PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 5799E
As of December 5, 2022

Subject: PG&E's Mid-Cycle Review Compliance Submittal for its 2018-2022 Demand Response funding Application

Division Assigned: Energy

Date Filed: 04-01-2020

Date to Calendar: 04-03-2020

Authorizing Documents: None

Disposition:	**Signed**
Effective Date:	**08-04-2022**

Resolution Required: Yes

Resolution Number: E-5103

Commission Meeting Date: 08-04-2022

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Annie Ho
415-973-8794
pgetariffs@pge.com

STATE OF CALIFORNIA **GAVIN NEWSOM,** *Governor*

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Pacific Gas and Electric Company

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

April 1, 2020

Advice 5799-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **PG&E's Mid-Cycle Review Compliance Submittal for its 2018-2022 Demand Response funding Application**

Purpose

Pacific Gas and Electric Company (PG&E) hereby submits this Tier 3 advice letter (AL) to the California Public Utilities Commission (Commission or CPUC) in compliance with the requirement of Decision 16-09-056.[1] This submittal also incorporates other Commission promulgations and requests pertaining to the Mid-Cycle Review (MCR) of PG&E's Demand Response (DR) programs for 2018-2022.[2]

Background

On January 16, 2017, PG&E filed Application 17-01-012 to request funding for its 2018-2022 DR programs pursuant to D.16-09-056.[3] PG&E's Application, along with those filed by the other two IOUs, were approved as part of Decision 17-12-003. Historically the DR program had been on a 3 year cycle (with some exceptions), but it was moved to a five-year cycle with the 2018-2022 submittal.[4] As part of the extension to a five-year cycle, the CPUC called for a MCR to be filed by each IOU through a Tier 3 AL no later than April 1, 2020. Furthermore, the CPUC called for the Energy Division (ED) to present a Resolution to the CPUC "no later than September 30, 2020" in order for

[1] Ordering Paragraph 9 states: "Beginning with the 2018 application for current demand response programs, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) shall file applications on a five-year cycle with a mid-cycle review. The 2018 demand response application shall be for program years 2018 through and including 2022. A mid-cycle review shall occur in 2020 for the two final years of the program cycle. The Utilities shall file a mid-cycle review tier-three advice letter no later than April 1, 2020 providing an update on each of their demand response programs and requesting approval of any necessary changes."
[2] D.17-12-003, D.19-07-009, Resolution E-4918 and a request by the Energy Division.
[3] Ordering Paragraph 6. (Note: Each of the three IOUs filed their respective Applications, which collectively are referenced as A.17-01-012 et al.)
[4] D.16-09-056 at p. 58.

the IOUs "to implement any changes for the 2021-2022 program years."[5] As part of the MCR process, PG&E presented a list of directives[6] jointly developed with the other IOUs and later separately met[7] with the ED to ensure proper scoping of the MCR.

MCR Guidelines

The following table provides a non-exhaustive list[8] of *key* requirements established by the CPUC for the MCR. In addition, PG&E proposes certain changes to its DR programs, which are highlighted under the "Summary" section below.

Issue	**Source**
Spend vs. Budget	D.17-12-003, OP 54
Common Parameters	D.17-12-003, OP 4
CBP Program Hours	D.17-12-003, p. 68-69, p. 137 and p. 147
Supply Side Pilot II	D.17-12-003, OP 37
Excess Supply Side Pilot	D.17-12-003, OP 38
5 in 10 Retail Baseline	D.19-07-009, OP 18
CBP Trigger Update	Resolution E-4918, OP 3
ADR Metrics	Request by ED Staff

Summary

Overall, total DR cumulative expenditures for 2018 and 2019 were $39.8M less than authorized for the two year period. On a programmatic level, underspend was driven primarily by lower than forecasted enrollments, attrition and performance.[9] In response, PG&E proposes certain programmatic modifications to address deficiencies or adjust program trajectory.[10] These include the following:

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[5] D.16-09-056 at p. 59.

[6] The three IOUs held a call with the Energy Division (ED) on August 28, 2019. In advance of the call, the IOUs jointly provided an agenda that contained MCR directives to ED staff on August 16, 2019.

[7] PG&E met with ED staff on December 2, 2019 to provide an update on the progress of the MCR. An overview document along with an agenda was prepared by PG&E and submitted to ED staff in advance on November 26, 2019 and November 27, 2019, respectively.

[8] The MCR goes beyond these specific items as it not only provides updates on topics that may not have been explicitly requested by the CPUC, but also makes recommendations about the continuation and/or modifications of current DR programs and pilots.

[9] This covers the three DR programs [SmartAC, Base Interruptible Program (BIP), and Capacity Bidding Program (CBP)] as well as AutoDR (ADR) incentives.

[10] D.16-09-056, at p. 59 specifies that "The mid-cycle review shall begin with a tier three advice letter filing by each of the Utilities on April 1, 2020 providing a full status report of each demand response program and recommending changes to the programs in response to any problems with the programs."

- SmartAC: Continue the *residential* program but cease to actively market for the balance of the funding cycle. Also, request authority from the Commission to close down the non-residential SmartAC tariff, which has been inactive.[11]

- Base Interruptible Program (BIP): Modify the eligibility requirements of BIP to require *average* demand in each month of the year to be 100kW during the peak Time-of-Use (TOU) hours instead of the current requirement for a maximum demand of 100kW during the peak TOU hours in a single month. This is to ensure that it is a resource that performs reliably when called upon at any time during the year.[12]

- Capacity Bidding Program (CBP): Improve the enrollment process for residential Aggregators by enabling an electronic enrollment pilot[13] consistent with PG&E's prior multi-party settlement agreement.[14]

- Supply Side II and Excess Supply Pilots: PG&E observes that these pilots have accomplished their intended objectives and recommends to the CPUC that they not be extended beyond 2020 – the current sunset year.[15]

Other areas of update include but are not limited to the following:

- Common Program Parameters: Reports the findings of the 2018 stakeholder effort to assess areas of potential alignment in programmatic design among the three

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[11] PG&E has taken action to not actively market its residential SmartAC program (E-RSAC). Separately, PG&E in its MCR is requesting the authority to close the non-residential SmartAC (E-CSAC) tariff. Since PG&E's E-CSAC tariff per D.12-04-045 was closed to new non-residential enrollments in 2012 and there are no existing participants, PG&E requests authority to close the E-CSAC tariff through a Tier 1 AL within 30 days of the issuance of the Final Resolution.

[12] If the Commission adopts PG&E's proposal in its Final Resolution, then PG&E proposes to file an Advice Letter within 45 days setting forth a plan for implementation.

[13] AL-5752-E-A, a Tier 2 AL, was filed on March 4, 2020. Per D. 17-12-003, page 137 "….We authorize the Utilities to request non-controversial changes to program tariffs and implementation procedures via a Tier 2 Advice Letter. If uncertain whether a particular change is appropriate for review through the Advice Letter process, we encourage the Utilities to *consult with Commission Staff* before submitting an Advice Letter." PG&E presented its desire to update its tariff for this proposal via a telephonic reach out to Energy Division staff on February 21, 2020.

[14] A motion for adoption of the settlement agreement was filed on June 26, 2017 and incorporated as Attachment 1 and Attachment 2 (Amendment) into D. 17-12-003.

[15] D.17-12-003, O.P. 37 and 38 pertaining to the Supply Side Pilot and the Excess Supply Pilot, respectively, providing funding for these two pilots through the end of 2020. Both O.P.s 37 and 38 left open the continuation of funding for 2021 and 2022 at the discretion of the Commission.

IOUs as it relates to CBP and BIP.[16] While it appears there are opportunities to align around program testing it would be difficult to align around other attributes due to impact on cost-effectiveness.

- CBP Program Hours: Based on the discretion given by the CPUC along with the timing of the Resource Adequacy proceeding and the MCR filing, PG&E chose to submit a separate tier 2 Advice Submittal to update its CBP program hours in lieu of presenting it in the MCR.[17]

- CBP 5 in 10 Retail Baseline: As requested by D. 19-07-009 (O.P. 18), PG&E includes a proposal for the utilization of a 5 in 10 retail baseline option. While PG&E could implement a 5 in 10 retail baseline during this funding cycle, it may be in the best interest of all stakeholders to wait until the Retail Baseline Working Group concludes its effort in assessing policy issues for the 10 in 10 baseline. This would enable the Commission to make a determination for the application of all day-of-adjustment baselines (i.e., 5 in 10, 10 in 10, etc.) at one time.

- CBP Price Trigger: As requested by Resolution E-4918, PG&E undertook the analysis of price data for the last 8 years (2012-2019). Based on the results and the timing of the expected approval of the MCR in the latter part of 2020, PG&E recommends *against* making changes to the CBP price trigger for the 2020 CBP program year.

- ADR Metrics: In response to a request by the ED,[18] PG&E provides a table in Appendix A of the MCR presenting ADR metrics for 2018 and 2019.

Protests

Anyone wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile or E-mail, no later than April 21, 2020, which is 20 days after the date of this submittal. Protests must be submitted to:

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[16] D.17-12-003, O.P. 5 called on the IOUs to work with interested parties and to report the results in their 2020 program update filing.

[17] AL-5752-E, a Tier 2 AL, was filed on February 3, 2020. Per D. 17-12-003 at p. 68-69: "Therefore, we direct PG&E to offer the new operation hours on an optional basis until the CAISO or the resource adequacy proceeding adopts new resource adequacy availability assessment hours or PG&E provides more evidence in the mid-cycle review of grid need." Further, at p. 147: "Future changes adopted by the Commission in the resource adequacy proceeding, which require changes in demand response program design, may be made through a Tier 2 Advice Letter filing by the Utilities or through the 2020 mid-cycle program update, whichever timing is most appropriate."

[18] PG&E was contacted by Energy Division staff in December 2019 about the inclusion of ADR metrics in the MCR. Subsequently, the three IOUs worked together to develop a uniform template for reporting of the data.

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 3 advice submittal become effective upon Commission approval.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A. 17-01-012 and R. 13-09-011. Address changes to the

General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

Attachments

cc: Service List A.17-01-012 and R.13-09-011

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Annie Ho
Phone #: (415) 973-8794
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: AMHP@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric	GAS = Gas	WATER = Water
PLC = Pipeline	HEAT = Heat	

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 5799-E

Tier Designation: 3

Subject of AL: PG&E's Mid-Cycle Review Compliance Submittal for its 2018-2022 Demand Response funding Application

Keywords (choose from CPUC listing): Compliance,

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.16-09-056

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? ☐ Yes ☑ No

Requested effective date:

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Erik Jacobson, c/o Megan Lawson Title: Director, Regulatory Relations Utility Name: Pacific Gas and Electric Company Address: 77 Beale Street, Mail Code B13U City: San Francisco, CA 94177 State: California Zip: 94177 Telephone (xxx) xxx-xxxx: (415)973-2093 Facsimile (xxx) xxx-xxxx: (415)973-3582 Email: PGETariffs@pge.com
	Name: Title: Utility Name: Address: City: State: District of Columbia Zip: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

Clear Form

Advice 5799-E
April 1, 2020

Attachment 1

PG&E's Demand Response Program 2020 Mid-Cycle Review

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PG&E's Demand Response Program 2020 Mid-Cycle Review

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List of Tables

PG&E's Demand Response Program 2020 Mid-Cycle Review

I. Introduction

Pacific Gas and Electric Company (PG&E) is presenting its 2018-2022 Demand Response (DR) mid-cycle update pursuant to the 2018-2022 DR Guidance Decision (D.16-09-056).[1] While the DR Guidance Decision extended the Application cycle from three to five years, it also called for a mid-cycle review (MCR) to occur in 2020 to inform the final two years (2021 and 2022). The Guidance Decision specified that, "[t]he Utilities shall file a mid-cycle review tier-three advice letter no later than April 1, 2020 providing an update on each of their DR programs and requesting approval of any necessary changes." Both the Guidance Decision and the subsequent clarifications by the California Public Utilities Commission (the Commission or CPUC) were utilized in preparing PG&E's mid-cycle filing.

This filing reviews the performance of DR programs and DR pilots for the years 2018 and 2019. Based on these two years, PG&E proposes limited enhancements to current DR programs that can be implemented for program years 2021 and 2022, and addresses the status and disposition of DR pilots.[2] However, this filing does not provide a policy vision for the design and implementation of DR programs beyond the current program cycle. PG&E requests that the Commission to the extent possible authorize a process that will result in a ruling no later than December 31, 2020 establishing principles and guidance for the post-2022 Investor-Owned Utility (IOU) DR program filing.[3]

II. Executive Summary

PG&E is planning the following programmatic changes to ensure that PG&E's DR programs are serving customers in a reliable, clean, and affordable manner:

1. <u>SmartAC™</u>: Cease actively marketing the SmartAC program to new participants due to increased costs per kilowatt-hour, challenges in recruiting customers, higher than forecasted attrition due to

[1] Ordering Paragraph (OP) 9.

[2] Many of PG&E's customers and communities are facing severe impacts, because of the spread of novel coronavirus (COVID-19). In this filing, PG&E has assumed normal business activities, but COVID-19 has created a situation that is not normal. If the unique and volatile situation created by COVID-19 persists or has lingering effects, it could impact some of the activities proposed in PG&E's Mid-Cycle Review filing. For instance, the pilots, DAC, XSP and SSP may be slimmed down, or deferred, due to the uncertainty and impact on customers due to COVID-19. Therefore, PG&E may seek authority to modify the delivery of its Demand Response programs and pilots as conditions warrant.

[3] D.16-09-056 at p. 59 called for the IOUs to file their 2023-2027 DR Funding Application by November 30, 2021.

market trends (i.e., adoption of smart thermostats rather than Load Control Switches (LCS)), and LCS technology failures.

2. Base Interruptible Program (BIP): Modify the eligibility requirements of the BIP to ensure that it is a resource that performs reliably when called upon at any time during the year. PG&E plans to require that average demand in each month of the year be 100 kilowatt (kW) during the peak Time-of-Use (TOU) hours instead of the maximum demand of 100 kW in a single month during the peak TOU hours.
3. Capacity Bidding Program (CBP): Improve the enrollment process for residential aggregators for the CBP and increase participation by DR aggregators, with a focus on residential capacity.

III. 2018-19 DR Portfolio Performance and Expenditure Variance

The load impact of PG&E's DR portfolio underperformed in 2018-19 relative to the load impact forecast in PG&E's 2018-22 DR Application (see Table 1 below). The primary driver of this underperformance was that the BIP load impact forecast was set before the 30 megawatts (MW) of reliability DR was carved out of PG&E's 330 MW reliability cap allocation for procurement through DRAM. In addition, the CBP underperformed due to challenges with PG&E's program enrollment system that proved to be prohibitive for new residential Aggregators. Further, the load impact of SmartAC declined faster than expected; however, this was largely due to PG&E deciding to reduce customer acquisition efforts because of the rising costs of new SmartAC capacity.

Table 1: Load Impacts				
Load Impacts (MW) of DR Resources	A.17-01-012		Ex Ante Load Impact	
	2018 (August)	2019 (August)	2018[a,c] (August)	2019[b,c] (August)
BIP	330	330	281	310[4]
CBP	49	52	34	32
SmartAC	72	74	54	49
Total	451	457	369	391

a) Source: PG&E's Monthly Report on Interruptible Load and Demand Response Programs (ILP) for August 2018.
b) Source: PG&E's Monthly Report on Interruptible Load and Demand Response Programs (ILP) for August 2019.
c) The ex ante load impacts here represent the expected capacity of the programs given the actual enrollment when dispatched under the ex ante conditions, i.e., 4-9 pm on the monthly system peak day under 1-in-2 weather conditions.

The lower-than-expected enrollment in programs was the primary driver of expenditures that were $39.8 million less than authorized in 2018-19. Variances in spending for each program relative to its authorized funding level can be found in Table 2 below, and explanations for these variances are provided in the respective sections for each program and budget category.

[4] While this number may suggest BIP combined with the RDRR DRAM (25 MW) would exceed the reliability MW cap of 330 MW, the monthly DR report is only a rough estimate based on the average per-customer impact multiplied by the customer count. The official ex ante load impacts, which determine the total reliability MW from PG&E's programs, will be made available in PG&E's load impact filing on 4/1/2020.

Table 2: Budget Variance

	in thousands	2018			2019			2018-19 Total		
Line Item	**Funding Categories**	**Authorized**	**Actual**	**Variance**	**Authorized**	**Actual**	**Variance**	**Authorized**	**Actual**	**Variance**
1	**Category 1: Supply-Side DR Programs**									
2	AC Cycling: Smart AC - Admin	$5,759	$4,907	$852	$5,759	$2,924	$2,835	$11,518	$7,831	$3,687
	AC Cycling: Smart AC - Incentive	$637	$265	$372	$637	$48	$589	$1,274	$314	$960
3	Base Interruptible Program (BIP) - Admin	$566	$354	$212	$566	$335	$231	$1,132	$689	$443
	Base Interruptible Program (BIP) - Incentive	$31,788	$26,001	$5,787	$31,788	$23,051	$8,737	$63,576	$49,052	$14,524
4	Capacity Bidding Program (CBP) - Admin	$664	$411	$253	$664	$379	$285	$1,328	$790	$538
	Capacity Bidding Program (CBP) - Incentive	$3,439	$1,613	$1,826	$3,439	$1,264	$2,175	$6,878	$2,877	$4,001
5	***Category 1 Total***	***$42,853***	***$33,551***	***$9,302***	***$42,853***	***$28,002***	***$14,852***	***$85,706***	***$61,553***	***$24,153***
6	**Category 2: Load Modifying DR Programs**									
7	OMBC/SLRP	$12	$7	$5	$12	$5	$7	$24	$12	$12
8	Permanent Load Shifting (PLS)	$	$	$	$	$	$	$	$	$
9	***Category 2 Total***	***$12***	***$7***	***$5***	***$12***	***$5***	***$7***	***$24***	***$12***	***$12***
10	**Category 3: DRAM and Rule 24/32**									
11	DRAM	$	$	$	$	$	$	$	$	$
12	Rule 24 O&M	$2,439	$979	$1,460	$2,511	$1,300	$1,211	$4,950	$2,279	$2,671
13	***Category 3 Total***	***$2,439***	***$979***	***$1,460***	***$2,511***	***$1,300***	***$1,211***	***$4,950***	***$2,279***	***$2,671***
14	**Category 4: Emerging and Enabling Technology Programs**									
15	AutoDR (Admin and Incentive)	$4,006	$2,289	$1,717	$4,050	$2,023	$2,027	$8,056	$4,313	$3,743
16	DR Emerging Technology	$1,380	$613	$767	$1,416	$362	$1,054	$2,796	$975	$1,821
17	***Category 4 Total***	***$5,386***	***$2,902***	***$2,484***	***$5,466***	***$2,386***	***$3,080***	***$10,852***	***$5,288***	***$5,564***
18	**Category 5: Pilots**									
19	Supply Side Pilot (Admin & Incentive)	$2,083	$624	$1,459	$2,114	$922	$1,192	$4,197	$1,546	$2,651
20	Excess Supply Pilot (Admin & Incentive)	$596	$616	-$20	$605	$501	$104	$1,201	$1,117	$84
21	Local Capacity Planning Areas and Disadvantaged Communities Pilot	$	$	$	$250	$109	$141	$250	$109	$141
22	***Category 5 Total***	***$2,679***	***$1,239***	***$1,440***	***$2,969***	***$1,532***	***$1,437***	***$5,648***	***$2,772***	***$2,876***
23	**Category 6: Marketing, Education, and Outreach (ME&O)**									
24	DR Core Marketing & Outreach [a]	$2,325	$2,117	$208	$2,388	$685	$1,703	$4,713	$2,803	$1,910
25	Education and Training	$252	$60	$192	$262	$68	$194	$514	$128	$386
26	***Category 6 Total***	***$2,577***	***$2,177***	***$400***	***$2,650***	***$754***	***$1,896***	***$5,227***	***$2,931***	***$2,296***
27	**Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications)**									
28	DR Measurement and Evaluation (DRMEC) [b]	$3,007	$829	$2,178	$3,036	$1,393	$1,643	$6,043	$2,221	$3,822
29	DR Integration Policy & Planning	$1,576	$1,659	-$83	$1,629	$1,397	$232	$3,205	$3,056	$149
30	Support for Market Activities	$3,791	$2,574	$1,217	$2,331	$4,710	-$2,379	$6,122	$7,284	-$1,162
31	Support for Retail & Customer Facing Activities	$4,235	$5,006	-$771	$3,794	$4,367	-$573	$8,029	$9,372	-$1,343
32	DR Potential Study	$400	$	$400	$400	$	$400	$800	$	$800
33	***Category 7 Total***	***$13,009***	***$10,068***	$2,941	***$11,190***	***$11,866***	***-$676***	***$24,199***	***$21,934***	***$2,265***
34	**TOTAL DR Portfolio**	**$68,955**	**$50,923**	**$18,032**	**$67,651**	**$45,845**	**$21,806**	**$136,606**	**$96,768**	**$39,838**

[a] The authorized values shown for 2018 and 2019 reflect the DR Core Marketing & Outreach approved funding net of the $158K elimination for PLS.

[b] The authorized values shown for 2018 and 2019 reflect the DRMEC approved funding net of the $225K elimination for PLS.

Note Negative values represent over-spend for the specific year generally due to front-loading of certain costs.

An over-or-under spend in a given year is not necessarily reflective of the overall 5 year spending trajectory.

IV. 2018-19 DR Program Performance and Expenditure Variances by Funding Categories, and Planned Changes

A. Category 1: Supply Side DR Programs

i. SmartAC (Air Conditioning (A/C) Cycling):

The SmartAC program is a central air conditioning (AC) direct load control program for bundled and unbundled residential customers. Program participants receive a one-time $50 incentive in exchange for having a LCS installed on or near their AC by PG&E's third-party contractor. Devices are remotely activated on SmartAC event days which can occur May 1 through October 31 during any day of the week. The program is bid into the CAISO wholesale market as a Proxy Demand Resource but can also be called for emergencies and near-emergency purposes by the CAISO or PG&E's grid and system operators.

The budget requested in A.17-01-012 for the SmartAC program of approximately $12.8 million for program administration and rebates and approximately $4 million for marketing reflected a load impact forecast (peak season Ex-Ante) of 72 MW for 2018 and 74 MW for 2019. Actual spending in 2018-19 was $8.1 million for program administration and rebates and approximately $2.5 million for marketing, which was driven by lower than expected peak season Ex-Ante load impacts of 54 MW in 2018 and 49 MW in 2019.

<u>Enrollment and Capacity</u>: There are three primary drivers of lower-than-expected SmartAC enrollments and capacity:

1. <u>Fewer customers are participating in the SmartAC program</u>. At its peak in 2010, 144,900 customers were capable of delivering 128 MW according to the load impact evaluation at that time. Since then, the number of participants has steadily declined to approximately 100,000 today. A key cause has been that SmartAC participants who move their residence often do not sign up for the program at their new residence. PG&E can then try to convince the new resident of that location (premise) that had the SmartAC device to join the program, and also try to convince the resident who moved to enroll their new location (premise). This task is costly and has become even more challenging as the preference among

customers for smart thermostats and an incentive structure that provides ongoing payments[5] becomes more prevalent.

