand Response Budget Request (CLEAN VERSION) | | |
| | Candice Potter<br>Jomo Thorne | Ch. 9, Cost Effectiveness Evaluation (CLEAN VERSION) | | |
| | Eunice Li | Ch. 10, Cost Recovery and Revenue Requirements (Attachment 10A – Budget by expense type) | | |
| | Candice Potter | Ch. 11, Cost-Effectiveness Report spreadsheets<br>Attachment A – Original cost effectiveness report<br>Attachment B – Corrected cost effectiveness report<br>Attachment C – Errata testimony (CLEAN) | | |
| | | | | |
| PG&E-3 | | 2023-2027 Demand response programs, pilots, and budgets 2023 bridge funding Rebuttal Testimony | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5299/496396794.pdf |
| | Randy Chiu<br>Jomo Thorne | Ch. 1, Rebuttal testimony of Jomo Thorne and Randy Chu 2023 program and pilot proposals | | |
| | Brad Wetstone | Ch. 2, Rebuttal testimony of Brad Wetstone Electric Rule 24 activities for third party demand response | | |
| PG&E-4 | | Demand Response Auction Mechanism, pursuant to the July 5, 2022 Scoping Memo in A.22-05-002<br>SUPPLEMENTAL TESTIMONY | Admitted by Decision 23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5309/496418259.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| PG&E-5 | | Council Response to PG&E (PGE_CEDMC001) August 12, 2022 | | https://docs.cpuc.ca.gov/PublishedD |
| | | | | ocs/SupDoc/A2205002/5342/49643 5853.pdf |
| PG&E-6 | | Demand Response Auction Mechanism pursuant to the July 5, 2022 Scoping Memo in A.22-05-002 REBUTTAL TESTIMONY | Admitted by Decision 23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5514/49701 6493.pdf |
| | Gil Wong | Ch. 7, Load Impacts, Measurement, and Evaluation (CLEAN VERSION) | | |
| | Jomo Thorne | Ch. 8, Proposed and Alternative Demand Response Budget Request (CLEAN VERSION) | | |
| | Candice Potter<br>Jomo Thorne | Ch. 9, Cost Effectiveness Evaluation (CLEAN VERSION) | | |
| | Eunice Li | Ch. 10, Cost Recovery and Revenue Requirements (Attachment 10A – Budget by expense type) | | |
| | Candice Potter | Ch. 11, Cost-Effectiveness Report spreadsheets<br>Attachment A – Original cost effectiveness report<br>Attachment B – Corrected cost effectiveness report<br>Attachment C – Errata testimony (CLEAN) | | |

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|---|---|---|---|---|
| PG&E-7 | Candice Potter<br>Jomo Thorne<br>Gil Wong<br>Chris Kato<br>Neda Assadi<br>John Hernandez | 2023-2027 Demand Response Funding application<br>Chapter 12<br>Second Supplemental Testimony to PG&E's Application for 2024-2027 Demand Response Portfolio | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5830/503284030.pdf |
| PG&E-8 | Neda Assadi<br>Anurooba Balakrishnan | 2023-2027 Demand Response Programs, Pilot, and Budgets 2024-2027 Full Proposal Rebuttal Testimony | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6051/508571690.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| | Wendy Brummer<br>Albert Chiu<br>Randy Chiu<br>John Hernandez<br>John Lin<br>Jomo Thorne<br>Brad Wetstone | Ch. 1, Program Policy Enhancements<br>Ch. 2, 2024-2027 Demand Response Program Proposals<br>Ch. 3, 2024-2027 Demand Response Technology and Pilots<br>Ch.4 , Cost Effectiveness Evaluation | | |
| | | | | |
| SCE-01 | C. Parson | Exhibit 1 – Policy<br>(2023 bridge year only) | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/4832/473860102.pdf |
| SCE-01 | C. Parson | Exhibit 1 – Policy<br>(2023 bridge year only) | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/4832/473860102.pdf |
| SCE-02 | E. Keating, M. Sheriff | Exhibit 2 – SCE's 2023 Proposed Demand Response Programs Bridge Funding Request (2023 Bridge year only) | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/4833/473872933.pdf |
| SCE-03 | E. Keating, C. Smith, M. Williams, N. Gonzalez, C. Rauss | Exhibit 3 – SCE's 2023-2027 Proposed Demand Response Programs by Category, (2023 Bridge year only) | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/4834/473872934.pdf |
| SCE-04 | R. Behlihomji, C. Smith, P. Gautam, N. Gonzalez, M. Ahyow, M. Sheriff | Exhibit 4 – Program Incentive Development/Cost-effectiveness Analysis/Program Enrollment and Load Impact Forecasts/Revenue Requirement and Cost Recovery<br>(2023 Bridge year only) | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/4835/472481853.pdf |

