Application No.: 22-05-002, et al.

Exhibit No.: Council-02

Witnesses Joseph Desmond

Commissioner John Reynolds

ALJs Garrett Toy and Jason Jungreis

OPENING PHASE II TESTIMONY OF THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL

Application 20-05-002, et al.
Demand Response Programs

April 21, 2023

A.22-05-002, et al. (DR Applications)
OPENING PREPARED PHASE II TESTIMONY OF
THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL

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OPENING PHASE II TESTIMONY OF
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I. EXECUTIVE SUMMARY

This testimony is submitted on behalf of the California Efficiency + Demand Management Council ("the Council"). The Council is a statewide trade association of non-utility businesses that provide energy efficiency, demand response, and data analytics services and products in California.[1] Our member companies employ many thousands of Californians throughout the state. They include energy efficiency ("EE"), demand response ("DR"), and distributed energy resources ("DER") service providers, implementation and evaluation experts, energy service companies, engineering and architecture firms, contractors, financing experts, workforce training entities, and energy efficient product manufacturers. The Council's mission is to support appropriate EE and DR policies, programs, and technologies to create sustainable jobs, long-term economic growth, stable and reasonably priced energy infrastructures, and environmental improvement.

On May 2, 2022, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") submitted Applications for approval of their 2024-2027 DR programs.

On July 5, 2022, Assigned Commissioner John Reynolds issued a Scoping Memo and Ruling ("Scoping Memo"). The Scoping Memo stated that the proceeding would be addressed in two Phases.[2] Phase I would address bridge funding for 2023 and the continuation of the DR Auction Mechanism ("DRAM") for 2023 solicitations and

[1] Additional information about the Council, including the organization's current membership, Board of Directors, antitrust guidelines and code of ethics for its members, can be found at http://www.cedmc.org. The views expressed by the Council are not necessarily those of its individual members.
[2] Scoping Memo, at p. 3.

2024 deliveries.[3] The Scoping Memo stated that Phase II issues would be scoped to address the 2024-2027 DR program proposals at a later time.[4]

On December 19, 2022, Assigned Commissioner Reynolds issued an Amended Scoping Memo and Ruling ("Amended Scoping Memo"). The Amended Scoping Memo outlined several Phase II scoping issues for the 2024-2027 utilities' DR programs and identified DRAM issues to be addressed in Phase II.[5] This testimony addresses Phase II issues only as the Amended Scoping Memo directs parties to submit separate testimony on DRAM.[6]

II. SUMMARY OF THE COUNCIL'S TESTIMONY

Q. Please state your name and business address

A. My name is Joseph Desmond. My business address is 849 East Stanley Blvd., #264, Livermore, CA 94550.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the California Efficiency + Demand Management Council ("the Council").

Q. Have you testified previously in this proceeding?

A. Yes. On August 3, 2022, the Council served my Reply Testimony in this proceeding (Ex. Council-01); on August 5, 2022, the Council and Leapfrog Power, Inc. ("Leap") served my Opening Testimony in this proceeding (Ex. Council/Leap-01); and on September 2, 2022, the Council and Leap served my Reply Testimony in this proceeding (Ex. Council/Leap-02). My Statement of Qualifications was appended to Ex. Council-01 and Ex. Council/Leap-01 as Appendix A.

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[3] Scoping Memo, at p. 3.
[4] *Id*.
[5] Amended Scoping Memo, at pp. 5-7.
[6] *Id*., at p. 7.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Exhibit Council-02, the Opening Prepared Testimony of the California Efficiency + Demand Management Council in A.22-05-002, et al. (DR Applications).

Q. Was Exhibit Council-02 prepared by you?

A. Yes.

Q. Are the statements made in your testimony true and correct to the best of your knowledge and belief?

A. Yes.

Q. To the extent that Exhibit Council-02 contains expressions of opinion, do they represent your best professional judgment?

A. Yes.

Q. Do you adopt Exhibit Council-02 as your sworn testimony in A.22-05-002, et al. (DR Applications)?

A. Yes. On

Q. What issues do you address in your Opening Testimony?

A. In my Opening Testimony, I respond to Amended Scoping Memo Phase II Issue Number 1 which asks:

> 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?[7]

I also address Amended Scoping Memo Phase II Issue Number 2 which is "[a]re PG&E's, SDG&E's, and SCE's proposed demand response programs and activities, including pilot recommendations, Emergency Load Reduction Program, and

[7] Amended Scoping Memo, at p. 5.

modifications to existing programs and policies, reasonable, and should they be adopted?"[8]

Specifically, I testify to the following:

- The investor-owned utilities' ("IOUs'") proposed Market-Integration Efficacy Study should be adopted subject to modifications.
- There is a need for competitive parity between the IOUs and third parties.
- The mid-cycle review process is necessary but can be improved.
- Dual participation should be reexamined.

I also testify regarding the IOUs' proposals regarding their Emergency Load Reduction Programs; Base Interruptible Programs; Automated DR, Technology Incentive and Technical Demonstration Programs; and Capacity Bidding Programs. In addition, I testify regarding PG&E's Automated Response Technology, PG&E's Online Platform for Residential DR Offers, and SCE's Mass Market DR Pilot.

III. MARKET-INTEGRATION EFFICACY STUDY

Q. Can you summarize PG&E, SCE, and SDG&E's recommendations for market-integration study?

A. Yes. PG&E, SCE, and SDG&E propose that the Commission conduct, as PG&E characterizes it, a

> large-scale study to determine whether DR market integration is a more effective mechanism to support the state of California's clean energy policy, whether the Commission's goals for DR market integration have been achieved, and what changes to policies, rules, or processes should occur to make DR a more useful resource.[9]

SCE asserts, "a more complete and granular evaluation of the CAISO market integration is needed, now that IOUs and DR stakeholders have been operating under

[8] Amended Scoping Memo, at p. 5.
[9] Pacific Gas and Electric Company – 2024-2027 Full Proposal – Prepared Testimony, submitted in this proceeding on May 2, 2022 (Exhibit ("Ex.") PG&E-2), at p. 2-8, lines 1-5.

the current construct developed by the Commission for almost a decade."[10] SDG&E recommends:

> that the Commission initiate a large-scale study to determine whether DR market integration is the best mechanism to support the State's clean energy policy, whether the Commission's goals for DR market integration have been achieved, and what changes to policies, rules, or processes should occur to make DR a more useful resource.[11]