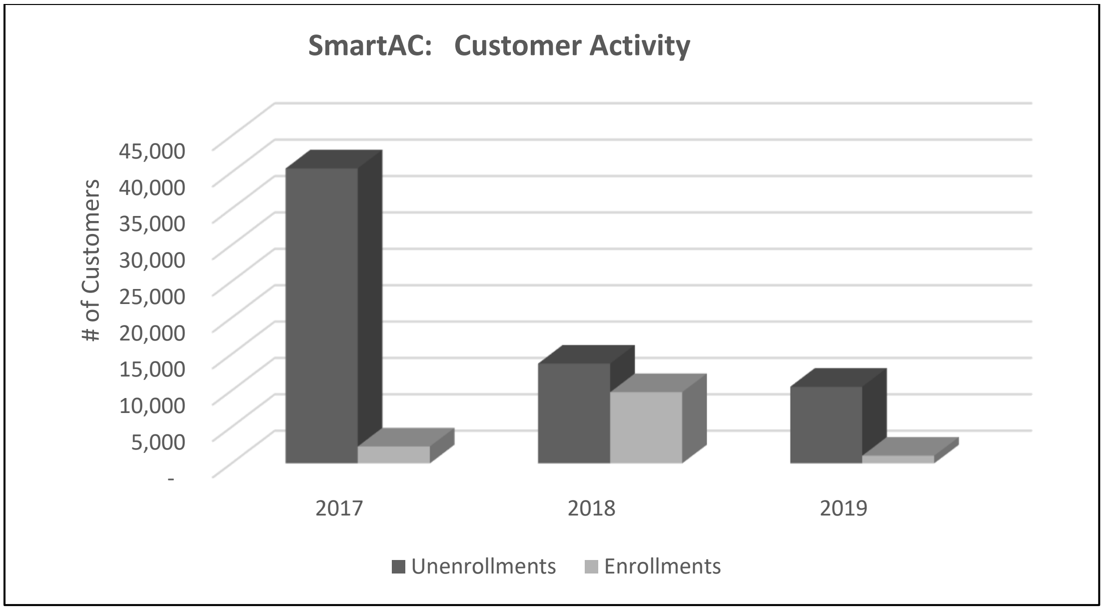
Furthermore, the CPUC's updated dual participation rule[6] prevents new customers from enrolling in both Smart Rate and SmartAC, which was historically a combination that approximately 20% of participants elected rather than participating in either program alone. PG&E has also observed customers, who historically participated in both SmartAC and SmartRate™, are leaving SmartAC because their county created or joined a Community Choice Aggregation (CCA) program and SmartRate is not available to these unbundled customers.[7] Customers leaving SmartRate for this purpose typically also often leave SmartAC. Additional drivers of unenrollments from the program have been: 1) an increase in customers qualifying for the Medical Baseline rate, which is not eligible for SmartAC and, 2) an effort by PG&E to unenroll customers who were found to have little or no AC load.

The collective impact of the above factors resulted in a net loss of 24,000 customers from the program during 2018 and 2019, whereas the capacity of SmartAC forecasted in the Application required at least 11,000-13,000 new customers each year (approximately 24,000 in total) to offset historical attrition rates. The following chart illustrates enrollments and unenrollments for years 2017, 2018 and 2019.

[5] Data collected by PG&E shows that once reminded of being on the SmartAC program, 55% of customers chose to de-enroll primarily due to the fact that the program design does not include ongoing incentives.

[6] D.18-11-029 (Remaining DR Issues and DRAM) rendered guidance by limiting new, incremental dual participation for participants in Critical Pricing Programs (i.e., PDP and SmartRate) and another utility or third-party administered DR program. Current enrolled customers prior to October 26, 2018 could continue to participate. Compliance with this new restriction was reflected in the tariff updates filed via Advice Letter 5437-E on March 11, 2019.

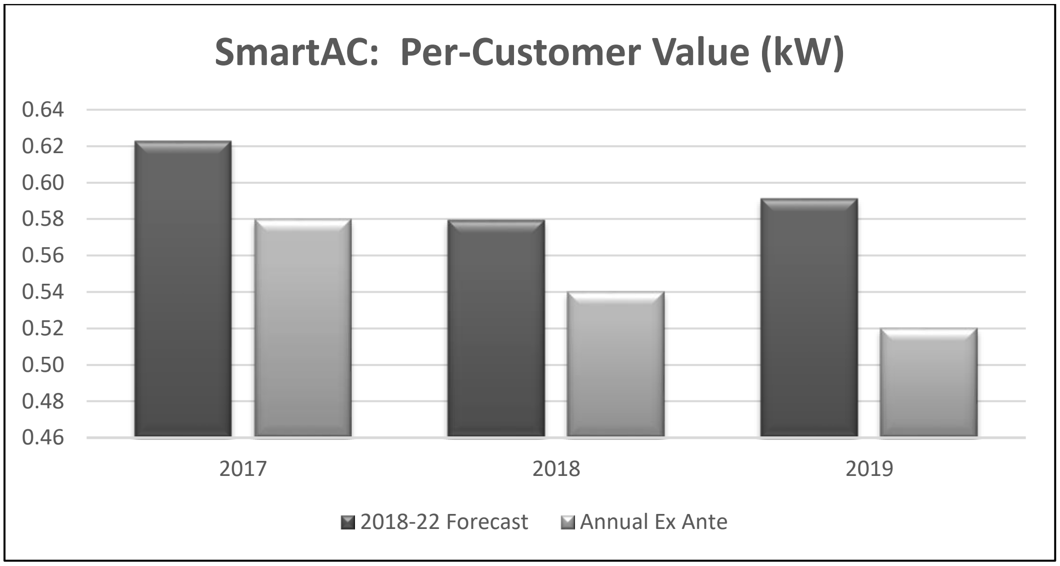
[7] Critical Peak Pricing programs such as PDP and SmartRate are part of the generation rate component, which is no longer supported by PG&E once a customer moves to a CCA (or ESP). This is because the new Load Serving Entity (LSE) would be the provider of generation.



2. <u>Legacy direct load control technology is failing and expensive to replace</u>. Almost 90% of the SmartAC direct load control devices that have been installed are legacy one-way paging technology, which communicates over the networks of the only two commercial paging companies offering service in PG&E's territory. Analysis of meter data for SmartAC participants identified program participants where either the SmartAC device or the communication network failed during SmartAC events. Roughly 12% of the installed population were impacted in 2018 and 2019. PG&E addresses this issue with a proactive maintenance program in which approximately 4,000 non-operating one-way devices are replaced annually with more reliable two-way switches that communicate over the Advanced Metering Initiative (AMI) network. Replacing all one-way devices (approximately 85,000) would cost approximately $12 million. With third-party DRPs recruiting customers into behavioral and smart thermostat DR programs with lower implementation costs, PG&E does not believe replacing all devices would be a prudent use of ratepayer funds as those costs could easily become stranded.

3. <u>Load reduction values have also declined</u>. As discussed earlier, the number of customers has declined and the technology challenges have reduced reliability of devices responding during events. The customer decline itself would reduce the capacity of the program, but the technology challenges also contributes because it reduces the average load impact per SmartAC customer (10% have a load impact of zero since the device cannot be reached).

Ultimately, the average load impact per customer was 10% less than forecasted in the 2018-22 DR application. The combined effect of lower enrollments and a lower average per customer load impact results in a lower capacity for the entire program than forecasted. The following chart illustrates the divergence between the forecasted load impact and performance (ILP Ex Post and Annual Ex Ante).



Program Utilization: SmartAC is both a reliability program used during emergencies and an economic program based on wholesale energy prices. It can be dispatched: (1) by order of the California Independent System Operator (CAISO)[8]; (2) at the discretion of PG&E's energy operations center or in response to a CAISO economic award in the wholesale market; or (3) during program testing. SmartAC is available for dispatch from May 1 through October 31, consistent with times of high A/C usage.

During 2018-19, PG&E targeted 15-20 hours of dispatch per customer during the season. The integration of SmartAC into the CAISO market as a Proxy Demand Resource (PDR) in 2018 required determining the offer price of the resource that would result in the targeted number of dispatch hours. During the first half of the 2018 season, PG&E set its offer price at a level that did not result in any market awards. The offer prices were lowered in the second half of the season and resulted in dispatches during the hottest days of the summer. In

[8] The CAISO can dispatch a) after the dispatch of Condition 2 Reliability Must-Run (RMR) units and prior to canvasing other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties, or b) otherwise based on its forecasted system conditions and operating procedures; or c) during emergency or near emergency situations.

2019, PG&E offered SmartAC PDRs into the market at a price similar to the offer price used in the second half of the 2018 season; however, no market awards were received for the first half of the season.

To increase the likelihood that the target number of hours was reached and that SmartAC was dispatched at times that it would be most beneficial to ratepayers, PG&E decided to apply a temperature threshold to its bidding strategy for the remainder of the season. The key element of this strategy was to offer the resources at relatively high prices when temperatures were forecasted to be relatively cool and the expected impact of SmartAC was low, and to offer the resources at lower prices when temperatures were hotter and the expected impact of SmartAC was greater. The result of these strategies employed in 2018-19 resulted in 4-18 hours of dispatch per customer in 2018 and 12-21 hours of dispatch in 2019. These dispatch hours were achieved in a combination of award dispatches totaling 8 days in both 2018 and 2019, 1 test event administered in 2018 and 2 test events administered in 2019, and 1 emergency event in 2018. Please refer to Table 3, which contains key metrics related to the SmartAC program. For more details on market-based activity and dispatches of SmartAC in 2018-19, please see Section G, Subsection iii, Part (a) PDR Portfolio and Activity.

Table 3: Key Metrics for SmartAC

	2018	**2019**
Enrolled customers (average)	111,688	102,531
August Ex Ante load impact	54	49
# of Day Ahead (DA) dispatches	9	10
# of market awards	8	8
# of test events	1	2

<u>Planned Program Changes</u>: As discussed above, the trend of increased adoption of smart thermostats (e.g., Nest) rather than LCS, other options for residential customers to participate in DR programs with third parties, high failure rates for legacy technology, and increasing costs of acquiring customers, PG&E plans to stop actively recruiting new customers into the SmartAC program. However, PG&E will continue to operate the existing SmartAC resource through the remainder of the funding cycle, and consider making a request to sunset the program in its next funding Application for years 2023-2027.

An outstanding issue that requires Commission approval, PG&E requests approval to formally close its Commercial SmartAC (E-CSAC) tariff. Since PG&E cannot enroll commercial customers and since there are no existing commercial customers enrolled in the SmartAC program,[9] PG&E recommends closure of the E-CSAC tariff that was previously utilized for commercial participants. If the CPUC concurs with the closure of E-CSAC, then PG&E requests authority to file a Tier 1 Advice Letter within 30 days of the Resolution approving PG&E's MCR filing. This Tier 1 Advice Letter would request closure of the E-CSAC tariff pursuant to the authority given to PG&E in the Resolution.

ii. Base Interruptible Program

The Base Interruptible Program is an emergency program open to large bundled and unbundled non-residential customers. Customers can enroll through a third-party aggregator or directly with PG&E. Program participants receive a monthly capacity incentive based on average demand in exchange for reducing to a predetermined level of consumption when an event is called. Participants are required to drop to their Firm Service Level (FSL) within 30 minutes of the event start time listed on an event notification. Non-compliance results in an excess energy charge and possible re-testing until compliance is demonstrated. BIP events can be called at anytime, 365 days a year, 24 hours a day, 7 days a week. The program is bid into the CAISO wholesale real-time market as a Reliability Demand Response Resource (RDRR), but can also be called for emergencies and near-emergency purposes by the CAISO or PG&E's grid and system operators.

The budget of approximately $32 million per year for 2018-19 that was requested for this program reflected the expectation that enrollment would meet PG&E's Reliability Cap allocation of 330 MW.[10] Shortly thereafter CPUC Resolution (Res.) E-4728 ordered the IOUs to procure reliability DR via the Demand Response Auction Mechanism (DRAM). PG&E subsequently procured 30 MW of Reliability Demand Response Resource via DRAM, reducing the maximum capacity that could enroll in BIP to 300 MW. PG&E attained a load reduction potential of 281 MW in August 2018 and a load reduction potential of 310 MW in August 2019, and spent approximately $25 million per year. While the primary driver of the underspend in this program relative to its authorized budget of approximately $7 million ($32M - $25M) per year was the allocation of 30 MW to DRAM

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[9] The SmartAC program is limited to residential customers since D.12-04-045 (OP 38) closed the program to new commercial participants in 2012. While then existing commercial customers were able to remain in the SmartAC program by now they have attritioned and no commercial participants are enrolled today. However, the legacy tariff (E-CSAC) for commercial participants remains open since an explicit Commission order has not been issued to close the tariff. The separate E-Residential Smart AC (E-RSAC) tariff for residential participants would not be impacted by the closure of E-CSAC.

[10] D.18-11-029, OP 2(a).

rather than BIP, an increase in enrollments by smaller customers who earned a lower incentive due to the tiered incentive structure[11] of the program, and an increase in excess energy charges due to underperformance of a small subset of customers, were also contributing factors.

Enrollment & Capacity: The number of individual customers enrolled in BIP rose from 384 in 2017 to 495 in 2018 and then to 517 in 2019. However, the majority of these new customers had less load and less load reduction potential; the *per-customer* ex ante impact for August dropped from 909 kW in 2017, to 609 kW in 2018 and 603 kW in 2019. In addition, several customers with significant load reduction potential left the program when the Prohibited Resources policy became effective.[12]

Program Utilization: BIP is a reliability program that can be called upon anytime throughout the year; therefore, PG&E called its BIP test events at various times to test the readiness of customers under different conditions (time of year, week, and day). During the 2018-19, BIP was called six times total; twice in 2018 and once in 2019 for PG&E Transmission emergencies, and participants not called upon in transmission emergencies were dispatched through one test in 2018 and two tests in 2019. Table 4 provides an explanation of these events and analysis of participant performance. The actual MW (Column B) represents the ex post load impacts for the events in 2018, but for the events in 2019, reflects the preliminary results PG&E sent to the CAISO seven days after each event, since the official ex post impacts for the events in 2019 will not be available until the load impact filing is submitted on April 1, 2020.

[11] The BIP tariff on Sheet 10 specifies a tiered incentive structure with an incentive of $8.00/kW for a Potential Load Reduction (PLR) between 1 kW and 500 kW; $8.50/kW for a PLR between 501 kW to 1,000 kW; and $9.00/kW for a PLR exceeding 1,001 kW.

[12] Res.E-4906 on page 73 specified the beginning of the prohibition as January 1, 2019.

Table 4: BIP 2018-2019 Performance During Emergencies and Tests						
			A	B	C	D
Date	Time	Type & Rationale	Forecast MW	Actual MW	Percentage of accounts reaching FSL (*)	Of those reaching FSL, the percentage of accounts that had a load at or below their FSL just before the event
7/18/18	2200-2400	**Emergency**: Loss of Transmission in the Humboldt area	2.8	1.6	50%	25%
7/27/18	1945-2400	**Emergency**: Loss of Transmission capacity due to the Mendocino Complex fire	2.1	1.2	100%	29%
9/26/18	1600-2200	Test	207.8	249.1	67%	54%
2/23/19	1900-2200	**Emergency**: Loss of a Transmission line in the San Luis Obispo area, when a private property owner cut down a tree, which fell onto a transmission tower	18.2	21.5	80%	87%
3/12/19	0630-0930	Test	122.3	147.4	67%	68%
10/6/19	1700-1900	Test	155.2	143.9	74%	73%

(*) FSL = Firm Service Level, which is the basis for measuring BIP performance.

The following discussion provides a guide to help interpret table 4:

- Throughout the September 26, 2018 BIP event, 67% of impacted accounts maintained a load that was at or below the FSL to which they committed. However, 64% of those accounts already had a load at or below the FSL to which they committed before the event began.
- Throughout the October 6, 2019 BIP event, 74% of impacted accounts maintained a load that was at or below the FSL to which they committed. However, 82% of those accounts had a load at or below the FSL to which they committed before the event began.
- The weighted average (column C) of the proportion of customers not reaching their FSL in 2018-19 events was 30%. However, of the 70% of customers who did meet the program requirement of being below their

FSL during the events, the usage of many of them was already at or below their FSL when the event was dispatched. Column D shows the percentage of accounts dispatched in each event that had metered load at or below the FSL in the hour before the event began.

Since many of the same accounts were dispatched for more than one event, an adjustment must be made to determine the percentage of accounts enrolled in BIP during 2018-19 that had metered load at or below the FSL in the hour before the event began. After making this adjustment, approximately 70% of the accounts dispatched in the six BIP events in 2018-19 had usage at or below their FSLs before the start of at least one of the events and did not further reduce load by a meaningful amount (more than 100 watts) for the duration of the event. 20% of the accounts dispatched in the six BIP events in 2018-19 had usage at or below their FSLs before the start of 3 of the 6 events. In addition, approximately 26% of all 517 BIP participants in 2019 had zero usage for at least 75% of the meter intervals for the entire year.

While failure to reduce load to a FSL is addressed by the existing retest process, and the ability to adjust the baseline of non-performing participants or remove them from the program after the fact, there currently is no mechanism for ensuring that there is a high probability that participants drop load during a BIP event. The majority of the accounts that have load below their FSLs before events are ones that have "peaky" load rather than consistent load. The reason for a large number of accounts with peaky load is that under the current eligibility requirement each account is only required to have 100 kW of maximum demand during the peak TOU hours in one of the previous 12 months. The impact of allowing accounts with peaky loads to participate in BIP is that these accounts are highly unlikely to drop load during a BIP event, yet these accounts hold capacity under the reliability cap.

<u>Planned Program Changes:</u>

PG&E conducted analysis on the impact of changing the program eligibility requirement to one that better reflects the 24x7x365 nature of the BIP program, and would ensure that all BIP participants have load to drop in an unpredictable emergency event. The current requirement is that each accounts have 100 kW of maximum demand during peak TOU hours[13] in one of the previous 12 months. PG&E assessed the impact of changing the requirement to each Account needing at least 100 kW *average* demand during peak TOU hours in

[13] Customers on legacy TOU rates must have at least 100 kilowatt (kW) or higher maximum demand during the summer on-peak or winter partial-peak for at least one month over the previous 12 months. Customers on the new TOU rates must have at least 100 KW or higher maximum demand during the summer on-peak and the winter on-peak for at least one month over the previous 12 months. The new peak TOU hours are 4-9 p.m. for Commercial and Industrial customers and 5-8 p.m. for Agricultural customers every day all year round.

each of the last 12 months to qualify. Based on 15-minute interval consumption data of all customers enrolled in BIP from January 2018 through September 2019, the impact of changing the eligibility requirement from each account having 100 kW of maximum demand during peak TOU hours in one of the previous 12 months, to each account having at least 100 kW *average* demand during peak TOU hours in *each* of the last 12 months would be the following:

Table 5: BIP 100 kW Threshold Metrics

	< 100 kW average demand in the peak TOU hours in every month	Accounts with >= 100 kW average demand in the peak TOU hours in every month
Number of customers in 2019	344	173
Proportion of BIP's total load reduction potential	17%	83%

In short, 344 accounts that represent 17% of the total load reduction potential of BIP would no longer qualify for the program. The remaining 173 participants that provide 83% MW of load reduction potential would continue to qualify for the program. While this change would likely result in a decline in enrolled BIP capacity, the capacity that qualifies will be more reliable. Further, while some participants with peaky load will no longer qualify for BIP, these participants could find the CBP to be a better fit due to its flexible nature and the ability to choose the price at which resources are dispatched. PG&E recognizes that if the proposal is adopted by the CPUC that it would impact certain participants. Therefore, PG&E proposes conducting outreach upon CPUC's approval to inform impacted participants of their options.[14]

Per the settlement agreement in A.17-01-012 between PG&E and California Large Energy Consumers Association, EnerNOC, Inc., CPower, Inc., EnergyHub, Inc., OhmConnect, Inc., Electric Motor Werks, Inc., and the California Efficiency + Demand Management Council, PG&E piloted a DA bidding of BIP with a small number of BIP customers. This pilot was conducted in 2018 with 8 accounts that represented a maximum of 43 MW of load who were able to determine the price at which their load reduction would be offered in the CAISO via the RDRR product. Sixteen market awards were received for 47 hours of dispatch, yielding

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[14] PG&E envisions that if the CPUC approves the proposal that it would file a Tier 1 Advice Letter within 45 days of the final Resolution clarifying implementation of the new requirement, which is anticipated to occur in 2021.

131 megawatt-hours (MWh) of energy. While the concept was proven to be feasible, the participants did not find the amount of revenue earned from the market awards to be compelling enough to request that the pilot be repeated in 2019. Therefore, the pilot was not active in 2019, and PG&E does not plan to offer it again for the remainder of the funding cycle.

iii. Capacity Bidding Program:

CBP enables aggregators or self-aggregators to be paid a capacity payment based on the amount of load they have committed for each month, and provides an energy payment based on the performance of their events when dispatched via CAISO market award. See Table 6 for a comparison of CBP options.

Table 6: Available CBP Options

Characteristic	Prescribed Option	Elect Option	Elect+ Option
Capacity and Price Nomination	Participant nominates a monthly capacity amount, and PG&E sets CAISO market bid price and dispatch strategy within specified operating hours.	Participant nominates monthly capacity amount and selects its own CAISO market bid price within specified operating hours.	Participant must participate in Elect Option and can also participate in the CAISO market for additional hours outside of the minimum specified operating hours.
Capacity Payment	Average of $10.35 per kW per month, based on performance.	Same as Prescribed Option.	Same as Prescribed Option.
Energy Payment	Pass-through of wholesale energy settlement.	Pass-through of wholesale energy settlement.	Pass-through of wholesale energy settlement.
Operating Hours	1 p.m.-9 p.m. from May to October.	1 p.m.-9 p.m. from May to October.	1 p.m.-9 p.m.+ (participant may choose to bid additional hours outside of the 1 p.m.–9 p.m. window) from May to October.

The budget requested for this program in the 2018 DR Application reflected a peak month load impact forecast of 49 MW in 2018 and 53 MW in 2019. However, the actual peak monthly nominations in 2018 were 34 MW and 30 MW in 2019, resulting in approximately $4 million less than expected spent on incentives. Variances from the targeted capacity levels are discussed below.

Enrollment & Capacity: As shown in Table 7, from 2018-2019, the number of enrolled CBP customers declined by 7% and the number of active CBP customers increased by 35%. Customers who have enrolled with a CBP Aggregator are considered active only when they nominate customers to be available for dispatch in a given month. Given the confidential nature of the arrangement between customers and Aggregators, PG&E is typically not made aware of reasons for departures; however, it appears that the decline in active and enrolled customers from 2018 was largely due to the implementation of the Prohibited Resources policy and the increase in available DRAM capacity as an alternative for some third-party DR providers.

Despite the decline in customers, the overall number of enrolled Aggregators remained relatively steady over the time period. New Aggregators joined in 2018 as PG&E launched Elect and Elect Plus options for the CBP (in addition to the “Prescribed” option), which provides Aggregators with the ability to choose the CAISO wholesale price at which their resources are bid into the market for greater control over the dispatch of their resources. No Aggregators selected the Elect Plus Option in 2018-19, which enables participants to utilize their capacity to earn CAISO energy payments outside of the program hours of 11 a.m. – 9 p.m.[15] However, PG&E plans to continue offering the Elect Plus Option, which may be of greater interest to Aggregators employing batteries who may have the flexibility to be dispatched more often.

