CALIFORNIA Efficiency + Demand Management COUNCIL

May 5, 2020

Via E-Mail (EDTariffUnit@cpuc.ca.gov)
California Public Utilities Commission
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

RE: Advice Letter (ALs) 5799-E (Pacific Gas and Electric), 4182-E (Southern California Edison), and 3522-E (San Diego Gas & Electric) (Demand Response 2018-2022 Mid-Cycle Review)
PROTEST OF CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, ENEL X NORTH AMERICA, INC., AND OHMCONNECT, INC.

Dear Energy Division Tariff Unit:

On April 1, 2020, pursuant to Decision ("D.") 16-09-056, investor-owned utilities Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E) (jointly, "the IOUs") submitted their Demand Response ("DR") 2018-2022 Mid-Cycle Review Advice Letters ("Mid-Cycle ALs"). These Advice Letters provide status reports on the IOUs' DR programs and proposed changes. The California Efficiency + Demand Management Council, CPower, Enel X North America, and OhmConnect, Inc. (collectively, "the Joint Parties") appreciate the opportunity to Protest these Advice Letter filings.[1] On April 12, 2020, Energy Division extended the deadline to protest or respond to these Advice Letters to May 5, 2020.

JOINT PARTIES' PROTEST

I. Issues Common to the IOUs' Advice Letters.

A. Exclusion of PSPS Events from DR Program Baselines.

The IOUs should revise their respective Capacity Bidding Program ("CBP") and Base Interruptible Program ("BIP") tariffs to exclude Public Safety Power Shutoff ("PSPS") events when calculating performance during a DR event. On January 31, 2020, the Commission approved PG&E's Advice Letter ("AL") 5702-E which requested approval to do this for BIP. As PG&E stated, without an exclusion of a PSPS event from BIP incentive calculation, a BIP participant would inappropriately have their

[1] The views expressed by the California Efficiency + Demand Management Council are not necessarily those of its individual members.

incentive reduced because the PSPS event "is out of the control of the participating customer", so it is reasonable to treat a PSPS event like a DR event for the purpose of the incentive calculation.[2] PG&E's logic is correct and should be applied to all IOUs' BIP and CBP DR programs.

From an operational standpoint, excluding PSPS events is especially necessary because aggregators are often unaware of whether their customers will be impacted by a PSPS event until the power shutoff occurs. For example, in 2019, prior to PSPS events, PG&E would typically send generic e-mails to all DR Providers ("DRPs") with customers registered through Electric Rule 24 that provided a very vague indication of the geographical areas that could be impacted by the event, with no indication of which customers would be affected.

Based on recent statements made by the Energy Division, it appears that the IOUs may already be excluding PSPS events when calculating the 2019 ex post load impacts of their DR programs. In its March 30, 2020 disposition letter in response to PG&E AL 5746-E, SCE AL 4152-E, and SDG&E AL 3503-E, the Energy Division directed the IOUs to account for PSPS events when calculating DR Auction Mechanism ("DRAM") resource performance. In this disposition letter, the Energy Division noted that the IOUs have been excluding PSPS events from their DR programs' baseline calculations in their most recent Annual Load Impact Reports.[3] Given that PG&E currently exempts BIP customer baselines from PSPS events and, according to the Energy Division, the IOUs appear to have adopted this in practice with regard to their load impact evaluations, the IOUs should formalize this practice in their CBP and BIP program tariffs.