All three IOUs propose that an advisory committee be formed that would be composed of representatives from the IOUs, Energy Division, California Independent System Operator ("CAISO"), California Energy Commission ("CEC"), and "other stakeholders as appropriate" to provide feedback on the study's direction and serve as contacts for the consultants to request data.[12]

Q. What is your opinion of this proposal?

A. I agree with the IOUs that, with DR bifurcation almost ten years old, the time is ripe to conduct a study as they propose. However, regardless of the study results, the Commission should strive to preserve optionality for DR participants and third parties to deliver Load Modifying and/or Supply Resource DR depending on their respective business models. Since the Commission adopted bifurcation, DR providers have made significant investments and strategic decisions to shape their business models to operate within this paradigm. On the other hand, some DR providers may prefer to provide both Load Modifying and Supply Resource DR, and some DR providers will likely prefer to solely deliver Load Modifying DR. The Commission should strive to accommodate both types of DR. However, IOUs and DR providers should have equal opportunity to deliver Load Modifying or Supply Resource DR.

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[10] Southern California Edison Company's (U 338-E) Testimony in Support of its Application for Approval of 2023-2027 Demand Programs: Exhibit 1 – Policy, submitted in this proceeding on May 2, 2022 (Ex. SCE-01), at p. 37, lines 7-9.

[11] Prepared Direct Testimony of E. Bradford Mantz – Chapter 1B on Behalf of San Diego Gas & Electric Company, submitted in this proceeding on May 2, 2022 (Ex. SDGE-1B), at p. EBM-92, lines 2-6.

[12] Ex. PG&E-02, at p. 2-8, lines 12-14; Ex. SCE-01, at p. 37, line 22 to p. 38, line 1; and Ex. SDGE-1B, at p. EBM-96, lines 10-13.

With regard to the proposed advisory committee, in addition to representatives of the IOUs, Energy Division, CAISO, and CEC, as the IOUs propose, its composition should include representatives of residential and non-residential DR participants as well as third-party DR providers. This may have been the intent of the IOUs, but for the sake of clarity, the Commission should specify that these groups be included on the advisory committee as well. I would be concerned that a lack of representation of these critical market segments could lead to recommendations that only meet the needs of a subset of the parties involved without consideration of the practical impacts to market entry and customer participation.

IV. COMPETITIVE PARITY

Q. Is it correct that Issue 1 in the Amended Scoping Memo for A.22-05-002 et al asks whether the IOUs' Applications advance the goals, principles, directives, and guidance adopted in Decision ("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?

A. Yes.

Q. Is it also correct that Issue 2 askes whether the IOUs' proposed DR programs and activities, including pilot recommendations, are reasonable?

A. Yes.

Q. In determining compliance with Commission directives and reasonableness, is it your opinion that the Commission should consider whether the IOUs' proposals in their Applications maintain competitive parity between the IOUs and third-party DR providers and, if so, why?

A. Yes. The Commission should examine whether the IOUs' proposals maintain or establish competitive parity between the IOUs and third-party DR providers, or whether the proposals create a real or perceived advantage for the customer to take service from the IOUs. Examining competitive parity is consistent with the principles adopted by the Commission in D.16-09-056. In particular, the Commission determined, "Demand response customers shall have the right to provide demand response through a service provider of their choice and Utilities shall support their choice by eliminating barriers to data access."[13] This principle states a preference for customers to freely choose their provider. However, the ability for customers to make choices may be undermined if there are perceived or real benefits that accrue to the customer by virtue of enrollment in the IOUs' programs that are not available to customers who select a third-party DR provider. This may come in the form of inconsistencies in program options, program eligibility, access to technology incentives, and the scope of IOU marketing efforts. Without a level playing field, customers will be constrained in their DR participation options. From the perspective of DR providers, a fair market environment that a level playing field affords is more likely to attract market participants. This in turn drives competition and innovation which improves grid reliability.

Q. Please describe what advantages the IOUs have included in their Applications that would inure to customers participating in the IOU-provided DR services and that would be disadvantageous to customers participating in third-party provided DR services?

A. There are several. The IOUs have the unique ability to designate their Supply Resource programs as Reliability Demand Response Resources ("RDRR"). For example, SCE's Smart Energy Program ("SEP") and Summer Discount Plan ("SDP") are RDRRs. RDRRs are dispatched far less frequently than Proxy Demand Resources ("PDR") because they are considered "emergency" programs. In contrast, when contracting out their DR capacity to load-serving entities ("LSE"), including IOUs, DR providers are required to bid this capacity into the CAISO market as a PDR. The option to choose between a PDR or RDRR is not available to DR providers.

Another example is the IOUs' unique ability to transition their Supply Resource DR programs to Load Modifying programs. Similar to being able to designate programs as RDRRs, SCE's proposal to transition its Capacity Bidding Program ("CBP") from a

[13] D.16-09-056, Ordering Paragraph 8.

Supply Resource to a Load Modifying program is not an option that is open to DR providers.

One more example of elements in the IOU applications that advantage them is their preferred access to technology incentives for their programs. Customers participating in IOU DR programs and the DRAM Pilot are eligible for technology incentives, but customers participating in third-party Resource Adequacy ("RA") contracts are not, even though they provide equally valuable DR RA capacity.

Q. Please describe how each of these instances provide the IOUs with an advantage over third-party DR programs.

A. Designating a Supply Resource DR program as an RDRR creates a clear recruiting advantage when competing for customers because the program will be dispatched less frequently, all things being equal. This is due to the fact that PDRs are bid into the CAISO market during the Availability Assessment Hours ("AAH") while RDRRs are only bid in during emergency conditions (unless the RDRR is also bid into the CAISO day-ahead market which is uncommon). Similarly, transitioning a DR program from a Supply Resource to a Load Modifying program enables the IOU to dispatch it based on other conditions that may more accurately reflect a need rather than the wholesale electricity market price. SCE implicitly acknowledges the advantage of less frequent dispatches when, in discussing its Market Integration Study proposal, it cites the "significant customer attrition resulting, in part, from the number and duration of events…" that results from the DR market integration.[14] All things being equal, customers will naturally prefer to participate in programs that require less frequent dispatch because fewer dispatches result in lower negative impacts on the quality of life of residential DR participants and the business operations of non-residential participants. If IOUs are to have the discretion to designate their programs as PDR/RDRR and Supply Resource/Load Modifying, then it should also be available to third-party programs like the DRAM and RA contracts executed by DR providers with

[14] Ex. SCE-01, at p. 32, lines 3-6.