Although there was an average increase of 177 active customers from 2018-2019, due to a net loss of four Aggregators the overall August capacity of the program dropped from 34 MW in 2018 to 30 MW in 2019. Among the Aggregators that joined in 2018-2019, none of the residential Aggregators met the minimum capacity of 100 kW per sub-Lap *and* LSE that was required to nominate a resource during those two seasons. Therefore, all active Aggregator portfolios during the 2018-2019 seasons consisted of Commercial & Industrial and Agricultural customers.

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[15] Activity outside of these hours does not impact capacity payments.

Table 7: Key CBP Metrics		
	2018	**2019**
Enrolled customers (average)	1,698	1,569
Active customers (average)	513	690
# of Aggregators	16	12
# of New first-time Aggregators	3	2
# of Aggregators that left CBP	0	6
Proportion of customers enrolled in Elect Program Option	95%	99%
Proportion of capacity (MW) enrolled in Elect Program Option	81%	83%
August Nominated MW	34	30

Drivers of weaker than expected enrollments: The drivers of weaker than expected enrollments were: (1) a preference among some Aggregators for BIP[16] if their portfolios could meet the more demanding requirements; (2) a preference among some third parties possessing requisite IT system capabilities for DRAM (ability to connect with CAISO systems and be/obtain a Scheduling Coordinator); and (3) issues with PG&E's customer enrollment process. On the last driver (#3), the PG&E IT systems that facilitate enrollment were originally built to receive enrollment requests via paper forms. Residential Aggregators, however, must enroll thousands, or even tens of thousands, of customers in order to reach a resource of a size that meets the CAISO's 100 kW minimum requirement for PDRs. In its 2018-2022 DR Application, PG&E had forecasted a load impact of 8 MW from residential Aggregators in 2019, however due to these systems limitations, no residential Aggregators participated in either the 2018 or 2019 season. Improvements to the residential enrollment process will be launched throughout 2020 in order to reach the residential peak capacity forecast in the 2018-2022 DR Application of 18 MW by 2022.[17]

Program Utilization: PG&E may trigger a CBP Prescribed Event for one or more Sub-LAPs under the following conditions: (1) if the CAISO DA market price exceeds $95/MWh and PG&E receives a market award, (2) a

[16] BIP generally provides for a higher incentive level compared to CBP (~$100/kW/yr. vs. ~$60/kW/yr.)

[17] PG&E filed AL-5752-E-A on March 4, 2020, requesting approval to modify its CBP tariff and CBP Aggregator Agreement (Form 79-1076), to enable electronic enrollment for residential participants.

dispatch instruction is received from the CAISO for a CBP resource; (3) when PG&E, at its sole discretion, forecasts that generation resources or electric system capacity may not be adequate; or (4) forecasted temperature for a Sub-LAP exceeds the temperature threshold for the Sub-LAP.

PG&E may trigger a CBP Elect and Elect Plus Options Event for one or more Sub-LAP when PG&E receives a market award from the CAISO for a PDR that's part of CBP as a result of the offer price specified by the Aggregator for a nominated portfolio.

Over the 2018-19 DR seasons, PG&E 's bidding of the CBP portfolio resulted in 45 days with market awards in 2018, and 13 days with market awards in 2019. In addition, test events were administered on 3 days in 2018 and 6 days in 2019. For more details on market-based activity and dispatches of CBP in 2018-19, please see Section G, Subsection iii (a) PDR Portfolio and Activity.

Planned Program Changes: PG&E has and continues to plan making modifications to CBP over the remainder of the 2018-22 funding cycle. These changes, as enumerated below, include activities both within and outside the scope of the Mid-Cycle Review.

- Recently filed update language associated with prohibited resources to more clearly specify obligations for residential CBP Aggregators and customers.[18]
- Expanding the enrollment options through piloting streamlined electronic processes to support residential participation.[19]
- Implementing 5-in-10 baseline for residential customers based on Commission guidance for the Mid-Cycle Review filing. See Section V of the MCR for details on PG&E's proposal for a 5-in-10 baseline.
- Leveraging the Demand Response Emerging Technology (DRET) Program to identify and evaluate improvements that would provide greater service and value for both Aggregators and the energy market, to possibly inform future program design.

[18] Advice Letter E-5752-E filed February 4, 2020.
[19] *Ibid* Footnote 17.

B. Category 2: Load Modifying DR Programs

PG&E's three load modifying programs: The Optional Binding Mandatory Commitment (OBMC) program, the Scheduled Load Reduction Program (SLRP), and the Permanent Load Shift (PLS) and their status are described below.

i. Optional Binding Mandatory Commitment:

The OBMC program was created as an alternative to rotating outages for participating customers. The OBMC Program exempts qualifying electric customers from the elimination of electric supply during scheduled rotating outages, if they commit to a partial power reduction of their entire site load during every rotating outage during system and local emergencies. Participating customers are required to submit a reduction plan that is acceptable to PG&E prior to participating in this program. OBMC customers must agree to dependably contribute a minimum 15 percent load reduction each time rotating outages are necessary. Customers are not paid for capacity or energy under this program and it is not bid into the CAISO market. In accordance with D.09-08-027, the program is capped at 10.9 MW. The OBMC is fully subscribed and now wait-lists customers who apply for this program. The 2018-19 expenditures on OBMC were $12k compared to the $24k authorized for the period due to stability of the program requiring less administrative effort than expected.

ii. Scheduled Load Reduction Program:

The SLRP was for industrial customers with the ability to provide load reduction on pre-selected day(s) during the summer season. SLRP has no customers enrolled and is capped at 0 MW per D.09-08-027 until modified or terminated in the General Rate Case proceeding. The SLRP is subject to Public Utilities Code Section 740.10 and cannot be closed, despite the lack of participation, without legislation.

iii. Permanent Load Shift:

In PG&E's 2017 bridge funding application, it requested approval to carry over unspent 2015-2016 funds rather than seeking additional funding. PG&E requested reduced funding for PLS in its 2018-2022 Application compared to funding for previous years; however, in the DR 2018-2022 funding Decision (D.17-12-003), the CPUC did not authorize new funding, stating that "The Utilities shall complete the projects in process utilizing the 2017 funding", and ordered that the program be closed indefinitely after completion of the outstanding projects. The initial budget for PLS in the 2015-16 funding cycle was $10,128,288. With the permission of the CPUC, PG&E subsequently shifted $4,850,000 to fund DRAM 1 and DRAM 2. These transfers left $5,278,288 for the PLS program. PG&E has spent $2,028,272 (approximately $165,000 of this amount in 2018-19) of the

2015-16 funds to-date, and plans to spend approximately $2 million more on the remaining PLS projects (incentives are paid upon commissioning), which should be completed this year.

C. Category 3: Rule 24/32

PG&E notes that the budget authorization in D.17-12-003 for Rule 24 supports operations and maintenance (O&M) to enable a capacity of 40,000 Electric Rule 24 (Rule 24) registrations of customer locations to participate in the CAISO markets. Since the filing of PG&E's opening testimony,[20] PG&E has been authorized to increase those capacities twice to support a total capacity of 200,000 customer locations.[21] Each of the budget authorizations for the incremental capacity includes the applicable incremental O&M necessary through 2022, to coincide with the end of the budget authorization approved in D.17-12-003. PG&E anticipates that it will consolidate Rule 24 O&M for all capacity levels in its next application cycle based on the costs to support the total applicable capacities of Rule 24 registrations during the 2023-2027 application cycle. This may include a transition to mass market levels of Rule 24 customer locations if it is determined that additional, mass market levels of Rule 24 capacities are prudent. While this may lead to an overall increase in the 2023-2027 Rule 24 O&M budgets relative to the 2018-2022 budget authorization, PG&E believes it is more efficient and procedurally expedient to consolidate Rule 24 O&M funding sources and ensure a smooth transition of Rule 24 operations between budget cycles.

Table 8: Rule 24 Budget vs. Spend

	2018	2019	Total (2018-19)
Authorized Budget	$2,439,000	$2,511,000	$4,950,000
Actual Costs	$978,544	$1,300,088	$2,278,632
Variance	$1,460,456	$1,210,912	$2,671,368

The Annual Rule 24 program expenditures for 2018 and 2019 were less than the authorized budget by $2.7 million. Several factors account for this variance with staffing levels being the most significant factor. The authorized budget was based on an assumption that the program would be supported by six Full-Time

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[20] A.17-01-012, PG&E Opening Testimony, filed January 17, 2017.

[21] Res.E-4837 approved an incremental 35,000 Rule 24 customer locations; Res.E-4983 approved an incremental 125,000 Rule 24 customer locations.

Equivalent (FTE) employees plus one FTE manager position. In practice, the program is administered by a smaller team. In 2018 and 2019, the program has been supported by three to four FTEs plus one Manager position at less than one FTE time. The main reason why fewer FTEs were needed is because there has been a smaller volume of manual exceptions handling work to be performed by Rule 24 team members relative to the level of exceptions handling work that was assumed in the budget. Exceptions handling is performed as part of PG&E's CISR-DRP Form validation process as well as for researching and populating missing data elements. With respect to CISR-DRP Form validation work, PG&E has observed a significant decline in the use of the CISR-DRP Forms since PG&E launched Click-Through Phase 1 in February 2018.[22] Given the relatively small number of CISR-DRP Forms submitted for processing in 2018 and 2019, PG&E has experienced a corresponding decline in the amount of form validation exceptions handling performed by Rule 24 team members. For missing data exceptions, PG&E has observed far fewer exceptions compared to levels assumed in the budget resulting in fewer FTEs needed to support that particular aspect of Rule 24 program administration.

It should also be noted that as a direct consequence of the decline in the use of the CISR-DRP Form since the deployment of Click-Through Phase 1, PG&E's costs for using an outside vendor to support CISR-DRP Form processing has decreased significantly compared to the level assumed in the budget. The budgeted amount for vendor supported CISR processing activity was based on the assumption of a 5-to-1 ratio of CISR-DRP Forms per each approved CAISO location. With fewer CISR-DRP Forms being submitted, PG&E's costs for form processing dropped significantly beginning in early 2018 compared to 2016 and 2017 when the CISR-DRP Form was the only mechanism available for customers to authorize data sharing with DRPs.

D. Category 4: Emerging and Enabling Technology Programs

The budget category for Emerging and Enabling Technology programs includes PG&E's Automated Demand Response (ADR) program and the DRET program.

i. **Auto DR:** PG&E's ADR program offers deemed rebates to residential customers who participate in DR programs for smart thermostats, and deemed and customized incentives for non-residential customers who participate in eligible DR programs. Policy and implementation are coordinated with Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) and recorded in a document called "Joint

[22] PG&E's Rule 24 quarterly reports to the CPUC from 2018 and 2019 include metrics showing the dramatic decline in the use of the CISR-DRP form compared to the growing volume of authorizations created using Click-Through.

Investor Owned Utilities (IOU) The Auto Demand Response Guidelines and Adopted Policies (Guidelines)". The Guidelines contain a summary of the regulatory history of ADR, broader implementation parameters specific to each IOU, and documents any proposed changes. In order to stay current with market and technology trends, D.18-11-029 established an annual process to address any issues and make changes via a Tier 2 advice letter. The first changes were made leveraging this new process on September 3, 2019.[23] The CPUC had identified a list of six issues in D.18-11-029 and essentially all but one was resolved with this first Tier 2 advice letter. The IOUs indicated that changes should not be made to the calculation of control incentives until further research is completed. Therefore, a study with a third-party is currently underway to support the IOUs in identifying a new approach. The IOUs' ADR teams agreed that the existing customized approach to calculate ADR incentives for non-residential customers is no longer the optimal approach for customers and the IOUs. Feedback from stakeholders indicates that the existing customized approach takes too much time and is overly complicated, while it's costly for IOUs to administer. In order to increase the ADR program's effectiveness, the IOUs' ADR teams agreed to develop a newly deemed non-customized methodology to calculate ADR incentives for non-residential customers. The IOUs do offer limited deemed incentives for some non-residential customers through PG&E's Fastrack, SCE's Express, and SDG&E's TD Programs now, but the utilities believe the underlying methodologies to calculate the deemed incentives and the incentives offered should be reconsidered before expanding the deemed approach. The study is scheduled to be completed in July of 2020 and the desired outcome is that the research project should inform shorter term updates to the Guidelines and longer term decisions pertaining to the strategic roadmap. The IOUs will work with Energy Division to review the outcome of the research project and identify the timeline and appropriate channel for implementing the program changes required for the new deemed non-customized methodology. Another significant activity related to the ADR Program pertains to PG&E's multiparty settlement agreement that was adopted by the Funding Decision (D. 17-12-003). The ADR provision of the settlement agreement included a collaborative process to be initiated by PG&E in order to: 1) develop a list of

[23] PG&E AL 5629-E; SCE AL 4069-E; SDG&E AL 3427-E.

residential ADR-enabled end-use devices to be considered for eligibility for ADR incentive and 2) develop relevant criteria to determine the order for evaluating load impacts attributable to the identified residential ADR-enabled end-use devices. Working with Opinion Dynamics, a vendor hired by PG&E to lead this collaborative process, a Request for Information intake form was distributed on October 24, 2019 to facilitate the submission of residential automated control technologies for rebate eligibility consideration in PG&E's ADR program. This is a device-focused collaborative process and the OpenADR certification is an important eligibility requirement. Fourteen companies submitted technologies and five of those have made the list for consideration. The first phase of the project concluded in mid-February 2020 and the second phase will require additional research. The following table offers the actual costs as compared to the authorized budget for the ADR program. The primary driver of the variance for the ADR program is that PG&E scaled back marketing of the program in recognition of the need for a change to the incentive structure and subsequently the timeline of IOU research project. PG&E intends to fully promote the program after a new incentive structure is in place.

Table 9: ADR Budget vs. Spend

	2018	2019	Total
Authorized	$ 4,006,000	$ 4,050,000	$ 8,056,000
Actual Costs	$ 2,289,175	$ 2,023,405	$ 4,312,582
Variance	$ 1,716,825	$ 2,026,595	$ 3,743,418

Finally, ADR application statistics pertaining the 2018 and 2019 ADR program activities are provided in Appendix A.[24]

[24] Energy Division requested that the IOUs include ADR metrics in their respective Mid-Cycle Filings.

ii. **Demand Response Emerging Technology:** The DRET Program is intended to explore potential enhancements to the existing DR portfolio and inform the ongoing development of PG&E's DR pilots and emerging technologies for future DR programs. PG&E does not plan any changes to the DRET program for the reminder of the funding cycle. For more information on past and ongoing DRET assessments, please refer to the Emerging Markets & Technology Demand Response Projects Semiannual Report.[25]

The following table offers the actual costs as compared to the authorized budget for the DRET program. The primary driver of the variance for the DRET Program was due to the DRET assessments in 2018 and 2019 being smaller in size and scale, which required less budget. If the size of future DRET assessments increase, it would also increase the program spending.

	Table 10: Demand Response Emerging Technology		
	2018	**2019**	**Total**
Authorized	$ 1,380,000	$ 1,416,000	$ 2,796,000
Actual Costs	$ 612,928	$ 362,338	$ 975,266
Variance	$ 767,072	$ 1,053,662	$ 1,820,734

E. Category 5: Pilots

PG&E's DR Application includes pilots' funding which is allocated to the Supply Side Pilot II (SSP II), the Excess Supply Pilot (XSP), and the Local Capacity Area Disadvantaged Communities Demand Response pilot (LCA DAC DR).

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[25] PG&E's Semi-Annual DRET Report is due April 1, 2020.

i. Supply Side II Pilot

Background

The Supply Side II (SSP II) was authorized to operate for years 2018-2020 per D.17-12-003, as the CPUC left open the possibility to extend for the remaining two years (2021-2022) of the funding cycle. SSP II investigates the operational feasibility of utilizing DR resources that are integrated and actively participating in the wholesale energy market and are also made available to distribution operators to address local distribution needs. Bundled and unbundled residential and non-residential customers can participate in the SSP II either directly enrolled or via third-party aggregator.

Status and Recommendation

At the end of 2019, PG&E conducted a check on the overall progress of SSP II and evaluated whether there are still merits to continue beyond 2020. At this stage, PG&E recognizes that, while testing the limits of what resources can do operationally in a multiple-use application paradigm is valuable, there are other components which SSP II is dependent on to truly understand the type of impacts and coordination needed to unlock multiple use. SSP II was designed with the intention to collaborate with other Electric Program Investment Charge (EPIC)[26] initiatives that contemplate the use of Distributed Energy Resource Management System (DERMS) to identify the types of technical & operational coordination, rules, actors, and development of process to ensure safe and reliable delivery coming from participants and their Behind-the-Meter Distributed Energy Resources (BTM DER) technologies.

Given that other projects in which SSP II is dependent on are either delayed or being scaled back, the SSP II's overall progress has been impacted. For 2020, PG&E will commence testing participants capabilities by having their resources continue wholesale market activities and, on occasion, simultaneously call distribution events to continue collection of data and determination of impacts when providing multiple operations. But without the other initiatives such as DERMS, PG&E does not believe that continuing SSP II beyond 2020 is practical. It is therefore PG&E's recommendation that SSP II close at the end December 2020 when the current funding expires.

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[26] The California Energy Commission's (CEC) EPIC program provides funding for research.
Link: https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program

On a related matter, PG&E was ordered to file an advice letter proposing an Evaluation, Measurement and Verification (EM&V) plan for the SSP II (and Excess Supply) pilots. Subsequently, after Energy Division's engagement, PG&E filed a new advice letter[27] requesting flexibility to conduct the EM&V once SSP II sunsets – be it in 2020 or in 2022. On February 7, 2020, PG&E received a disposition letter approving the deferral of the SSP II EM&V at the conclusion of the pilot. For more information on past and ongoing XSP efforts, please refer to the Supply Side DR Pilot 2019 Summary and Findings Report prepared by Olivine, the pilot administrator.[28]

<u>Budget Variance</u>

The cumulative spending for 2018 and 2019 was approximately $1.5 million and is under spent by about $2.6 million dollars. The variance in spending is mainly attributed to delays launching the entirety of the pilot. As mentioned, other projects and initiatives that SSP-II is dependent on, either experienced delays or the initiative's scope was scaled back.

ii. Excess Supply Pilot

<u>Background</u>

The XSP was authorized to operate in years 2018-2020 per D.17-12-003, as the CPUC left open the possibility to extend the remaining two years (2021-2022) of the funding cycle. The XSP explores how participants can assist with mitigating over supply of energy occurring at the wholesale level by either shifting or consuming more energy. Bundled and unbundled residential and non-residential customers can participate in the XSP either directly enrolled or via third-party aggregator.

<u>Status and Recommendation</u>

PG&E and program administrator Olivine remain active supporting the operations of XSP and continue to test various program design elements that have led to the collection of lessons and data that has assisted with answering pilot objectives and contributed to other working groups (e.g., DR Load Shifting Working Group, CAISO's ESDER Phase 3). Although additional lessons are still being discovered, it is PG&E's assessment that the existing XSP design has run its course and continuing beyond 2020 may produce limited marginal learnings, if any. Prior to the XSP, no specific initiatives or demonstrations contemplated the enablement of customers using more or shifting energy usage when the grid was experiencing over supply conditions. That all changed after the Commission approved PG&E's 2018-2022 DR Programs, Pilots and Budgets (D.17-12-003).

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[27] AL 5711-E filed on December 13, 2019.

[28] PG&E provided the report to the Energy Division on March 31, 2020.

Thereafter, a handful of initiatives over the course of the past two years were commenced by state agencies (CPUC and CEC) focusing on a variety of forward-looking themes, but not limited to new models of DR, and development of standards to make appliances and BTM technologies demand more flexible. These initiatives are perceived as producing guidance and next steps on composing future models and services that customers and third-parties can benefit from. It is unknown whether the pace and direction of these initiatives will lead to in the near to mid-term. Therefore, rather than continuing XSP in parallel with state agency led initiatives, PG&E believes closing XSP by the end of 2020 is prudent.

On an related matter, PG&E was ordered to file an advice letter proposing an EM&V plan for the XSP (and SSP-II). Subsequently, after Energy Division engagement, PG&E filed a new advice letter[29] requesting flexibility to conduct the EM&V once the XSP sunsets – be it in 2020 or in 2022. On February 7, 2020, PG&E received a disposition letter approving the deferral of the XSP EM&V to the conclusion of the pilot.

For more information on the past and ongoing XSP efforts, please refer to the Excess Supply DR Pilot 2019 Summary and Findings Report prepared by Olivine, the pilot administrator.[30]

Budget Variance

The cumulative spending for 2018 and 2019 was approximately $1.1 million and is under spent by around $84,000. XSP spending is aligned with the approved 2018-2019 budget which consists of activities supporting the enablement of customer BTM DER technologies (e.g., energy storage) and Electric Vehicle Charge Network participants providing load-shift / load consumption grid services using DR as the pathway.

iii. Demand Response Disadvantaged Communities Pilot

Background

The 2018-2022 DR Decision (D.17-12-003) authorized funding for each IOU to undertake a pilot targeting DR in constrained Local Capacity Areas (LCA DAC DR pilot). Specifically, PG&E's funding authorization was for $1 million over three years with 10% of the budget dedicated to EM&V. Subsequently, D.18-11-029 established the parameters for undertaking the LCA DAC DR pilot and ordered the Utilities to each submit a Tier 2 Advice Letter with details of their respective proposals. PG&E filed Advice Letter 5477-E on February 8, 2019 with its

[29] *Ibid* Footnote 27.

[30] *Ibid* Footnote 28.

proposal. The proposal was to roll-out the LCA DR DAC pilot in specific Fresno areas targeting residential participants. On May 23, 2019, the CPUC approved Advice Letter 5477-E effective June 6, 2019.

Status and Recommendation

PG&E is partnering with DR program provider Olivine to implement the LCA DAC DR pilot in South-Central Fresno during the summer of 2020 and the winter of 2020-2021. As of the time of the submittal of this Mid-Cycle Review Advice Letter, PG&E and Olivine have completed all pre-launch pilot planning and are in the midst of the pilot enrollment period. PG&E and Olivine are working with local community-based organizations Grid Alternatives and the Fresno Housing Authority to market the pilot under the name *Olivine Community: Fresno.* A $20 per enrollee referral fee will also be used to encourage word of mouth marketing.

The pilot's goal is to enroll 2,500 participants from the South-Central Fresno community. Enrolled participants will complete a pre-pilot survey, will be asked to participate in 10 load shedding events during the summer and 10 load shifting events during the winter, and complete a post-pilot survey. Enrollees who participate in all 20 events over the course of 2020 and 2021 and complete the pre-and post-pilot surveys could receive compensation approaching $200. Pilot research objectives are to better understand:

- Awareness and Willingness to Participate: What is the current level of awareness of DR program availability and understanding of how DR programs create value for customers and the community? What is the current level of interest in participating in DR programs? If possible, compare responses of DAC households to non-DAC households.
- Energy Use and Ability to Participate: How do the different DAC households use energy in their homes? How well can DAC households respond to and participate in DR programs? If the population is large enough, we intend to compare usage and responses by households in and outside of DACs.
- Outreach: What are the best methods to reach different types of households in DACs, including those that are hard to reach?
- Messaging: What kind of messaging resonate best with households?
- Benefits: What kinds of DR incentives and program offerings will be of greatest value to DAC households and benefit them the most?