| | | | | |
|---|---|---|---|---|
| SCE-05 | | Witness Qualifications | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/4836/473859279.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| SCE-06 | T. Becnel | Exhibit 6-Phase I Reply Testimony | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5298/496412517.pdf |
| SCE-07 | Coher, David B. | Exhibit 7 - Supplemental Testimony on Nexant Report and Auction Mechanism served August 5, 2022 | Admitted by Decision 23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5305/496415743.pdf |
| SCE-08 | Coher, David B. | Reply Testimony On Nexant Report And Auction Mechanism | Admitted by Decision 23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5437/496694957.pdf |
| SCE-09 | N. Gonzalez | Supplemental Testimony in Support Of Its Application for Approval Of Its 2023-2027 Demand Response Programs: Exhibit 9 | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5787/501872332.pdf |
| SCE-10 | C. Smith | Supplemental Testimony in Support Of Its Application for Approval Of Its 2023-2027 Demand Response Programs Exhibit 10-Capacity Bidding Program Elect Proposal | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/5829/502981014.pdf |
| SCE-11 | T. Tayavibul<br>C. Smith | Supplemental Testimony in Support Of Its Application for Approval Of Its 2023-2027 Demand Response Programs Exhibit 11 - Systems and Technology Budget Updates | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/5829/502987695.pdf |
| SCE-12 | N. Gonzalez | Supplemental Testimony In Support Of Its Application for Approval Of Its 2023-2027 Demand Response Programs Exhibit 12 - Updated Program Cost-Effectiveness | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/5829/502978475.pdf |
| SCE-13 | T. Tayavibul | Supplemental Testimony In Support Of Its Application for Approval Of Its 2023-2027 Demand Response Programs Exhibit 13 - Emergency Load Reduction Program Pilot Budget and Program Updates | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205004/5829/502984752.pdf |

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|---|---|---|---|---|
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| SCE-14 | T. Tayavibul<br>R. Behlihomji<br>C. Smith<br>E. Keating | Phase II Rebuttal Testimony | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6044/508571795.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| | N. Gonzalez | | | |
| SDGE-1A | B. Mantz | Prepared Direct Testimony of E. Bradford Mantz – Chapter 1A on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496415874.pdf |
| SDGE-2A | E. Kutzler | Prepared Direct Testimony of Ellen Kutzler – Chapter 2A on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496435805.pdf |
| SDGE-3A | A. Bernhardt | Prepared Direct Testimony of April Bernhardt – Chapter 3A on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496416389.pdf |
| SDGE-4A | L. Garcia-Rodriguez | Prepared Direct Testimony of Lizzette Garcia-Rodriguez – Chapter 4A on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496415780.pdf |
| SDGE-5A-R | B. Gettig | Revised Prepared Direct Testimony of Brenda Gettig – Chapter 5A on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5340/496439874.pdf |
| SDGE-6A | K. Pitsko | Prepared Direct Testimony of Kenny Pitsko– Chapter 6A on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496435697.pdf |
| SDGE-7A | B. Mantz | Prepared Rebuttal Testimony Of E Bradford Mantz On Behalf Of San Diego Gas & Electric Company (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496418339.pdf |

