PG&E
Energy Division Data Request
Specific Proposal for Implementation of Competitive Neutrality Cost Causation Bill Credit
May 7, 2018

I. Introduction

On January 30, 2018, Pacific Gas & Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) filed a "Joint IOU Proposed Approach to Determine Cost Refunds to Eligible Community Choice Aggregation (CCA) and Direct Access (DA) Customers" with respect to the Commission's Order Instituting Rulemaking (OIR) to Enhance the Role of Demand Response in meeting the State's Resource Planning Needs and Operational Requirements.

The conceptual proposal filed by the IOUs in January 2018 addressed, at a high level, the process to develop the bill credit for eligible direct access/community choice aggregation (DA/CCA) customers that was common to the three investor-owned utilities (IOU's). In this data response, PG&E offers an illustrative example of how the rate credits would be developed and applied to customers' bills within PG&E's service territory. At this level of rate granularity, the methods to develop the credits among the utilities will most certainly be different across the various IOU's service territory even though the general description of the processes offered in the January 30, 2018, proposal remain the same. Furthermore, PG&E shares additional thoughts on how certain elements of the Competitive Neutrality Cost Causation (CNCC) could be implemented. These additional insights are in some cases unique to PG&E's thinking and may not necessarily be in-line with the positions held by SCE and SDG&E. In the spirit of providing additional information, as requested by the Energy Division, PG&E is sharing these ideas recognizing that SCE's and SDG&E's respective approach to implementation may differ from that of PG&E. This data response contains essentially the same information as PG&E's

PowerPoint presentation served on the parties on March 26, 2018, in preparation for the workshop, which was later delated.

II. Standard for Determining the Bill Credit

Overview

The objective of applying the CNCC principle and providing a credit to DA/CCA customer bills is to ensure that DA or CCA customers whose DA or CCA has a DR Program(s) that is found similar to the IOU's program, are not eligible to participate in that IOU's program and will not pay for the IOU's DR program. Customers who are located in a CCA territory and taking energy supply from the CCA or Joint Powers Agencies' (JPA) portfolio, or who are served directly by a DA provider, (together "Competing Provider"), may choose to participate in a DR program offered by that Competing Provider. However, for the DA/CCA customer to receive a bill credit, the Competing Provider's DR program must be deemed to be "similar" to that of PG&E by the CPUC through a CPUC Resolution.[1] Because of the distribution rate making process, all the IOU's DR costs would continue to be recovered from all its customers, but costs associated with the deemed "similar" DR program would be returned through bill credits for CCA & DA customers of the Competing Provider offering a similar program.

Applicable Costs

Those costs directly associated with the "similar" program would be included in the bill credit. Generally, this would include program incentives, marketing and administration costs.[2]

Allocation and Rate Calculations

The following steps describe the cost and allocation assumptions and rate calculations that PG&E would use to develop the bill credits. This proposed approach is consistent with the way in which DR costs are allocated among customer groups. Specifically, DR costs are

[1] D.17-10-017, p. 27.
[2] PG&E's authorized funding can be readily grouped into these three budget buckets.

currently collected in distribution rates, and are allocated among customer groups in the same manner as other distribution costs generally set forth in PG&E's General Rate Cases (Phase 2).[3] Accordingly, PG&E proposes to apply the credit to distribution rates by first allocating the DR program costs to each rate group based on the distribution allocation factor.[4] However, to simplify the credit process, PG&E proposes a volumetric rate credit for all customer groups. In some cases, this is inconsistent with distribution rate design which is used to collect the DR costs. For example, for large, non-residential customers, all distribution costs are collected in demand and customer charges with no distribution revenue collected in volumetric charges. In this data response, PG&E also provides illustrative calculations of the credit amount.