Budget Variance

Of the $1 million authorized for the Disadvantaged Communities Pilot over the period 2019-2022 PG&E has spent roughly $109K through the end of 2019. The delay in spending for the Disadvantaged Communities Pilot is because the Advice Letter approving the Pilot design was not effective until June 2019.[31] PG&E and Olivine (the Disadvantaged Communities Pilot implementor) have completed the planning and development work for the pilot and are, at the time of this submittal, engaged in recruitment and enrollment of Pilot participants. The study period for the Disadvantaged Communities Pilot was originally set to be from July 2020 through March 2021. Post study period analysis was to continue through July of 2021 with a final pilot report made tentatively available by October 2021.[32] PG&E expects that it will be spending the entire $1 million approved for the pilot through the end of the budget cycle.

F. Category 6: Marketing, Education, and Outreach

i. **Marketing & Outreach:** Of the $4.7 million authorized for Marketing, Education, and Outreach (ME&O) of PG&E's demand response program in 2018-19, roughly 75% was initially earmarked for SmartAC. However, it became clear at the end of 2018 that spending almost $2 million per year marketing the program would no longer sufficiently offset the attrition rate for reasons explained in the earlier SmartAC section. The reduced spending on marketing of SmartAC in 2019 relative to 2018 reflects the decision to reduce the effort to acquire new customers, and is the primary driver of the variance between authorized funding and total 2018-19 expenditures of almost $1.9 million. Marketing expenditures other than those made to support SmartAC focused on promoting Automated Demand Response (ADR) as well as maintenance of PG&E demand response webpages. Table 9 provides a variance of the authorized versus spent levels for ME&O.

	Table 11: Marketing and Outreach		
	2018	**2019**	**Total**
(A) Authorized	$ 2,325,000	$ 2,388,000	$ 4,713,000
(B) SmartAC	$1,770,913	$528,659	$2,299,572
(C) Other	$346,565	$156,757	$503,322
(D) Total Costs	$ 2,117,477	$ 685,416	$ 2,802,894
(A – D) Variance	$ 207,523	$ 1,702,584	$ 1,910,106

[31] AL 5477-E-A: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5477-E-A.pdf

[32] Due to limitations to conduct face-to-face pilot recruitment in the near term as result of Covid19, the original schedule may need to be adjusted accordingly.

ii. **Education and Training:** $514,000 was authorized in 2018-19 to prepare PG&E employees for presenting program offerings to customers, but actual spend was $128,000. The focus on third party programs resulted in fewer opportunities for direct marketing to customers and a reduction in the need for education and training.

G. Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications)

i. EM&V

The goal of PG&E's DR Measurement and Evaluation activities is to provide valuable insight on the design, operation, and effectiveness of PG&E's DR offerings through rigorous evaluation and research. The activities also inform long term resource planning and projection of Resource Adequacy values.

a. DR Portfolio Performance 2018-2019

Table 10 compares the ex ante load impacts from the Monthly Report on Interruptible Load and DR Programs (ILP) with the ex ante estimates provided in A.17-01-012 for 2018 and 2019. Compared to A.17-01-012, the ex ante load impacts of CBP and SmartAC for 2018 and 2019 have been revised downward by a meaningful amount as updated information was available to be incorporated into the Monthly Reports. At the time of the 2018-2022 application, CBP was expected to receive most of the customers from a discontinued aggregator program, the Aggregator Managed Portfolio. That assumption did not fully materialize, partly because DRAM has become an alternative to customers who participate through an aggregator. SmartAC experienced a decline in ex ante aggregate impacts due to lower enrollment and reduced per-customer impacts with aging devices.

Table 12: Load Impacts				
Load Impacts (MW) of DR Resources	A.17-01-012		Ex Ante Load Impact	
	2018 (August)	2019 (August)	2018[a,c] (August)	2019[b,c] (August)
BIP	330	330	281	310[33]
CBP	49	52	34	32
SmartAC	72	74	54	49
Total	451	457	369	391

a) https://www.pge.com/pge_global/common/pdfs/save-energy-money/energy-management-programs/demand-response-programs/case-studies/December2018_ILPreport.pdf. See the month of August in Table I-1.
b) https://www.pge.com/pge_global/common/pdfs/save-energy-money/energy-management-programs/demand-response-programs/case-studies/December2019_ILPReport.pdf. See the month of August in Table I-1.
c) The ex ante load impacts here represent the expected capacity of the programs given the actual enrollment when dispatched under the ex ante conditions, i.e., 4-9 pm on the monthly system peak day under 1-in-2 weather conditions.

In the 2018-2022 DR Application, RDRR DRAM was not taken into account and BIP at the time was close to the 330 MW of reliability-only DR cap already. However, in the subsequent load impact filings, BIP's load impacts were estimated with the assumption that RDRR DRAM MW may take up somewhere between 20 and 30 MW from the 330 MW cap, which implied a lower MW ceiling BIP can enroll customers up to.

b. Updated Portfolio-Adjusted Ex Ante Load Impacts for August 2020-2022 Reflecting Program Changes

Table 13 reports the average hourly ex ante load impacts for 4 – 9 p.m. on the August monthly system peak day under 1-in-2 weather conditions, based on PG&E's load impact filing in April 2019, adjusted to reflect the planned program changes as described in Section IV. The MW forecast may differ from PG&E's load impact filing in April 2020, which is based on program characteristics and operations that have been approved by the

[33] While this number may suggest BIP combined with the RDRR DRAM (25 MW) would exceed the reliability MW cap of 330 MW, the monthly DR report is only a rough estimate based on the average per-customer impact multiplied by the customer count. The official ex ante load impacts, which determine the total reliability MW from PG&E's programs, will be made available in PG&E's load impact filing on 4/1/2020.

Commission, whereas the updated MW forecast in this mid-cycle filing assumes implementation of all the planned program changes.

Table 13: Hourly Ex Ante Load for 4-9 p.m. on August Monthly System Peak Day Under 1-in-2 Weather			
Program	**2020 (MW)**	**2021 (MW)**	**2022 (MW)**
BIP	295	305	314
CBP	38	48	62
SmartAC	46	42	38
Total	**379**	**395**	**414**

Incentive levels often drive customer choice, if those participants can meet participation criteria. Higher payments drive higher participation, which results in an assumption that PG&E's BIP program will be fully subscribed, followed by parties seeking to participate in DRAM, followed by participating in either PG&E's CBP program or a CCA program. Specific program assumptions for the updated MW forecast include:

- BIP will have enrollment increasing over time, reaching the reliability-only MW cap of 330 MW at the peak month (June) in 2022.[34] August impact, which is slightly lower than June impact, is estimated to provide 314 MW in 2022. The enrollment in 2019 indicates that more medium sized customers are joining the program, resulting in a lower average customer impacts. This explains the lower impact for 2020, compared to the impact for 2019 in Table 12. And this trend is expected to continue in the near future. Lastly, no RDRR DRAM is expected to provide load reduction between 2020 and 2022.

- Non-residential CBP aggregators are expected to increase up their nominations from 36 MW in August 2020 to 38 MW in August 2021 and 40 MW in August 2022. Residential customers are expected to provide 2 MW in 2020, to reflect a learning curve initially. Also, prior DRAM sellers who are not awarded contracts in 2020 and beyond are likely to migrate their customers to CBP. Given the program's flexibility in accepting more nomination without requiring a long-term commitment, CBP can serve as a "parking lot" for capacity that has not been awarded a DRAM contract. As the residential sector may likely continue to grow, residential CBP MW is forecasted to ramp up to 22 MW in 2022.

- SmartAC will lose program impacts by 9% per year due to customer attrition without replacement.

[34] This projection does not consider the 100kw monthly average during peak TOU hours proposal in this Mid-Cycle filing. If the Commission ultimate adopts PG&E's proposal or a version of it, PG&E would update its projections in its subsequent LIP filing.

It is worth noting that exogenous factors increase the uncertainty in these forecasts including:

- DRAM participation levels and the future of DRAM for 2021 and 2022;
- The amount of Resource Adequacy (RA) procured by CCAs—their PDR could either result in reduced supply for DR or increased supply as a result of new business opportunities for sellers.

Table 14 shows EM&V's authorized budget and expenditure through December 2019. Since evaluation begins after the program season, most of the EM&V expenditure is incurred in the year following. This explains the significant variance of EM&V at this point.

Table 14: Authorized Budget, Expenditure and Variance of EM&V

	2018	2019	Total
Authorized	$ 3,007,000	$ 3,036,000	$ 6,043,000
Actual Costs	$ 829,000	$ 1,393,000	$ 2,221,000
Variance	$ 2,178,000	$ 1,643,000	$ 3,822,000

ii. DR Integration and Planning

a. DR Resource Utilization and Market Integrated Activities

As approved in the 2018-2022 decision, the *Support for Retail and Customer-Facing Activities* sub-category budget funds systems support for the following retail activities: customer enrollment, aggregator enrollment/nominations, event forecasting, event dispatch, customer notifications, and retail program settlement calculations (which are not the same as CAISO settlements). These functions were historically enabled by multiple vendor systems, but were consolidated into PG&E's new DR Management System (DRMS) in 2018 in order to boost the delivery of DR programs. The cumulative 2018-2019 spending for the *Support for Retail & Customer Facing Activities* budget category was $9.37 million and is over spent by $1.34 million.

The *Support for Market Activities* sub-category budget funds the systems and personnel to enable PG&E's BIP, CBP, and SmartAC programs to be registered at the CAISO such that they can be dispatched as a Supply Resource DR by PG&E. This budget also funds enhancements and services to support the changes to CBP proposed in the DR Application. These functionalities were also incorporated into PG&E's new DRMS in 2018. The cumulative 2018-2019 spending for the *Support for Market Activities* sub-budget category was $7.28 million and is over spent by $1.16 million.

Overspend in both categories over the 2018-2019 period was necessary in order to stand up PG&E's new DRMS, and will be mitigated by underspending over the 2021-2022 period.

b. Management of Market-Integrated DR portfolio

Decision (D.) 14-12-024 mandates that event-based DR programs shall be integrated into the CAISO market in order to maintain RA value.[35] This section describes Pacific Gas and Electric Company's (PG&E's) efforts to further support the integration of its BIP, CBP, and SmartAC programs into the CAISO wholesale markets, over the course of 2018 and 2019.

The CAISO offers two products, both relying on the same technical functionality and infrastructure, via which DR resources can be bid into the wholesale markets. The first, a Proxy Demand Resource (PDR) product, enables Demand Response Providers (DRP) like PG&E to bid energy, non-spinning reserves, or to be picked up in the residual unit commitment (RUC) market. Energy bids may be submitted into either the DA or 5-minute Real-Time (RT) markets. Non-spinning reserve bids may be submitted into either the DA or RT Non-Spinning Reserve markets. PDR resources must provide a minimum load curtailment of 0.1 MW (100 kW) for DA and RT energy and 0.5 MW (500 kW) for DA and RT energy Non-Spinning Reserve. The second, a RDRR product, enables DRPs to bid energy as either an economic resource in the DA market, or a reliability resource in the RT market. RDRRs may not submit RUC availability or Ancillary Services (AS) bids, and may not self-provide AS. RDRR resources must provide a minimum load curtailment of 0.5 MW (500 kW) within 40 minutes of being called, and have a minimum run-time of 1 hour, and maximum run-time of 4 hours.

PDR and RDRRs both model the physical characteristics of a resource supplied to the CAISO and are the basis for bidding, awards, dispatch, outages, and settlements. Each PDR and RDRR resource are composed of customers within a single sub-Load Aggregation Point (Sub-LAP), and per CAISO rules in 2018 and 2019, and were served by the same LSE. PG&E sources PDR capacity from customers enrolled in either the CBP or SmartAC programs and bids them into the DA market. RDRR resources are comprised of customers enrolled in the BIP and bid only into the Real-Time 15-minute market, with the exception of a pilot in 2018 where a limited number of RDRR resources were also bid into the DA market.

[35] D.14-12-024, OP 4.a.

iii. PDR and RDRR Portfolio and Activities

a. PDR Portfolio and Activity

In 2018 and 2019, a total of 26 market resources backed by SmartAC capacity were bid into the CAISO wholesale market as PDR. During this period, SmartAC was dispatched on 19 different days; 16 of these dispatches were the result of market awards that totaled 1,022 MWh, two dispatches were for program tests, and one dispatch was the result of a transmission system emergency (Mendocino Complex Fire in July 2018). The average price of awards received for SmartAC events resulting in dispatches in the 2018 and 2019 were $331/MWh and $63/MWh, respectively. Temperatures, as measured by Cooling Degree Day Hours, during the SmartAC season were 22% cooler in 2019 compared to 2018, which translated to fewer MW available to bid in the market. Average DLAP closing prices were 27% lower on average during hours SmartAC was bid into the market in 2019 compared to 2018. This is also seen in the lower average market award price in 2019. In the end, the SmartAC bidding strategy employed resulted in market awards (8) or program tests (2) occurring on ten of the fifteen hottest days in 2019. A summary of SmartAC market activity in 2018-19 can be found in the table below:

Table 15: SmartAC Activity

	2018	2019
Enrolled & Active customers (average)	111,688	102,531
# of DA dispatches	9	10
# of distinct hours dispatched*	33	32
# of days with market awards	8	8
# of distinct hours awarded	28	26
Average market award price	$311	$63
MWh dispatched due to market awards	628	394

*****Number of hours in the year with a SAC market award

A total of 83 market resources backed by CBP capacity were bid into the CAISO wholesale market as PDR during the 2018-2019 seasons. CBP was dispatched on 60 distinct trade dates; 58 days as a result of market awards (for a total of 599 MWh), and 2 days as a result of program testing. The average price of awards received for CBP events resulting in dispatches in the 2018 and 2019 were $377/MWh and $151/MWh, respectively. A summary of CBP activity in 2018-19, and comparison to 2017, can be found in the table below:

Table 16: CBP Activity		
	2018	**2019**
Enrolled customers (average)	1,698	1,569
Active customers (average)	513	690
August Nominated MW	34	30
# days with dispatches	46	14
# of distinct hours dispatched	112	22
# of days with market awards	45	13
# of distinct hours awarded	109	18
Average market award price	$377	$151
MWh dispatched due to market awards	473	96

A summary of total PDR bidding activity can be found in the table below:

Table 17: PDR Bidding Activity (2018-2019 DR Seasons)				
Market Product/ Program	**Number of Resources**	**MWh Bid**	**MWh Awarded**	**MWh Dispatched**
PDR – CBP	83	44,853	605	568
PDR - SmartAC	26	104,807	1,106	1,023

The bidding of PDR resources was informed by operational constraints, which are based on the CBP and SmartAC tariffs. For example, PG&E monitors the dispatches for each PDR to ensure the 5 event and 30 hour monthly maximums, as well as the three consecutive event days, are observed. When the limits have been reached, the PDR is not bid in the market. Similarly, when forecast prices indicate that a PDR resource would exceed its 5 event maximum in a given month, an opportunity cost is added to the dispatch trigger price to maximize the value of call days. The price PG&E bids its PDR resources sourced from CBP customers is determined by the program option. The CBP Prescribed option is bid at the tariff price trigger of $95 per MWh, whereas Elect and Elect Plus are bid at the price chosen by the Aggregator. SmartAC capacity is bid only when a pre-determined temperature trigger is reached, and the bid prices are informed by the number of SmartAC events that are targeted for the season.

b. RDRR Portfolio and Activity

Over the record period of 2018 and 2019, PG&E bid a total of 40 RDRR resources into the CAISO real time markets[36], averaging 197 MWs bid every hour. PG&E submitted a total of 519,624 individual bids totaling 2,854,474 MWhs. Table 15 below summarizes RDRR bidding activity. PG&E received no RDRR market awards during either DR season.

Table 18: RDRR Bidding Activity (2018-2019 DR Seasons)

Market Product/ Program	Number of Resources	MWh Bid	MWh Awarded	MWh Dispatched*
RDRR	40	2,854,474	0	0

* As described previously, the BIP program was activated by CAISO on three occasions for emergency dispatches – twice in July 2018 and once in February 2019. These MWhs reflect emergency dispatches, and not market awards.

The CAISO requires each resource that provides energy, capacity and other capabilities to be tested for each service, which the resource bids or self-provides into the CAISO market. Between fall 2018 through summer 2019, PG&E's DR Operations team engaged CAISO staff to develop protocols for conducting annual RDRR market dispatch tests, which were codified into CAISO's Resource Testing Guidelines (Procedure 5330). As such, PG&E now has the capability to both test individual BIP customers (via test events, and re-testing where necessary) and entire RDRR resources via the CAISO Procedure 5330, starting in 2020.

V. Miscellaneous Topics

A. IOU Program Alignment / Common Parameters

The funding decision called for an effort to be led by the IOUs "with interested parties to determine whether there are parameters in programs that can be uniform across the three Utilities" while still maintaining a cost-effectiveness of 1.0 under the Total Resource Cost ratio.[37] This effort was to be begin no later than June 1, 2018 and the results were to be reported on in the mid-cycle review. As part of this effort, the IOUs worked together to help drive a productive set of telephonic meetings with parties over the course of several months

[36] BIP bids are to the 15 minute market (FMM) which are then carried over to the 5 minute market (RTM).

[37] OP 4 of D.17-12-003.

between May 2018 and September 2018. The discussions were limited to DR programs offered by all three IOUs that were open to third-party Aggregators. Therefore, the scope was limited to both the BIP and CBP. A "Recap" of the Common Parameters effort was prepared for all three IOUs. This document is included in Appendix B .

The one area that PG&E subsequently looked into was for having a 15 minute dispatch option (currently 30 minutes for PG&E). A survey of BIP participants was undertaken, which suggested limited interest in a 15 minute BIP option. Moreover, PG&E emphasizes that a shorter response time may negatively impact cost-effectiveness with a presumed higher incentive level and higher execution cost. Separately, a key driver for assessing the need for a faster responding BIP would primarily be based on CAISO's and CPUC requirements, which as PG&E understands is still under consideration.

B. 5 in 10 Baseline Proposal

In compliance with D.19-07-009, OP 18, PG&E is providing a proposal for the implementation of a 5-in-10 residential retail baseline that would utilize a +/- 40 percent adjustment cap. PG&E's proposal includes the following elements as requested by the Commission's decision:

i. **Estimated Costs:** PG&E estimates that the cost would range from $30,000 to $60,000 depending on the specific features. This cost would include both work associated with modifying PG&E's internal IT system supporting DR programs along with an external system provided by a vendor that supports CBP. PG&E stresses that these costs are high-level conceptual estimates that would need to be refreshed and potentially further refined based on the specific implementation details of a final authorization by the CPUC. This cost range is a function of whether the existing Day-of-Adjustment (DOA) is utilized or a new Day-of-Adjustment is implemented. Moreover, there would be additional costs if there was a need to support weekend calculations if the CBP program were to be eventually expanded beyond week days.

Table 19: Cost Estimate for 5 in 10 Retail Baseline		
System	**Cost using Current DOA**	**New DOAs**
PG&E's System	$25,000	$25,000
External Vendor System	$5,000	$25,500
Sub-total	$30,000	$50,000
Weekend Functionality (incremental to sub-total)	$10,000	$10,000
Grand Total	$40,000	$60,000

ii. **<u>Statistics about the accuracy of the aggregate and individual baseline</u>**: PG&E engaged Christensen Associates Energy Consulting ("Christensen"), a consultant, to assess the accuracy of baselines. Since PG&E did not have nominated residential data for CBP, it utilized residential SmartAC data as a proxy for undertaking the assessment. The scope of the analysis was to determine whether the 5-in-10 baseline methodology with a 40 percent adjustment cap would be more accurate than the current wholesale 10-in-10 baseline methodology with a 20 percent adjustment cap. Furthermore, the assessment considered both aggregate resource-level load profiles as well as the sum of the individual customer profiles within each resource. The analysis revealed that the aggregate 5-in-10 baseline with a 40 percent adjustment cap performs best overall. Several other related findings include the following:

- 10-in-10 baseline performance is not affected by the various methods (aggregate vs. sum of individual; and adjusted vs. unadjusted) to the same extent as 5-in-10 baseline performance.
- 10-in-10 baselines perform better in winter.
- Winter baseline performance tends to be better than summer baseline performance.
- Summer baselines exhibit a fair amount of error regardless of method.

The full study is included in Appendix C to this filing.

iii. **<u>An assessment of the benefits</u>:** Based on the results of the study undertaken by Christensen and the cost involved with implementing a 5 in 10 retail residential baseline, PG&E believes it would be appropriate to roll out on a trial basis *(emphasis added)* a 5 in 10 retail baseline, with a 40 percent adjustment factor for the 2021 CBP residential program year. Based on the final policy outcome from the Retail Baseline Working Group, a 5 in 10 retail baseline option could be made permanent in the next funding cycle (2023-2027).

iv. **<u>Timeline</u>:** PG&E estimates that if the CPUC rendered a decision on the mid-cycle filing and authorized funding by year-end 2020 that it could pilot[38] a retail 5 in 10 baseline for use in the 2021 and 2022 CBP Program years. PG&E's CBP runs from May 1 through October 31 of the year. If the CPUC does not render a decision by year-end 2020 then PG&E respectfully requests that it be given a day for day delay in implementing if the CPUC approves the provisional use of a 5 in 10 retail baseline. Moreover, if the CPUC approves implementation of the 5 in 10 retail baseline as part of the mid-cycle review, PG&E would fund shift within budget Category 7 to support the requisite work as needed. Lastly, PG&E would also request authority to update its CBP tariff to reflect this new baseline option through a Tier 1 advice filing for the DR season it would be effective.

[38] PG&E recommends piloting the retail 5 in 10 baseline for the duration of the five-year funding cycle (2021 and 2022) due to ongoing activities associated with the Retail Baseline Working Group (RBWG) established by D.19-07-009, OP 19. While the RBWG's charter is focused on retail 10 in 10 baseline issues there may be cross-over topics for the retail 5 in 10 baseline, which may have policy implications for all Day-Matching baseline options. Because the RBWG is chartered with authorship of a report by April 1, 2021 for inclusion in the next funding cycle (2023-2027) due November 2021, PG&E believes that implementation of retail 5 in 10 baseline during the current funding cycle (2018-2022) should be on a provisional basis. Hence, the recommendation to pilot the retail 5 in 10 during the current funding cycle. PG&E believes piloting is consistent with D.17-12-003, Finding of Fact 74 that stated "Alternative baselines should not be addressed in the mid-cycle review, but rather, in a future decision in this proceeding."

C. CBP Trigger

As required by Resolution E-4918, PG&E has undertaken a refresh of its methodology utilized for determining its CBP Price Trigger (Prescribed Option) based on the approach previously filed via Advice Letter 5425-E. Advice Letter 5425-E utilized a harmonic mean to reduce the effect of outliers in the data to determine a price trigger of $95 based on eight years of market price data for 2011-2018. As stipulated by Resolution of E-4918,[39] PG&E utilized a roll-forward of market prices for the years 2012-2019 using the same harmonic mean approach. The resulting assessment reveals the trigger price would rise to $100. However, due to the timing of the mid-cycle filing (4/1/2020) and the need for approval by the CPUC, which PG&E expects to be in the latter part of 2020, there won't be an opportunity to refresh for the 2020 CBP season with Commission approval. In addition, due to the CBP program hours that will now be limited to 1 p.m. to 9 p.m. for 2020, which is expected to have a different price profile, PG&E believes that it is reasonable to take a pause for 2020 and not update its CBP price trigger at this time. That said, PG&E welcomes guidance from the CPUC as to how it should proceed for the 2021 and 2022 program years.

VI. Conclusion

This filing reviews the performance of DR programs and DR pilots for the years 2018 and 2019.

