BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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| Application of Pacific Gas and Electric Company (U 39 E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 | Application 22-05-002 (Filed May 2, 2022) |
| And Related Matters. | Application 22-05-003<br>Application 22-05-004 |

**OPENING COMMENTS OF
THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, LEAPFROG POWER, INC., AND OHMCONNECT, INC. ON PROPOSED DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027**

Dated: November 28, 2023


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## TABLE OF CONTENTS

*Page*

## TABLE OF AUTHORITIES

*Page*

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

| | |
|---|---|
| Application of Pacific Gas and Electric Company (U 39 E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027 | Application 22-05-002 (Filed May 2, 2022) |
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The California Efficiency + Demand Management Council ("the Council"), Leapfrog Power, Inc. ("Leap"), and OhmConnect, Inc. ("OhmConnect") (collectively "the Joint Parties") respectfully submit these Opening Comments on the Proposed Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027 ("PD"), mailed in this proceeding on November 6, 2023. These Opening Comments are timely filed and served pursuant to Rule 14.3 of the California Public Utilities Commission's ("CPUC's") Rules of Practice and Procedure and the instructions accompanying the PD.

## I. OVERVIEW

The Joint Parties generally support the provisions of the PD pertaining to non-residential demand response ("DR") programs, especially program consolidation and higher incentives for the Capacity Bidding Program ("CBP"), and higher incentives for the Base Interruptible Program ("BIP"). Unfortunately, the PD creates unnecessary uncertainty for residential DR programs by eliminating SDG&E's residential direct-enrolled program and creates a potential gap in residential direct-enrolled options in the PG&E service area. The Joint Parties also have significant concerns regarding the further limitations that would be imposed on residential technology incentives, especially for participants in third-party DR programs, by failing to apply its proposed updated definition of a "Qualifying" DR Program to the investor-owned utilities' ("IOUs'") current smart thermostat incentive programs.

The PD's elimination of the annual IOU reporting requirement, especially in light of the statutorily mandated Load Shift Goal ("LSG") through the California Energy Commission ("CEC"), is highly problematic because it eliminates any accountability to the IOUs for meeting the LSG or any future DR procurement requirement. Instead, the Commission should develop IOU allocations of the LSG and impose accountability for failure to meet them. The Joint Parties respectfully request the CPUC to revise the PD as described below and in Appendix A to ensure more robust residential DR options as well as continued growth in third-party DR.

## II. THE PROPOSED DEFINITION OF A "QUALIFIED" DR PROGRAM SHOULD BE ADOPTED WITH A MINOR ADJUSTMENT

The Joint Parties support the PD's proposed definition of a "qualified" DR program when customers are subject to a requirement to participate in a DR program as a condition for receiving specified DR enabling technology incentives or rebates.[1] This updated definition improves clarity on what counts as a "qualified" program by specifying that these include market-integrated DR programs counted for RA *irrespective of whether the administrator is an IOU, CCA, or third-party DRP.*[2] It is the Joint Parties' understanding that this would include bilateral contracts between IOUs/community choice aggregators ("CCAs") and third-party DRPs for resource adequacy ("RA"). The Joint Parties have stressed in the past the importance of including bilateral RA contracts as "qualified" programs for purposes of meeting any DR participation requirements as a condition for receiving a DR enabling technology incentive in order to ensure customers participating in third party-administered programs and RA contracts remain eligible for these incentives, regardless of the disposition of the DR Auction Mechanism ("DRAM").

In addition, the Joint Parties were encouraged by the two criteria that would need to be satisfied for a Load Modifying DR program to be considered a "qualified" DR program. Criterion 2.b is critical to ensure that the capacity value of a qualifying Load Modifying program would be accounted for. Criterion 2.a appears to imply that a qualifying Load Modifying program would need to have a CAISO-based real-time market or day-ahead market price trigger. This is a logical approach that could also include a "hard" trigger such that a Load Modifying program would be required to dispatch once the adopted CAISO market price trigger was

[1] Proposed Decision, at Attachment 1.
[2] Proposed Decision, at Attachment A-1, emphasis added.

reached. This criterion also appears to include room for dynamic rates to be included by the dispatch signal being "*linked* to the energy prices in the Day-Ahead [sic] or real-time market" (emphasis added). Though these criteria appear to be adequate, another potential way to strengthen the criteria would be to modify Criterion 2.a to allow for a broader range of dispatch signals. For example, in considering past IOU DR programs prior to bifurcation, local (as granular as necessary) or system load could be another potential option for meeting the operational domain.