IOUs or other LSEs. Without such parity, IOUs will have a distinct competitive advantage relative to DR providers in customer recruitment.

Q. Please describe how excluding third-party DR programs from technology incentives provides the IOUs with an advantage over third-party DR programs?

A. It is important for third-party DR provider customers to have equal access to incentives for several reasons. First, access to technology that is funded by all ratepayers should be available to all ratepayers as long as they are participating in a DR program that provides RA capacity or equivalent (in the case of Load Modifying DR). If the IOUs' DR program participants can have access to that equipment at a lower overall cost, then, all else being equal, IOU DR programs are likely to be more attractive. At the very least, this and creates an undue preference for customers to participate in an IOU, rather than third-party, DR program. Similarly, this could act as a pressuring factor to discourage DR providers from engaging in bilateral RA contracts with IOUs and non-IOU LSEs. Table 1 below shows the current IOU DR programs that are eligible for technology incentives.[15]

Table 1: IOU DR Programs Eligible for Technology Incentives

	PG&E	SCE	SDG&E
Residential	CBP DRAM SmartRate	SEP CBP DRAM	AC Saver DRAM
Non-Residential	CBP DRAM PeakDay Pricing Qualifying Pilots	CBP DRAM Critical Peak Pricing Realtime Pricing Qualifying Pilots	CBP DRAM Critical Peak Pricing Qualifying Pilots

[15] *Joint Investor-Owned Utilities' Draft Updates to the Auto Demand Response Control Incentives Guidelines and Adopted Policies*, Appendices A and B, August 15, 2022.

The value of technology incentive eligibility is attested to by PG&E and SCE, who point out how Automated Demand Response ("ADR") incentives can drive long-term DR participation by customers. PG&E states regarding the impact on DR participation when receiving an ADR incentive, "that 84 percent of accounts do remain in a DR program for three years and 60 percent stay enrolled for five or more years."[16]

Similarly, SCE states,

> Energy Solutions found that once an account is enrolled in a DR program after receiving an Auto-DR incentive, they tend to remain enrolled for at least three years, and almost 60% of accounts stayed in DR for five or more years after incentive payment. These results show that the Auto-DR Incentive Program is a strong driver of sustained engagement with DR programs and that most customers that receive the incentive do become ongoing DR participants.[17]

These are powerful statements that, when considered in the context of overall technology incentive eligibility, clearly point to the benefits of opening technology incentive programs to all third-party DR that supports grid reliability, including RA capacity, and Load Modifying DR that can reliably reduce demand.

Q. What relief do you recommend to rectify the IOU advantages that you describe?

A. The Commission should allow DR providers the option to contract out their capacity as RDRRs, subject to and with equal access to the Emergency DR Program headroom, if the contracting LSE wants Supply Resource RA capacity. For contracting LSEs who prefer to reduce their RA requirement by reducing their load forecast, DR providers should be able to provide Load Modifying DR.

[16] Ex. PG&E-02, at p. 4-9, lines 1-3.

[17] Southern California Edison Company's (U 338-E) Testimony in Support of its Application for Approval of 2023-2027 Demand Response Programs: Exhibit 3 – SCE's 2023-2027 Proposed Demand Response Programs by Category, submitted in this proceeding on May 2, 2022 (Ex. SCE-03), at p. 59, line 17 to p. 60, line 2.

V. MID-CYCLE REVIEW PROCESS

Q. Do you support a mid-cycle review process and if so, why?

A. Yes. Under a five-year program cycle and even under what is effectively a four-year cycle for the 2024-2027 period, it is critical that there be a mid-cycle review. This serves as an opportunity not only for the IOUs to make course corrections to their DR program portfolios, it also provides other parties an opportunity to provide feedback as well. Without this, DR programs could not be improved absent the IOUs unilaterally requesting authorization to revise individual programs on a case-by-case basis or as part of another DR application proceeding. There should be a predictable timeframe by which IOUs and other parties can provide feedback on the IOU DR programs outside of the application process every five years.

Q. Are there opportunities to improve the current process?

A. Yes. My primary concern about the mid-cycle review process for the 2018-2022 program cycle is that it was not resolved until over a year after the IOUs submitted their respective advice letters. The IOUs submitted their advice letters on April 1, 2020 but the Commission only approved Resolution E-5112 for SCE's advice letter on July 15, 2021, and Resolution E-5103 for PG&E and Resolution E-5113 for SDG&E on August 4, 2022. On account of the delayed resolution, program modifications were delayed as well. As SCE succinctly described it, "the value of a mid-cycle review and the opportunity to make timely portfolio or programmatic changes can be significantly hampered by a lengthy review process."[18] I recognize that the delay was likely due to the Emergency Reliability proceeding (Rulemaking ("R.") 22-11-003.) and so this is not a criticism of the Commission. Nevertheless, the significant delays in Commission approval of the IOUs' advice letters limited the benefits of the approved program modifications. I echo SCE's request that the Commission seek to resolve the IOUs' mid-cycle advice letters no later than five months following submission.[19] I also support retaining an April 1 due date, in this instance, in 2026. This would allow for two years of

[18] Ex. SCE-01, at p. 41, lines 14-15.
[19] *Id*., at p. 42, lines 4-5.

experience with the 2024-2027 DR program portfolio to inform any revisions for implementation in 2027.

VI. DUAL PARTICIPATION

Q. Please address PG&E's dual participation proposal.

A. For all of the reasons explained by PG&E in its Opening Testimony and Supplemental Testimony, it is imperative that dual participation rules be reassessed as expeditiously as is reasonable.[20] The current patchwork of programs offered by different jurisdictional entities and regional energy networks ("REN"), on top of the IOUs' DR programs, including the CEC Demand Side Grid Support Program, the Market Access Programs offered by the IOUs, RENs, and Community Choice Aggregators ("CCA"), dynamic rates-based load shifting pilots currently deployed, and a more broad-based dynamic rate framework being developed in R.22-07-005, has resulted in a complicated DR landscape. The services produced for each program are not necessarily the same and, as DERs can often provide more than one service at a time, there is more value to be unlocked by enabling dual participation. Therefore, the time is certainly ripe to reexamine the dual participation rules to ensure clarity and transparency with regard to opportunities and requirements for participating in multiple programs.