PG&E plans to make the following changes:

- SmartAC: Cease actively marketing the SmartAC program but continue the program through the remainder of the funding cycle (2020-2022).
- BIP: Modify the eligibility requirements of BIP, requiring *average* demand in each month of the year to be 100 kW during the peak TOU hours instead of the maximum demand of 100 kW during the peak TOU hours in a single month, to ensure that it is a resource that performs reliably when called upon at any time during the year.
- CBP: Improve the enrollment process for residential aggregators and implement a 5-in-10 retail baseline on a provisional basis if the CPUC concurs and provides appropriate guidance.

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[39] E-4918, OP 3 states "The IOUs shall provide another update to their CBP price triggers in their 2020 mid-cycle review using the last 8 years of market price data including 2019 data and a methodology to reduce the effect of outliers in the data."

- Excess Supply and Supply Side II Pilots: PG&E plans to dispense of the pilots, unless determined otherwise by the Commission.[40]

PG&E requests the following from the Commission in order to effectuate the proposed items:

- Approve PG&E's proposal to update the BIP eligibility criterion to be 100kW on average per month during the peak TOU hours.[41]
- Support expeditious approval of PG&E's outstanding Advice Letter for enabling the electronic enrollment pilot for residential CBP participants.[42]
- Make a determination about the timing and structure for the implementation of a 5-in-10 baseline.[43]
- Grant PG&E authority to file a Tier 1 Advice Letter within 30 days of the Resolution approving PG&E's MCR filing, to file for the closure of the Commercial Smart AC program (E-CSAC tariff).
- Authorize a process that will result in a ruling no later than December 31, 2020 establishing principles and guidance for the 2023-2027 IOU DR program filing.

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[40] A.17-01-012 states in OP 38, "Should the Energy Division determine that the objectives of the pilots are not met and they should still be pursued, then the Energy Division shall authorize funding up to the original requested budget ears 2021 and 2022."

[41] If the CPUC in its Resolution approving the Mid-Cycle Review filing concurs with PG&E's proposal for a revised BIP eligibility criterion, then PG&E proposes to file a Tier 1 Advice Letter within 45 days to clarify implementation.

[42] PG&E AL 5752-E-A requested approval by May 1, 2020 in order to be able to utilize for the 2020 CBP program year.

[43] If the CPUC in its Resolution approving the Mid-Cycle Review filing provides guidance for the implementation of a 5-in-10 baseline for 2021, then PG&E could file a Tier 1 Advice Letter within 60 days to clarify implementation.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

ADR METRICS REQUESTED BY ENERGY DIVISION

Summary of PG&E Automated Demand Response Control Incentive Information for 2018 and 2019

SUMMARY OF REQUESTS

		2018 Applications				2019 Applications			
		RECEIVED [1]	CANCELLED [2]	PAID [3]	ALLOCATED (UNPAID) [4]	RECEIVED [1]	CANCELLED [2]	PAID [3]	ALLOCATED (UNPAID) [4]
Non-Residential Calculated	# of Service Accounts	39	19	18	2	167	36	58	73
	Total $	$519,598	$182,000	$198,959	$138,639	$1,588,730	$336,400	$383,530	$868,800
Non-Residential Deemed	# of Service Accounts	75	23	32	20	20	0	0	20
	Total $	$91,600	$31,600	$39,400	$20,600	$163,800	$0	$0	$163,800
Residential	# of Service Accounts	11,214	9,617	1,597	0	14,532	12,746	1,642	144
	Total $	$560,700	$480,850	$79,850	$0	$726,600	$637,300	$82,100	$7,200

REQUESTS BY CUSTOMER TYPE [5]

		2018 Applications					2019 Applications				
		AGRICULTURE, MINING & CONSTRUCTION	MANUFACTURING	WHOLESALE, TRANSPORT, OTHER UTILITIES	RETAIL STORES	OTHER	AGRICULTURE, MINING & CONSTRUCTION	MANUFACTURING	WHOLESALE, TRANSPORT, OTHER UTILITIES	RETAIL STORES	OTHER
Non-Residential Calculated	# of Service Accounts	19	1	16	0	3	98	5	59	1	4
Non-Residential Deemed	# of Service Accounts	0	0	0	66	9	0	0	0	5	15

The information reported for each year is tracked for applications received in that calendar year only. Does not include any applications received prior to 2018.

[1] Total Eligible SAs Received and Total Estimated Incentives

[2] Total SAs Cancelled by Customer or Utility (i.e., ineligible, withdrawn, or cancelled) - Residential: All EE rebate applicants screened for ADR rebate eligibility

[3] Actual Incentives Paid is reported in the calendar year the application was received. Actual payment could be issued in subsequent calendar year.

[4] Estimated unpaid incentives (i.e., 1st and/or 2nd Payment is pending or has not been issued yet)

[5] Received

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

RECAP OF COMMON PARAMETERS EFFORT

D. 17-12-003

Recap of "Common Parameters" Effort

September 25, 2018

Overview

Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Pacific Gas & Electric Company (PG&E), collectively the "IOUs" undertook efforts to comply with the requirements of Ordering Paragraph 4[1] of Decision 17-12-003. This effort resulted in a series of telephonic meetings between the IOUs and interested parties[2] between May 2018 and September 2018. The scope of DR programs covered by this effort was limited to BIP and CBP, as these two programs are open to participation by third-party Aggregators. The IOUs' respective direct load control air conditioning programs were not discussed. Overall, the discussions resulted in a better understanding of Aggregator preferences along with challenges with program attributes, which may serve to provide useful input for the 2020 mid-cycle as well potential modifications in the near term. As an over-arching observation, while certain issues had direct implications on cost-effectiveness, there were topics that did not directly impact CE but merit consideration. These additional topics may or may not actually be reflected in the program tariffs.

Discussion Timeline

The IOU led discussions with "interested parties" are summarized in the following table.

Topic	**Dated Noticed**	**Deadline for for Party Input**	**Date of Stakeholder Call**	**Post Notes (IOU only)**
Kick off & BIP (#1)	May 11, 2018	N/A	May 17, 2018	May 17, 2018
BIP (#2)	May 23, 2018 & June 19, 2018	June 22, 2018	June 26, 2018	June 27, 2018
CBP (#3)	July 11, 2018	August 3, 2018	August 7, 2018	August 8, 2018
CBP (#4)	August 21, 2018	September 7, 2018	September 12, 2018	September 17, 2018

[1] "No later than June 1, 2018, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall begin to work with interested parties to determine whether there are *parameters in programs that can be uniform across the three Utilities*, while ensuring that cost-effectiveness analyses for the programs result in a 1.0 total resource cost ratio. The Utilities shall report on the discussions and the results of the efforts in their 2020 program update filing."

[2] While different parties participated on different calls they generally included but were not limited to the three IOUs (PG&E, SCE and SDG&E), CLECA, Energy Division, CPower, Gridpoint, Enersponse, Sidereal Energy, Irvine Company, IPKeys.

Discussion Results -- BIP

- Testing/Resting Protocols: There may be opportunities for the IOUs to align around pre-enrollment testing and retesting. It was observed that PG&E has the most level of rigor in testing/retesting. The testing/resting process for each IOU is summarized.

    - PG&E's current procedure is as follows
    - Pre-test to determine ability to load drop before being allowed to join the program
    - 1st event – if fail, PG&E will adjust their FSL
    - 2nd event/retest – if fail again, then removed from program
      (Attachment A contains a flow-chart of PG&E's process for testing).
    - SCE and SDG&E currently do not have pre-test or re-test (SDG&E has re-certification.)

  Note: PG&E issued a straw proposal for testing/resting and excess energy charges. Both can be found in Attachment A. Further, Attachment B provides a flow-chart of PG&E's BIP retest process.

- Incentives: Interested parties generally agree that it would be difficult to align among the three IOUs as each has a different avoided cost profile.

- Excess Energy Charge: Since this issue is related to incentives it would be difficult to align except for the issue of how excess energy charges relate to testing/retesting. As part of the IOU discussion, PG&E released a straw proposal for aligning Excess Energy Charges (See Attachment B).

- BIP Options (15 and 30 minutes): CLECA in particular advocates for a 15 minute dispatch option. Although, it's unclear if participants would welcome it (note: It may be worth polling BIP participants). Moreover, a shorter response time may negatively impact cost-effectiveness with a presumed higher incentive level and higher execution cost. A key driver for assessing the need for a faster responding BIP would primarily be based on the CAISO's need, which is still being assessed in the slow/fast DR forum.

Discussion Results – CBP

- Dispatch Options: It was observed that not all utilities offer both a Day-Ahead (DA) and a Day-of-Option (DO). In particular, PG&E only has a DA option.

- Dispatch Notification: Each IOU utilizes a different cut-off for the notification to Aggregators (i.e., 3 p.m. for SDG&E; 4 p.m. for PG&E and 5 p.m. for SCE). Generally speaking, it appears that interested parties have a preference for consistency over a specific time. It may be worth aligning all three IOUs' notification time to 5 p.m. as it provides maximum flexibility. Note, since this is not specifically related to cost-effectiveness, there may be the opportunity to align on this issue prior to the mid-cycle review.

- Dispatch Window (Event Hours): The IOUs have differing dispatch windows. While interested parties appeared to have a preference for having the two options, they also realize that grid needs may ultimately dictate whether there will be multiple options and what those options will be. Here is a summary of the current offerings by each IOU.

IOU	**Program Option**	**Dispatch Window #1**	**Dispatch Window #2**
SDG&E	DA & DO	11 a.m. to 7 p.m.	1 p.m. to 9 p.m.
SCE	DA & DO	1 p.m. to 7 p.m.	N/A
PG&E	DA	11 a.m. to 7 p.m. (All three sub-options)	1 p.m. to 9 p.m. (ONLY Elect & Elect+)

- Enrollment Dates: Enrollment dates are driven by the nomination deadlines which can be tied to individual IOU processes and systems. However, there may be opportunities to have greater alignment among the IOUs.

- Enrollment Forms: Both SCE and PG&E utilize the APX system, which appears to facilitate enrollment as compared to SDG&E's form/process.

- 100 kW Minimum Bid: While both SCE and PG&E have a 100Kw minimum per suLlap participation threshold, SDG&E doesn't since its service territory is all in one-subLap. There may be very limited opportunities to address this issue.

Attachment A

Straw Proposal

Potential Alignment on BIP Testing and Excess Energy Charges

For Discussion Purposes Only

Based on the discuss at our meeting on June 4th, PG&E puts forth the following straw proposal for discussion purposes.

BIP Testing: Adopt PG&E Methodology

The issue of BIP retest procedures was raised at the recent Load Impact Workshop. The Energy Division and ORA appeared to support PG&E's retest process.

PG&E's process:

- Insures that participants are not allowed to consistently underperform.
- Considers the possibility that a customer was having an operational challenge on the day of the test by giving them a retest.
- Accounts for the relative size of a customer's load reduction when measuring the retest threshold.
- Combined with a relatively stringent penalty for under-performing during an event appears to strike the right balance with participants.

Background/Rationale: The Customer's FSL is based on a test of their operation to ensure they can reach the chosen level, prior to enrollment in the BIP. Therefore, we already know they can reach the FSL, so we work with reps and aggregators to determine the reasons for the failure to meet the FSL in the specific event. Many times, there was an operational challenge or a unique circumstance that prevented them from meeting their FSL, which was corrected during the retest. There will likely be a negative customer experience from changing FSL without giving them a chance to redress the issue. Impact to aggregators of FSL changes: private contract between aggregator and their customer is dependent on the FSL, and is not easily changed; we would expect pushback from aggregators for FSL changes without first providing their customers the opportunity to cure. Changing FSLs involves a fair amount of effort from DR Ops and Customer Billing perspective -- it is a manual process, issues with tracking and monitoring multiple changes, FSL can only be changed on the first of the month.

- PG&E method compared to automatic reset method -- During last year's BIP event the following was observed:
  - 5/3/17 Event: 48 customers require retest
  - 7/11/17 Retest: 36 customers meet their FSL; 12 require a further retest and 3 changed their FSL
  - 10/17/17 Retest: 11 customers meet their FSL, 1 changes FSL and requires a further retest
  - 11/29/17 Retest: remaining customer meets new FSL
  - End of process -- There were four FSL changes instead of 48.

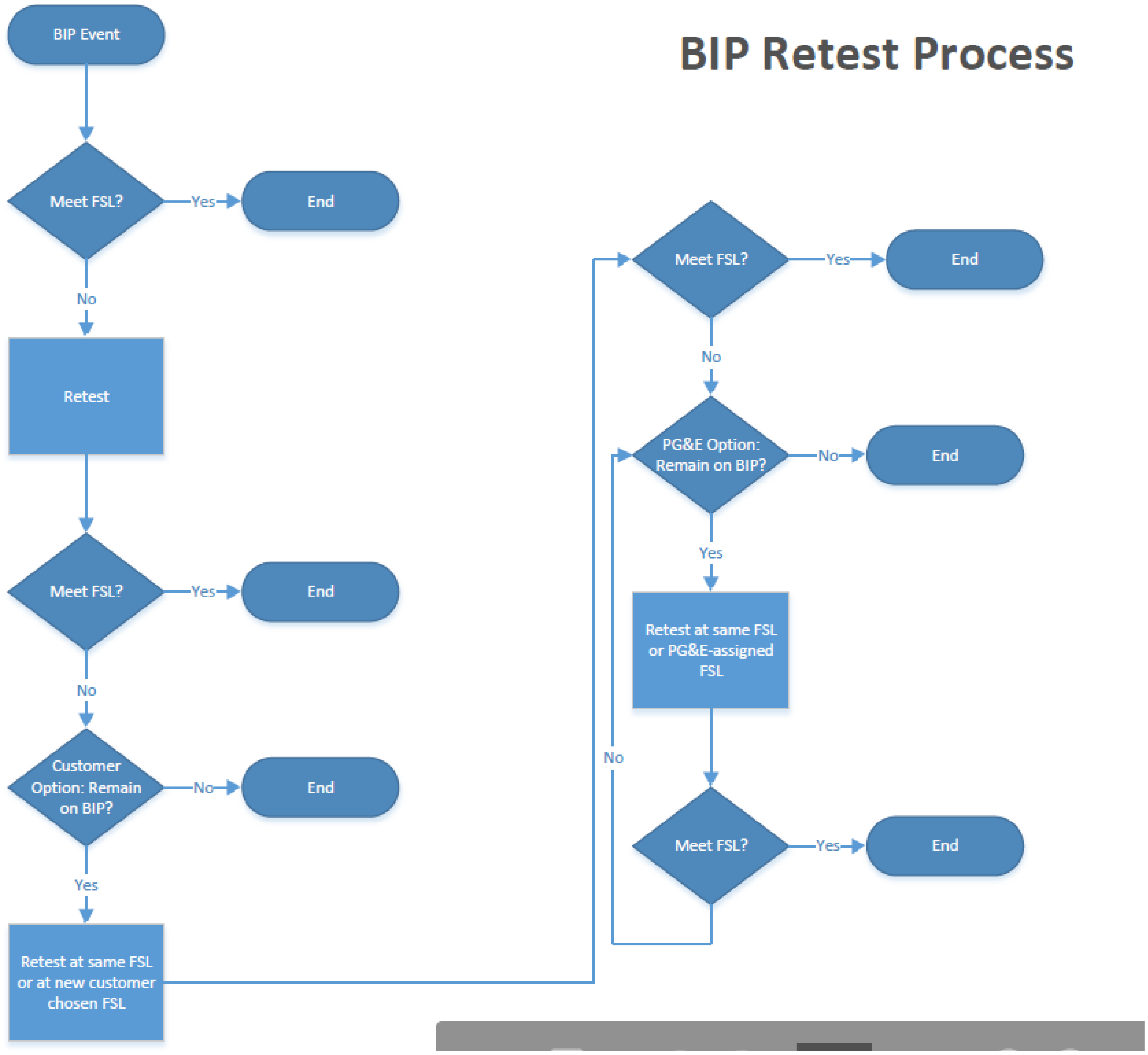
Excess Energy Charges:

Option A: The excess energy charge is designed to effectively claw back any excess incentives paid to participants between verification events (test or non-test). Excess energy chares will be constructed as a "feebate" wherein the customer will refund to the IOU a pro-rate portion of the incentives paid between verification events based on the difference between the participant's calculated Potential Load Reduction (PLR) based on designated FSL and the participant's PLR based on FSL observed during verification event.

Simple Example							
Average Summer Season On-Peak Demand	Designated FSL	Calculated PTR based on Designated FSL	Observed FSL during Event	Calculated PTR based on Observed FSL during Event	% Under-Performed	Incentives Paid Between Verification Events	Excess Energy Charge
A	B	C = A - B	D	E = A - D	F = 1- (E/C)	G	H = F * G
1,000 KW	250 MW	750 KW	500 KW	500 KW	33%	$38,250	$12,625

Option B: Excess energy charges will be set to reflect any costs that are incurred by the LSE related to underperformance by the DR resource. The rationale here is now that BIP resources are integrated into the CAISO market, LSEs may not be covered for a resource failing to deliver which could result in significant charges that are incurred by LSEs in the CAISO settlement process. Is there a way to construct the excess energy charge so that it is based on CAISO settlements data?

Attachment B



PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

ANALYSIS OF THE 5 IN 10 RETAIL BASELINE

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Residential Baseline Assessment for Pacific Gas and Electric Company as Required by California Public Utilities Decision 19-07-009

Daniel G. Hansen

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March 17, 2020

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Executive Summary

In its Decision 19-07-009 dated July 11, 2019, the California Public Utilities Commission ("CPUC") ordered an assessment of benefits of using a 5-in-10 baseline method for residential customers, including "statistics on the accuracy of the aggregate and individual baseline."[1] Of particular interest is the baseline to apply to the residential Capacity Bidding Program ("CBP"), and whether the 5-in-10 methodology with a 40 percent adjustment cap would perform better than the current wholesale 10-in-10 baseline methodology with a 20 percent adjustment cap.

This report documents a baseline evaluation that compares the 5-in-10 and 10-in-10 methods, each calculated in two ways: using the resource-level aggregate load profile; and using the sum of the individual customer profiles within each resource. The performance of each baseline method is assessed across a range of day types: summer and winter; non-holiday weekdays and weekends/holidays; and extreme and moderate weather days. The baselines are assessed against observed customer loads.

The results show that the aggregate 5-in-10 adjusted baseline performs best overall, displaying minimal bias and comparatively good accuracy. Another prominent finding is that the 5-in-10 baselines calculated as the sum of customer-level baselines tend to be too high (*i.e.*, the calculated baseline is above the observed test-day load, resulting in a positive mean error value). Other general findings include:

- 10-in-10 baseline performance is not affected by the various methods (aggregate vs. sum of individual; and adjusted vs. unadjusted) to the same extent as 5-in-10 baseline performance.
- 10-in-10 baselines perform better in winter, but by a smaller margin than the 5-in-10 aggregate adjusted method has relative to the 10-in-10 methods during the summer.
- Winter baseline performance tends to be better than summer baseline performance.
- Summer baselines exhibit a fair amount of error regardless of method. The best performing baseline (aggregate 5-in-10 adjusted baseline) has a mean absolute error (MAE) of 0.22 kWh/hr/customer.

In summary, when assessing the performance of a demand response resource, it appears that the aggregate 5-in-10 baseline method with a 40 percent adjustment cap performs best overall. However, the 10-in-10 baslines seem to perform somewhat better in winter. When using the 5-in-10 method, applying the same method to individual customer loads and adding the resulting baselines up to the resource level tends to result in baselines that are too high.[2]

[1] Decision 19-07-009, July 11, 2019, Order paragraph 18, page 113.

[2] A possible exception to this is summer extreme weather weekdays, as shown in Appendix A.

1. Introduction and Purpose of the Study

In its Decision 19-07-009 dated July 11, 2019, the California Public Utilities Commission ("CPUC") ordered an assessment of benefits of using a 5-in-10 baseline method for residential customers, including "statistics on the accuracy of the aggregate and individual baseline."[3] Of particular interest is the baseline to apply to the residential Capacity Bidding Program ("CBP"), and whether the 5-in-10 methodology with a 40 percent adjustment cap would perform better than the current wholesale 10-in-10 baseline methodology with a 20 percent adjustment cap.

This report documents a baseline evaluation that compares the 5-in-10 and 10-in-10 methods, each calculated in two ways: using the resource-level aggregate load profile; and using the sum of the individual customer profiles within each resource. Because Pacific Gas and Electric Company ("PG&E") does not currently have residential CBP customers, our assessment is conducted using its residential SmartAC customers. For purposes of the evaluation, a "resource" is defined as a sub-load aggregation point ("subLAP").

The performance of each baseline method is assessed across a range of day types: summer and winter; non-holiday weekdays and weekends/holidays; and extreme and moderate weather days. Because SmartAC event days are excluded from our set of test days, the baselines can be assessed against observed customer loads.

The report is organized as follows. Section 2 describes the methods used to evaluate the baseline methods; Section 3 summarizes the results by season and day type; and Section 4 contains a summary of findings and conclusions.

2. Study Methodology

2.1 Test Day Selection

In order to evaluate the various baseline methods, we selected a set of test days for each subLAP corresponding to a range of day types and weather conditions:

- Summer versus winter: for analysis purposes, summer is defined as June through September 2019 and winter is defined as November 2018 through February 2019;
- Non-holiday weekdays versus weekends/holidays; and
- Extreme and moderate weather conditions.

In selecting the test days, dates are ranked within resource and day type (*i.e.*, by subLAP, season, and non-holiday weekdays versus weekends/holidays) according to average daily temperature. Seven extreme temperature days (hottest in summer, coldest in winter) and seven moderate temperature days (the middle of the temperature distribution) are selected for each subLAP and day type. Due to a lower

[3] Decision 19-07-009, July 11, 2019, Order paragraph 18, page 113.

number of available days, we select only moderate temperature dates for weekends/holidays. The selection process thus provides 42 test days for each subLAP:

- 28 non-holiday weekdays (7 hot summer, 7 moderate summer, 7 cold winter, 7 moderate winter); and
- 14 weekend/holiday dates (7 moderate summer, 7 moderate winter).

Test-day selections are specific to each subLAP and SmartAC event days are excluded from the set of potential test days to prevent event-day demand response from affecting the analysis.

2.2 Baseline Calculations

For non-holiday weekdays, we compare the performance of 5-in-10 and 10-in-10 baselines. In each case, eligible baseline days exclude weekends, holidays, and SmartAC event days. The 10-in-10 baseline is based on the average load during the ten baseline-eligible days preceding the test day. In contrast, the 5-in-10 baseline examines the same ten baseline-eligible days, but only averages the loads on the five highest-load days. Baselines are calculated assuming three different event windows. The main report summarizes an event window from 5:00 through 8:00 p.m. (hours-ending 18 through 20). Appendix B summarizes event windows from 11 a.m. to 2:00 p.m. (hours-ending 12 through 14) and 2:00 to 5:00 p.m. (hours-ending 15 through 17).

The baseline adjustment differs by method:

- The 5-in-10 baseline has a 40% adjustment cap (0.71 to 1.40) and is based on average loads in two hours preceding and following the event, each with a two-hour buffer. For example, for our simulated HE 18 to 20 event window, the four hours used as the basis for the adjustment are HE 14, 15, 23, and 24 (with HE 16, 17, 21, and 22 serving as the “buffer” hours).
- The 10-in-10 baseline has a 20% adjustment cap (0.80 to 1.20) and is based on average loads in three hours preceding the event with a one-hour buffer. For example, for our simulated HE 18 to 20 event window, the three hours used as the basis for the adjustment are HE 14, 15, and 16 (with HE 17 serving as the “buffer” hour).