B. Assessment of a 5-in-10 Baseline for Non-Residential CBP Customers.

In D.19-07-009, the IOUs were directed to perform assessments to determine, among other things, whether a residential 5-in-10 baseline with a 40% day-of adjustment would be more accurate for a residential CBP compared to a 10-in-10 baseline with a 20% adjustment cap.[4] In its Mid-Cycle AL, PG&E found that the 5-in-10 baseline "performed best overall."[5] Similarly, when discussing its Residential CBP pilot, SDG&E specified that it will use a 5-in-10 baseline because it would "provide the lowest bias and better accuracy."[6] Given these positive assessments for residential customers, the Commission should direct all three IOUs to assess the accuracy of a non-residential 5-in-10 baseline with a 40% adjustment cap. Though the Commission directed in D.19-07-009 that the retail and wholesale baselines of the IOU DR programs be aligned, if the IOUs perform this assessment and it is determined that the 5-in-10 baseline is

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[2] PG&E AL 5702-E, at p. 2.
[3] Energy Division Non-Standard Disposition Letter in response to Joint Advice Letter 5746-E (PG&E), 4152-E (SCE), and 3503-E (SDG&E), at p. 7, March 30, 2020.
[4] Decision 19-07-009, at Ordering Paragraph ("OP") 18.
[5] PG&E AL 5799-E, Attachment 1, at p. 39.
[6] SDG&E AL 3522-E, Attachment A, at p. 11.

viable for non-residential customers, this analysis could be provided to the California Independent System Operator ("CAISO") to support adding a non-residential 5-in-10 baseline to its tariff as an option for Proxy Demand Resources ("PDRs").

C. Leveling the Competitive Playing Field between IOU and Third-Party DR Programs.

In D.17-12-003, the Commission ruled on a number of issues meant to level the competitive playing field between IOU and third-party DR programs. First, the Commission extended the availability of existing technology incentives to customers of third-party DR providers (DRPs), stating "[p]roviding technology incentives to both third-party customers and utility customers enrolled in supply side programs/activities not subject to cost-effectiveness analysis provides improved customer choice."[7] More than two years since this directive, the process by which customers of third parties apply for an incentive in at least two of the three IOUs' technology incentive programs remains lacking. Specifically, conflicting messaging raises doubts in the minds of third-party customers about whether they are indeed eligible for such an incentive. Specific comments on each IOU's process are provided in the sections below. As highlighted below, there are opportunities for improvement but, rather than the Commission approving anything specific in its Resolution on the Mid-Cycle ALs, it may be more productive to develop specific improvements through a workshop process where parties can discuss in a more collaborative setting.

Second, D.17-12-003 addresses the disparity in awareness among customers between IOU and third-party DR options, stating that "it is the role of the Utilities to ensure that customers are provided with a clear and complete set of demand response options available to them."[8] To assess the IOUs' success in fulfilling this role, the Commission should direct the IOUs to disclose at least twice per year key metrics on the page views, clicks, and interactions on pages relating to third-party DRP programs, including the web pages that list third-party DRP programs and other associated programs, such as technology incentives. This information is eminently easy to collect and report and is readily available to organizations that have deployed a comprehensive web tracking and analytics platform, such as Google Analytics. Such platforms provide robust and detailed analytics regarding page interactions and views, site and page-specific referral sources, audience segmentation tools (such as geography, demographics, and technology used to access the site), and behavior conversion tracking.

This information will enable the IOUs and the Commission to better understand the efficacy of pages that ratepayers have funded and should be able to use to discover, evaluate, and enroll in the DR programs that best meet their preferences. Without such information, it is difficult to discern whether or not these web pages are

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[7] D.17-12-003, Finding of Fact ("FoF") 87.
[8] *Id*., at p. 106.

being used as intended, and/or whether additional changes should be made to increase their value to customers.