<u>Illustrative Example</u>

The below pro-forma illustration utilizes PG&E's 2018-2022 DR funding cycle based on the DR programs the company offers at this time. These programs include the following:[5]

- SmartAC: An air condition load control program offered through direct enrollment
- BIP: A commercial and industrial emergency program offered through direct enrollment and third-party Aggregators.
- CBP: A capacity program offered only through third-party Aggregators

The four-step process for determining the credit is as follows:

(1) Determine the cost of each DR program for which a competitive offering can be provided by a Competing Provider. PG&E would use the authorized cost for each DR program

[3] Demand response funds are allocated in the same manner as other distribution revenue requirements and do not receive a unique allocation. Allocation of distribution revenue requirement is determined in GRC Phase II proceedings and was last decided in D.15-08-005, which adopted a Marginal Cost and Revenue Allocation Settlement Agreement addressing allocation of costs. (See Marginal Cost and Revenue Allocation Settlement Agreement, pages 8 through 15.)

[4] The Distribution Revenue Allocation Factors are determined from the apportionment of annual Distribution-related revenues calculated using Present Rates effective 3/1/18 by the Commission-approved 2018 Sales Forecast by Customer Class.

[5] PG&E also has a demand response auction mechanism pilot (DRAM), which may become a permanent program. However, Commission D.17-10-017 has indicated that DRAM is not subject to CNCC, "This Decision confirms that the Demand Response Auction Mechanism, if adopted as a permanent mechanism, is not eligible for the Competitive Neutrality Cost Causation Principle implementation because the auction mechanism is a procurement mechanism designed to allow third party direct participation into the CAISO market; it is not a demand response program." Therefore, PG&E understands that DRAM would not be subject to the CNCC principle.

offered by PG&E. In this example, PG&E calculates rate credits for three programs it offers. Each program and the authorized budget for purposes of the example is provided below in Table 1. In this example, PG&E has used the average revenue across the five-year period, but the actual credits in any specific year would be based on that year's specific revenue requirement.

Table 1 – Illustrative DR Program Costs

SMART AC						
	2018	**2019**	**2020**	**2021**	**2022**	
Smart AC Admin	$ 5,759,000	$ 5,759,000	$ 5,759,000	$ 5,759,000	$ 5,759,000	
Smart AC Incentives	$ 637,000	$ 637,000	$ 637,000	$ 637,000	$ 637,000	
Smart AC Marketing	$ 1,616,000	$ 1,644,490	$ 1,673,543	$ 1,703,173	$ 1,733,392	**5-Year Average**
TOTAL COSTS SUBJECT TO CREDIT	**$ 8,012,000**	**$ 8,040,490**	**$ 8,069,543**	**$ 8,099,173**	**$ 8,129,392**	**$ 8,070,119.57**
Base Interruptible Program (BIP)						
	2018	**2019**	**2020**	**2021**	**2022**	
BIP Admin	$ 566,000	$ 566,000	$ 566,000	$ 566,000	$ 566,000	
BIP Incentives	$ 31,788,000	$ 31,788,000	$ 31,788,000	$ 31,788,000	$ 31,788,000	
BIP Marketing	$ -	$ -	$ -	$ -	$ -	**5-Year Average**
TOTAL COSTS SUBJECT TO CREDIT	**$ 32,354,000**	**$ 32,354,000**	**$ 32,354,000**	**$ 32,354,000**	**$ 32,354,000**	**$ 32,354,000.00**
Capacity Bidding Program (CBP)						
	2018	**2019**	**2020**	**2021**	**2022**	
CBP Admin	$ 664,000	$ 664,000	$ 664,000	$ 664,000	$ 664,000	
CBP Incentives	$ 3,439,000	$ 3,439,000	$ 3,439,000	$ 3,439,000	$ 3,439,000	
CBP Marketing	$ 386,615	$ 398,221	$ 410,188	$ 422,526	$ 435,247	**5-Year Average**
TOTAL COSTS SUBJECT TO CREDIT	**$ 4,489,615**	**$ 4,501,221**	**$ 4,513,188**	**$ 4,525,526**	**$ 4,538,247**	**$ 4,513,559.36**

(2) Using the current recovery of DR program costs from all customer classes, allocate the costs to individual customer class rate schedules. Since DR program costs are currently recovered through PG&E's distribution rates, this results in an allocated cost for both bundled and DA/CCA customers. Attachment A provides the allocation of each program cost to each customer group based on PG&E's distribution revenue allocation factors, utilizing PG&E's 2018 sales forecast.

(3) Divide the allocated cost for each program by the total forecast sales in each customer group (including bundled and DA/CCA sales). This produces a DR Unit Rate per kWh by customer class and by DR program as shown in Attachment A.

(4) The rate developed in step (3) is the average cost per kWh for each program as the DR program costs are recovered in rates. This rate per program per customer class is equal to the credit for each program.

<u>Applying the DR Rate Credit and Determining the Bill Credit</u>

The reduction to the customer's bill will be applied as a credit ($ per kWh) to the distribution charge on the customer's bill. In order to calculate and apply the credit amount to the customer's PG&E service account, the programs determined to be similar that are offered by each DA and CCA provider need to be identified. Once known, PG&E will apply a credit rate to all customers of the DA or CCA provider by multiplying the applicable credit rate by each customer's monthly kWh usage. The applicable credit rate will be based on the rate schedule within the appropriate customer class (Residential, Commercial, Industrial, etc.) and the specific DR programs being offered by the DA or CCA provider. Specifically, for example, if a DA or CCA provider offers similar programs to SmartAC and BIP, all residential customers of that DA or CCA provider would see a credit of $0.00074 per kWh (See Attachment A, $0.00059 + $0.00015).

Unique Program Considerations

PG&E recommends that customers eligible for the CARE and FERA discounts (as well as medical baseline) receive the same credit rate as other residential customers of a DA or CCA, who are entitled to receive the credit.

III. Tariff for the Credit

PG&E supports the approval of a single rate schedule that would include the appropriate credit rates for each program, set forth for all customer groups. The existing tariff for the Revenue Cycle Service Credit (Schedule E-CREDIT)[6] could serve as a model for the Competitive Neutrality Cost Causation bill credit.

IV. Timing and Administration of the Bill Credit

Timing

As set forth per D.17-10-017, the utility must cease cost recovery from the Competing Provider's customers for its affected DR program one year after the Commission issues a

[6] https://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-CREDIT.pdf

Resolution deeming a Competing Provider's program to be "similar." More specifically, the IOUs must begin processing the bill credit within one billing cycle following the end of the implementation period.[7] It should be noted that a bill cycle on average is about 30 calendar days. Therefore, the initiation of the bill credit can be expected to occur up to approximately 395 days (365 + 30) after the CPUC's Resolution.[8] Similarly, participants in the IOU's DR program subject to the CNCC, who are served by the Competing Provider, would be unenrolled at this time.

Administration of the Bill Credit

The process by which the bill credit would be administered and delivered is one that is open for consideration. However, PG&E's position is that it should be the least costly and least complex approach. PG&E's assumption is that the bill credit would be accounted for as a reduction to distribution charges on a monthly basis. The credit once initiated after the one year period (+ 1 bill cycle) would continue as part of the ongoing crediting process. An important consideration is that the bill credit amount could be too small for it to show up on the bill itself.[9] Consequently, the issuance of the credit may not be large enough to rise to a level where it would be itemized as a reduction. Although, it would still impact the underlying charge associated with distribution service.

[7] D.17-10-017 at p. 27-28.
[8] The exact timing of the bill is dependent on the meter read schedule of the customer. See 2018 meter read schedule: https://www.pge.com/en_US/residential/save-energy-money/analyze-your-usage/your-usage/view-and-share-your-data-with-smartmeter/reading-the-smartmeter/meter-reading-schedule.page
[9] Per Attachment A, the bill credit amount is generally at the 4th and 5th decimal levels, but in certain cases it may not even reach the 4th and 5th decimal levels (e.g., Rate E-20T where for SmartAC and CBP would round to zero).

V. Customer Notification Letters

The IOUs' joint proposal filed on January 30, 2018, included draft sample letters to direct enrolled and Aggregator enrolled customers in the utility's program. As indicated in the proposal, while IOUs would communicate with their direct enrolled customers, it would be the Aggregator's responsibility to communicate with their customers in the IOU's program as they own the relationship. The IOUs would simply be responsible for letting the Aggregators know about the 1) impacted participants and 2) the DA/CCAs where the utility's program may not continue to be offered.[10]

As required by D. 17-10-017, Ordering Paragraph 3, the IOUs included a set of "draft standardized customer letter" in the joint filing in January 2018. These draft pro-forma templates were intended simply as a starting point for creating a communiqué that is suitable for all parties, including the IOUs, the Competing Providers, 3rd Party Aggregators and ultimately the DA/CCA customers. Finally, PG&E notes that since the notification letter is required 60 days after the issuance of the CPUC Resolution deems a program to be similar, there would still be unknowns as to how the unwinding of program costs would occur; therefore, there may not be enough detail at that point in time to address the specifics of the future bill credit.

VI. Timeline of Activities

D. 17-10-017 stated the incumbent IOU has 30 days from the issuance of the CPUC Resolution to "begin the process to cease cost recovery and marketing to the Competing Provider's customers of the similar program." PG&E interprets this to mean that within 30 days after the issuance of the Resolution, the incumbent utility, and Aggregators in its programs, cannot enroll or continue to market the "similar" program to impacted customers. Next, within 60 days the required notification letters would be "sent" to direct enrolled customers and

[10] PG&E notes that it is the third-party Aggregator's responsibility to both remove their customers from the utility's DR program, and to stop offering/enrolling customers in the DA/CCA's area in the utility's DR program. Ultimately, the IOUs may not have visibility nor be in a position to enforce compliance by third-party entities.

Aggregators. Finally, within one year (+ 1 bill cycle), the incumbent IOU would start issuing the bill credits and remove participants who no longer are eligible to participate in the IOU's program. While these milestones were specified by D. 17-10-017, there are other activities that will undoubtedly have to occur between the two book-ends of the CPUC adopting a Resolution deeming a DR program to be similar and the point when bill credits begin to be issued approximately one-year (+ 1 bill cycle) out. A second order issue is how these milestones pertain to third-party Aggregators and whether they should be identical or lag those of direct IOU enrolled customers. These are critical issues that merit further exploration at the workshop.

VII. Recovery and Tracking of Implementation Costs

D. 17-10-017 allows IOUs to include in their Tier 3 filing "a proposal for recording incremental costs associated with implementing the bill credit, a forecast of activities and costs, and the proposed cost recovery."[11] PG&E proposes to track the implementation costs in the Demand Response Expense Balancing Account (DREBA) and to transfer these costs to the Distribution Revenue Adjustment Mechanism (DRAM) for recovery through PG&E's Annual Electric True-up filing. Essentially, the costs associated with the implementation of the bill credit would be captured in the overall program costs borne by all customers. PG&E believes these costs should be recoverable without a reasonableness review.

PG&E appreciates this opportunity to describe its approach to implementation of CNCC and development of the bill credit for eligible DA/CCA customers.

[11] D.17-10-017, p. 29.

Attachment A

Pacific Gas & Electric Company

Demand Response Programs - Competitive Neutrality Cost Causation - Rate Analysis

Customer Class	DR Program Allocation[1]	Average Annual Program Costs SMART AC	EBIP	CBP	Total	2018 Total Bundled & DA/CCA Sales	Average Program Rate embedded in Distribution ($/kWh) SMART AC	EBIP	CBP	Total
Res	50.59%	$ 4,082,421	$ 16,366,876	$ 2,283,268	**$ 22,732,565**	27,664,032,970	$ 0.00015	$ 0.00059	$ 0.00008	**$ 0.00082**
SLP	13.83%	$ 1,116,242	$ 4,475,138	$ 624,306	**$ 6,215,686**	7,946,121,858	$ 0.00014	$ 0.00056	$ 0.00008	**$ 0.00078**
A10 T	0.00%	$ 63	$ 253	$ 35	**$ 351**	2,496,297	$ 0.00003	$ 0.00010	$ 0.00001	**$ 0.00014**
A10 P	0.06%	$ 5,144	$ 20,625	$ 2,877	**$ 28,646**	65,222,401	$ 0.00008	$ 0.00032	$ 0.00004	**$ 0.00044**
A10 S	10.49%	$ 846,185	$ 3,392,451	$ 473,265	**$ 4,711,901**	9,976,544,170	$ 0.00008	$ 0.00034	$ 0.00005	**$ 0.00047**
E-19 T	0.01%	$ 886	$ 3,553	$ 496	**$ 4,935**	55,138,054	$ 0.00002	$ 0.00006	$ 0.00001	**$ 0.00009**
E-19 P	0.63%	$ 51,233	$ 205,399	$ 28,654	**$ 285,286**	967,426,911	$ 0.00005	$ 0.00021	$ 0.00003	**$ 0.00029**
E-19 S	9.46%	$ 763,472	$ 3,060,842	$ 427,004	**$ 4,251,318**	11,695,282,760	$ 0.00007	$ 0.00026	$ 0.00004	**$ 0.00036**
Streetlight	0.26%	$ 20,796	$ 83,375	$ 11,631	**$ 115,802**	275,719,662	$ 0.00008	$ 0.00030	$ 0.00004	**$ 0.00042**
AG	8.39%	$ 677,281	$ 2,715,296	$ 378,799	**$ 3,771,376**	6,189,888,334	$ 0.00011	$ 0.00044	$ 0.00006	**$ 0.00061**
E20T[2]	0.20%	$ 15,950	$ 63,947	$ 8,921	**$ 88,818**	5,606,477,033	$ 0.00000	$ 0.00001	$ 0.00000	**$ 0.00002**
E20P	4.19%	$ 337,836	$ 1,354,421	$ 188,949	**$ 1,881,206**	7,989,023,836	$ 0.00004	$ 0.00017	$ 0.00002	**$ 0.00024**
E20S	1.67%	$ 135,045	$ 541,411	$ 75,530	**$ 751,986**	2,380,354,864	$ 0.00006	$ 0.00023	$ 0.00003	**$ 0.00032**
Standby T	0.14%	$ 11,210	$ 44,943	$ 6,270	**$ 62,423**	303,297,960	$ 0.00004	$ 0.00015	$ 0.00002	**$ 0.00021**
Standby P	0.07%	$ 5,405	$ 21,670	$ 3,023	**$ 30,099**	12,462,266	$ 0.00043	$ 0.00174	$ 0.00024	**$ 0.00242**
Standby S	0.01%	$ 948	$ 3,801	$ 530	**$ 5,279**	4,657,081	$ 0.00020	$ 0.00082	$ 0.00011	**$ 0.00113**
Total	100.00%	$ 8,070,120	$ 32,354,000	$ 4,513,559	**$ 44,937,679**	81,134,146,457	$ 0.00010	$ 0.00040	$ 0.00006	**$ 0.00055**

Footnotes:

[1] DR Program Allocation factors determined from 3/1/18 Distribution Rate Revenue Allocations prior to non-allocated, CPUC Fee and CARE Shortfall revenues by Customer Class.

[2] Due to the minimal amount of DR Program cost recovery allocated to E-20 Transmission voltage level customers, the average DR Program rate rounds to zero in the 5th decimal. Unrounded rate values are as follows:

E-20T	SMART AC	CBP
Average Rate	$ 0.000003	$ 0.000002