The adjustment ratio is calculated as follows:
Adjustment Ratio = (Avg. Load on Event Days / Avg. Load on Baseline Days), applying the maximum and minimum allowed values for each baseline described above.

The adjusted baseline is then calculated as the Adjustment Ratio times the unadjusted baseline during the event hours.

The baselines for weekends and holidays are somewhat different. In place of the 5-in-10 baseline, a 3-in-5 baseline is used. It uses a 100 percent adjustment cap (0.5 to 2.0) and places greater weight on the higher-load days.[4]

In place of the 10-in-10 baseline, a 4-in-4 baseline is applied to weekends and holidays. A 20 percent adjustment cap is used (0.83 to 1.20) and the days are given equal weight.

Each baseline is calculated in two ways: using the aggregate subLAP load; and for each individual customer within the subLAP, then added up to form a subLAP-level baseline.

3. Baseline Study Findings

This section summarizes the performance of the various baseline methods, with results separated by season and day type (non-holiday weekday vs. weekends/holidays). Two metrics are used:[5]

- Mean error (ME) calculated as:
  $ME_{b,s,t}$ = baseline $load_{b,s,t}$ – observed $load_{b,s,t}$, for baseline *b* and subLAP *s* and test day *t*.
- Mean absolute error (MAE), calculated as the absolute value of ME.

ME and MAE are first calculated at the subLAP + test day level after averaging baseline and observed loads across the simulated event hours of the test day. Summaries of ME and MAE across subLAPs and/or test days are calculated by averaging ME and MAE across the subLAPs + test days, weighted to account for the number of customers in the subLAP.

ME provides an indication of the bias associated with a baseline.

- A positive ME value indicates a baseline that is too high;
- A negative ME value indicates a baseline that is too low.

In contrast, MAE is limited to non-negative values and provides a measure of the accuracy of the baseline. Higher MAE values are associated with less accurate baselines.

In each sub-section below, we present three items:

- A table summarizing the ME and MAE values by baseline method, the use of the day-of adjustment, and whether the baseline is calculated using the aggregate subLAP load or using each customer's load data (with the resulting baselines added up within each subLAP).
- Two scatter plots comparing the ME values for:
    - Aggregate and sum of individual baseline methods; and

[4] The weights applied to the three selected dates are: 50 percent on the highest-load day; 30 percent on the second-highest load day; and 20 percent on the third-highest load day.

[5] We have also examined mean percentage error (MPE) and mean absolute percentage error (MAPE). We found that it produced misleading results for the HE12-14 event window in particular, as obsereved loads can be very low or negative during those hours due to rooftop solar generation, thus producing very high percentage errors.

    - 10-in-10 and 5-in-10 baseline methods.
- The first scatter plot reflects unadjusted baselines while the second figure reflects adjusted baselines.

In the figures, each data point represents one test day within a single subLAP, and the size of each circle reflects the number of customers in the subLAP.

Appendix A contains tables that summarize non-holiday weekday ME and MAE values for extreme versus moderate weather conditions, by season. Appendix B provides the same tables and figures presented in this section, but for two earlier event windows. The results are qualitatively similar to those presented in this section.

3.1 Summer

This section summarizes baseline performance during the summer months of June through September.

3.1.1 Non-holiday weekdays

Table 3.1 summarizes the ME and MAE values for summer non-holiday weekdays. We have the following observations:

- The 5-in-10 adjusted baseline using the aggregate subLAP load (shown on the bottom row of the table) performs best, with the least bias and the greatest accuracy across the presented alternatives.
- The adjustment improves performance of the 5-in-10 baseline but has a smaller effect on the performance of the 10-in-10 baseline.
- 10-in-10 baseline performance isn't overly affected by the use of the aggregate baseline versus the sum of individual customer baselines.
- Adjusted 5-in-10 baseline performance improves considerably using the aggregate method.

On the final point, note that adding the individual 5-in-10 baselines is associated with a significantly positive mean error, meaning the baseline overstates the observed loads. This effect is reduced (and sometimes reversed) using the aggregate baseline. This outcome makes intuitive sense, in that the 5-in-10 method selects the five highest load days among the ten previous eligible days. Making this selection on a customer-specific basis is bound to lead to a higher baseline than selecting a single set of five days the aggregate resource-level load.

This difference doesn't exist for the 10-in-10 methodology because all customers have their baseline based on the same ten days regardless of whether it's based on the aggregate or individual baselines.

Table 3.1: Summer Non-holiday Weekday Baseline Performance Summary, HE18-20 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
10in10	Sum of Individual	-0.468	0.621	2.241
	Aggregate	-0.466	0.620	
5in10	Sum of Individual	0.152	0.555	
	Aggregate	-0.100	0.551	
10in10 Adjusted	Sum of Individual	-0.418	0.527	
	Aggregate	-0.359	0.402	
5in10 Adjusted	Sum of Individual	0.224	0.386	
	Aggregate	0.009	0.218	

Figure 3.1 illustrates the mean error values associated with the unadjusted baselines for each subLAP-test day combination. The blue circles correspond to the 10-in-10 baselines, the orange circles correspond to the 5-in-10 baselines, and the size of the circles reflects the number of customers in the subLAP. The horizontal axis measures the ME for the sum of the individual baselines, while the vertical axis measures the ME of the aggregate baseline. A 45° line has been drawn in to make it easier to assess differences in the aggregate and sum of individual ME values. (Points on the 45° line indicate that the two ME values are the same.)

As shown in Table 3.1, the average observed load during this event window is 2.241 kWh/hr/customer, so many of the errors are a fairly large percentage of the observed load (*e.g.*, all errors above 0.6 kWh/hr/customer exceed 25 percent of the observed load).

Figure 3.1: Summer Non-holiday Weekday Mean Error by Test Day and subLAP, Unadjusted HE18-20 Event

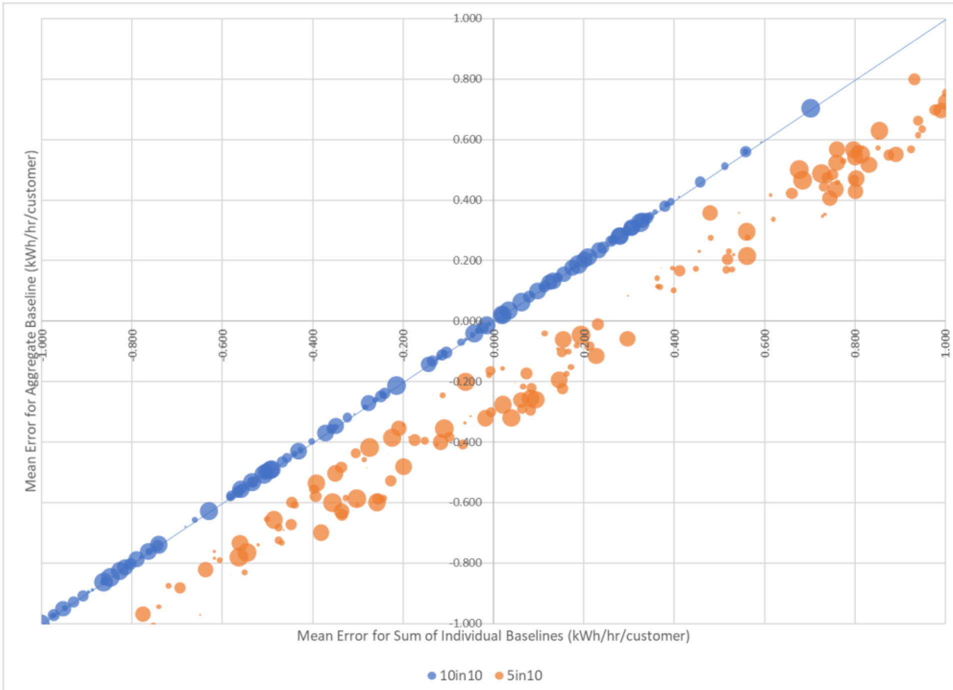
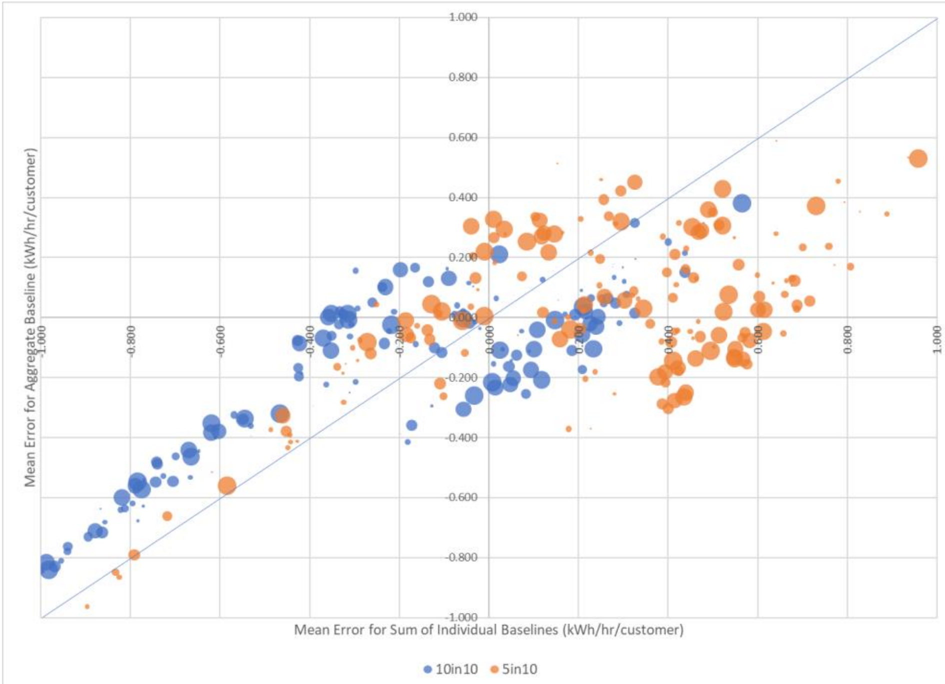


Figure 3.2 illustrates the same information for adjusted baselines. Both figures show that the orange circles tend to skew toward the right, indicating baselines that are too high when summing individual baselines. In contrast, the orange circles are comparatively well balanced across the y-axis (*i.e.*, as many above as below, indicating less bias).

Figure 3.2: Summer Non-holiday Weekday Mean Error by Test Day and subLAP, Adjusted HE18-20 Event



3.1.2 Weekends and holidays

Table 3.2 summarizes the ME and MAE values for summer weekends and holidays. We have the following observations:

- While the 3-in-5 adjusted baseline is the most accurate (MAE = 0.128 kWh/hr/customer), several other methods have less bias.
- The 4-in-4 baselines are nearly without bias and are more accurate than all but the 3-in-5 adjusted baseline.
- As was the case with weekday 5-in-10 baselines, the 3-in-5 baselines are too high when summed across individual customers.

Table 3.2: Summer Weekend/Holiday Baseline Performance Summary, HE18-20 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
4in4	Sum of Individual	-0.005	0.283	1.658
	Aggregate	-0.003	0.283	
3in5	Sum of Individual	0.606	0.676	
	Aggregate	0.301	0.476	
4in4 Adjusted	Sum of Individual	-0.028	0.239	
	Aggregate	-0.033	0.187	
3in5 Adjusted	Sum of Individual	0.421	0.430	
	Aggregate	-0.078	0.128	

Figures 3.3 and 3.4 illustrate the mean error values associated with the unadjusted and adjusted baselines (respectively) for each subLAP-test day combination on summer weekends and holidays. The most prominent observation is that the orange circles representing the 3-in-5 baselines skew toward the right, indicating an upward bias when the baseline is calculated as the sum of individual baselines.

Figure 3.3: Summer Weekend/Holiday Mean Error by Test Day and subLAP, Unadjusted HE18-20 Event

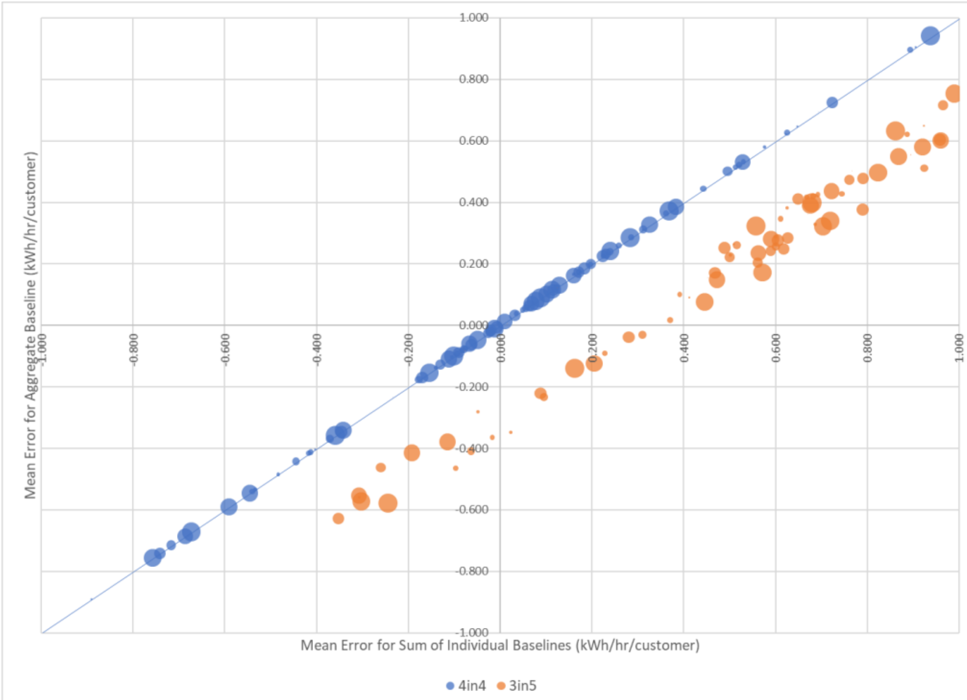
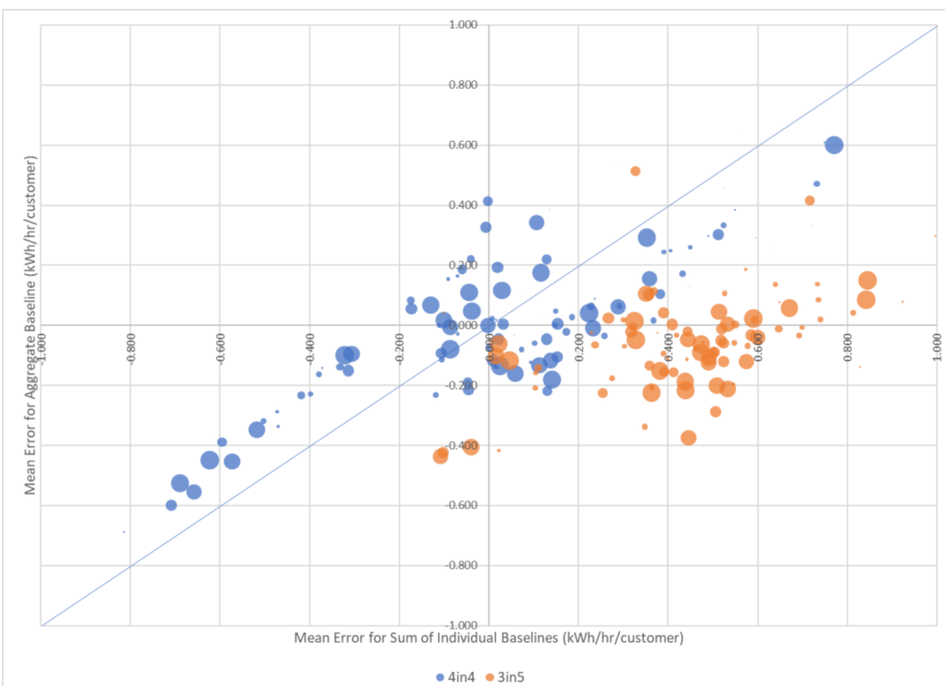


Figure 3.4: Summer Weekend/Holiday Mean Error by Test Day and subLAP, Adjusted HE18-20 Event



3.2 Winter

This section summarizes baseline performance during the winter months of November through February.

3.2.1 Non-holiday weekdays

Table 3.3 summarizes the ME and MAE values for winter non-holiday weekdays. We have the following observations:

- 10-in-10 ME and MAE values tend to be lower than the corresponding summer values, indicating more accurate and less biased baselines on average.
- All variants of the 10-in-10 baselines perform well.
- The 5-in-10 unadjusted aggregate baseline is the most accurate across all baselines, but has a similar amount of bias as the 10-in-10 baselines. The 5-in-10 *adjusted* aggregate baseline also performs well.
- The 5-in-10 baseline using the sum of individual baselines continues to produce upward-biased baselines (*i.e.*, positive ME values).

Table 3.3: Winter Non-holiday Weekday Baseline Performance Summary, HE18-20 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
10in10	Sum of Individual	-0.022	0.063	1.154
	Aggregate	-0.021	0.062	
5in10	Sum of Individual	0.278	0.278	
	Aggregate	0.022	0.052	
10in10 Adjusted	Sum of Individual	-0.038	0.058	
	Aggregate	-0.052	0.154	
5in10 Adjusted	Sum of Individual	0.238	0.238	
	Aggregate	-0.031	0.125	

Figures 3.5 and 3.6 illustrate the mean error values associated with the unadjusted and adjusted baselines (respectively) for each subLAP-test day combination on winter non-holiday weekdays. Both figures clearly show the rightward bias of the orange circles (high positive ME for the 5-in-10 sum of individual baselines). At the same time, the

adjusted baseline values in both figures are quite close to the horizontal axis, reflecting the good performance of the aggregate 5-in-10 baselines.

Figure 3.5: Winter Non-holiday Weekday Mean Error by Test Day and subLAP, Unadjusted HE18-20 Event

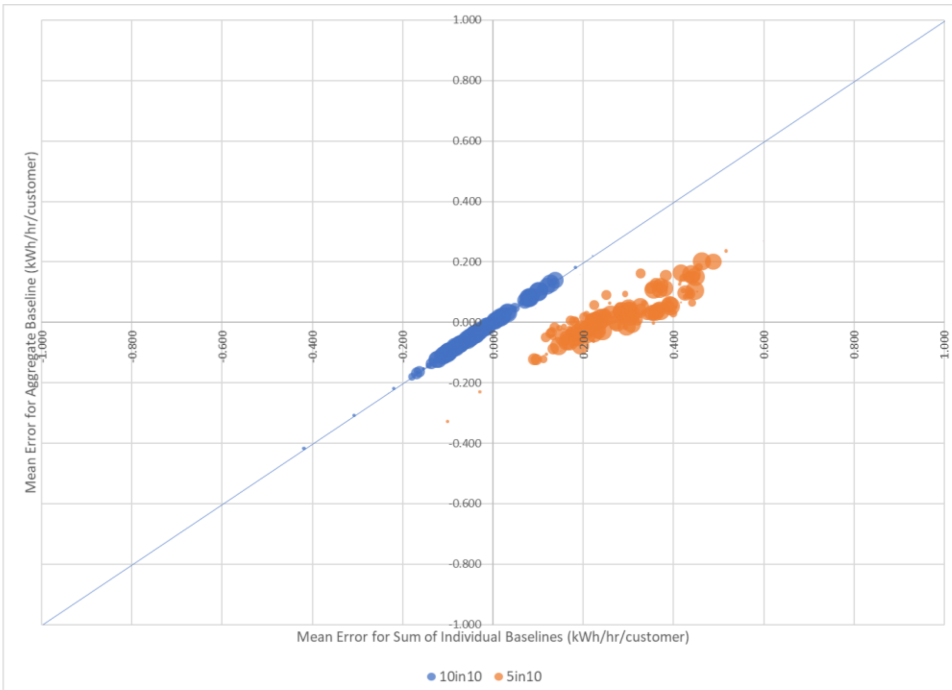
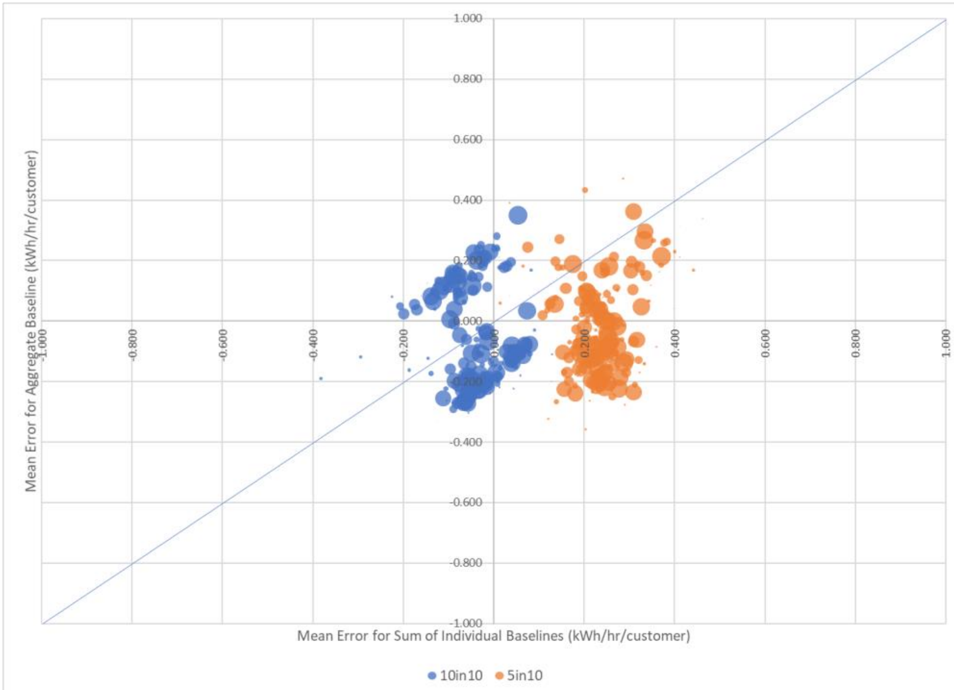


Figure 3.6: Winter Non-holiday Weekday Mean Error by Test Day and subLAP, Adjusted HE18-20 Event



3.2.2 Weekends and holidays

Table 3.4 summarizes the ME and MAE values for winter weekends and holidays. We have the following observations:

- Many of the baselines perform well, with low bias and error.
- The exceptions are the 3-in-5 baselines calculated as the sum of the individual baselines, which have much higher ME and MAE values than the other tested methods.

Table 3.4: Winter Weekend/Holiday Baseline Performance Summary, HE18-20 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
4in4	Sum of Individual	0.002	0.048	1.168
	Aggregate	0.002	0.048	
3in5	Sum of Individual	0.365	0.365	
	Aggregate	0.057	0.076	
4in4 Adjusted	Sum of Individual	-0.027	0.044	
	Aggregate	-0.021	0.114	
3in5 Adjusted	Sum of Individual	0.296	0.296	
	Aggregate	-0.001	0.124	

Figures 3.7 and 3.8 illustrate the mean error values associated with the unadjusted and adjusted baselines (respectively) for each subLAP-test day combination on winter weekends and holiday. The figures show the good overall performance of the 4-in-4 baseline methods and the aggregate 3-in-5 baselines. The now familiar rightward shift in the 3-in-5 sum of individual baseline ME values reflects the comparatively poor performance of that method.