D. Aggregator Eligibility for Technology Incentives

One of the common themes in the IOUs' Mid-Cycle ALs is very high cancellation rates of enabling technology incentive applications, especially for residential customers. In 2018 and 2019, PG&E received 11,214 and 14,532 Automated Demand Response ("AutoDR") program applications respectively, with 9,617 and 12,746 applications cancelled, a rate of 86% and 87%.[9] SDG&E's Technology Deployment program received 7,993 applications in 2019, 3,281 of which were cancelled.[10] SCE's non-residential AutoDR program received 14 applications in 2018 with 12 being cancelled[11], and its residential program received 28,557 and 24,934 applications in 2018 and 2019, with 7,862 and 10,576 cancellations.[12]

One possible reason for this may be the effort required on the part of the customer to apply for their incentive payment. To help alleviate this problem, all IOUs should allow customers to sign over their incentive payments to DR aggregators similar to what has been allowed for incentives through the California Solar Initiative and Self-Generation Incentive Program. This approach would allow DR aggregators to "front" the incentive payment for their customers while eliminating a significant administrative burden on the customer for applying for the incentive. This would provide an immediate offset to the customer's cost of participating in a qualifying DR program which would very likely improve DR enrollments and associated load impacts.

E. The IOUs Should Pilot Shift, Shimmy and Shape Programs.

The IOUs should develop pilots to test the type of DR products envisioned by the March 2017, 2025 California Demand Response Potential DR Potential Study ("DR Potential Study").[13] The DR Potential Study has highlighted the need for shift, shimmy, and shape DR products to aid in intermittent renewables integration. Over the past five years, the Commission has committed a significant amount of ratepayer funds to retain the Lawrence Berkeley National Laboratory (LBNL) to conduct a series of these DR Potential Studies. The Joint Parties would like to ensure that these important investments are put to the best use now rather than years from now. Since the last DR Potential Study was completed by LBNL, few steps have been taken by the IOUs to define and develop these products other than the IOUs' Excess Supply Pilots. The IOUs should use the next two years to develop and pilot the shift, shimmy, and shape products using their respective over-generation/excess supply pilot funding. The

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[9] PG&E AL 5799-E, Attachment 1, at p. 23.
[10] SDG&E AL 3522-E, Attachment D, at p. 6.
[11] SCE did not provide the number of cancelled non-residential AutoDR applications in 2019.
[12] SCE AL 4182-E, Attachment D, at Table D2-2.
[13] 2025 California Demand Response Potential Study – Final Report on Phase 2 Results, March 1, 2017.

knowledge and experience that can be gained in 2021 and 2022 could inform expanded programs in the IOUs' next program applications.

II. PG&E

A. SmartAC

PG&E provides several reasons for its SmartAC program's decline in participation and associated load impacts, including negative net customer enrollments and the cost of replacing legacy direct load control technology.[14] As a result, 24,000 customers have left the SmartAC program in 2018-2019.[15] Though PG&E cites several logical reasons for this attrition, it is not clear to what extent each of these reasons has contributed to such a rapid decline. The loss of these customers is particularly unfortunate because they have experience with DR and as such, they may be open to participating in a different DR program.

In order to maintain the engagement of residential DR participants, and to perhaps reengage some of its recently departed SmartAC participants, PG&E should develop a bring-your-own-device ("BYOD") direct load control program similar to SCE's Smart Energy Program, in parallel with SmartAC. A PG&E program equivalent to the Smart Energy Program could attract more residential customers by allowing participation by customers with smart thermostats as well as other technologies such as electric water heaters, pool pumps, etc. While the Joint Parties put forward this recommendation because there is value in supporting DR opportunities in all venues, a continued need to ensure a level competitive playing field between IOU and third-party DR programs should be emphasized, as discussed above.

B. BIP

i. Revisions to Eligibility Requirements

PG&E proposes to revise the BIP eligibility requirements from each account having 100 kW of maximum demand during peak time-of-use ("TOU") hours in one of the previous 12 months to requiring each account to have an average 100 kW demand during peak TOU hours in each of the last 12 months prior to enrolling in the program.[16] PG&E's argument for this revision, which would eliminate 344 of the 517 customers currently participating in BIP and corresponds to a 17% loss of BIP capacity, is that accounts with "peakier" load are unlikely to drop load during a BIP event.[17] According to PG&E, this proposal is based on an analysis "on the impact of changing the program eligibility requirements to one that better reflects the 24x7x365 nature of the BIP

[14] PG&E AL 5799-E, Attachment 1, at pp. 5-7.
[15] *Id.*, at p. 6.
[16] *Id.*, at pp. 13-14.
[17] *Id.*

program, and would ensure that all BIP participants have load to drop in an unpredictable emergency event."[18]

The Commission should not approve PG&E's proposal. On a practical level, the problem that PG&E is seeking to address – ensuring that actual load reduction occurs during a BIP event – will not be resolved by its proposed solution. PG&E's analysis examines average demand during peak TOU hours but it has apparently not considered that because BIP is a 24-hour program, an event could be called at any time of the day including outside of the peak TOU hours. The reality is that most customers do not have a consistent load so there will inevitably be times when a customer's load will be below its FSL. So, even those customers qualifying under PG&E's proposed new requirement may face the same problem used to justify this revised eligibility requirement because their loads could very well be below their respective Firm Service Levels ("FSL") at the time of an event. Therefore, the problem that PG&E is attempting to address does not go away; instead, PG&E is left with less DR capacity and fewer customers that are able to participate in BIP. PG&E's suggestion that newly-disqualified BIP customers could participate in the CBP is a short-sighted solution because PG&E would be losing DR capacity capable of reducing load within 30 minutes at any time of the day or day of the week in favor of DR that is only required to be available for 5 hours per day on non-holiday weekdays.[19]

Discriminating against customers based on their load curves is counter-productive, especially considering that PG&E has such a large amount of remaining headroom in its allocation of the statewide emergency DR cap that was approved in D.10-06-034. According to PG&E's April 1, 2020 Annual DR Load Impact Report, PG&E forecasts a maximum of 237 MW of BIP capacity in August 2020 which is far below the 330 MW of emergency DR allotted to it in D.10-06-034.[20] If PG&E's BIP capacity was capped out, it would be understandable for it to seek customers with more consistent load. However, PG&E should not be looking for opportunities to the reduce the size of its DR portfolio when the Commission is clearly so concerned about sufficient capacity to meet reliability needs, and especially when the program is over $14 million under-spent.[21]

Furthermore, revising the load eligibility requirements risk exacerbating the economic impact of new TOU rates on agricultural customers that participate in the BIP. These new TOU rates, which will be phased in in 2021 and 2022, will increase the energy costs of those agricultural customers that are unable to shift their load accordingly. Due to the seasonality of agricultural water pumping load, most participating agricultural customers, which would likely represent a vast majority of the lost capacity, would likely be removed from the BIP and as such, the impending higher

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[18] PG&E AL 5799-E, at p.13.
[19] *Id*.
[20] PG&E April 1, 2020 Demand Response Load Impact Report, Appendix RR, Table RR.1.
[21] PG&E AL 5799-E, Attachment 1, at p. 4.

TOU-related energy costs would be compounded by the elimination of BIP incentives. Energy costs tend to be one of the top expense categories for agricultural customers, so their removal from BIP could lead to higher food costs or place stress on supply chains at a time when people and businesses are struggling under a highly acute economic crisis.

If the Commission approves PG&E's proposal, as a transition plan, PG&E proposes to conduct outreach to inform impacted participants of their options.[22] PG&E should have reached out to those customers that would be removed from the BIP prior to making this proposal rather than waiting until the Commission approves it. If PG&E had done so, it would have had an opportunity to determine whether CBP would be a good fit for these customers so that it could make an informed decision. Without this information, it is possible that the approximately 40 MW of lost capacity could be lost from PG&E's portfolio.

ii. Excess Energy Charge

As part of the IOUs' efforts to more closely align their BIP and CBP programs, pursuant to D.17-12-003, one issue discussed was a common approach to applying Excess Energy Charges when a BIP participant underperforms during a test or market event. PG&E proposes two options for aligning the treatment of Excess Energy Charges. Option A consists of a "claw back" approach in which a BIP customer would pay back a portion of its incentive payment that would be based on a to-be-determined formula.[23] Option B consists of a pass-through of any CAISO energy market charges to the offending BIP customer that are incurred by the IOU due to the under-performance of the BIP customer.[24]

The Joint Parties strongly recommend that Option B be adopted for PG&E and the other IOUs. Option B is a simpler and more efficient approach. BIP customers would be penalized commensurate with the financial harm incurred by the IOU due to underperformance which is far fairer compared to an arbitrary formula that could provide a financial incentive to the IOU to seek opportunities to penalize a BIP customer. In contrast, Option A is seriously flawed in several ways. First, no formula for Option A has been developed yet so the Commission should not approve something that has not been defined yet. Second, regardless of the penalty formula, the performance penalty will be highly arbitrary and punitive in that it does not reflect the financial repercussions faced by an IOU for the under-performance of the BIP participant. Third, this approach would create serious risk management problems for DR aggregators. Because Option A would allow the IOU to claw back some of the incentives paid to the DR aggregator, the DR aggregator would be unable to record these revenues or pay their customers while the IOU determines how much of the incentives, if any, would be clawed back.

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[22] PG&E AL 5799-E, Attachment 1, at p. 14.
[23] *Id*., at p. AppB-5.
[24] *Id*.

Furthermore, if Option A was adopted, DR aggregators would also need to re-contract with all of their customers to reflect the revised financial terms.

iii. Additional Proposed Changes

The Joint Parties propose several changes to PG&E's BIP in addition to those put forth by PG&E.

a. Exempt Customers from Re-Testing if They Reduce Their FSL to the Demand Level Achieved During the Failed Test.

Under PG&E's current BIP rules, if a customer fails to reduce its load down to or below its FSL during the event, PG&E may require a re-test that will not count against the program event limits. If the customer fails the re-test, it has the option to 1) de-enroll from the program, 2) be re-tested at the FSL in effect during the re-test, or 3) modify its FSL to an achievable level that meets program requirements.[25] Even under Option 3, PG&E retains the right to re-test at the modified FSL.

Customers choosing to modify their FSL should be exempt from an additional test until the next open enrollment window if the modified FSL is consistent with the customer's load during the initial test and subsequent re-test(s). In this instance, the customer has already demonstrated that it can meet the modified FSL, so another test would be duplicative and place an unnecessary burden on the customer. In addition, if customers decide to de-enroll during the open season (the month of November), they should no longer be subject to testing because their participation concludes at the end of the calendar year.

b. Excess Energy Charges Should Not Escalate After the Open Enrollment Period Based on Failed Tests Occurring Prior to the Open Enrollment Period.

PG&E's BIP tariff specifies that "[i]f a customer fails to reduce its load down to or below its FSL throughout the curtailment event, including a test event, PG&E may require a re-test that will not count toward the Program event limits. The Excess Energy Charge will increase to $8.40 per kilowatt-hour (kWh) for the re-test and will continue at this level for the remainder of the calendar year."[26] However, if a BIP customer fails a test event in late fall, which would trigger a re-test and an increase of the Excess Energy Charge, if the re-test occurs on or after January 1, the Excess Energy Charge should re-set to $6/kWh.

c. Allow Electronic Signature of Add/Delete/Update Forms.

PG&E should enable electronic signatures for its BIP add/delete/update forms to streamline this process. PG&E may be able to leverage the infrastructure being

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[25] PG&E Electric Schedule E-BIP, Sheet 12.
[26] _Id_.

developed as part of its improved residential CBP enrollment process which would greatly improve the efficiency of the open enrollment process.

C. CBP

i. Improved Enrollment Process for Residential CBP.

The Joint Parties appreciate and support PG&E's recent and proposed efforts to streamline enrollment in its residential CBP by implementing electronic processes to support residential participation. As recommended above, PG&E should leverage the associated electronic signature process for BIP and non-residential CBP participants.

ii. Additional Proposed Changes.

a. Allow Changes in Price by Hour for CBP Elect, Not Only By Day.

Under CBP Elect and CBP Elect +, the aggregator specifies the CAISO market bid price for each day.[27] Aggregators should be allowed to specify unique hourly bid prices, not only by day. This would allow aggregators to reflect on a more granular basis the hour-by-hour opportunity cost of their customers, whereas under the current rules, aggregators are forced to assign the highest hourly bid price for all hours.

III. SCE

A. BIP

i. Aggregator Management System Enhancements.

SCE reported that it has not yet implemented the enhancements to its BIP aggregator management system to allow aggregators to submit and manage their customer add/delete forms, unenroll service accounts in BIP aggregations, and receive event notifications because only one aggregator has been participating in the BIP.[28] SCE cites the cap on reliability DR that was approved in D.10-06-034 as a potential cause for such limited aggregator participation, and because of this and its ability to service the current BIP aggregator using workarounds, it will re-evaluate the need for system enhancements after CSRP stabilization.[29] It is reasonable to expect that some new reliability cap headroom will have been created for SCE since the Commission's rules governing prohibited resources have taken effect which may lead to more aggregator participation in the BIP going forward.[30] To the extent this expected headroom attracts new aggregators, SCE should take this into consideration when re-evaluating the need for aggregator system enhancements.

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[27] PG&E Electric Schedule E-CBP, Sheet 2.
[28] SCE AL 4182-E, at p. B-11.
[29] *Id*.
[30] SCE's April 1, 2020 Demand Response Load Impact Report has redacted the amount of available reliability DR headroom so an exact amount of headroom is unknown.

ii. Aggregator Management System Enhancements.

a. Customer Demand Eligibility Requirement.

SCE should align its BIP minimum load eligibility requirement to be consistent with PG&E's current requirement that a BIP customer have an average peak monthly demand of 100 kW or greater in at least one of the prior twelve months. Currently, SCE requires a BIP customer to have an average monthly peak demand of 200 kW or greater.[31] Given reduced BIP participation, reducing the minimum load requirement would very likely lead to greater BIP participation and enable SCE to replace its recently-lost capacity.[32]

B. CBP

i. Expanding CBP to Residential Customers.

The Joint Parties strongly support SCE's proposal to bypass the pilot phase for the residential CBP and to implement the 5-in-10 baseline with a +/- 40% adjustment cap.[33] To improve enrollment in its residential CBP program, SCE should implement a streamlined residential enrollment process, similar to the process being deployed by PG&E.

ii. Price Trigger Reset.

SCE performed an analysis to determine whether the CBP minimum price trigger was warranted.[34] Upon doing so, it found that the May-October day-ahead market ("DAM") trigger should be increased from $75/kwh to $80 and the November-April DAM trigger should be increased from $65 to $75.[35] For administrative efficiency, SCE proposes to institute a year-round $75 price trigger.[36] SCE should forego adopting this year-round price trigger and instead adopt an $80 summer price trigger and a $75 winter price trigger. The higher summer price trigger is clearly warranted given the customer fatigue cited by SCE, whereas maintaining a $75 summer price trigger will do nothing to address this problem.[37]

iii. Additional Proposed Changes

a. Adopt CBP Elect with Hourly Bids.

SCE should expand its CBP to include a CBP Elect product similar to the one offered by PG&E. As indicated by the fact that 99% of customers participating in PG&E's CBP were enrolled in CBP Elect in 2019, it is clear that there is significant

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[31] SCE Schedule TOU-BIP, Sheet 1.
[32] SCE AL 4182-E, at p. B-9.
[33] SCE AL 4182-E, at pp. B-18-B-19.
[34] *Id.*, at p. B-18.
[35] *Id.*, at pp. B-17-B-18.
[36] *Id.*, at p. B-18.
[37] *Id.*, at p. B-16.

customer interest in this option.[38] In addition, the proportion of active customers in PG&E's CBP increased by 35%, and its CBP enrollments and load impacts are significantly greater than SCE's.[39] Similar to the Joint Parties' recommendation for PG&E, SCE's CBP Elect should also allow for differentiated hourly bids rather than being limited to a single daily bid. Providing a CBP Elect option would likely improve retention and participation which, as SCE explained, has been below SCE's original forecasts used in A.17-01-018.[40]

The Joint Parties take issue with SCE's statement that DRAM providers are bidding in their resources at or close to the bid cap.[41] This has not been a universal practice among all DRAM providers; furthermore, the two reports cited by SCE to support this statement are based on 2018 data. Since the release of these reports, the Commission has adopted rules to ensure more frequent dispatch of DRAM resources. Therefore, SCE's attempts to continue painting DRAM providers with a single outdated brush should be ignored.

C. Smart Energy Program

i. Expansion of Enabling Technologies.

SCE reported that it has consolidated approved third-party vendors to those that have the capability to support multiple DR enabling technologies to enable SCE to control end-uses beyond HVAC systems in the long-term.[42] The Joint Parties strongly support these efforts and encourage SCE to add additional end-uses as quickly as is feasible to broaden participation options for customers and grow the amount of capacity the program can deliver.

D. Technology Incentives Program

SCE should implement improvements to its existing technology incentives program claim process to make it easier for third-party customers to apply for and receive these incentives as directed by D.17-12-003.[43] For instance, SCE should develop a centralized web page that provides information on the available technology incentives, the eligibility requirements (including stating that customers of third-party programs are eligible), and links to a stand-alone application for technology incentives. All existing information on the Programmable Communicating Thermostat program in particular, including the rebate notice in SCE's marketplace, discusses the Smart Energy Program only, leading customers to believe that one must be enrolled in that program to claim the technology incentive. The only mention of third-party eligibility is in

[38] PG&E AL 5799-E, Attachment 1, at p. 17.
[39] *Id.*, Attachment 1, at pp. 16-17.
[40] SCE AL 4182-E, at p. B-16.
[41] *Id.*
[42] *Id.*, at p. B-23.
[43] D.17-12-003, at OP 28.

a separate set of terms and conditions, which is not user-friendly and does not link to an application.

It is the Joint Parties' understanding that SCE is in the middle of changing its rebate flow and a new application pathway is forthcoming. SCE should develop a more neutral web page (i.e. one that will not lead customers toward a specific SCE program at the expense of third parties) that describes the available technology incentives and provides clear instructions for all customers, including those of third parties, regarding how to apply for the incentive.

IV. SDG&E

A. CBP

i. Adopt CBP Elect with Hourly Bids.

As with SCE, SDG&E should expand its CBP to include a CBP Elect product similar to the one offered by PG&E. As PG&E has indicated, there is significant customer interest in this option, so this might similarly improve SDG&E's enrollments and program load impacts which, as SDG&E has indicated, have fallen significantly since 2015.[44] Similar to the Joint Parties' recommendation for PG&E, SDG&E's CBP Elect should also allow for differentiated hourly bids.

ii. Remove DRAM-related Eligibility Requirements.

Resolution E-4728 authorized SDG&E to limit participation by new aggregators in its CBP to those that either a) win a DRAM contract, or b) the total DRAM contracts required by SDG&E under the DRAM rules meet the minimum 2 MW procurement, or, c) the winning DRAM bids are expected to exhaust the available registration capacity under Electric Rule 32.[45] This requirement was put into effect to drive aggregators toward SDG&E's DRAM. However, the 2 MW minimum procurement requirement is a relic of earlier DRAM auctions and, given the 21.6 MW procured by SDG&E for 2020 delivery, this requirement is clearly no longer needed. As such, the Commission should direct SDG&E to remove this requirement from its CBP tariff.

iii. Transition Residential CBP Pilot Directly to Full Program.

SDG&E proposes to implement a one-year residential CBP pilot, pursuant to D.17-12-003.[46] This would presumably entail implementation in 2021, then shutting down the pilot in 2022. Given SDG&E's struggles to achieve cost effectiveness in its current DR portfolio, it should forego the residential CBP pilot and deploy it as a full program while implementing PG&E's residential CBP enrollment system improvements.

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[44] SDG&E AL 3522-E, Attachment A, at pp. 2-3.
[45] SDG&E Schedule CBP, at Sheet 1.
[46] *Id*., Attachment A, at p. 10.

Should the Commission feel that transitioning directly to a full residential CBP is premature, SDG&E should at the very least extend its residential CBP pilot through 2022. Otherwise, a one-year pilot in 2021 would entail aggregators enrolling customers for 2021, then no longer utilizing them in 2022 while the Commission decides whether to expand the pilot into a full program in the 2023-2027 program cycle. Aggregators would likely have little motivation to participate in the pilot knowing that their marketing and enrollment efforts could go to waste in 2022. This approach of enrolling customers and then de-enrolling them risks disenfranchising them and reducing the likelihood that they would participate in residential CBP should the Commission direct SDG&E to adopt it as a full program in the next program cycle. Instead, deploying residential CBP as a two-year pilot would provide continuity to these customers and aggregators, who would serve as the foundation for a full residential CBP, should the Commission adopt it.

B. AC Saver

SDG&E proposes to expand its program eligibility to include net energy metered ("NEM") customers in light of the recently-revised Resource Adequacy ("RA") measurement hours.[47] The Joint Parties support this step to make it consistent with the other IOUs and hope that it will improve participation and associated load impacts.

C. Technology Deployment Program

i. Replacing Customer Incentive with Bill Credit.

SDG&E proposes to implement a customer bill credit for its commercial thermostat incentive in lieu of issuing checks to reduce the administrative burden to customers of completing the incentive application process.[48] The Joint Parties appreciate SDG&E's intent. However, providing incentive checks rather than a bill credit is preferable to many customers because it allows a customer to directly offset the capital cost of the enabling technology. Though a bill credit certainly constitutes a benefit, an incentive payment has a more tangible impact on a customer, thus validating their participation.

ii. Additional Proposed Changes.

a. Further Improving the Incentives Claims Process.

SDG&E should adopt several improvements to its existing incentives claim process to make it easier for third-party customers to apply for and receive these incentives as directed by D.17-12-003. Unlike SCE, SDG&E does offer a landing page that describes the available technology incentives, the eligibility requirements (including stating that customers of third-party programs are eligible) and links to the application to claim the incentive. Unfortunately, the applications are prompted to either "sign up" with Nest or "enroll" with ecobee.

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[47] SDG&E AL 3522-E, Attachment C, at p. 8.
[48] *Id.*, Attachment D, at p. 4.

As presented to the customer, this language can be perceived to mean that they must enroll in an SDG&E DR program to receive the incentive. More troublesome, the text in the Nest registration link explicitly discusses enrollment in Rush Hour Rewards.[49] SDG&E should either provide a stand-alone application for the incentive to be used by all customers, or alter the language in its existing Nest and ecobee links to be more broad (e.g., “register your thermostat to receive the rebate”). The messaging should not lead customers to believe that they must enroll in Rush Hour Rewards to be eligible for the incentive.

CONCLUSION

Based on the arguments presented above, the Joint Parties recommend the Commission adopt the proposals and recommendations provided above.

Respectfully submitted,

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[49] See: https://nest.com/energy-partners/sdge; “Residential and commercial customers of SDG&E will receive a $50 incentive for signing up for Rush Hour Rewards. As a residential customer if you stay enrolled with SDG&E through the season, you’ll receive an additional $20.”

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cc: Courtesy Electronic Service to Service List in A.17-01-012, et al. (Demand Response Programs)