VII. EMERGENCY LOAD REDUCTION PROGRAM ("ELRP")

Q. What are the IOUs' proposals for the ELRP?

A. PG&E proposes to eliminate the minimum dispatch requirements for sub-Groups A.2, A.4, and A.5.[21] SCE proposes to continue to operate ELRP for A.1, A.3, and A. 6 customers, transition ELRP to an emergency reliability resource, reduce the incentive payment to $1/kWh and cease the use of Flex Alerts as the program trigger for A.6.[22]

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[20] Ex. PG&E-2, at p. 2-8, line 30 to p. 2-10, line 25 and Pacific Gas and Electric Company – Chapter 12 – Second Supplemental Testimony to PG&E's Application for 2024-2027 Demand Response Portfolio, submitted in this proceeding on March 3, 2023 (Ex. PG&E-7, p. 12-13, line 17 to p. 12-16, line 9.
[21] Ex. PG&E-2, at p. 4-30, lines 16-19.
[22] Ex. SCE-03, at p. 76, lines 1-10.

Q. Does the Council support the continuation of the ELRP beyond 2025? Please explain why or why not.

A. Yes, if the following necessary changes are made: 1) make A.6, also known as Power Saver Rewards, opt-in rather than opt-out; and 2) put Group B participation on a level playing field with Group A in terms of Incremental Load Reduction ("ILR") calculation methodology and minimum dispatch requirements. This is consistent with the need that I addressed above for competitive parity between the IOUs and DR providers. The current ELRP rules advantage IOU DR program participants in Group A relative to Group B participants which are comprised of CBP participants and customers enrolled in RA contracts between DR providers and LSEs.

Under current rules, the Group A ELRP performance is calculated at the meter level while Group B performance is calculated at the CAISO resource level. This approach unfairly favors Group A over Group B participants because it only counts positive Group A customer performance while Group B performance is based on the net (positive minus negative) performance across all customers within a PDR. Group A participants with positive incremental load curtailment (i.e., they successfully reduce their load relative to their baseline during an ELRP event) are paid the full value for that curtailment; because the ELRP is a best-efforts program, any Group A participants that provide negative load curtailment are simply not compensated and are subject to no penalty. Conversely, because the performance of Group B participants is calculated at the resource level, individual participant performance, and therefore payment, is impacted by the performance of others in the resource. In some cases, positive incremental load curtailment by the participants within a given resource may be offset by negative curtailment by other customers within that same resource, leading to no payment whatsoever. Figure 2 below portrays a hypothetical ELRP event in which the same customers (characterized as Meter A through Meter D) would receive a different amount of compensation for the exact same ILR depending on whether they are in Group A or Group B.

Figure 2: Comparison of Group A vs. Group B ELRP Performance and Compensation

Meter	Meter-Level Performance	Group A ELRP Compensation	Group B ELRP Compensation
Meter A	1 MWh	$2,000	$2,000
Meter B	2 MWh	$4,000	$4,000
Meter C	-0.5 MWh	0	-$1,000
Meter D	-0.5 MWh	0	-$1,000
Group A Performance (Gross)	**3 MWh**	**$6,000**	**N/A**
Group B Performance (Net)	**2 MWh**	**N/A**	**$4,000**

In this example, the aggregate ILR of Meters A and B is 3 MWh, while the aggregate ILR of Meters C and D is -1 MWh. Under Group A, Meter A would earn $2,000 and Meter B would earn $4,000. Because ELRP is a best-efforts program, the negative performance of Meters C and D would be zeroed out, so the total Group A revenue would be $6,000. However, under Group B, the negative performance of Meters C and D would reduce the Meter A and B ILR by -1 MWh, as mentioned above, resulting in only 2 MWh of net ILR. Therefore, total Group B revenue would be $4,000.

To summarize, identical performance across the same four meters result in 50 percent greater compensation for Group A customers. This is a major flaw in the ELRP compensation mechanism that must be rectified because it creates a clear advantage for Group A participation because it motivates customers enrolled with aggregators in Group B to instead directly enroll with their local IOU in order to participate in Group A.

Another key advantage available to IOUs but not DR providers is the minimum dispatch requirement for sub-groups A.2, A.4, and A.5. Because the ELRP is an energy-only, best-efforts (i.e., no penalty) program, customers and DR aggregators want as many opportunities as possible to earn revenues. It is unfair and inappropriate for selected Group A sub-Groups to benefit from a degree of certainty over the number of hours they will be dispatched, while Group B does not. It is especially ironic that when there is a desire among some state agencies and parties that third-party DR be dispatched more frequently, a minimum dispatch requirement does not exist for Group B participants to help motivate more frequent dispatch.

The benefits of a minimum dispatch requirement for an energy-only program are clear. Some relative revenue certainty is needed because, though the voluntary nature of the ELRP may create the appearance of no commitment costs, in reality there are often underlying costs to customers and DR providers to participate and the only way to recover these costs for an energy-only program is through dispatch revenue. Although the prolonged Labor Day heatwave triggered the program for all participants for multiple days in 2022, such conditions may not materialize in the future.

In addition, the opt-out model for sub-Group A.6 (also known as Power Saver Rewards ("PSR")) should be reconsidered. I am particularly concerned about the load impacts and cost of the IOUs' sub-Group A.6. For all IOUs, the per-customer impact was very low relative to the actual amount paid to each customer, a symptom of free-ridership. Given the recent reliability problems that California has been facing recently, it is understandable that the Commission would want to take every reasonable measure to maximize customer load curtailments when they are needed most; however, compensating customers for incidental, rather than intentional, load curtailment defeats the purpose of a DR program which should be to motivate active load curtailment. This free-ridership is demonstrated in PG&E's and SCE's respective April 3, 2023 Load Impact assessments which found that the ex post load impacts of sub-Group A.6 were largely attributable to Flex Alerts with little to no increment load impacts associated with the ELRP.[23]

[23] PG&E 2022 ELRP Report, submitted on April 3, 2023, at p. 119 and SCE 2022 Load Impact Report, submitted on April 3, 2023, at Appendix A, at p. 44.

Consequently, I agree with the recommendations made in these reports to increase average ILR by increasing the number of self-enrolled ELRP participants and discontinuing A.6 auto-enrollment.[24]

Q. Are the IOUs' ELRP proposals reasonable?

A. As to PG&E's proposal, I do not support eliminating the minimum dispatch requirements for sub-Groups A.2, A.4, and A.5 because the ELRP is an energy-only, best-efforts (i.e., no penalty) program, so some customers and DR aggregators want as many opportunities as possible to earn revenues. As I explained above, it is unfair and inappropriate for selected sub-Groups to benefit from a degree of certainty of their opportunity to earn revenues, while others do not.

As to SCE's proposal, I support continuing the ELRP for all Groups and sub-Groups, not only A.1, A.3, and A.6 customers. With regard to transitioning the ELRP to an emergency reliability resource, presuming this means SCE intends to make it an RDRR program, I would oppose this because, as I have already stated, the IOUs should not have unilateral authority to created RDRR programs when third parties do not. I also oppose reducing the incentive to $1/kWh because SCE provides no explanation for why it should do so, nor does it address the inevitable reduction in load impacts that would result. Finally, I would support eliminating the Flex Alert as a program trigger for sub-Group A.6 participants. As I explained above, free ridership is clearly a major problem with sub-Group A.6 which is exacerbated by a Flex Alert trigger when many customers will conserve regardless of their participation in the ELRP.

Q. What changes to ELRP do you recommend?

A. I recommend the following improvements to the ELRP:

Adopt a minimum dispatch requirement for Group B: To generate more certainty that there will be an opportunity to earn revenues by curtailing load when it is needed most, I recommend that the Commission adopt a 10-hour annual minimum dispatch for

[24] PG&E 2022 ELRP Report, submitted on April 3, 2023, at p. 119 and SCE 2022 Load Impact Report, submitted on April 3, 2023, at Appendix A, at p. 44.

Group B customers. This is consistent with the minimum dispatch requirement for non-BIP aggregators under sub-Group A.2.

<u>Calculate Group B performance at meter level:</u> The Commission should direct the IOUs to measure Group B performance for the purposes of calculating ILR in a manner that is consistent with Group A customers, to ensure that the ILR is compensated equally between the two participation pathways.

VIII. BASE INTERRUPTIBLE PROGRAM ("BIP")

Q. What are the IOUs' proposals for their BIP?

A. PG&E proposes the following:

- Year-round enrollment up to the reliability cap.[25]
- Eliminate the lottery system.[26]
- Require new customers to remain enrolled for a minimum of six months before unenrolling or raising the Firm Service Level ("FSL").[27]
- Increase monthly incentives.[28]
- Adopt a limit of 10 events/30-day period and events on three consecutive days.[29]
- A new 15-minute option.[30]

SCE proposes to increase incentives and remove event days from the customers' BIP incentive calculation.[31]

SDG&E proposes to retire the program at the end of 2023.[32]

[25] Ex. PG&E-2, at p. 3-7, line 15 to p. 3-8, line 2.
[26] *Id.*, at p. 3-8, lines 3-26.
[27] *Id.*, at p. 3-8, line 27 to p. 3-9, line 33.
[28] *Id.*, at p. 3-10, lines 1-18 and Table 3-4.
[29] *Id.*, at p. 3-11, lines 1-19.
[30] *Id.*, at p. 3-11, lines 20-30 and p. 3-12, Table 3-5.
[31] Southern California Edison Company's (U 338-E) Testimony in Support of its Application for Approval of 2023-2027 Demand Response Programs: Exhibit 4 – Program Incentive Development/Cost-Effectiveness Analysis/Program Enrollment and Load Impact Forecasts/Revenue Requirements and Cost Recovery, submitted in this proceeding on May 2, 2022 (Ex. SCE-04), at Table II-3 and Ex. SCE-03, at p. 15, line 2 to p. 16, line 18.
[32] Ex. SDGE-1B, at p. EBM-8, line 13 to EBM-9, line 5.

Q. Are the IOUs' proposals reasonable?

A. Yes.

IX. AUTOMATED DR ("ADR"), TECHNOLOGY INCENTIVE ("TI") AND TECHNICAL DEMONSTRATION ("TD") PROGRAMS

Q. What are the IOUs' proposals for their respective ADR, TI, and TD programs?

A. PG&E proposes the following:

- Maintain the option for its ADR program which was approved in D.21-12-015 for 100 percent payment after the installation of the technology is confirmed as dispatchable and DR program participation is verified on the condition that the customer commits to a five-year enrollment for those participants electing the 100 percent option.[33]
- Expand its ADR FastTrack application from non-residential SMB customers to increase the number of measures, business sectors, and customer segments, including large commercial and industrial customers.[34]
- Expand ADR eligibility to include RDRR resources, including the BIP.[35]
- Discontinue the Residential Deemed Incentive application.[36]

SCE proposes the following:

- Maintain its Programmable Controllable Thermostat ("PCT") Incentive Program and use the PCT incentive to apply an instant discount at the point-of-sale through its SCE Marketplace.[37]
- Maintain the ADR Technology Incentive Program option approved in D.21-12-015 of 100 percent payment after the installation of the technology is confirmed

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[33] Ex. PG&E-2, at p. 4-8, lines 15-17.
[34] *Id.*, at p. 4-9, lines 9-17.
[35] Ex. PG&E-2, at p. 4-8, lines 15-17.
[36] *Id.*, at p. 4-12, lines 5-8.
[37] Ex. SCE-03, at p. 56, lines 22-27.

as dispatchable and DR program participation is verified on the condition that the customer commits to a five-year enrollment.[38]

- Research expanding its Express Control Incentives option to increase the number of business sectors and customer sizes.[39]
- Expand ADR eligibility to include BIP-15 program.[40]

SCE also indicates "it is not currently anticipating that DRAM will be a qualifying program option after 2023."[41]

SDG&E recommends to sunset its TI Program at the end of 2023 because the changes to the program design over the past several years have been ineffective in spurring contractor and customer participation.[42] SDG&E also notes that this program would have been found to be not cost-effective.[43]

Q. Are PG&E's proposals reasonable?

A. I support some of PG&E's proposals and oppose others. I do not believe that expanding ADR eligibility solely to RDRRs goes far enough. I agree with PG&E that it is an appropriate time to revisit the restriction to RDRRs of receiving AutoDR incentives in light of more frequent events, especially in light of the continuing capacity needs facing the State.[44] I also agree with PG&E's argument that ADR incentives could "help reduce BIP attrition" and that "customers who received ADR incentives through a DR program have a high potential of becoming long-term DR participants."[45]

I do not support PG&E's proposal to discontinue the Deemed Incentive Application. I am concerned that ceding these technology incentives to non-DR program proceedings risks future outcomes that may not benefit DR participants. A related, more practical concern is that it would require interested parties, many of which

[38] Ex. SCE-03, at p. 59, lines 3 to p. 60, line 8.
[39] *Id.*, at p. 60, lines 9-21.
[40] *Id.*, at p. 61, lines 1-14.
[41] *Id.*, at p. 61, lines 17-18.
[42] Ex. SDGE-1B, at p. EBM-54, lines 15-21.
[43] *Id.*, at p. EBM-54, lines 21-22.
[44] Ex. PG&E-2, at p. 4-10, lines 21-24.
[45] *Id.*, at p. 4-11, lines 9-11.

have limited budgets dedicated to regulatory engagement, to participate in a broader range of Commission proceedings. Also, funding through other programs carries a risk that these incentives could one day go away if they are found not to be core to those programs. Therefore, removing these incentives should be contingent on the Commission recognizing that any consideration to remove these incentives in the future in these other proceedings must be linked to re-introducing them in the DR proceeding. Nevertheless, this approach would not address the gap in residential technology incentives that would exist should they be eliminated from the successor program.

I also disagree with PG&E's presumption that the DRAM will be discontinued, thereby justifying a lower budget.[46] Though the Commission may choose not to extend the DRAM Pilot, it is premature to consider it a fait accompli. If the DRAM is ultimately extended, PG&E's ADR budget would then be lower than it should be.

Q. Are SCE's proposals reasonable?

A. I support some of SCE's proposals and oppose others. I support SCE's proposed revisions, but I do not believe the proposed eligibility expansion goes far enough. Furthermore, SCE's remark that it does not foresee DRAM as a qualifying program after 2023 is, as with PG&E, premature and risks creating confusion over whether the program would remain eligible for ADR incentives should the Commission choose to retain it.[47]

Q. Are SDG&E's proposals reasonable?

A. No. I disagree with SDG&E's proposal to sunset its TI Program. SDG&E is likely correct in citing the program changes over the past few years as the culprit behind low participation in the program, as this aligns with the analysis provided by PG&E and SCE to justify extending the 100 percent payment option. However, SDG&E's solution to cancel the program rather than identify and implement improvements is shortsighted. I also find SDG&E's remark that its TI Program would not be cost-effective to be less relevant because none of its DR programs are cost effective based on the current DR

[46] Ex. PG&E-2, at p. 4-12, lines 13-14.
[47] Ex. SCE-03, at p. 61, lines 17-20.

cost-effectiveness paradigm. Therefore, in this instance, I do not see that as a valid justification for sunsetting the program.

Q. What changes do you recommend to the IOUs' proposals?

A. For all of the IOUs, I recommend that ADR incentives be made equally available to all customers that participate in a DR program or third-party Resource Adequacy contract, subject to the same participation requirements. As I have explained, PG&E and SCE have cited the benefits of ADR incentives in incentivizing DR participation. Excluding customers who are enrolled in a third-party DR contract is discriminatory against them, favors customers participating in IOU DR programs, and is counter to the Commission's Competitive Parity principles.

Q. Do you recommend changes to any IOU-specific proposals?

A. Yes. PG&E should retain its Residential Deemed Incentive Application. As I explained above, funding them through other programs places a greater burden on parties by forcing them to engage in yet another proceeding to ensure they are retained and properly funded. In addition, it introduces a risk that the priorities of those programs could change relative to DR programs that could have detrimental effects on these incentives. PG&E should also retain the budget it proposed to eliminate due to its premature presumption that the DRAM Pilot would not be extended. If it is not ultimately extended, the unused budget would simply be returned to ratepayers.

SCE should expand eligibility to its BIP-30 and clarify that DRAM will be eligible for AutoDR incentives if DRAM is extended. It is unreasonable to expand eligibility to BIP-15 but not BIP-30. Both programs provide valuable capacity and, based on SCE's own admission that ADR incentives promote longer DR program participation, including BIP-30 will improve BIP participation.

I recommend that SDG&E retain its TI Program and align it with PG&E's and SCE's programs by adopting the 100 percent up-front incentive option that is linked to a five-year DR participation requirement and expanding eligibility to its BIP.

Q. What do the IOUs propose with regard to the Smart Communicating Thermostat ("SCT") Program that was approved in D.21-12-015?

A. PG&E recommends folding its SCT program into its proposed Automated Response Technology ("ART") program.[48] SCE makes no recommendations specific to this program. SDG&E proposes to not extend the program beyond 2023.[49]

Q. Are the IOUs' SCT proposals reasonable?

A. As a matter of principle, I believe that technical incentives should not be limited to specific programs and should be made available to all DR programs, direct-enrolled and third-party. As I quoted PG&E and SCE above, when these incentives are leveraged to enroll customers in a DR program, they tend to participate for a longer period of time.

PG&E provides very little explanation for its proposal other than that other programs can be the source of these incentives especially with regard to whether and how DR providers could continue to have access to the program incentives.[50] This also ignores the value of the SCT Program to encourage DR enrollment by allowing DR providers to leverage these up-front incentives when recruiting customers. The IOUs' own technology incentive programs utilize this approach, be it PG&E's ART Program, SCE's Marketplace, and SDG&E's Smart Energy Program.

SDG&E provides a more detailed explanation for its proposal, citing two distinct challenges: 1) thermostats purchased by customers directly through retail channels cannot be signaled directly by SDG&E[51] and 2) explaining the TD program design to customers.[52]

I agree that all devices receiving TD incentives should enrolled in DR programs and do not oppose SDG&E adding an enrollment payment for participating in its Smart Energy Program ("SEP"). As with my concern with PG&E's proposal, eliminating the

[48] Ex. PG&E-2E, at p. 7-10, lines 19-21.
[49] Ex. SDGE-1B, at p. EBM-53, line 16 to p. EBM-54, line 7.
[50] Ex. PG&E-2, at p. 4-12, lines 6-8.
[51] Ex. SDGE-1B, at p. EBM-49, lines 7-10
[52] *Id.*, at p. EBM-50, line 1.

third-party option of the SCT Program would eliminate the opportunity to leverage customer purchases of smart thermostats to enroll them into other DR programs. This highlights one of the benefits of retaining the SCT Program, especially given that SDG&E no longer utilizes a marketplace which could have been used in conjunction with up-front technology incentives to enroll customers in DR programs. The SCT Program ensures that ratepayer funds are only used for technology incentives that lead directly to DR participation.

As I have stated, I support a five-year DR participation requirement. However, with more interest among the IOUs and the Commission to explore moving some market-integrated DR programs into RDRR, or transition to Load Modifying DR, and develop a CalFUSE-type dynamic price framework, what constitutes an eligible DR program should be expanded to include DR programs that participate as a PDR, RDRR, or in a dynamic rate-driven load shifting framework like CalFUSE that eventually comes out of R.22-07-005.

Q. Has an evaluation been performed on the SCT Program?

A. Not to my knowledge.

Q. Should an evaluation be performed for the SCT Program?

A. Yes. This is an important step to take for any pilot program. Without one, it is not clear whether the pilot should be retained or how it can be improved.

Q. Should the IOUs retain the SCT Program? If so, why?

A. Yes. First, as I have shown above, there are no data examining the efficacy of the program. The concept behind this pilot is new in that it applies an approach already used by some IOUs through their marketplaces to leverage up-front smart thermostat incentives to incentivize residential customers to enroll in a DR program. This pilot provides a similar opportunity to third parties to leverage up-front technology incentives to enroll new customers in DR programs. Additional experience is needed to inform the success and potential improvements to the pilot, so the Commission should extend it for another two years at minimum, with an evaluation done for the mid-cycle review.

Q. What initial improvements do you recommend?

A. This program is currently only available to DR providers participating in the DRAM Pilot. However, this unnecessarily limits participation to DR providers who have been awarded DRAM contracts. This pilot should be opened to third-party customers who are participating in the Capacity Bidding Program as well as in Resource Adequacy contracts with the IOUs or any other LSE. I also recommend eliminating the limitation of incentives under this program to Climate Zones 9-15. Referring to one of the principles above, a customer's eligibility should not be constrained by their location.

X. <u>CAPACITY BIDDING PROGRAM ("CBP")</u>

Q. What changes do the IOUs propose to make to their CBP?

A. PG&E proposes the following:

- Increase monthly capacity incentives.[53]
- Revise program hours to 4:00-9:00 p.m.[54]
- Accelerate energy payments BIP.[55]
- Revise the payment/penalty structure.[56]
- Streamline the CBP by removing the Prescribed and Elect+ Options.[57]
- Remove all event duration options other than 1-4 hours.[58]
- Testing enhancements.[59]
- Weekend participation.[60]
- Continue electric enrollment.[61]

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[53] Ex. PG&E-2, at p. 3-26, line 1 to p. 3-27, line 5.
[54] *<u>Id</u>*., at p. 3-27, lines 6-22.
[55] *<u>Id</u>*., at p. 3-27, line 23 to p. 3-28, line 9.
[56] *<u>Id</u>*., at p. 3-17, line 3 to p. 3-18, line 14 and Table 3-9.
[57] *<u>Id</u>*., at p. 3-18, line 15 to p. 3-19, line 23.
[58] *<u>Id</u>*., at p. 3-18, line 15 to p. 3-19, line 23.
[59] *<u>Id</u>*., at p. 3-19, line 24 to p. 3-20, line 26.
[60] *<u>Id</u>*., at p. 3-20, line 27 to p. 3-21, line 22.
[61] *<u>Id</u>*., at p. 3-28, line 10 to p. 3-29, line 12.

If the Commission directs the IOUs to put their DR programs on supply plans, PG&E recommends revising the nomination window,[62] providing two Elect bid price options,[63] and recovering RA-related market penalties via the DREBA.[64]

SCE proposes the following:

- Change the CBP availability hours from 5:00-9:00 p.m. to 4:00-9:00 p.m.[65]
- Increase the maximum number of monthly events from five to six while maintaining the monthly 30-hour limit.[66]
- Eliminate the off-peak months and instead reallocate the incentives from November-April to the capacity incentives for the May through October period.[67]
- Modify its nomination schedule by replacing the monthly nomination process with a single, annual nomination by January 31 each year.[68]
- Impose a collateral requirement on CBP aggregators.[69]
- Eliminate the Day-Of CBP.[70]
- Align energy payments with the settled Locational Marginal Price ("LMP") at the awarded energy quantity rather than the dispatched quantity and cap energy payments at 100 percent of the awarded energy quantity.[71]

SDG&E recommends replacing the current CBP products with CBP Elect and Day-Of 1:00-9:00 p.m. Elect products,[72] updating the non-performance penalty,[73] and extending the Capacity Bidding Residential Pilot through 2024.[74]

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[62] Ex. PG&E-2, at p. 3-22, line 1 to p. 3-23, line 25.
[63] *Id*., at p. 3-23, line 26 to p. 3-25, line 13.
[64] *Id*., at p. 3-25, lines 14-26.
[65] Ex. SCE-03, at p. 20, lines 4-7.
[66] *Id*., at p. 20, lines 7-9.
[67] *Id*., at p. 21, lines 3-12 and p. 23, lines 1-7, Table III-9.
[68] *Id*., at p. 21, lines 13-21.
[69] Ex. SCE-03, at p. 21, lines 3-21.
[70] Ex. SCE-03, at p. 21, line 22 to p. 22, line 9.
[71] *Id*., at p. 22, lines 10-25.
[72] Ex. SDGE-1B, at p. EBM-17, lines 3-13.
[73] *Id*., at p. EBM-17, line 14 to p. EBM-18, line 9.
[74] *Id*., at p. EBM-19, line 11 to p. EBM-20, line 11.

Q. Are the IOUs' CBP proposals reasonable?

A. As to PG&E, I support 1) increasing monthly capacity incentives, 2) accelerated energy payments, 3) revised payment/penalty structure, 4) streamlining the CBP, 5) weekend participation, and 6) continue electronic enrollment. I oppose 1) changing the nomination window, 2) providing two Elect bid price options, 3) recovering RA-related penalties via the DREBA, and 4) testing enhancements.

As to SCE, I support revising the availability hours because it aligns with the Availability Assessment Hours ("AAH") for the months during which SCE would offer the CBP going forward. I do not support capping energy payments at 100 percent of the awarded amount because the CAISO rules allow for additional energy payments for uninstructed energy when resources deliver more than their schedule. I support eliminating CBP for November through April (with the incentives reallocated to the remaining months) and eliminating the Day-Of CBP. I oppose increasing the maximum number of events from five to six if the Commission reduces the monthly limit to 24 hours because it would closely align with five five-hour dispatches.

I strongly oppose SCE's proposed nomination schedule and collateral requirement. The nomination schedule does not reflect the month-to-month capacity availability of CBP participants, especially agricultural customers, and would eliminate one of key benefits of the CBP relative to the DRAM or other third-party RA contracts. With regard to the collateral requirement, SCE provides no evidence or even an explanation for why it is necessary.

I support SDG&E's proposal.

Q. Do you recommend changes to SCE's existing CBP, exclusive of its proposed modifications in its Application?

A. Yes. I recommend that the monthly availability requirement be reduced from 30 to 24 hours per month. A 30-hour monthly limit is not consistent with the availability requirements under the DR Maximum Cumulative Capacity ("MCC") Bucket which sets a minimum monthly requirement of 24 hours. In fact, SCE itself has stated that it "has seen significant customer attrition resulting, in part, from the number and duration of events…"[75]

XI. PG&E'S AUTOMATED RESPONSE TECHNOLOGY ("ART") PROGRAM

Q. What are your general observations about PG&E's ART Program Proposal?

A. My initial reaction is that the proposal is lacking substantial detail, so it is difficult to fully understand and analyze what is being proposed. It appears designed to appeal to a broad range of residential customers by allowing the use of many enabling technologies. However, several critical details remain to be developed, especially those listed under "Other Program Designs Elements for Consideration" in Table 3-16.[76]

According to PG&E, the DR resources under this program would be market-integrated as PDR.[77] At the same time, PG&E has indicated that "all technologies are required to support daily automatic load management function(s) for TOU or any other time varying rate plan (e.g., Real-Time Pricing)."[78] Under the current CAISO baselines, it is not clear to me how DR customers simultaneously participating in a PDR while also participating in any type of dynamic pricing other than TOU rates will allow for the accurate measurement of their CAISO market performance. If this is going to be used on a daily basis, then the CAISO baselines will not work because they rely on looking back to recent "like" days when no DR events have occurred. It is critical that the baselines can measure an impact every day rather than a diminishing impact as the prior impacts become normalized. Also, it is hard to build an aggregator business around this program because there is no up-front incentive, and it is pay-for-performance which does not provide the financial certainty that is generally needed for customers and DR providers.

I have some concerns about the role of third-party aggregators. PG&E indicated that it would "conduct an exploration to assess if the ART Program should expand to

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[75] Ex. SCE-01, at p. 37, lines 3-6.
[76] Ex. PG&E-2, Table 3-16, at p. 3-39, line 8.
[77] *Id.*, at Table 3-16, at p. 3-39, line 4.
[78] *Id.*, at Table 3-16, at p. 3-39, line 7.

include other Demand Response Providers (DRP)."[79] PG&E does not discuss the criteria by which it will make this assessment so it is not clear whether aggregators will have an option to participate at all. Based on the details that PG&E provides in its proposal, I see nothing that would indicate this program should not include an aggregator option

I am concerned that PG&E's budget is too low given its estimated load impacts. PG&E estimates a total load impact of 104 MW.[80] Assuming this quantity is reached in 2027, this corresponds to an annual budget of $1,124,145 for Administration and $4,496,580 for Implementation and Incentives.[81] This would translate to an incentive payment of $43.24/kW-year for a year-round program, for an average of $3.60/kW-month. This is far lower than the value of capacity and far lower than PG&E's current or proposed CBP incentives. Consequently, I am concerned that customers and aggregators may not find this program particularly attractive. If PG&E is expecting ART Program load impacts that exceed its CBP load impact estimates but with lower incentives, I am concerned that PG&E is setting itself up for failure.

Q. What changes do you recommend to PG&E's ART Proposal?

A. I recommend that new options be considered to measure the performance of resources that are dispatched on a daily or near-daily basis to address the problems this creates with like-day baselines. The most effective option would be through the creation of universal control groups; however, allowing sub-metering for behind-the-meter technologies like energy storage would address the issue for some, but not all, technologies.

Q. What relief would you recommend to address this issue?

A. Because the incentive structure(s) will be determined based on discussions with third parties, I recommend the Commission direct PG&E to re-submit the program budget when it submits the final program design, subject to PG&E's estimated load

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[79] Ex. PG&E-2, at p. 3-37, lines 31-33.
[80] *Id*., at p. 3-41, Table 3-18.
[81] *Id*., at p. 3-40, Table 3-17.

impacts and the cost-effectiveness requirement that is ultimately approved by the Commission in this proceeding.

XII. PG&E'S ONLINE PLATFORM FOR RESIDENTIAL DR OFFERS

Q. Is PG&E's Online Platform for Residential DR offers reasonable?

A. Based on the amount of detail provided, I generally support this proposal.

Q. Do you recommend any changes?

A. Yes. For customers that choose to participate in PG&E's CBP-Residential program, PG&E should direct them to a web page with participating CBP-Residential aggregators. This may already be PG&E's intent, but I recommend the Commission specifically direct PG&E to take this step to ensure customers are aware of all CBP aggregator options available to them.

XIII. SCE'S MASS MARKET DR PILOT

Q. Is SCE's Mass Market DR Pilot reasonable?

A. It is difficult to say based on the amount of detail SCE provided. It also appears to be partially redundant with SCE's Smart Energy Program so additional details are needed to ensure this program can be better analyzed.

Both programs target mass market customers using a broad array of enabling technologies. The Mass Market DR ("MMDR") Pilot appears intended to test out other elements such as incentive structures and aggregate load reduction capabilities of multiple devices at a single dwelling. It would be helpful to know exactly how SCE envisions the MMDR Pilot and Smart Energy Program interacting with one another. Also, the time frame seems excessively long for a pilot. When DR program cycles were three years in length, an IOU would take approximately six months to deploy a pilot for the summer following Commission approval; then, after two summers of deployment, an assessment would be performed in Year 3. If the IOU chose to deploy the pilot as a full program, the assessment would be used to support this in the next program cycle. In this instance, SCE proposes to use the full four remaining years in the 2023-2027 program cycle for this pilot.

Q. What changes do you recommend to the deployment timeline?

A. I recommend that, if approved, the pilot should be deployed in 2024-2025 with an assessment performed immediately following summer 2025. SCE should be directed to submit an advice letter by the end of 2025 to adopt the pilot as a full program for deployment in summer 2026. This could also be done as part of the mid-cycle review.

It may also be worthwhile to combine with the SEP. This would enable SCE to leverage the established, proven elements of that program while continuing to test the new elements under consideration for the MMDR Pilot.

Q. Does this conclude your testimony?

A. Yes, it does.