Figure 3.7: Winter Weekend/Holiday Mean Error by Test Day and subLAP, Unadjusted HE18-20 Event

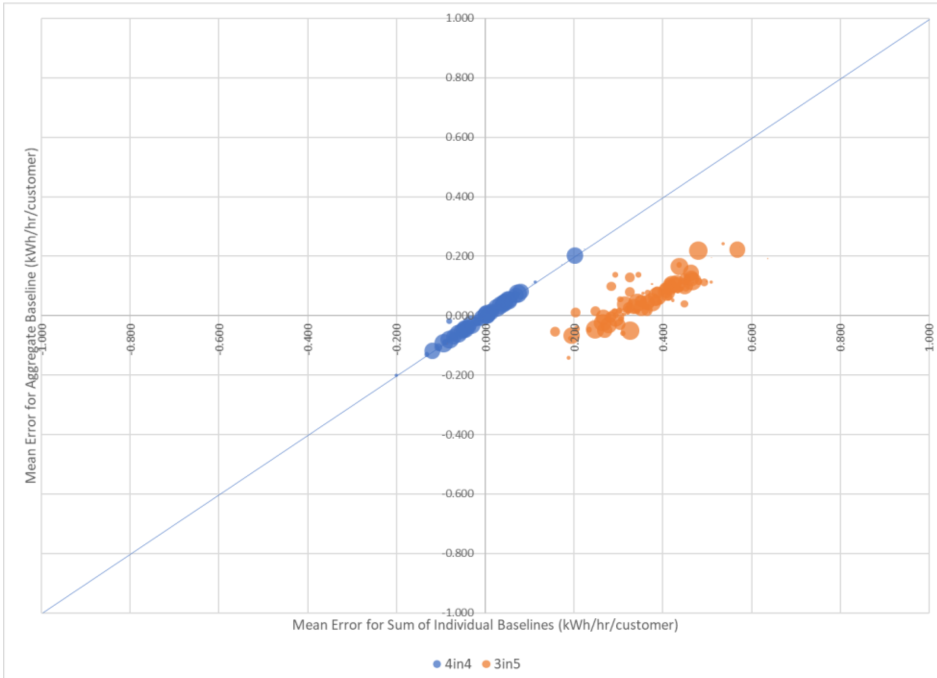


Figure 3.8: Winter Weekend/Holiday Mean Error by Test Day and subLAP, Adjusted HE18-20 Event

4. Summary and Conclusions

This report summarizes the performance of various baseline calculations, which are used to assess the performance of demand response programs such as the Capacity Bidding Program. This assessment was required in the CPUC's Decision 19-07-009.

The comparisons of primary interest are as follows:

- 5-in-10 versus 10-in-10 baselines (with their weekend/holiday counterparts of 3-in-5 and 4-in-4);
- Unadjusted and adjusted baselines;
- Each calculated using both the aggregate resource load and by adding the customer-specific baselines within each resource

For purposes of the evaluation, we examined Program Year 2019 participants in PG&E's residential SmartAC program.[6] A "resource" is defined as the SmartAC customers within each subLAP. The primary simulated event window was 5:00 to 8:00 p.m., which was evaluated over 42 test days selected on a subLAP-specific basis. The test days represented a range of day types:

- Summer (June through September) and winter (December through February);
- Non-holiday weekdays and weekends/holidays; and
- Extreme and moderate weather days.

The results show that the aggregate 5-in-10 adjusted baseline performs best overall, displaying minimal bias and comparatively good accuracy. Another prominent finding is that the 5-in-10 baselines calculated as the sum of customer-level baselines tend to be too high (*i.e.*, the calculated baseline is above the observed test-day load, resulting in a positive MPE value). Other general findings include:

- 10-in-10 baseline performance is not affected by the various methods (aggregate vs. sum of individual; and adjusted vs. unadjusted) to the same extent as 5-in-10 baseline performance.
- Winter baseline performance tends to be better than summer baseline performance.
- Summer baselines exhibit a fair amount of error regardless of method. The best performing baseline (aggregate 5-in-10 adjusted baseline) has a mean absolute error (MAE) of 0.22 kWh/hr/customer.

In summary, when assessing the performance of a demand response resource, it appears that the aggregate 5-in-10 baseline method with a 40 percent adjustment cap performs best overall. However, 10-in-10 baselines seem to perform somewhat better in winter. When using the 5-in-10 method, applying the same method to individual

[6] Baselines are not directly relevant to SmartAC. However, PG&E did not have any residential CBP customers (the primary program of interest) at the time of the study.

customer loads and adding the resulting baselines up to the resource level tends to result in baselines that are too high.[7]

[7] A possible exception to this is summer extreme weather weekdays, as shown in Appendix A.

Appendices

Appendix A Non-holiday Baseline Performance by Weather Day Type

Appendix B Baseline Performance for Other Simulated Event Windows

Appendix A. Non-holiday Baseline Performance by Weather Day Type

Tables A.1 and A.2 summarize summer and winter baseline performance (respectively) for extreme and moderate weather days. The two days were combined in the tables of Section 3.

During summer months (as shown in Table A.1), baselines for extreme days tend to be below the observed loads (*i.e.*, negative ME values) while the moderate-day baselines tend to overstate observed loads. The differences by weather day type are not as prominent during winter months, as shown in Table A.2.

As shown in Table A.1, summer extreme days are the one instance in which the 5-in-10 adjusted baseline calculated from individual customer baselines (the second-to-last row) performs well. Table A.2 shows that the 10-in-10 baselines perform best on winter non-holiday weekdays.

Table A.1: Summer Non-holiday Weekday Baseline Performance Summary, Extreme vs. Moderate Weather Days

Baseline Method	Type	Extreme		Moderate	
		ME	MAE	ME	MAE
10in10	Sum of Individual	-0.978	0.978	0.041	0.264
	Aggregate	-0.976	0.976	0.043	0.265
5in10	Sum of Individual	-0.353	0.412	0.657	0.698
	Aggregate	-0.603	0.604	0.403	0.498
10in10 Adjusted	Sum of Individual	-0.843	0.843	0.007	0.211
	Aggregate	-0.627	0.646	-0.092	0.159
5in10 Adjusted	Sum of Individual	0.001	0.311	0.447	0.461
	Aggregate	0.030	0.281	-0.013	0.154

Table A.2: Winter Non-holiday Weekday Baseline Performance Summary, Extreme vs. Moderate Weather Days

Baseline Method	Type	Extreme		Moderate	
		ME	MAE	ME	MAE
10in10	Sum of Individual	-0.033	0.060	-0.010	0.065
	Aggregate	-0.032	0.059	-0.010	0.065
5in10	Sum of Individual	0.270	0.270	0.285	0.285
	Aggregate	0.009	0.039	0.036	0.066
10in10 Adjusted	Sum of Individual	-0.037	0.050	-0.038	0.066
	Aggregate	-0.129	0.160	0.026	0.148
5in10 Adjusted	Sum of Individual	0.237	0.237	0.239	0.239
	Aggregate	-0.081	0.116	0.020	0.134

Appendix B. Baseline Performance for Other Simulated Event Windows

Tables B.1 through B.8 and Figures B.1 through B.16 replicate the tables and figures from the body of the report for two alternate event windows. While the body of the report reflects and event window of HE18-20 (5 to 8 p.m.), this appendix shows results for two earlier event windows: HE12-14 (11 a.m. to 2 p.m.); and HE15-17 (2 to 5 p.m.).

Table B.1: Summer Non-holiday Weekday Baseline Performance Summary, HE12-14 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
10in10	Sum of Individual	-0.303	0.438	0.678
	Aggregate	-0.303	0.438	
5in10	Sum of Individual	0.126	0.425	
	Aggregate	-0.091	0.418	
10in10 Adjusted	Sum of Individual	-0.295	0.394	
	Aggregate	-0.284	0.394	
5in10 Adjusted	Sum of Individual	0.154	0.323	
	Aggregate	-0.083	0.290	

Table B.2: Summer Non-holiday Weekday Baseline Performance Summary, HE15-17 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
10in10	Sum of Individual	-0.469	0.630	1.502
	Aggregate	-0.468	0.630	
5in10	Sum of Individual	0.127	0.574	
	Aggregate	-0.120	0.573	
10in10 Adjusted	Sum of Individual	-0.436	0.536	
	Aggregate	-0.416	0.480	
5in10 Adjusted	Sum of Individual	0.176	0.396	
	Aggregate	-0.082	0.240	

Table B.3: Summer Weekend/Holiday Baseline Performance Summary, HE12-14 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
4in4	Sum of Individual	0.031	0.142	0.397
	Aggregate	0.032	0.142	
3in5	Sum of Individual	0.526	0.530	
	Aggregate	0.237	0.274	
4in4 Adjusted	Sum of Individual	0.014	0.128	
	Aggregate	0.025	0.119	
3in5 Adjusted	Sum of Individual	0.425	0.425	
	Aggregate	0.132	0.162	

Table B.4: Summer Weekend/Holiday Baseline Performance Summary, HE15-17 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
4in4	Sum of Individual	0.027	0.251	1.011
	Aggregate	0.028	0.251	
3in5	Sum of Individual	0.668	0.678	
	Aggregate	0.347	0.433	
4in4 Adjusted	Sum of Individual	-0.007	0.227	
	Aggregate	0.002	0.212	
3in5 Adjusted	Sum of Individual	0.467	0.467	
	Aggregate	0.095	0.136	

Table B.5: Winter Non-holiday Weekday Baseline Performance Summary, HE12-14 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
10in10	Sum of Individual	0.025	0.175	0.374
	Aggregate	0.026	0.175	
5in10	Sum of Individual	0.376	0.385	
	Aggregate	0.166	0.239	
10in10 Adjusted	Sum of Individual	0.027	0.176	
	Aggregate	0.038	0.167	
5in10 Adjusted	Sum of Individual	0.360	0.370	
	Aggregate	0.162	0.224	

Table B.6: Winter Non-holiday Weekday Baseline Performance Summary, HE15-17 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
10in10	Sum of Individual	0.015	0.114	0.634
	Aggregate	0.015	0.114	
5in10	Sum of Individual	0.309	0.309	
	Aggregate	0.106	0.151	
10in10 Adjusted	Sum of Individual	0.003	0.104	
	Aggregate	-0.011	0.060	
5in10 Adjusted	Sum of Individual	0.274	0.274	
	Aggregate	0.060	0.079	

Table B.7: Winter Weekend/Holiday Baseline Performance Summary, HE12-14 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
4in4	Sum of Individual	0.037	0.163	0.532
	Aggregate	0.037	0.164	
3in5	Sum of Individual	0.433	0.444	
	Aggregate	0.159	0.247	
4in4 Adjusted	Sum of Individual	0.033	0.160	
	Aggregate	0.040	0.143	
3in5 Adjusted	Sum of Individual	0.391	0.406	
	Aggregate	0.133	0.208	

Table B.8: Winter Weekend/Holiday Baseline Performance Summary, HE15-17 Event

Baseline Method	Type	Mean Error (kWh/Cust)	Mean Absolute Error (kWh/Cust)	Avg. Observed kWh/Cust
4in4	Sum of Individual	0.008	0.115	0.797
	Aggregate	0.009	0.116	
3in5	Sum of Individual	0.371	0.372	
	Aggregate	0.095	0.162	
4in4 Adjusted	Sum of Individual	-0.005	0.107	
	Aggregate	-0.021	0.064	
3in5 Adjusted	Sum of Individual	0.302	0.302	
	Aggregate	0.022	0.060	

Figure B.1: Summer Non-holiday Weekday Mean Error by Test Day and subLAP, Unadjusted HE12-14 Event

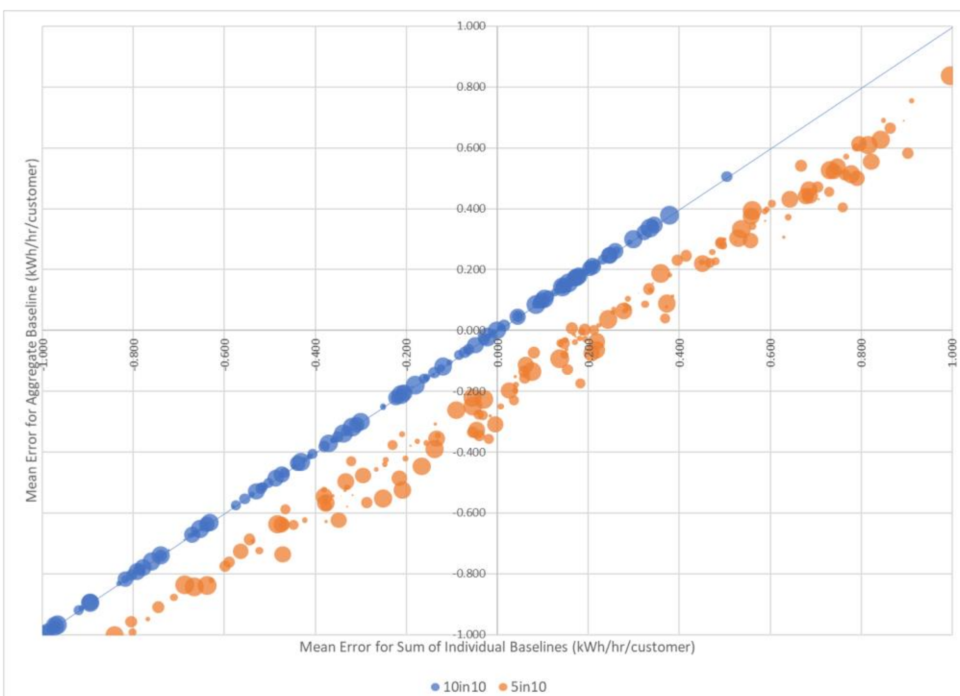


Figure B.2: Summer Non-holiday Weekday Mean Error by Test Day and subLAP, Unadjusted HE15-17 Event

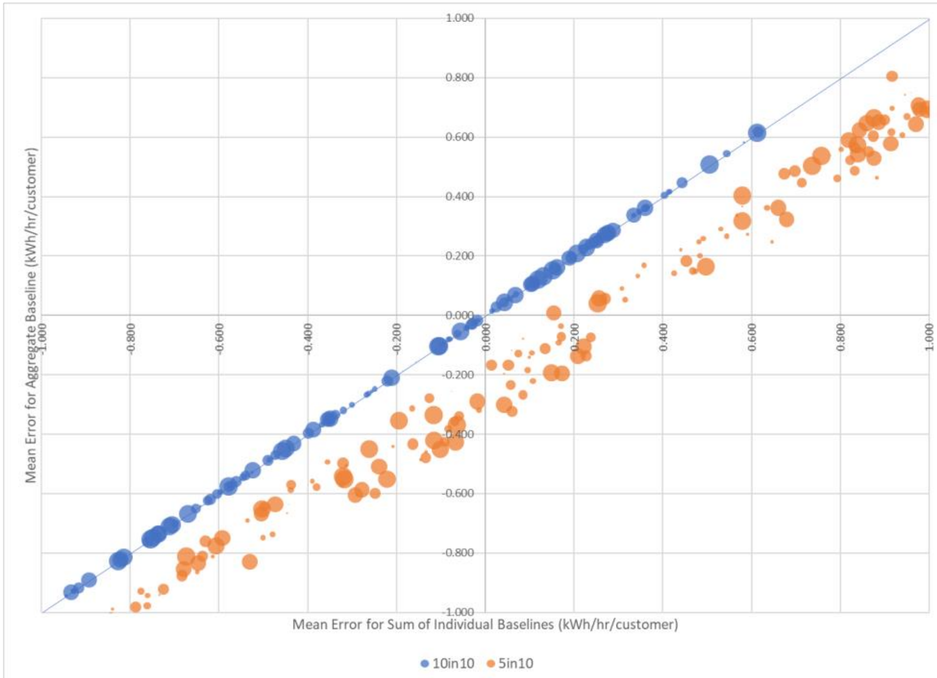


Figure B.3: Winter Non-holiday Weekday Mean Error by Test Day and subLAP, Unadjusted HE12-14 Event

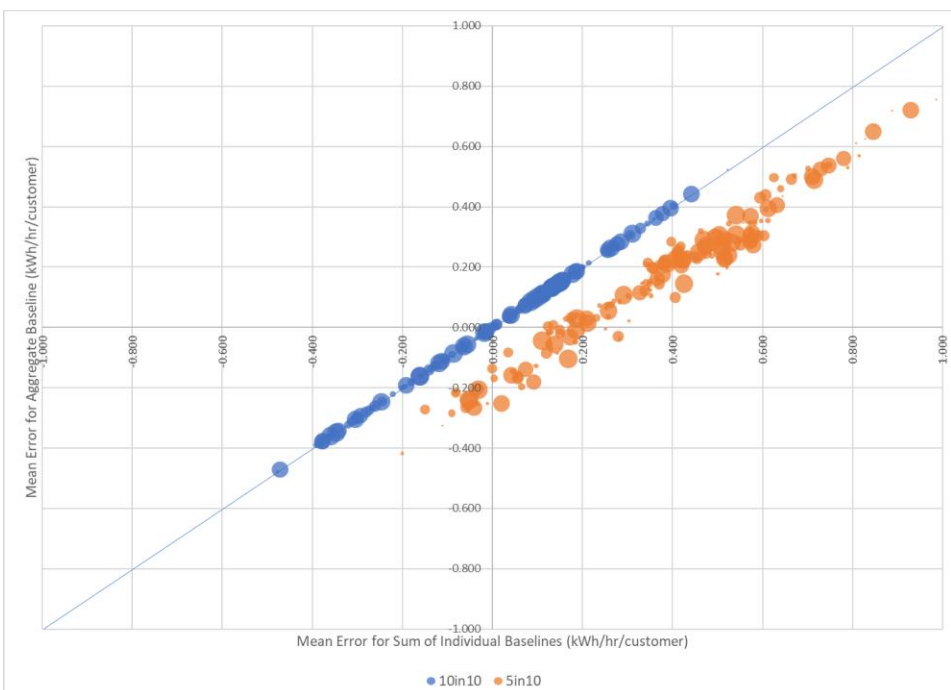


Figure B.4: Winter Non-holiday Weekday Mean Error by Test Day and subLAP, Unadjusted HE15-17 Event

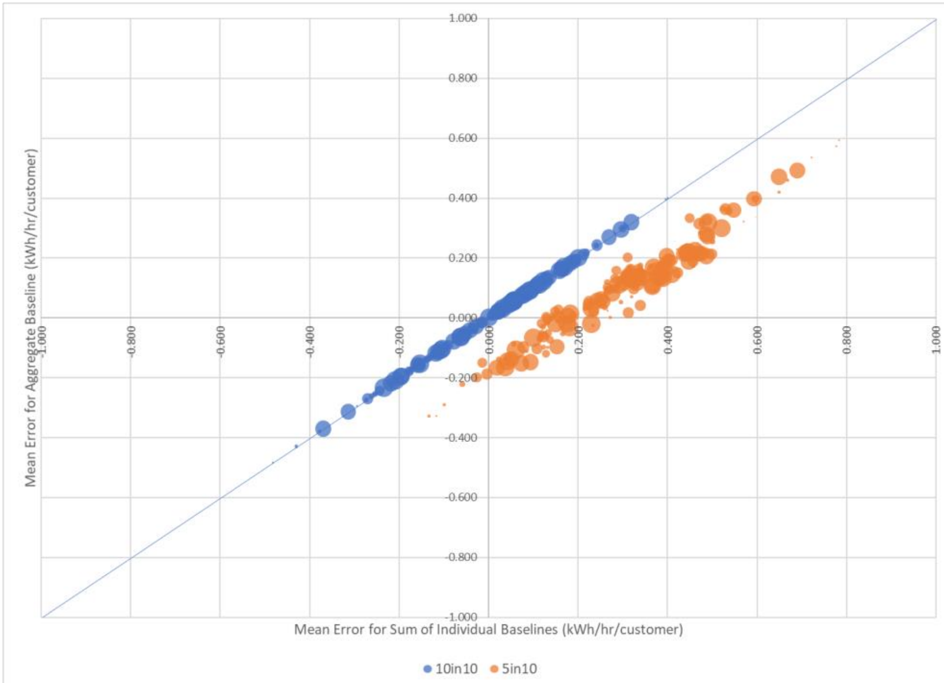


Figure B.5: Summer Non-holiday Weekday Mean Error by Test Day and subLAP, Adjusted HE12-14 Event

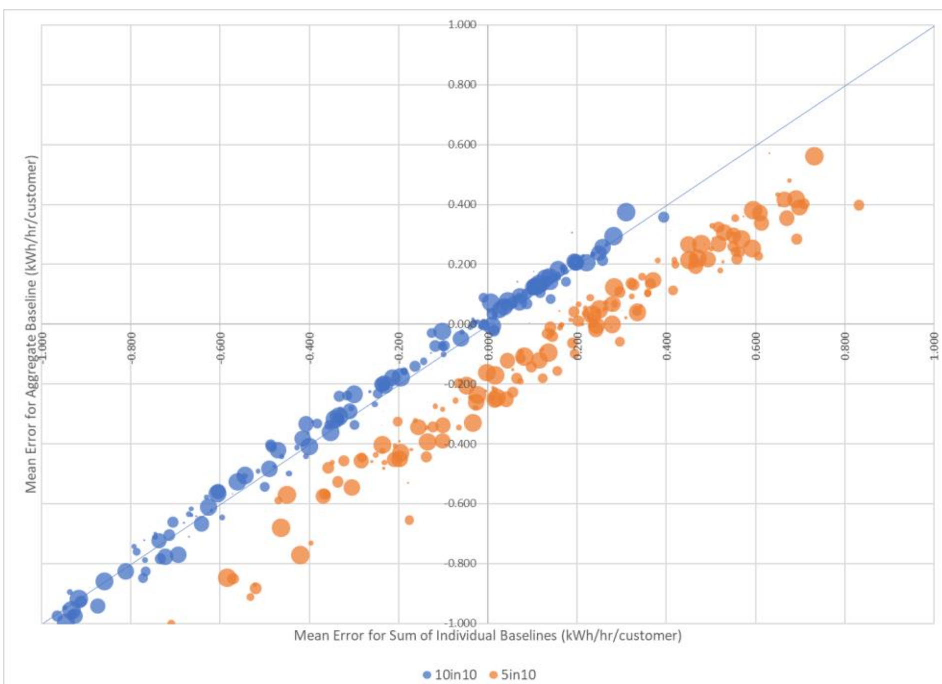


Figure B.6: Summer Non-holiday Weekday Mean Error by Test Day and subLAP, Adjusted HE15-17 Event