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|---|---|---|---|---|
| SDGE-8A | B. Gettig | Prepared Rebuttal Testimony Of Brenda Getting On Behalf Of San Diego Gas & Electric Company (Phase I) | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5333/496441157.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| | | | | |
| SDGE-1C | B. Mantz | SDG&E's Prepared Supplemental Testimony of E Bradford Mantz – Chapter 1C served August 5, 2022 (DRAM) | Admitted by D.23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5444/496679919.pdf |
| SDGE-2C | B. Mantz | Prepared Rebuttal Testimony Of E Bradford Mantz On Behalf Of San Diego Gas & Electric Company (Demand Response Auction Mechanism) served September 2, 2022 (DRAM) | Admitted by D.23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5444/496688629.pdf |
| SDGE-1 | B. Mantz | Prepared Direct Testimony of E. Bradford Mantz – Chapter 1B on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511719791.pdf |
| SDGE-2 | E. Kutzler | Prepared Direct Testimony of Ellen Kutzler – Chapter 2B on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511719564.pdf |
| SDGE-3 | A. Bernhardt | Prepared Direct Testimony of April Bernhardt – Chapter 3B on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/512123299.pdf |
| SDGE-4 | L. Garcia-Rodriguez | Prepared Direct Testimony of Lizzette Garcia-Rodriguez – Chapter 4B on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/512127330.pdf |
| SDGE-5 | B. Gettig | Prepared Direct Testimony of Brenda Gettig – Chapter 5B on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511719359.pdf |

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|---|---|---|---|---|
| SDGE-6 | K. Pitsko | Prepared Direct Testimony of Kenny Pitsko– Chapter 6B on Behalf of San Diego Gas & Electric Company (May 2, 2022) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511719905.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| SDGE-7 | B. Gettig | Supplemental Testimony of Brenda Gettig – Cost Effectiveness Report on Behalf of San Diego Gas & Electric Company (February 3, 2023) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511720114.pdf |
| SDGE-8 | B. Gettig | Supplemental Testimony of Brenda Gettig – Chapter 5B on Behalf of San Diego Gas & Electric Company (March 3, 2023) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511719138.pdf |
| SDGE-9 | B. Mantz | Supplemental Testimony of E Bradford Mantz – Chapter 1B on Behalf of San Diego Gas & Electric Company (March 3, 2023) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6327/512176936.pdf |
| SDGE-10 | B. Mantz | Rebuttal Testimony of E Bradford Mantz on Behalf of San Diego Gas & Electric Company (May 12, 2023) (Phase II) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/6322/511719792.pdf |
| Cal Advocates -01 | Stephen Castello<br>Paul Koenig<br>Ky-An Tran | Public Advocates Office Errata to Opening Testimony on Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5996/507814162.pdf |
| Cal Advocates -02 | Stephen Castello<br>Paul Koenig<br>Ky-An Tran | Public Advocates Office Errata to Rebuttal Testimony on Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6073/509012942.pdf |
| CLECA-01 | Samuel Harper | Direct Testimony of Samuel Harper on behalf of CLECA | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5946/506878469.pdf |
| CLECA-02 | Samuel Harper | Rebuttal Testimony of Samuel Harper on behalf of CLECA | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6055/508571049.pdf |

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|---|---|---|---|---|
| CLECA/IPC-01-R | California Large Energy Consumers Association and | SCE Response to Data Request Set IPC-CLECA-SCE-04 | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6341/512137770.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| | Industrial Pumping Customers | | | |
| Council-01 | Desmond, Joseph | Reply Testimony of California Efficiency + Demand Management Council | Admitted by D.22-12-019 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5294/496415724.pdf |
| Council-02 | Desmond, Joseph | Opening Phase II Testimony of the California Efficiency + Demand Management Council | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5954/506961192.pdf |
| Council-03 | Desmond, Joseph | Rebuttal Phase II Testimony of the California Efficiency + Demand Management Council | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6045/508571033.pdf |
| Council/Leap-02 | Desmond, Joseph | Opening Testimony of California Efficiency + Demand Management Council and Leapfrog Power, Inc. | Admitted by D.23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5306/496418289.pdf |
| Council/Leap-03 | Desmond, Joseph | Reply Testimony of California Efficiency + Demand Management Council and Leapfrog Power, Inc. | Admitted by D.23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5439/496679879.pdf |
| CPower-1 | Chamberlin, Jennifer | Phase 1 Supplemental Testimony of CPower, Inc., on 2023 Demand Response Auction Mechanism and Nexant Report | Admitted by D.23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5310/496415652.pdf |
| EVE-1 | Vellone, Joseph | Phase II Issues Prepared Testimony of Joseph Vellone on Behalf of EV.ENERGY CORP | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5945/506523290.pdf |
| EROC-1 | Scott D. Lipton | CV for Scott D. Lipton | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5942/506523074.pdf |

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|---|---|---|---|---|
| | | | | |
| EROC-22 | Scott D. Lipton | Scott D. Lipton Prepared Testimony on Behalf of Enchanted Rock | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5942/506878461.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| Google-1 | Aaron Berndt | RESPONSE TO SPECIFIC ALJ QUESTIONS PREPARED TESTIMONY AND EXHIBITS OF AARON BERNDT ON BEHALF OF GOOGLE LLC | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2202005/5612/497866903.pdf |
| IPC-01 | Robert R. Stephens | Direct Testimony of Robert R. Stephens on behalf of Industrial Pumping Customers | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5947/506896039.pdf |
| IPC-02 | Robert R. Stephens | Rebuttal Testimony of Robert R. Stephens on behalf of Industrial Pumping Customers | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6056/508572024.pdf |
| JCCA-01 | Alice Havenar-Daughton, Rebecca Simonson, Feliz Ventura, Peter Levitt | Prepared Direct Testimony of the Joint Community Choice Aggregators | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5952/506896049.pdf |
| JDRP-01 | Chamberlin, Jennifer; Agrawal, Poonum | Phase 2 Opening Testimony of Joint Demand Response Parties (CPower and Enel X North America, Inc.) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5950/506523080.pdf |
| JDRP-02 | Chamberlin, Jennifer; Agrawal, Poonum | Phase 2 Rebuttal Testimony of Joint Demand Response Parties (CPower and Enel X North America, Inc.) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6043/508571361.pdf |
| Leap-01 | Hamid, Amaani | Opening Prepared Phase II Demand Response Auction Mechanism Testimony of Leapfrog Power, Inc. | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6263/511023153.pdf |
| OhmConnect-1 | Maria Belenky | OPENING TESTIMONY OF MARIA BELENKY on behalf of OHMCONNECT, INC. (July 13, 2022) | Admitted by Decision 22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5200/493823349.pdf |

| | | | | |
|---|---|---|---|---|
| OhmConnect-2 | Maria Belenky | SUPPLEMENTAL TESTIMONY OF OHMCONNECT, INC. ON THE DEMAND RESPONSE AUCTION MECHANISM PILOT (AUGUST 5, 2022) | Admitted by Decision 23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5307/496416733.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| OhmConnect-3 | Maria Belenky | REPLY TESTIMONY OF OHMCONNECT, INC. ON THE DEMAND RESPONSE AUCTION MECHANISM PILOT (September 2, 2022) | Admitted by Decision 23-01-006 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5440/496676234.pdf |
| OhmConnect-4 | Cliff Staton | OPENING TESTIMONY OF CLIFF STATON on behalf of OHMCONNECT, INC. (April 21, 2023) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5957/506897360.pdf |
| OhmConnect-5 | Cliff Staton | REBUTTAL TESTIMONY OF CLIFF STATON on behalf of OHMCONNECT, INC. (May 12, 2023) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6049/508571369.pdf |
| Polaris-1 | David Meyers | Opening Prepared Phase II Testimony of Polaris Energy Services | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5951/506523081.pdf |
| SBUA-1 | Ted Howard | Testimony of Ted Howard on Behalf of Small Business Utility Advocates | Admitted by D.22-12-009 | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5199/496341590.pdf |
| SBUA-2 | Francis E. Wyatt | Phase II Direct Testimony of Francis E. Wyatt on behalf of Small Business Utility Advocates | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5943/506877045.pdf |
| SBUA-3 | Francis E. Wyatt | Phase II Rebuttal Testimony of Francis E. Wyatt on behalf of Small Business Utility Advocates | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6041/508571792.pdf |
| SC-01 | Sahm White | PREPARED INTERVENOR TESTIMONY OF SAHM WHITE on behalf of SIERRA CLUB (April 7, 2023) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/5976/507387395.pdf |
| SC-03 | Sahm White | Olivine Community: Fresno Energy Program | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6430/513343643.pdf |

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|---|---|---|---|---|
| VGIC-01 | Ed Burgess | Opening Testimony of Ed Burgess on Behalf of Vehicle Grid Integration Council | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6431/513350890.pdf |

| Exh. No. | Sponsor/Witness | Description | Entered into Evidence | Link on CPUC Supporting Documents Website |
|---|---|---|---|---|
| VGIC-02 | Ed Burgess | Rebuttal Testimony of Ed Burgess on Behalf of Vehicle Grid Integration Council | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002;A2205003;A2205004/6431/513349148.pdf |
| WG-1 | Amanda Myers Wisser | Prepared Direct Testimony of Amanda Myers Wisser on Behalf of Weave Grid, Inc. (April 21, 2023) | | https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2205002/5961/507237026.pdf |

**(END OF ATTACHMENT 4)**

# ATTACHMENT 5

Summary DR Programs Table

Note:

- 2019 and 2025 were selected as representative years within the previous and current application terms.
- Budget and Load Shed data is from representations in data requests by the CPUC to the IOUs.
- Budget includes program and administrative budget.

## Supply Side Demand Response Programs

Note: $/kilowatt (kW) metric is not done on a comparative basis. KWs between programs do not have the same operational properties or value.

| Name | Program or Pilot | IOU | Authorized 2019 Budget ($Million) | Authorized August 2019 Load Shed (in MW) | 2019 $/kW | Propose 2025 Budget ($Million) | Nominated Load Shed - 2025 (MW) | 2025 $/kW | Misc | Eligible Customers |
|---|---|---|---|---|---|---|---|---|---|---|
| Base Interruptible Program | Program | PG&E | $32.4 | 330 | $98.18 | $43.8 | 316 | $138.61 | | Aggregators and Non-Residential customers |
| | | SCE | $70.8 | 656 | $107.93 | $68.7 | 539 | $127.46 | 15- and 30-minute dispatch options | |
| | | SDG&E | $0.9 | 6 | $150.00 | $0.0 | 0 | N/A | SDG&E proposes to no longer have a BIP program. 2024 budget request includes admin costs for winding down BIP | |
| Capacity Bidding Program | Program | PG&E | $4.1 | 52 | $78.85 | $6.8 | 82 | $82.93 | | Non-Residential & Residential |
| | | SCE | $3.0 | 50 | $60.00 | $2.1 | 17 | $123.53 | | Non-Residential |
| | | SDG&E | $2.1 | 7 | $300.00 | $1.7 | 6 | $283.33 | | |
| Capacity Bidding Program - Residential | Pilot | SDG&E | $0.7 for 2022&23 | N/A | N/A | N/A | N/A | N/A | Extended for 2023 but should end or convert to program for 2024 | Residential |
| Demand Response Auction Mechanism | Pilot | PG&E | $6.0 | 80 | $75.00 | Pending Decision on DRAM future | | | | Non-Residential |
| | | SCE | $12.0 | 177 | $67.80 | | | | | |
| | | SDG&E | $1.4 | 13 | $107.96 | | | | | |

| Name | Program or Pilot | IOU | Authorized 2019 Budget ($M) | Authorized August 2019 Load Shed (MW) | 2019 $/kW | Proposed 2025 Budget ($M) | Nominated Load Shed - 2025 (MW) | 2025 $/kW | Misc | Eligible Customers |
|---|---|---|---|---|---|---|---|---|---|---|
| SmartAC | Program | PG&E | $6.4 | 74 | $86.47 | $1.4 | 20 | $55.00 | Phasing out new customer recruitment, funding for admin only. | |
| Summer Discount Program | Program | SCE | $50.3 | 242 | $207.85 | $36.4 | 172 | $211.63 | | Residential, small, medium, large commercial, and industrial |
| Agricultural and Pumping Interruptible | Program | SCE | $6.9 | 54 | $127.78 | $5.2 | 23 | $226.09 | Immediate dispatch through direct load control | Non-residential (mostly agricultural) |
| Smart Energy Program | Program | SCE | $3.5 | 38 | $92.11 | $5.2 | 59 | $88.14 | | Residential, non-residential |
| | | SDG&E | $2.4 | 22 | $109.09 | $2.6 | 8 | $325.00 | SDG&E SEP program was previously called the AC Saver program and had a Day-Ahead and Day-Of component | |

## Load Modifying Demand Response Programs

| Name | Program or Pilot | IOU | Authorized 2019 Budget ($M) | Authorized August 2019 Load Shed (MW) | Proposed 2025 Budget ($M) | Nominated Load Shed - 2025 (MW) | Misc | Eligible Customers |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| Emergency Load Reduction Program | Pilot | PG&E | N/A | | $106.3 | N/A | Program budget first allocated for $32.5M in 2021. | Commercial, Residential |
| | | SCE | N/A | | $78.2 | N/A | Program budget first allocated for $36.7 M in 2021. | Commercial, Residential |
| | | SDG&E | N/A | | $37.1 | N/A | | Commercial, Residential |
| Optional Binding Mandatory Curtailment/Scheduled Load Reduction Program | Program | PG&E | $0.0 | 0 | $0.0 | 0 | The program is ordered by statute, but there is no participation. | |
| | | SCE | $0.0 | 0 | $0.0 | 0 | | |
| Automated Response Technology Program | Program | PG&E | N/A | N/A | $5.5 | 75 | Broadening of Smart Thermostat programs to other smart devices | |
| Ag DR Pilot | Pilot | PG&E | N/A | N/A | $1.2 | 18 | | Ag TOU |

## Other Programs

| Name | Program or Pilot | IOU | Authorized 2019 Budget ($M) | Authorized August 2019 Load Shed (MW) | Proposed 2025 Budget ($M) | Nominated Load Shed - 2025 (MW) | Misc | Eligible Customers |
|---|---|---|---|---|---|---|---|---|
| DR Emerging Technology Program | Program | PG&E | $1.4 | N/A | $1.1 | N/A | | |
| | | SDG&E | $0.7 | | $1.3 | N/A | | |
| Emerging Markets and Technology (same as DRET at PG&E and SDG&E) | Program | SCE | $2.9 | | $3.9 | N/A | | |
| AutoDR | Program | PG&E | $4.0 | N/A | $2.4 | N/A | | |
| Technology Incentive Program (same as AutoDR) | Program | SCE | $7.8 | N/a | $5.3 | N/A | Consists of AutoDR and Programmable Communicating Thermostat incentives | |
| Direct Dispatch Pilot | Pilot | SDG&E | N/A | N/A | $1.4 | N/A | | Commercial, Industrial |
| Electric Vehicle DR Pilot | Pilot | SDG&E | N/A | N/A | $1.1 | N/A | | Residential |
| Flex DR Pilot | Pilot | SCE | N/A | N/A | $1.6 | N/A | | Water and wastewater operators |
| Grid Isolation Controls Pilot | Pilot | SDG&E | N/A | N/A | $1.0 | N/A | | Residential |
| Mass Market DR Pilot | Pilot | SCE | N/A | N/A | $0.3 | N/A | | Residential |
| Smart Panel Pilot | Pilot | PG&E | N/A | N/A | $2.8 | N/A | | Residential (equipment subsidy priority for low-income and DAC) |
| Battery Storage DR Pilot | Pilot | SDG&E | N/A | N/A | $1.5 | N/A | | Residential, Small Commercial |

# (END OF ATTACHMENT 5)