The Joint Parties see no reason why the PD should not apply this definition *now* to all IOU DR enabling technology incentive programs. The PD does not address this issue, only stating that though the updated definition is adopted, it caveats this by conditioning its applicability on whether "the Commission requires such enrollment as an eligibility condition for a customer's participation in a non-DR program."[3] This requirement already exists for the IOUs' respective Automated Demand Response ("AutoDR") programs, for example, so there is no good reason for the CPUC not to apply it now to all residential and non-residential DR enabling technology incentive programs.

## III. ELIMINATING THE DR ENROLLMENT REQUIREMENT FOR CUSTOMERS PARTICIPATING IN A TECHNOLOGY INCENTIVE PROGRAM IS UNSUPPORTED BY THE EVIDENCE

The PD declines to adopt the PG&E proposal to require customers that receive technology incentives to automatically enroll in a DR program, on the vague basis that "parties were generally opposed to the proposal" and, citing the Public Advocates Office ("Cal Advocates"), that requiring DR participation "could have negative bill impacts on low-income or medically vulnerable customers, or any others that do not understand how the DR programs operate."[4] The PD's characterization of general opposition to the proposal is not supported by the record; furthermore, eliminating the DR enrollment requirement would ignore the recent lessons learned in the dangers of free ridership with opt-out participation in sub-Group A.6 of the Emergency Load Reduction Program ("ELRP").

The PD mischaracterizes Cal Advocates' position as being in opposition to PG&E's proposal, but it focuses too narrowly on PAO's testimony. Cal Advocates was not actually opposed to this proposal stating, "While these mandates might ultimately be appropriate, the

[3] Proposed Decision, at p. 25.
[4] *Id*., at p. 35.

Commission should take care to consider the impacts and potential negative customer consequences before applying a blanket mandate."[5] Cal Advocates was simply cautioning about the potential for negative ramifications and suggested how to avoid them.

If the CPUC was to accept the narrative that the misuse of technologies by low-income or medically vulnerable customers is a significant and broad-based risk, it opens the door to speculation that these customers could end up misusing these technologies in a way to also *diminish* grid reliability. In any event, it is unclear why a customer should qualify for a ratepayer-funded DR enabling technology incentive if 1) there is no assurance that the technology in question will be used in such a way as to provide benefits to the grid, and 2) the Commission believes there is a chance that the customer's misuse of the technology could have negative bill impacts. In either instance, without a DR participation requirement tied to receipt of a DR enabling technology incentive, this seems like a misuse of ratepayer funds, something the Commission should be trying to avoid in light of the large-scale free ridership that has been observed in ELRP A.6.

The PD's rejection of PG&E's proposal also neglects to address the importance of leveraging technology incentives to maximize the benefits of these incentives to ratepayers when it does the opposite in its discussion approving PG&E's ART program. In it, the PD cites the ART program as a "way for PG&E to leverage existing technology program incentives and bring them back into the DR portfolio."[6] The Joint Parties agree that this is a benefit, but it is not clear why the PD would praise this feature of the ART program while rejecting a blanket policy of a DR participation requirement as a condition for receiving a technology incentive. In its rebuttal testimony, the Council addresses this by expressing support for Google's recommendation for pre-enrollment in DR programs. In the context of smart thermostat incentives, the Council explains the importance of leveraging them because it would maximize the reliability value that each participant can provide to the grid.[7] Providing incentives to customers to qualify for technologies that are capable of providing DR should entail a *requirement* to provide DR.

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[5] Public Advocates Office Errata to Opening Testimony, submitted in this proceeding on May 1, 2023 (Exhibit ("Ex.") Cal Advocates-01), at p. 2-4, lines 1-3.
[6] Proposed Decision, at p. 65.
[7] Rebuttal Phase II Testimony of the California Efficiency + Demand Management Council, submitted in this proceeding on May 12, 2023 (Ex. Council-03), at p. 6, lines 19-25.

## IV. ELIMINATING THE JOINT IOU STATUS REPORTS ON PROGRESS TOWARDS INTERIM DR GOAL IGNORES THE CEC'S LSG

The PD errs in approving the SCE proposal to eliminate the IOU requirement to file the Joint IOU Status Report Toward Interim Goal ("Status Report").[8] The Status Report was adopted by D.14-12-024 as part of a settlement in which the IOUs agreed to "an interim statewide DR Goal for cost-effective, event-based DR by 2020 equal to 5% of the sum of the individual peak demands of SCE, SDG&E and PG&E" that would "be in effect until superseded by a IOU-specific, firm DR Goal" with "annual reporting by the IOUs to this Commission, the CAISO, and the [CEC of actual IOU event-based DR achieved toward meeting the interim statewide DR Goal…"[9]

The PD justifies eliminating this important tracking tool by finding the SCE argument reasonable that "the purpose of the Status Report has been frustrated, due to various policy changes and [a] delay in the release of the final phase of the DR potential study."[10] This argument essentially "throws in the towel" on enforcing accountability for the interim five percent Supply Side DR procurement requirement to which the IOUs agreed in the settlement adopted in D.14-12-024. In effect, the Proposed Decision agrees with SCE's argument that the CPUC's own lack of commitment in this area justifies eliminating the 5 percent interim DR goal.

This is particularly concerning when the CEC has adopted its LSG pursuant to Public Resources Code 25302.7, as modified by Senate Bill 846 (2022), which directs the CEC to adopt a LSG in consultation with the Commission and the CAISO. The CEC has since adopted a 7,000 MW load shift goal by 2030, which includes 1,410 MW of IOU Supply-Side DR and 3,000 MW of Load Modifying DR. With these DR procurement targets finally in place, eliminating the only existing mechanism for tracking IOU conformance with them is extremely inopportune timing and would remove any impetus for achieving the LSG. Rather than eliminating the Status Report, the Commission should retain it and promptly initiate a process to adopt explicit IOU-specific allocations of the LSG to ensure accountability that they will actually be met. The Status Report could then be modified to report on the IOUs' progress in meeting these goals; if they were found to be lagging, the CPUC would know this through the Status Report which could inform the necessary actions to address the shortfall. The Joint Parties fear that without this

[8] Proposed Decision, at pp. 39 and 212 (Ordering Paragraph 126).
[9] D.14-12-024, Attachment A, at p. 13
[10] Proposed Decision, at p. 39.

vehicle for highlighting IOU progress in meeting the LSG, there will be no accountability, and consequently, little chance of success.

## V. THE PD ERRS IN NOT APPROVING A 10-DISPATCH LIMIT WITHIN A ROLLING 30-DAY WINDOW

The PD rejects the PG&E proposal to limit BIP dispatches to three consecutive days and 10 events every 30 days because it would "reduce the efficacy of the program."[11] No evidence was presented in this proceeding to support such a finding other than Cal Advocates' argument that adopting such a limit "is shortsighted because extreme heat events are likely to become more intense and more frequent in the future."[12] This is an insufficient basis for rejecting PG&E's proposal.

The Joint Parties agree that, as the PD notes, critical grid conditions can exist for longer than three consecutive days, but respectfully remind the Commission that, like all DR programs, customer willingness to participate is a pivotal factor in BIP's success. This is an especially important consideration in light of the Commission's recent "clarification" that a CAISO Energy Emergency Alert ("EEA") Warning is the threshold at which Reliability Demand Response Resources ("RDRR") must be made available in the CAISO market for economic and exceptional dispatch, which will very likely lead to more BIP dispatches. Even if market prices rarely reach the minimum $950/MWh RDRR bid price, CAISO operations will have the prerogative to exceptionally dispatch BIP. Even in spite of the higher BIP incentives adopted in this PD, current BIP participants may find that the opportunity cost of potentially far more frequent dispatches, in combination with the potential for ten consecutive days of dispatches in a calendar month, will not justify the associated opportunity cost.

In fact, maintaining a 10-event-per-month limit without a limit on the number of consecutive dispatches creates the possibility that 20 consecutive events could conceivably be called – ten during the last ten days of a calendar month and ten more during the first ten days of the following calendar month. In spite of Cal Advocates' reasoning that "events have only been called for a small fraction of the maximum ten event per month and 180 hours per year", for a customer to participate in BIP, it must be very sure that it can financially manage an extended

[11] Proposed Decision, at p. 49.
[12] *Id*.

series of events.[13] Otherwise, the underperformance penalties are so severe that a BIP participant could incur a highly consequential financial impact that far exceeds its program incentives, leading them to forego BIP participation rather than take the risk that they be subject to an exceptionally high number of consecutive dispatches.

Furthermore, with regard to limiting events to three consecutive days, it is unfair to subject the BIP to a far more rigorous standard than any other RA-qualifying DR program. RA-qualifying, non-emergency DR is allowed a one-day outage after three consecutive dispatches and the BIP should be allowed the same. This was never a concern prior to the RDRR "clarification" in D.23-06-029, but the CPUC should recognize that the calculus of BIP participation has shifted more toward incurring greater risk; it can help improve the risk-reward balance by adopting PG&E's proposal.

For these reasons, the Joint Parties strongly support a one-time window during which current BIP participants may disenroll or update their Firm Service Level, and for new customers to enroll, in response to the updates approved in the final decision.[14]

## VI. SUNSETTING PG&E'S SMARTAC PROGRAM IS PREMATURE AND AT A MINIMUM, NEEDS A BETTER TRANSITION PLAN

The PD approves PG&E's proposal to sunset its residential SmartAC program ("SmartAC program"), which it claimed was due to its poor cost-effectiveness, by ceasing marketing and enrollment at the end of 2023.[15] The expectation appears to be that the ART program will "take the baton" and eventually replace SmartAC as PG&E primary direct-enrolled residential DR program. However, this transition plan appears to be overly hasty because it is entirely unclear at this point whether the ART program will be ramped up enough in time for summer 2024 deployment. The Commission should continue to allow for marketing and enrollments in the SmartAC program through 2024 to allow time for the ART program to be approved and deployed.

The PD's reasoning for approving the sunsetting of PG&E's SmartAC program is not supported by its cost-effectiveness scores using either the 2021 Avoided Cost Calculator ("ACC") or the 2022 ACC. The Total Resource Cost ("TRC") of the SmartAC program under the 2021 ACC, with and without accounting for the cost and savings of the Automated Demand Response

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[13] Proposed Decision, at p. 49.
[14] _Id_., at pp. 60 and 213 (Ordering Paragraph 21).
[15] _Id_., at p. 62.

("AutoDR") program, is 0.89; compared to the CBP, with a 2021 ACC of 0.71 and 0.81, respectively, the SmartAC program appears to be more cost effective. This remains the same when the two programs are compared under the 2022 ACC, with SmartAC having a TRC score of 2.64 (with AutoDR) and 2.62 (without AutoDR).[16] Therefore, in relative and absolute terms, the SmartAC program is more cost effective than PG&E's CBP, which it notably did not propose to sunset. Though the PD finds that the ART program is more cost-effective than SmartAC, the ART program TRC score is theoretical only, whereas the SmartAC TRC score is not.[17]

Sunsetting the SmartAC program also risks eliminating an important DR option for residential customers while the ART program ramps up. The CPUC has not approved the final version of the ART program, but assuming the CPUC ultimately adopts it, it is possible that it will not be fully deployed, or will only be partially deployed, in 2024. As a hedge against this possibility, the Commission should direct PG&E to continue SmartAC program marketing and recruitment efforts through 2024 or until the ART program is fully deployed. This will ensure that a DR program option is available for direct-enrolled customers in 2024 while the ART program is litigated, marketed, and deployed.

## VII. THE TRANSITION PLAN AND BUDGET FOR PG&E'S AUTOMATED RESPONSE TECHNOLOGY PROGRAM SHOULD BE REVISED

The PD approves PG&E's Automated Response Technology ("ART") program and directs PG&E to submit a Tier 2 advice letter by February 28, 2024, to provide additional details before it may deploy the program.[18] The Joint Parties agree that transitioning what PG&E now terms as the Bring Your Own Thermostat ("BYOT") program to the ART program is logical and generally supports the shift toward a multi-technology program. However, the BYOT program is scheduled to end at the end of 2023 and the ART program will not launch until sometime in summer 2024. In the meantime, without modifications to the PD, there is no mechanism in place to maintain funding for the devices currently enrolled in the BYOT program until the ART program launch. These devices, which provide substantial load impacts, will not be able to provide load shift capacity until the ART program launch. It is possible that this churn will stop many customers from re-enrolling and participating in future DR programs, risking the loss of a substantial portion of valuable capacity. If this occurs, PG&E would need to expend program

[16] Proposed Decision, at p. 9 (Table 1 and Table 2).
[17] *Id.*, at p. 62.
[18] *Id.*, at pp. 65 and 213-214 (Ordering Paragraph 24).

funding to re-enroll these participants via marketing and enrollment incentives into the ART program.

Furthermore, the BYOT program currently has approximately 108,000 smart thermostats enrolled but the ART program only budgets for 120k thermostats, meaning that should all current BYOT program participants transition to the ART program, it will be close to oversubscription shortly after the launch date. Part of the risk associated with the ART program is that the device incentives will be paid from energy efficiency, Self-Generation Incentive Program, Integrated Demand Side Management, and electric vehicle program budgets, all of which are located outside of the IOUs' DR program portfolios. These funding quantities are not clearly defined, and it is unclear whether these or any other technology programs have suitable headroom in their budgets to scale the ART program. For this reason, the ART program budget should be increased to include device incentives to ensure it can scale. It also appears that the proposed $23.8 million ART program budget will not even cover four years of participation of the ~108k thermostats currently enrolled in BYOT program. It is unlikely that any vendor would be able to support the ART program given the proposed budget and program design. If the projected cost effectiveness of the ART program using 2022 ACC figures is accurate, PG&E could increase the size of the program budget by 2-3 times (up to $75M over the four years) and still remain cost-effective.

## VIII. THE PD IS CORRECT TO REJECT IOU EFFORTS TO TRANSITION THEIR PROGRAMS TO RDRRS AND LOAD MODIFYING DR IN THE ABSENCE OF AN EQUITABLE POLICY THAT INCLUDES THIRD-PARTY DR PROVIDERS

The Joint Parties fully support the PD's rejection of SCE's effort to convert its Smart Energy Program and Summer Discount Plan from Proxy Demand Resources ("PDR") to RDRR, and its CBP to a Load Modifying DR program.[19] Though the Joint Parties can certainly sympathize with SCE's intentions to reduce customer fatigue, before such conversions are allowed to occur, the Commission should establish a clear set of rules and requirements, equally and fairly applicable to IOUs and third-party DR providers, for transitioning economic Supply Side DR programs to emergency and/or Load Modifying DR programs. In fact, the Joint Parties would strongly support such a measure, preferably in a new DR rulemaking, as part of a broader

[19] Proposed Decision, at pp. 68, 70, and 98.

reconsideration of bifurcation, but it appears possible that this issue may be scoped within the new RA rulemaking.

## IX. THE CBP PENALTY STRUCTURE SHOULD BE TIED TO THE NOMINATION TIMELINE

The Proposed Decision errs by rejecting PG&E's and San Diego Gas & Electricity Company's ("SDG&E's") proposed updated CBP capacity payment schedules.[20] Despite the Proposed Decision's assertions to the contrary, the simplified approach the two proposals take would go farther to incentivize participation. However, their rejection is less consequential because the Proposed Decision correctly declines to adopt PG&E's and SCE's revised nomination timelines.[21] These timelines would be unreasonable even in the event the CPUC directed the IOUs to show their DR programs on their supply plans. However, as a matter of principle, there should be a balance between the rigor of the CBP penalty mechanism and the rigor of the nomination timeline such that a shorter nomination timeline warrants a more rigorous penalty structure and vice versa. This is on account of the fact that a CBP aggregator is able to determine with greater precision how much capacity it can responsibly nominate for a given month if the nomination timeline is short, e.g., PG&E's T-15. Conversely, if the CPUC were to adopt a longer nomination timeline, e.g., SCE's proposal for a January 31 annual deadline, the accuracy of the nominated amount would be poorer. Therefore, the penalty structure should be far less rigorous in recognition of the difficulty in accurately forecasting the appropriate amount of capacity that can be responsibly delivered by the CBP aggregator. If the CPUC should ever require IOUs to place their DR programs on supply plans, the CPUC should simultaneously revisit the CBP penalty structure if it intends for the CBP nomination timeline to change.

## X. PG&E'S CBP ELECT BID CAP IS INCONSISTENT WITH THE $949/MWH BID CAP ADOPTED IN D.23-06-029

The PD approves the extension of the $650/MWh PG&E CBP Elect bid cap beyond 2023.[22] However, this is in contradiction with the $949/MWh bid cap for Proxy Demand Resources providing RA capacity that had been approved in D.23-06-029. In fact, in that decision, the CPUC explicitly clarified that the $949/MWh bid cap superseded PG&E's

[20] Proposed Decision, at p. 81.
[21] *Id*., at pp. 86 and 94.
[22] *Id*., at p. 86.

$650/MWh CBP Elect bid cap in order to maintain consistency.[23] The PD should be modified to defer to that decision on this issue.

## XI. THE CPUC SHOULD DIRECT ENERGY DIVISION TO CONVENE AN ELECTRIC RULE 24/32 WORKING GROUP

The Joint Parties appreciate the PD's approval of the IOUs' Electric Rule 24 (PG&E and SCE) and Electric Rule 32 (SDG&E) (collectively, "Rule 24/32") funding request.[24] It is critical that the IOUs' capabilities in this area stay ahead of customer demand and no evidence has been presented in this proceeding to indicate that demand will not continue to grow.

Though the Joint Parties would prefer to see Rule 24/32 expanded to unbundled customers in this PD, we strongly support an Energy Division-convened working group to discuss critical improvements, which should not be limited to expanding to unbundled customers.[25] The PD should be modified by replacing Energy Division discretion on whether to convene the working group with CPUC direction to do so by a date certain. The PD should also be modified to specify the vehicle by which any changes to Rule 24/32 will be proposed to the CPUC, as well as a deadline for doing so. Finally, the PD should be modified to specify that the IOUs should not be the final arbiters of what Rule 24/32 changes are to be proposed to the CPUC.

## XII. POWER SAVER REWARDS SHOULD BE DISCONTINUED IMMEDIATELY

The Joint Parties support the PD's extension of the ELRP Group, sub-Groups A.1 to A.5, through 2027.[26] As the PD cites, it has generally delivered benefits;[27] as a pilot, it is also appropriate to defer consideration of cost-effectiveness, especially in light of the PD's choice to suspend a 1.0 TRC cost-effectiveness requirement for established DR programs.

The Joint Parties also regretfully support sunsetting of the sub-Group A.6, also known as Power Saver Rewards ("PSR").[28] As the PD recognizes, the program "carries significant free-ridership problems."[29] However, it should be noted that this outcome could have been avoided had the Commission not adopted A.6 as an opt-out program in the first place. Several parties predicted in R.20-11-003 (Emergency Reliability) that defaulting millions of customers into A.6

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[23] D.23-06-029, at p. 88.
[24] Proposed Decision, at pp. 103-106 and 216 (Ordering Paragraphs 38-40).
[25] _Id._, at p. 108.
[26] _Id._, at pp. 133 and 217 (Ordering Paragraphs 46-48).
[27] _Id._, at p. 132.
[28] _Id._, at pp. 136-137.
[29] _Id._, at p. 136.

would result in significant free-ridership which is exactly what occurred.[30] This is especially unfortunate because A.6 fills an important niche – direct-enrolled residential customers – that, if made opt-in instead of opt-out, could have served a useful source of valuable load curtailment during acute grid conditions, and could have acted as a feeder program for residential customers to participate in IOU or third-party capacity-based programs. Instead, because millions of free riders have already been automatically enrolled, removing them after the fact while converting the program to opt-in would likely be logistically and politically difficult, as the PD appears to acknowledge.[31]

Because of the severe free-ridership problems, A.6 should be discontinued at the end of 2023 rather than at the end of 2025. Otherwise, the free ridership, which has cost almost $200 million dollars so far, will continue for another two years, even with a lower incentive, with virtually no incremental benefit beyond what would occur naturally during a Flex Alert.[32] In spite of the PD's claims, without evidence, that maintaining A.6 is "reasonable to keep the program running as designed to ensure grid reliability" A.6 has provided little incremental reliability benefits relative to the Flex Alert program, as the Residential ELRP Baseline Evaluation Report has made clear.[33] Therefore, it is not clear what benefit will be derived from maintaining the program in 2024 and 2025 when the benefits were so outweighed by the costs in prior years. The Commission should prioritize good stewardship of ratepayer funds and cancel the program at the end of 2023.

## XIII. THE PD SHOULD ALLOW FOR COMPENSATION TO BIP CUSTOMERS DURING ELRP-ONLY EVENTS

The PD errs in rejecting the California Large Energy Consumers Association ("CLECA") proposal for BIP participants that are duel-enrolled in ELRP be fully compensated for load curtailed during non-overlapping ELRP-only events.[34] In spite of the cited intent of the ELRP as an "insurance policy made available during emergency conditions to supplement the reliability already provided by the RA program", the Joint Parties note that the Commission has recently adopted "clarifications" to the criteria, adopted through a settlement approved in D.10-06-034,

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[30] Opening Phase 2 Prepared Testimony of the Joint Parties submitted in R.20-11-003 (Emergency Reliability) on September 1, 2021 (Ex. Joint Parties-01), at p. 9, line 17 to p. 10, line 4.
[31] Proposed Decision, at pp. 134-135.
[32] *Id.*, at p. 194 (Finding of Fact 138).
[33] *Id.*, at p. 136.
[34] *Id.*, at p. 140.

under which RDRRs can be activated for economic and exceptional dispatch for the purpose of BIP being dispatched more frequently. CLECA's proposal would simply provide an avenue for BIP participants to provide load curtailment, when possible, without being subject to a must-offer obligation or other CAISO market commitment. Double compensation can easily be avoided by prohibiting payment for any load ELRP curtailments that coincide with a BIP event. There is a precedent for this approach under the IOUs' now retired Demand Bidding Programs in which BIP participants were allowed to dual participate. The PD should be modified to properly prioritize ELRP load curtailment while avoiding double compensation.

## XIV. THE PD ERRS IN REJECTING SDG&E'S AC SAVER PROGRAM TRANSITION TO THE SMART ENERGY PROGRAM

The PD rejects SDG&E's proposal to transition its AC Saver program to the Smart Energy Program ("SEP"), which would retire the air conditioning switch portion of the SEP and expand it to other devices, due to low cost-effectiveness.[35] The CPUC should revise the PD to retain SDG&E's SEP and direct them to continue deploying the AC switch portion of the program.

The PD's criticisms of SDG&E's SEP do not consider the simple fact that SDG&E's service area is small, thus limiting the number of eligible customers. The PD's praising of PG&E's and SCE's cost-effective administration of their respective comparable programs, though certainly deserved, is unfortunately not relevant in this instance because PG&E and SCE benefit from a large customer pool which leads to larger load impacts. Even though SDG&E's SEP cost-effectiveness is estimated at 0.7 TRC, even using the 2022 ACC, no evidence has been presented in this proceeding that supports the notion that PG&E's or SCE's administration models would lead to a higher cost effectiveness. The PD takes a similar position in rejecting PAO's proposal for statewide administration of the CBP, stating that "Cal Advocates' arguments that a statewide administrator will improve cost-effectiveness are also not sufficiently supported."[36] As discussed earlier in these comments, the PD made clear that a TRC at or above 1.0 is not required for a program to be continued. This exception is particularly appropriate to apply in the case of SDG&E's SEP, as there is currently no alternative program in place that

[35] Proposed Decision, at pp. 73-74.
[36] *Id.*, at p. 75.

would allow direct-enrolled residential customers to continue contributing towards grid reliability. The program should not be retired until a new alternative is in place.

In addition to retaining existing customer participants by transitioning these customers to the SEP, the Commission should also direct SDG&E to continue supporting the existing deployed AC Saver one-way direct load control switches. The Joint Parties do not dispute SDG&E's claim that maintaining the current switches is not cost-effective, but simply discarding the load impacts of the existing participants when the program has poor cost effectiveness (relative to the other IOUs) would be short-sighted, especially if the alternative is to have no SEP at all. At a minimum, the Commission should maintain a program for direct-enrolled residential customers in the SDG&E service area, and maintain the existing customers enrolled in programs.

## XV. THE BASIS FOR REJECTING OHMCONNECT'S PROPOSAL FOR MARKETING SUPPLY SIDE DR PROGRAMS IS FLAWED

The PD rejects OhmConnect's proposal to provide information on an annual basis to ELRP A.6 participants on other available DR programs.[37] According to the PD, the purpose of the ELRP "would be defeated if the high-performing customers are stripped from the program" and that "the budget originally approved for ELRP should be spent on improving program efficacy, rather than promoting potential competitors."[38]

The Joint Parties are genuinely perplexed by the PD's rejection of OhmConnect's proposal which would simply make ELRP A.6 participants aware of other market-integrated DR program options that are offered by IOUs, non-IOU LSEs (e.g., community choice aggregators), and third-party DR providers.[39] The PD displays an unreasonable suspicion of OhmConnect's intentions when, if its proposal is viewed objectively, is clearly intended to attract customers to participate in a more reliable capacity-based program.

The PD's argument that the purpose of ELRP "is defeated if the high-performing customers are stripped from the program" appears to imply that participation in the ELRP for its own sake is of greater importance and value to the Commission than participation in "higher-engagement and higher-impact demand response programs" such as a DR program that provides

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[37] Proposed Decision, at p. 171.
[38] *Id*.
[39] Opening Testimony of Cliff Staton on behalf of OhmConnect, submitted in this proceeding on April 21, 2023 (Ex. OhmConnect-4), at p. 8, lines 9-11.

Resource Adequacy capacity.[40] The Commission should be open to any and all proposals put forth by parties to lock in these "high-performing customers" who, if deployed as part of an RA-based program such as the Capacity Bidding Program, would reduce the chances of even needing to dispatch the ELRP. As OhmConnect testified, "the proposed on-ramp would help create additional value by driving customers into economic programs that help *prevent* grid emergencies in addition to responding to any that may arise."[41] The CPUC should view such an outcome as a positive development because additional DR RA capacity improves grid reliability. At minimum, the CPUC should approve OhmConnect's proposal on a limited basis for the purpose of marketing the IOUs' residential DR programs, including residential CBP. Choosing not to take even this very basic and seemingly obvious step implies that spending $180 million (or even half of that if the A.6 incentives are reduced) on 107 MW of DR capacity is an acceptable outcome. If that is the case, the Joint Parties do not agree and urge the CPUC to take this very commonsense action and approve marketing of all residential IOU DR programs, at minimum, to ELRP A.6 participants. Ideally, the CPUC would adopt this approach for all direct-enrolled ELRP participants, residential and non-residential, to spur additional participation in capacity-based DR programs.

## XVI. CONCLUSION

The Joint Parties appreciate the opportunity to provide these Opening Comments.

Dated: November 28, 2023

Respectfully submitted,

/s/ JOSEPH DESMOND
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[40] Proposed Decision, at p. 171.
[41] OhmConnect-4, at p. 8, lines 12-14.

## APPENDIX A

## THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, LEAPFROG POWER, INC., AND OHMCONNECT, INC. PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS FOR THE PROPOSED DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027

The California Efficiency + Demand Management Council, Leapfrog Power, Inc., and OhmConnect, Inc. propose the following modifications to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs in the Proposed Decision Directing Certain Investor-Owned Utilities' Demand Response Programs, Pilots, and Budgets for the Years 2024-2027, mailed in A.22-05-002, et al. (DR Applications) on November 6, 2023 ("Proposed Decision").

Please note the following:

- A page citation to the Proposed Decision is provided in brackets for each Finding of Fact, Conclusion of Law, or Ordering Paragraphs for which a modification is proposed.
- Added language is indicated by **bold type**; removed language is indicated by **bold strike-through**.
- A new or added Finding of Fact, Conclusion of Law, or Ordering Paragraph is labeled as "**NEW**" in **bold underscored** capital letters.

**PROPOSED FINDINGS OF FACT:**

63. [189] PG&E's ART **program** proposal lacks specifics.

**~~88. [190] A CBP bid cap of $650 per MWh helps ensure that bids are likely to lead to dispatch during emergency events.~~**

**~~144. [194] ELRP is still a pilot program.~~**

**~~145. [195] Reducing the ELRP Sub-group A.6 incentive rate will reduce the cost to ratepayers of ELRP.~~**

**~~146. [195] SCE's PSR incentives will be decreased for 2024 and 2025.~~**

**NEW**. **Commission approval of IOU MCR advice letters by March 31, 2026, would provide time for changes to be implemented in time for summer 2026.**

**NEW. SDG&E's SEP is currently its only DR program for direct-enrolled residential customers.**

**NEW. The $949/MWh Proxy Demand Response bid cap adopted in D.23-06-029 superseded PG&E's $650/MWh CBP bid cap.**

**PROPOSED CONCLUSIONS OF LAW:**

6. [196] It is reasonable to adopt the definition of "qualified" DR programs in Attachment 1 **for all DR enabling technology incentive programs**.

~~**10. [197] 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. [197] ~~**As Power Saver Rewards is a ratepayer-funded program open only to customers of the IOUs, it**~~ **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**~~.

20. [198] ~~**It is no longer necessary to have the**~~ **The** IOUs **should** submit the Status Report on their progress toward ~~**a statewide DR goal of five percent**~~ **the Load Shift Goal**.

39. [199] It is reasonable for PG&E to sunset the SmartAC program~~**, given the start of the ART program**~~ **at the end of 2024 or once the ART program has been approved and deployed.**

43. [199] PG&E 's ART program is reasonable, as amended, and PG&E should be authorized to recover **up to** ~~**$23.8**~~ **$75** million for the ART program.

~~**50. [200] It is reasonable to end SDG&E's SEP, due to cost-effectiveness concerns.**~~

~~**62. [200] It is reasonable for PG&E to continue to utilize a $650 per MWh bid cap for CBP Elect and Elect+.**~~

~~**109. [203] Disenrollment of customers in ELRP sub-group A.6 with only two years left of program operation is not reasonable.**~~

~~**110. [204] It is reasonable to end sub-group A.6 auto-enrollment procedures.**~~

~~**113. [204] It would be unreasonable to change the sub-group A.6 dispatch trigger, given the low number of years remaining.**~~

122. [204] 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**~~ **2023**.

<u>**NEW. It is reasonable to allow IOUs to request a higher budget in the MCR for specific programs when program demands warrants it.**</u>

<u>**PROPOSED ORDERING PARAGRAPHS**</u>**:**

10. [209] 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. **This list should clarify that DR programs providing Resource Adequacy via bilateral contracts are considered "qualified" programs as long as they satisfy the specifications provided in Attachment A.**

13. [210-212] 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.

**(g) The Commission disposition of MCR advice letters shall occur no later than March 31, 2026.**

16. [212] Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall ~~**immediately cease filing**~~ **update** 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**, to report on their progress toward meeting the Load Shift Goal**.

24. [213-214] 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**~~ **$75** 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.

~~**27. [214] San Diego Gas & Electric Company is directed to terminate its Smart Energy Program no later than December 31, 2023.**~~

51. [218] Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ~~**authorized to end the filing of**~~ **directed to update** the Demand Response Interim Goal Report ~~**at the end of 2023**~~ **to report on their progress in meeting their allocation of the statewide Load Shift Goal**.

<u>**NEW. The Energy Division shall host a stakeholder workshop to determine what changes or updated to Rule 24/32 are needed.**</u>

<u>**NEW. The IOUs are directed to sunset the ELRP Sub-group A.6 at the end of 2023.**</u>