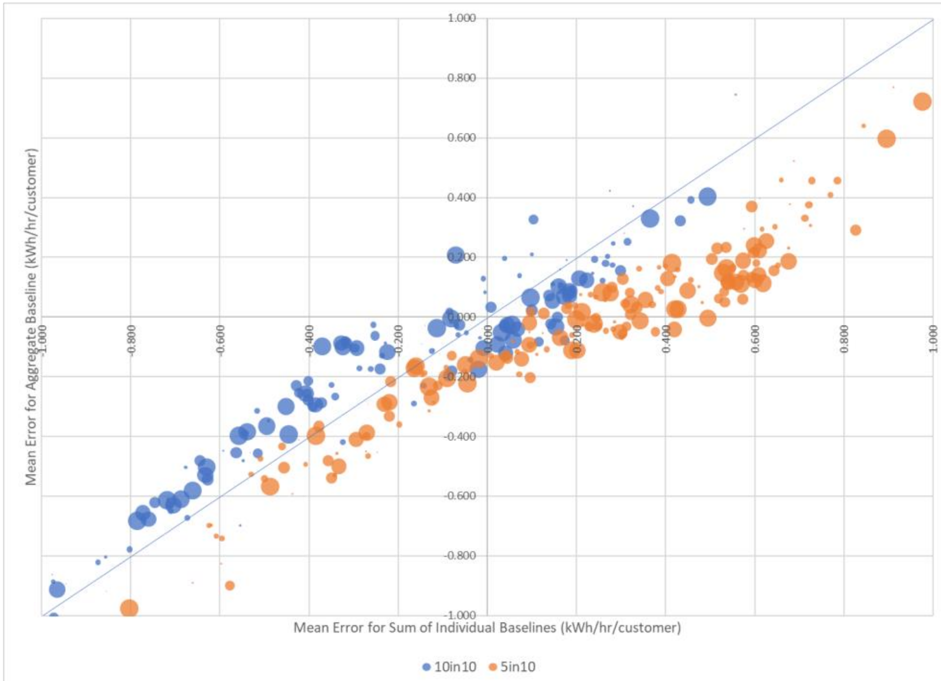


Figure B.7: Winter Non-holiday Weekday Mean Error by Test Day and subLAP, Adjusted HE12-14 Event

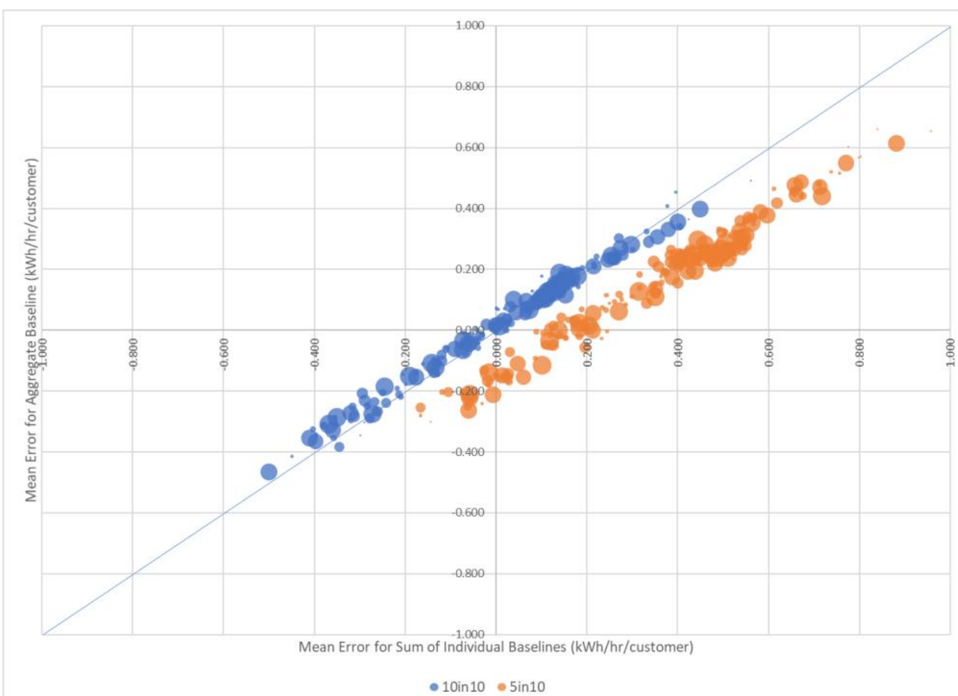


Figure B.8: Winter Non-holiday Weekday Mean Error by Test Day and subLAP, Adjusted HE15-17 Event

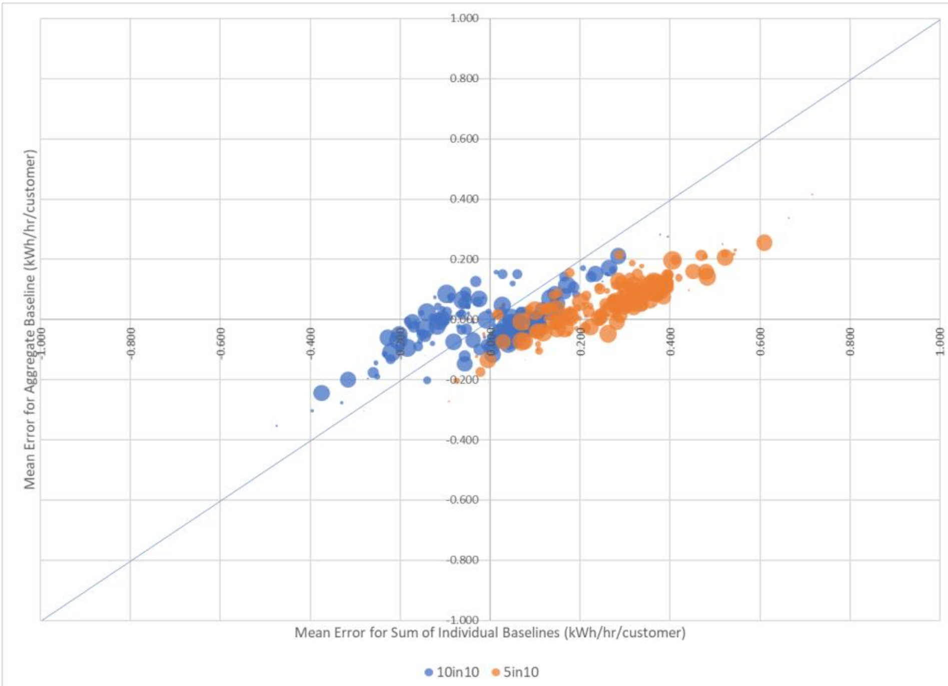


Figure B.9: Summer Weekend/Holiday Mean Error by Test Day and subLAP, Unadjusted HE12-14 Event

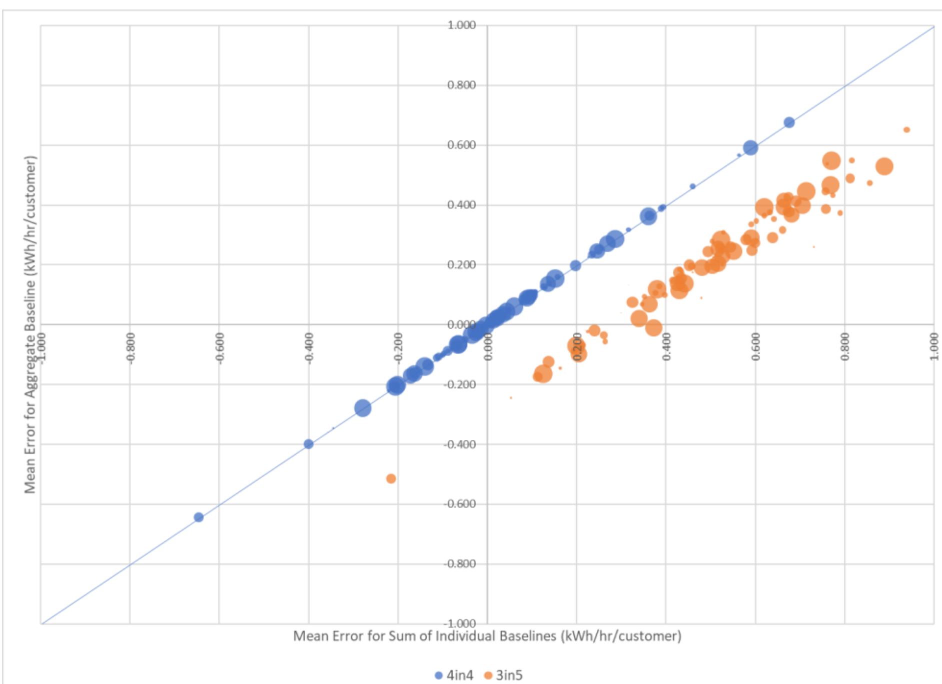


Figure B.10: Summer Weekend/Holiday Mean Error by Test Day and subLAP, Unadjusted HE15-17 Event

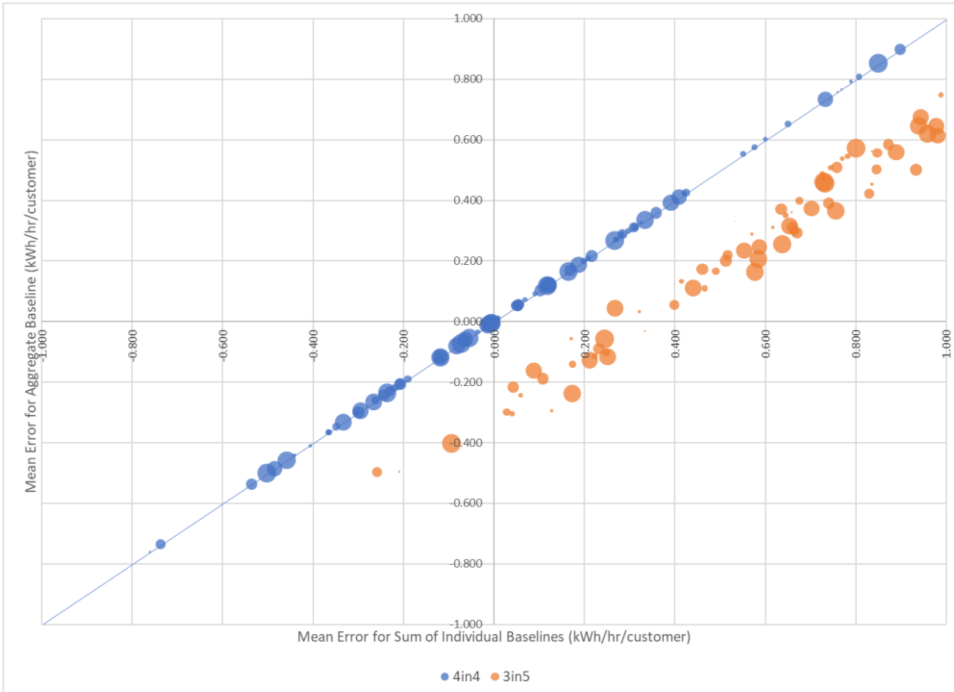


Figure B.11: Winter Weekend/Holiday Mean Error by Test Day and subLAP, Unadjusted HE12-14 Event

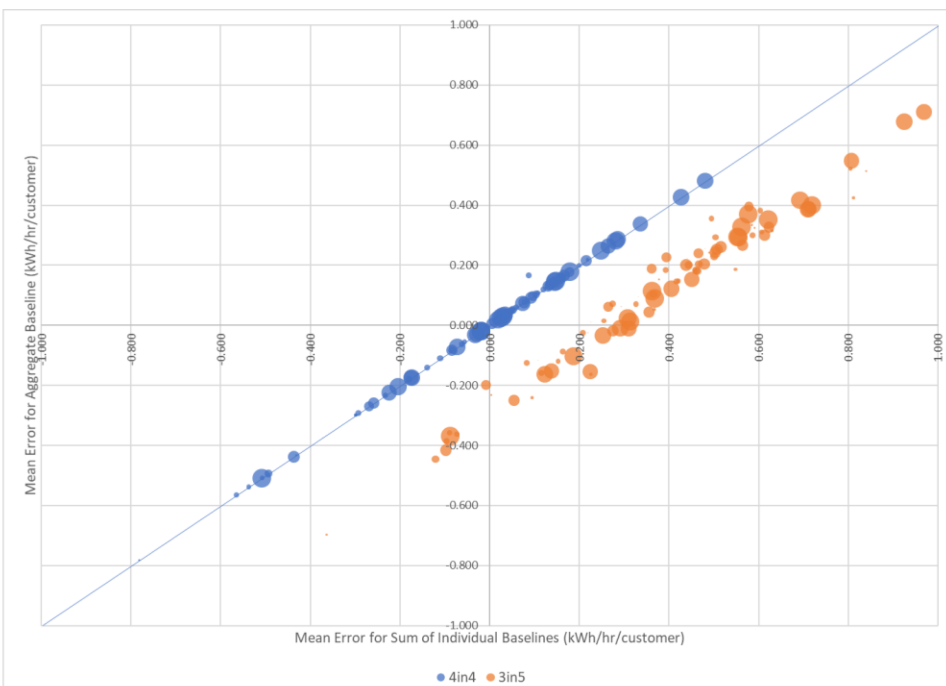


Figure B.12: Winter Weekend/Holiday Mean Error by Test Day and subLAP, Unadjusted HE15-17 Event

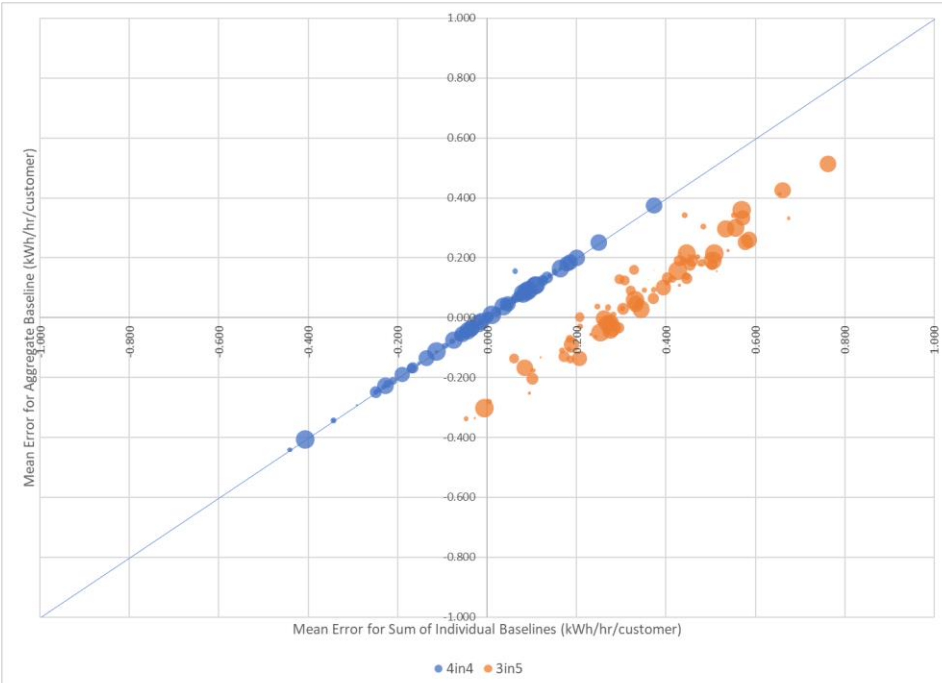


Figure B.13: Summer Weekend/Holiday Mean Error by Test Day and subLAP, Adjusted HE12-14 Event

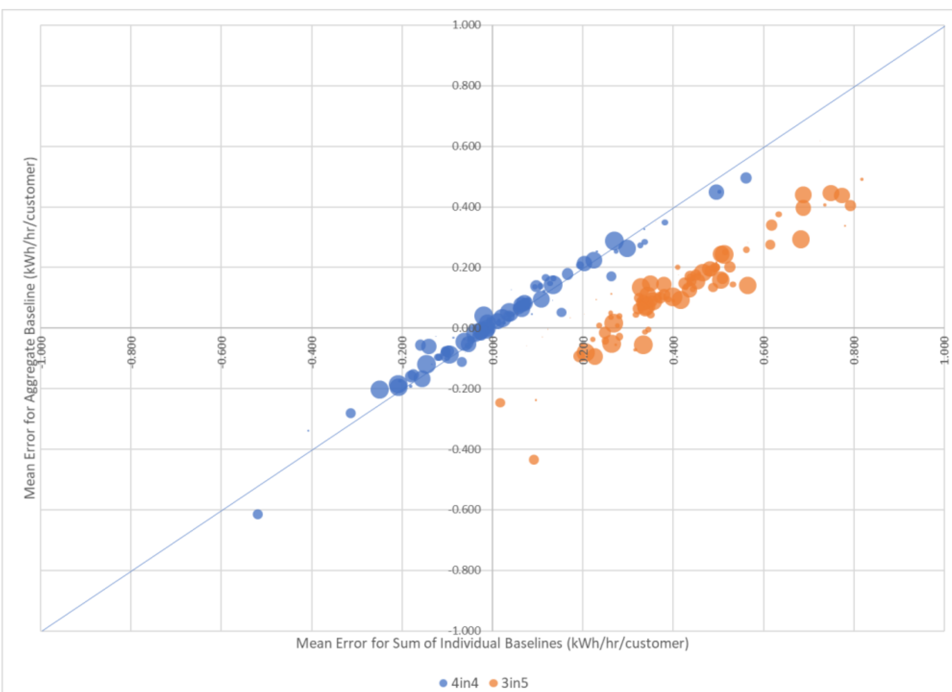


Figure B.14: Summer Weekend/Holiday Mean Error by Test Day and subLAP, Adjusted HE15-17 Event

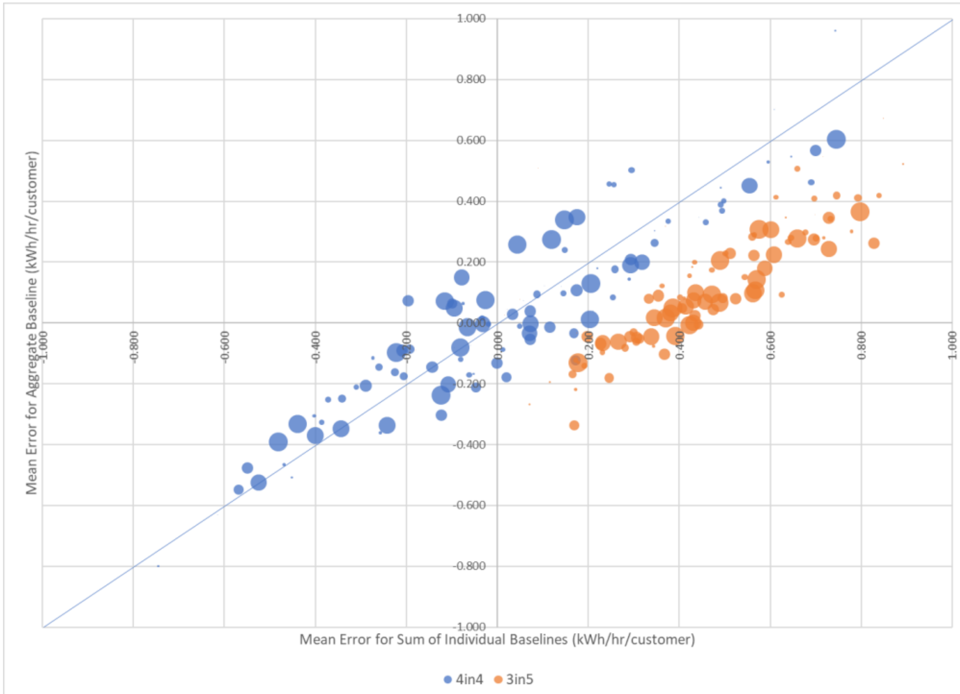


Figure B.15: Winter Weekend/Holiday Mean Error by Test Day and subLAP, Adjusted HE12-14 Event

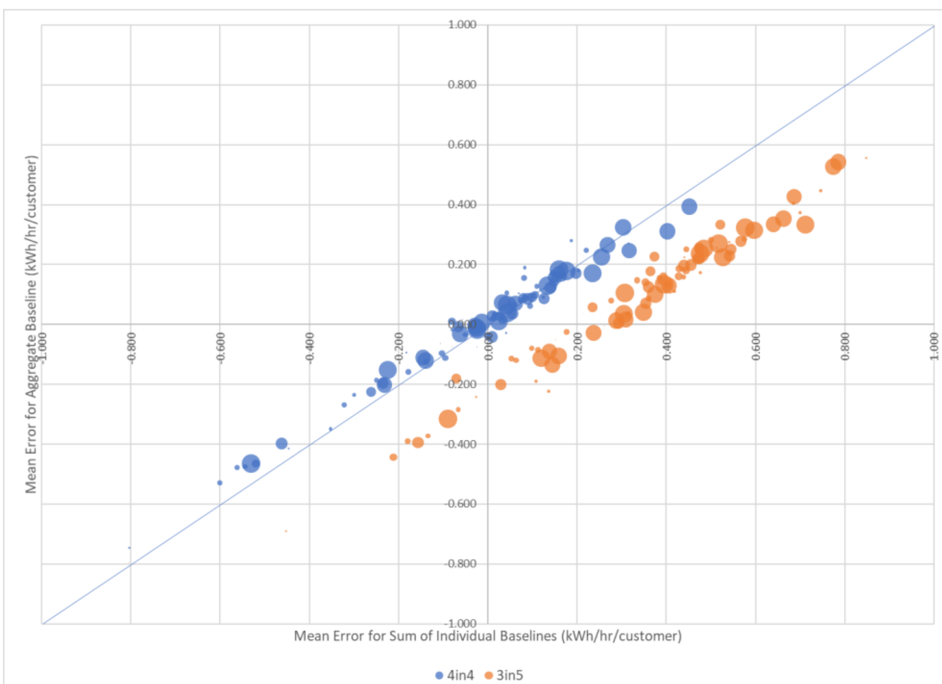
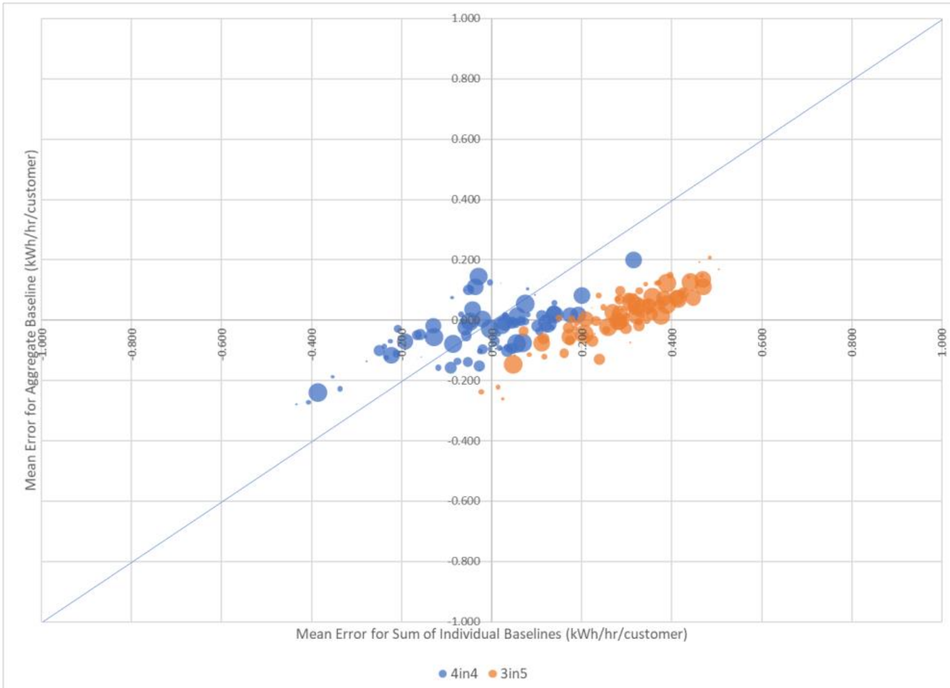


Figure B.16: Winter Weekend/Holiday Mean Error by Test Day and subLAP, Adjusted HE15-17 Event



PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company
Alcantar & Kahl LLP

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
P.C. CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

Downey & Brand
East Bay Community Energy
Ellison Schneider & Harris LLP
Energy Management Service
Engineers and Scientists of California
Evaluation + Strategy for Social Innovation
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
IGS Energy
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas

SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Utilities
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy