Application No.:	A.22-05-___
Exhibit No.:	SCE-03
Witnesses:	P. Gautam N. Gonzalez E. Keating G. Littman C. Rauss C. Smith T. Tayavibul M. Williams

(U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) TESTIMONY IN SUPPORT OF ITS APPLICATION FOR APPROVAL OF 2023–2027 DEMAND RESPONSE PROGRAMS:

EXHIBIT 3 – SCE'S 2023–2027 PROPOSED DEMAND RESPONSE PROGRAMS BY CATEGORY

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 2, 2022

SCE's Testimony in Support of its Application for Approval of 2023 – 2027 Demand Response Programs:

Exhibit 3 – SCE's 2023 – 2027 Proposed Demand Response Programs by Category

<u>Table Of Contents</u>

Table Of Contents (Continued)

Section	Page	Witness

Table Of Contents (Continued)

Section	Page	Witness

Table Of Contents (Continued)

SCE's Testimony in Support of its Application for Approval of 2023 – 2027 Demand Response Programs:

Exhibit 3 – SCE's 2023 – 2027 Proposed Demand Response Programs by Category

Table Of Contents (Continued)

SCE's Testimony in Support of its Application for Approval of 2023 – 2027 Demand Response Programs:

Exhibit 3 – SCE's 2023 – 2027 Proposed Demand Response Programs by Category

Table Of Contents (Continued)

Section	Page	Witness

Table Of Contents (Continued)

Table Of Contents (Continued)

SCE's Testimony in Support of its Application for Approval of 2023 – 2027 Demand Response Programs:

Exhibit 3 – SCE's 2023 – 2027 Proposed Demand Response Programs by Category

<u>Table Of Contents</u> (Continued)

SCE's Testimony in Support of its Application for Approval of 2023 – 2027 Demand Response Programs:

Exhibit 3 – SCE's 2023 – 2027 Proposed Demand Response Programs by Category

Table Of Tables

Table **Page**

Table Of Tables (Continued)

SCE's Testimony in Support of its Application for Approval of 2023 – 2027 Demand Response Programs:

Exhibit 3– SCE's 2023 – 2027 Proposed Demand Response Programs by Category

List Of Figures

I.

INTRODUCTION

This Exhibit describes the demand response (DR) programs Southern California Edison Company (SCE) proposes to include in its DR portfolio for the five-year cycle of 2023–2027. This Exhibit is organized based on the budget categories adopted in Decision (D.) 17-12-003 issued by the California Public Utilities Commission (the CPUC or Commission), namely: 1) Supply-Side DR Programs, 2) Load Modifying DR programs, 3) the Demand Response Auction Mechanism (DRAM),[1] 4) Emerging and Enabling Technology Programs, 5) Pilots, 6) Marketing, Education, and Outreach (ME&O), and 7) Portfolio Support (including Evaluation Measurement and Verification (EM&V) as well as Systems and Notifications).[2] SCE's proposals also reflect the Commission's decisions issued in the Emergency Reliability Rulemaking (R.20-11-003), including D.21-03-056, D.21-06-027, D.21-12-015, and D.21-12-069.

Each program section herein provides a description of the program, any proposed program changes, and the requested program funding for 2024–2027. As discussed in SCE-01, by letter dated September 30, 2021, the Commission's Executive Director extended, from November 1, 2021 to May 2, 2022, the deadline for SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (together, the IOUs) to file their respective 2023–2027 DR portfolio applications.[3] The Executive Director's letter also anticipated that the IOUs would apply for "Bridge Funding" for their respective 2023 DR programs, given that the Commission issued orders with respect to 2023 DR programming in D.21-12-015 as part of the Emergency Reliability Rulemaking. SCE's bridge funding proposal for 2023 is specifically supported by the testimony included in SCE-02 of this application. Given the timing of this application, and as anticipated by the Executive Director's letter, SCE is proposing that the Commission rule on the 2023 bridge funding proposal on an accelerated schedule (to

---

[1] Funding for Rule 24 is also presented in this budget category.

[2] *See* D.17-12-003, Decision Adopting Demand Response Activities and Budgets for 2018 Through 2022, Ordering Paragraph (OP) 54.

[3] *See* Letter from Rachel Peterson, Executive Director, CPUC, to Tara Kaushik, dated September 30, 2021.

allow for program implementation as of January 1, 2023) and subsequently rule on the 2024–2027 portion of this application on a later schedule. That said, many of the program descriptions in this volume of SCE's application apply to the full five-year cycle of 2023–2027, reflecting SCE's vision for future DR programming and lessons learned from the current and prior cycles.

The program descriptions herein assume that (i) the 2023 bridge funding application will be approved in time to meet a January 1, 2023 implementation date for the programs proposed for that year, and (ii) the 2024–2027 portion of this application will be approved in time for the programs proposed to meet a January 1, 2024 implementation date. If the Commission does not approve either of these two components of SCE's application in time to meet those dates (or other dates depending on the program), SCE may need to propose alternative implementation plans and costs. As the program administrator, SCE will continue to evaluate each program in its portfolio. If there are significant changes in enrollment, changes in the rules for DR programs to count towards resource adequacy (RA), impacts from other proceedings, or customer-driven modifications, SCE may seek Commission approval in its current budget cycle for tariff changes via the advice letter process.

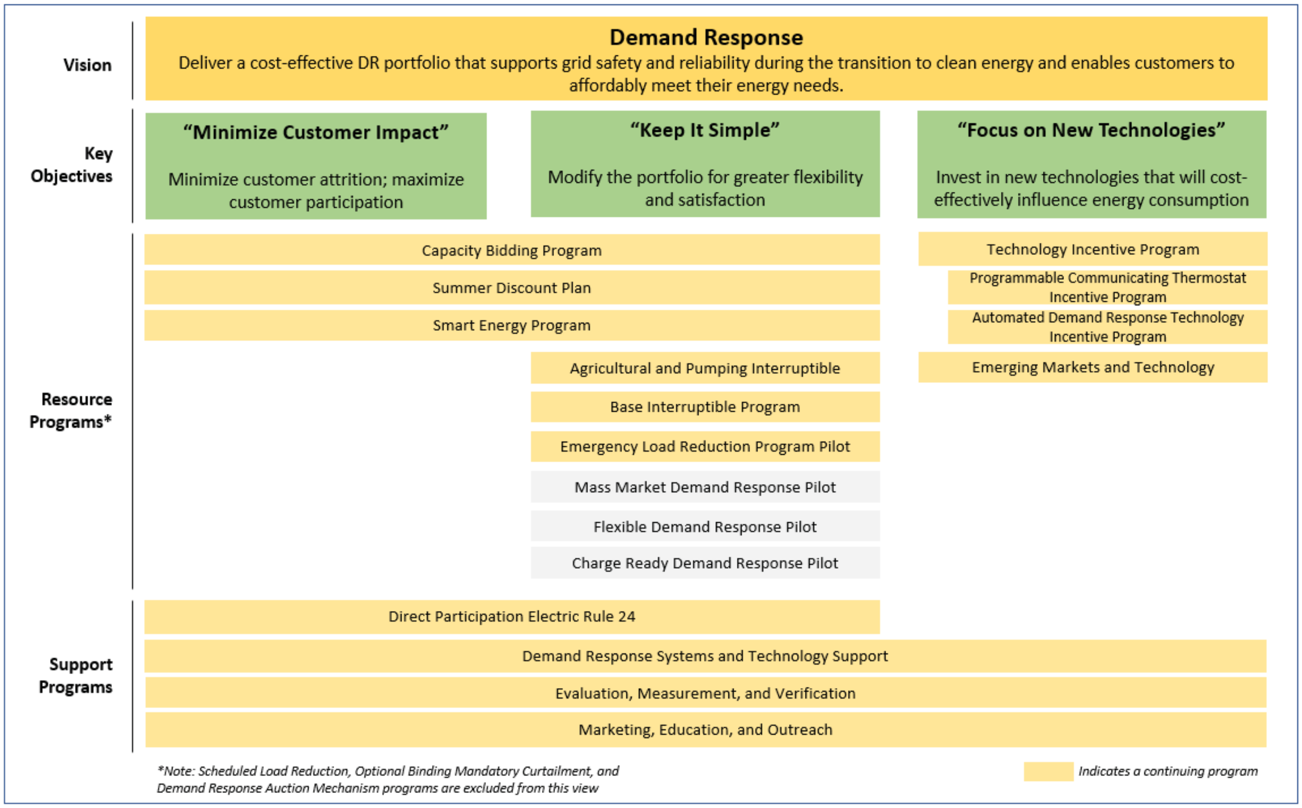
II.

PORTFOLIO OVERVIEW

A. Description of SCE's Demand Response Program Portfolio

As described in SCE-01, SCE's 2023–2027 portfolio is designed to improve and increase participation in existing core DR programs. In addition, SCE will also develop strategies and opportunities for new models of DR that will be flexible and support SCE's and California's clean energy goals. Figure II-1 below illustrates how these programs align with SCE's key objectives. In support of its focus on portfolio diversification, SCE proposes two pilots to inform the development of new programs or the improvement of existing programs, including (i) a Mass Market DR pilot to inform the development of a new technology-agnostic mass market program in SCE's next program cycle, and (ii) a Flexible DR pilot that will identify opportunities among water and wastewater customers to shift demand from periods of under-supply to periods of over-supply. SCE's legacy core programs (indicated in orange in Figure II-1 and described in Chapter III) align closely with SCEs objectives to minimize customer impact and, at the same time, maximize flexibility and satisfaction through program optimization. SCE's proposals to extend the Emergency Load Reduction Program (ELRP) ordered in the Emergency Reliability Rulemaking (R.20-11-003) and to incorporate Charge Ready DR customers into the ELRP are two prominent examples of how SCE intends to achieve these objectives.

Figure II-1
Demand Response Portfolio Strategy



Programs described in this Exhibit are organized by category consistent with Commission direction in D.17-12-003.[4] Programs and activities comprising SCE's DR portfolio for 2023–2027 are described in this Exhibit, with SCE's budget and associated cost recovery proposal for the 2023 bridge year described in SCE-02, and SCE's budget for the remainder of this program cycle (2024–2027) and associated cost recovery proposal described in Exhibit SCE-04.

B. Summary of DR Portfolio Budget Request

1. Portfolio Budget

SCE's proposed budget for the 2024–2027 period is a total of $791 million as shown in Table II-1 below for each category in the DR portfolio. Amounts shown include SCE labor expenses (including administration, and overhead costs), non-labor expenses, and incentives.

[4] D.17-12-003, OP 54.

Table II-1
SCE 2024–2027 Proposed DR Budget
(Nominal $millions)

2024-2027 Portfolio Budget						
Line No.	**Category**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	Category 1: Supply-Side Demand Response Programs	119.086	117.571	119.243	120.244	476.143
2	Category 2: Load Modifying Demand Response Programs	.006	.003	.003	.003	.016
3	Category 3: Demand Response Auction Mechanism (DRAM) and Direct Participation Electric Rule 24	.938	.961	.990	.966	3.855
4	Category 4: Emerging and Enabling Technology programs	11.320	9.121	9.250	9.287	38.978
5	Category 5: Pilots (1 & 2)	79.660	80.190	21.110	20.772	201.732
6	Category 6: Marketing, Education, and Outreach (ME&O)	3.956	4.043	4.716	4.835	17.550
7	Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications)	14.364	12.275	12.684	13.051	52.374
9	**Grand Total**	**229.331**	**224.164**	**167.996**	**169.158**	**790.648**

Notes:
1. The Pilots figures for 2024–2027 include ELRP.
2. Marketing and EM&V costs for pilots are included in Category 5 and not in Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

2. <u>Forecast Methodology</u>

SCE-02 of this application describes the method SCE used to derive its proposed 2023 bridge year funding amount.

The annual budget forecasts for the remainder of the program cycle (2024–2027) are based upon the individual program budgets described below. For each program, the annual proposed budget is based upon a detailed labor estimate based on the number and level of positions required to support each program and administrative overheads that capture the cost of division management, and support from multiple organizations including, for example, Contracts & Solicitation, Strategy, Planning & Operational Performance, Compliance, and Regulatory Affairs. Labor costs were escalated at the appropriate annual rate. The average annual rate of labor escalation for this period is 2.83%.[5]

---

[5] The escalation rates applied from 2024 to 2027 are sourced from the IHS Markit (previously known as Global Insight) Power Planner forecast. This Commission approved escalation source and methodology is consistent with SCEs 2021 GRC's (D.21-08-036 for A.19-08-013, pp. 539-540), and in use for over 20 years.

Similarly, each program's annual budget includes a detailed non-labor budget estimate that reflects the specific activities planned each year including, where applicable, device purchases and installation, systems enhancements and support, ME&O activities, support costs for vendors supporting the program, escalation where appropriate, and other program-specific non-labor expenses. Finally, the program budgets include, where applicable, incentive costs based on the number of forecasted participants and load reduction.

III.

CATEGORY 1: SUPPLY SIDE DEMAND RESPONSE PROGRAMS

Per the budget categories set forth in OP 54 of D.17-12-003, this Section discusses SCE's Budget Category 1, Supply-Side DR programs (*i.e.*, programs that are integrated in the wholesale energy market of the California Independent System Operator (CAISO)). SCE's supply-side DR programs include (i) the Agricultural and Pumping Interruptible Program (AP-I), (ii) the Base Interruptible Program (BIP); (iii) the Capacity Bidding Program (CBP), (iv) the Smart Energy Program (SEP), and (v) the Summer Discount Plan Program (SDP).

A. Agricultural and Pumping Interruptible Program

The AP-I is a supply-side DR program that provides participating customers year-round monthly bill credits in exchange for allowing SCE to temporarily interrupt service to their pumping equipment during reliability events. Eligibility is limited to the pumping equipment of agricultural and water customers.

AP-I participants have provided a consistent amount of load reduction over the lifetime of the program, particularly during the last two years' reliability events. In 2020, SCE had eight events covering August 14 through August 18 and September 5 through September 7. Two of the events were called as CAISO Stage 2 emergencies, five were called as CAISO warnings, and one was called for local reliability. In 2021, SCE had one event on July 9 that was dispatched due to a CAISO Stage 2 emergency. Event hours varied between events. Table III-2 below shows the average load reduction from each event derived from the *ex post* load impact analysis for each program year.

Table III-2
AP-I 2020 and 2021 Load Reductions By Event[6]

Line No.	Event Date	Dispatch Type	Average Load Reduction (MW)
1	08/14/20	Full Dispatch	36.64
2	08/15/20	Full Dispatch	35.12
3	08/16/20	Full Dispatch	32.93
4	08/17/20	Full Dispatch	34.09
5	08/18/20	Full Dispatch	37.96
6	09/05/20	Full Dispatch	29.44
7	09/06/20	Full Dispatch	26.92
8	09/07/20	Partial Dispatch	7.05
9	07/09/21	Full Dispatch	36.12

1. Program Background

Participation in AP-I requires that a load control device (LCD) be installed at the customer's facility. SCE is responsible for the installation and maintenance of the LCD at no charge to the participating customer.[7] When a service interruption is deemed necessary and is allowed under the tariff, SCE sends a signal to the LCD installed on or near the customer's pumping equipment. The signal automatically turns off electric service to the equipment for the duration of the interruption event. Customers are unable to override or opt-out of AP-I events. Electric service to the pumping equipment can only be restored after SCE sends a signal to the LCD. AP-I is available to agricultural and pumping customers with a measured demand of 37 kW or greater, or with at least 50 horsepower of connected load.[8]

---

6 *See* 2020 SCE Agricultural & Pumping Interruptible Demand Response Evaluation, p. 2, and 2021 SCE Agricultural & Pumping Interruptible Demand Response Evaluation, p. 3. These reports are available at http://www.calmac.org.

7 *See* SCE Tariff Schedule AP-I, Agricultural and Pumping – Interruptible, Special Condition 5. Current tariff schedules *are available* at https://www.sce.com/regulatory.

8 *See id.*, Applicability.

Under the current AP-I tariff, the number of interruptions cannot exceed one per day and ten per month.[9] A single interruption cannot exceed six hours, and the total hours of interruption cannot exceed 180 hours per calendar year.[10] Participants can enroll in the program at any time during the year but can only unenroll between November 1 and December 1 each year.[11] AP-I was integrated into the CAISO wholesale energy market as a Reliability Demand Response Resource (RDRR) in June 2015.

In February 2022, there were 925 service accounts enrolled in the AP-I program.[12] September enrollments during the years of the current program cycle are shown in Table III-3 below. AP-I enrollment decreased from 1,124 accounts in September 2018 to 940 accounts in September 2019 due to program attrition and implementation of the Commission's Prohibited Resources policy.[13] Though participation rebounded to some extent in 2020, it dropped again in 2021.

Table III-3
AP-I September Enrollment Statistics[14]

Line No.	Year	Number of Enrolled Service Accounts	Enrollment Status
1	2018	1,124	Closed
2	2019	940	Closed
3	2020	1,017	Lottery
4	2021	968	Open

9 In D.21-12-015 (Attachment 1, p. 6), the Commission approved SCE's proposal that AP-I parameters be modified to match BIP event parameters. The Commission's Energy Division (ED) approved modifications to Schedule AP-I submitted in Advice 4689-E effective January 19, 2022.

10 *See* SCE Tariff Schedule AP-I, Agricultural and Pumping – Interruptible, Special Condition 4.

11 *Id*., Special Condition 7.

12 *See* SCE Interruptible Load Program (ILP) and Demand Response Program (DRP) Report for February 2022 (filed with CPUC February 28, 2022), Table I-1.

13 *See* D.14-12-024, OP 11, and D.16-09-056, OP 3 through 5.

14 The Enrollment Status Column reflects whether the program was closed to enrollment, open to enrollment, or open to enrollment through a lottery mechanism. Regarding the number of enrolled service accounts, *see* SCE ILP and DRP Report for September 2018, Table I-1, SCE ILP and DRP Report for September 2019, Table I-1, SCE ILP and DRP Report for September 2020, Table I-1, and SCE ILP and DRP Report for September 2021, Table I-1. These reports *are available* at https://www.sce.com/regulatory/CPUC-Open-Proceedings included under the proceeding R.13-09-011.

2. **Proposed Program Changes**

In order to maximize participation in AP-I by eligible customers, SCE proposes to modify the program by removing event days (*i.e.*, days on which an AP-I event is triggered, including measurement & evaluation purposes) from the customer's AP-I incentive calculation.[15] This modification addresses an unintended impact to AP-I customer bill credits that could potentially discourage participation.

By way of explanation, during the summer and winter seasons, an AP-I customer's bill credit is calculated based on the customer's monthly average summer on-peak (MASO) or monthly average winter mid-peak demand (MAWM). The monthly averages for the summer and winter season are calculated using the customer's total monthly summer on-peak or winter mid-peak kilowatts per hour (kWh), respectively. Currently, the AP-I incentive rate is multiplied by the average kWh across *all* summer on-peak and winter mid-peak hours in each billing period, although participating customers consume less energy on event days due to their load being interrupted. Thus, if an AP-I event occurs during these periods, the customer's total monthly kWh is lower due to the AP-I interruption, thus reducing the customer's AP-I program incentive bill credit, and thereby potentially discouraging participation. When multiple events occur within a given billing period, including those event days from the calculation of the customer's average kWh usage results in an artificially lower customer average usage, driving down customer incentives and further discouraging participation.

In 2020, AP-I program experienced eight dispatches, compared to one event in 2018 and two events in 2019.[16] Most of these eight events in 2020 occurred during heat emergencies and were consecutive or took place during a single billing period and the highest paying incentive months. The increase in AP-I events in 2020 highlighted the need to modify AP-I to remove event days from the participating customers' AP-I incentive calculations.

---

[15] SCE already removes event days from the calculation of credits for the Critical Peak Pricing program.

[16] The duration of event on September 8, 2019, was 10 minutes.

This proposed modification will require a change to SCE's billing system that is expected to cost approximately $1.5 million, which will be split 50/50 with BIP, which SCE is proposing the same type of modification and covered in the next section below. Accordingly, $750,000 is accounted for in the proposed AP-I program budget for 2024 under the non-labor category.

3. <u>Program Budget</u>

Table III-4 summarizes SCE's proposed AP-I program budget and incentives for the 2024–2027 period.[17]

Table III-4
AP-I Program
2024–2027 Proposed Budgets
(Nominal $ millions)

Agricultural & Pumping Interruptible (API)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.241	.254	.305	.314	1.114
2	Non-Labor Total	1.081	.334	.339	.345	2.098
3	**Program Total**	**1.322**	**.588**	**.644**	**.659**	**3.213**
4	Incentives	4.585	4.611	4.651	4.691	18.538
5	Marketing	.094	.079	.079	.079	.332
6	EM&V	.059	.060	.061	.062	.241
7	**Grand Total**	**6.060**	**5.338**	**5.435**	**5.491**	**22.324**

Note: Marketing and EM&V costs are presented here to provide a complete view of the AP-I program but are included in the proposed budgets for Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

<u>**AP-I Labor Budget**</u>: The proposed AP-I budget for labor will fund approximately 1.8 full-time employees (FTEs), including administration and overhead expenses, to manage the program. In addition, the proposed AP-I labor budget includes an additional approximately 0.1 FTEs in 2025 and 0.2 FTEs in 2026-2027 for Business Customer Division (BCD) account management support. BCD account managers help promote the AP-I program by educating eligible customers on the program.

[17] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for AP-I alone is included in this application.

While these BCD activities traditionally have been funded through SCE's General Rate Case (GRC), SCE submits that with the growing importance of DR, and commensurate increase in support required of BCD, these activities should be funded in this proceeding and not in the GRC, beginning with SCE's next GRC funding cycle in 2025.

AP-I Non- Labor Budget: The proposed AP-I non-labor budget includes costs for LCD devices and installation as well as staff training and administrative expenses. In addition, the non-labor budget includes the 2024 billing system modification described above.

AP-I Marketing Budget: The AP-I marketing budget, included in the Marketing, Education and Outreach budget (presented in Chapter VIII), includes funding for an annual marketing campaign, updates to customer-facing materials, such as fact sheets, frequently asked questions or FAQs, updates to webpages on SCE.com, annual summer readiness campaigns, annual window notifications, and other customer outreach and education activities.

AP-I Incentives Budget: Testimony pertaining to AP-I incentives is included in SCE-04, Chapter II.

4. Expected Load Impact

Testimony pertaining to AP-I load impact is included in SCE-04, Chapter III.

B. Base Interruptible Program

BIP is a supply-side DR program that provides bill credits to large commercial and industrial customers in exchange for the customer's agreement to reduce demand upon notice from SCE.[18] This program is also open to third-party DR aggregators.

BIP is the largest DR program (in MW) in SCE's portfolio and has consistently performed well during program events, particularly in the last two years when reliability events have occurred. In 2020, SCE had eight events covering August 14 through August 18 and September 5 through September 7. Two of the events were called as CAISO Stage 2 emergencies, five were called as CAISO warnings, and

[18] *See* SCE Tariff Schedule BIP, Time-of-Use-General Service Base Interruptible Program. Current tariff schedules *are available* at https://www.sce.com/regulatory.

one was called for local reliability. In 2021, SCE had one event on July 9 that was dispatched due to a CAISO Stage 2 emergency. Event hours varied between events. Table III-5 below shows the average load reduction from each event derived from the ex-post load impact analysis for each program year. Participants have maintained a consistent Firm Service Level (FSL) achievement rate at or above 90% through all of the recent critical reliability events, where the full BIP portfolio was dispatched. For purposes of understanding the table below, program level FSL achievement rate is defined as the aggregated load impact divided by the difference between the aggregated reference load and the aggregated FSL.

Table III-5
BIP 2020 and 2021 Load Reductions By Event[19]

Line No.	Event Date	Dispatch Type	Average Load Reduction (MW)	FSL Achievement Rate
1	08/14/20	Full Dispatch	484	90%
2	08/15/20	Full Dispatch	451	91%
3	08/16/20	Full Dispatch	427	93%
4	08/17/20	Full Dispatch	514	91%
5	08/18/20	Full Dispatch	520	90%
6	09/05/20	Full Dispatch	411	93%
7	09/06/20	Full Dispatch	418	91%
8	09/07/20	Partial Dispatch	8	49%
9	07/09/21	Full Dispatch	409	94%

1. Program Background

BIP participants, either directly enrolled customers or DR aggregators (BIP-Agg), choose the reduction that meets their minimum operational requirements, also known as the FSL, at the time of

[19] *See* 2020 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex -post and Es-Ante Report, p. 5 and 2021 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-Ante Report, p. 5. These reports *are available* at http://www.calmac.org.

enrollment. DR Aggregators can enroll multiple accounts in their BIP-Agg portfolio as long as the group can meet the minimum requirements of the program. SCE assesses excess energy charges for energy usage above the contracted FSL during periods of interruption. Participants have the option to enroll in either a 15-minute (BIP-15) or 30-minute (BIP-30) response time.[20] Participants can enroll in the program at any time during the year but can only unenroll or change their FSL between November 1 and December 1 each year.[21] Under the current BIP tariff, the number of interruptions cannot exceed one per day, and ten per calendar month.[22] The duration of each interruption cannot exceed six hours, and interruptions are capped at a total of 180 hours per calendar year.[23]

In February 2022, there were 42 service accounts enrolled in BIP-15 and 291 accounts enrolled in BIP-30.[24] September enrollments, during the current funding cycle, are shown in Table III-6. In September 2019, BIP-30 enrollment decreased to 432 service accounts (from 497 service accounts in September 2018) due to program attrition and implementation of the Commission's Prohibited Resources policy.[25] Since 2020, SCE's BIP-30 enrollment has continued to decline due to the significant number of events that occurred in 2020. As shown in Table III-6, BIP-15 enrollment has remained relatively steady.

---

[20] *Id*., Special Condition 2.

[21] *Id*., Special Condition 14.

[22] *Id*., Special Condition 15.

[23] *Id*.

[24] *See* SCE Interruptible Load Program (ILP) and Demand Response Program (DRP) Report for February 2022, Table I-1.

[25] *See* D.16-09-056, OP 3 and 4.

Table III-6
BIP-15 and BIP-30 September Enrollment History[26]

Line No.	Year	Number of Enrolled Service Accounts		Enrollment Status
		BIP-15	BIP- 30	
1	2018	49	497	Closed
2	2019	51	432	Closed
3	2020	52	417	Lottery
4	2021	42	305	Open

2. Proposed Program Changes

Similar to SCE's proposal for the AP-I program, SCE proposes to modify the BIP incentive calculation to remove event days (including measurement & evaluation purposes) from the incentive calculation in order to maintain and grow the program.[27] This proposed incentive modification is a result of the increase in event dispatches that occurred in 2020. The current BIP incentive rate is multiplied by the average kWh across all summer on-peak, mid-peak, and winter mid-peak hours in each billing period. When multiple events occur, especially within the same billing period, including these BIP event days in the calculation of average kWh can significantly decrease the participants' incentives and thereby discourage participation. The increase in BIP events in 2020 highlighted this issue, which affects all customers and aggregators participating in BIP. As discussed above, this proposed modification will require a change to SCE's billing system that is expected to cost approximately $1.5 million and that will be split 50/50 with the AP-I program. Therefore, $750,000 is accounted for in the BIP program budget under non-labor for this modification.

---

[26] *See* SCE ILP and DRP Report for September 2018, Table I-1, SCE ILP and DRP Report for September 2019, Table I-1, SCE ILP and DRP Report for September 2020, Table I-1, and SCE ILP and DRP Report for September 2021, Table I-1. These reports are available at https://www.sce.com/regulatory/CPUC-Open-Proceedings included under the proceeding R.13-09-011.

[27] As noted, SCE already removes event days from the calculation of the Critical Peak Pricing incentives. In addition, PG&E also excludes event days from their BIP incentive calculation.

As ordered by Commission Resolution E-5112 (Resolution on SCE's Mid-Cycle Review Advice Letter), SCE has performed an analysis regarding the potential removal of both BIP and Public Safety Power Shutoffs (PSPS) events from the calculation of BIP baselines.[28] That analysis showed that in 2020, 14 service accounts enrolled in BIP were affected by PSPS events, all but one of which took place in the winter months. SCE estimates that for the affected service accounts, BIP incentives were reduced by approximately $30,000 in total, due to the PSPS events in 2020. Based on this analysis, SCE does not recommend excluding PSPS events from BIP incentive calculations due to the relative costs of such benefit. The time and costs needed to track PSPS event days, which tend to occur in the winter months when BIP incentives are lower, for each service account are greater than the potential incentives.

Additionally, to meet this requirement, SCE analyzed the impacts of excluding BIP events currently being used to calculate incentives and, based on the results, SCE requests to adjust the incentive calculation to exclude BIP event days. SCE's analysis shows that in 2021, 82% of BIP customers would benefit from excluding the July 9 event usage data during their on-peak average usage. If the July 9 event had been excluded, customers would have saved an estimate of $281,926 on that single month's bill. This amount can increase when more events are dispatched. The analysis also showed that 17% of BIP customers had no financial impact by excluding the event date usage. Finally, there was one percent of customers who would not benefit from excluding the event day and would have incurred just under $10,000 on that monthly bill.

3. **Program Budget**

Table III-7 shows SCE's proposed BIP program budget and incentives for the 2024–2027 period.[29]

---

[28] *See* Resolution E-5112, p. 13.

[29] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for BIP alone is included in this application.

Table III-7
BIP Program
2024–2027 Proposed Budgets
(Nominal $ millions)

Base Interruptible Program (BIP)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.921	1.165	1.616	1.669	5.371
2	Non-Labor Total	.755	.010	.013	.014	.792
3	**Program Total**	**1.675**	**1.176**	**1.629**	**1.683**	**6.163**
4	Incentives	66.650	67.514	68.237	68.908	271.310
5	Marketing	.094	.079	.079	.079	.332
6	EM&V	.156	.158	.160	.162	.636
7	**Grand Total**	**68.576**	**68.927**	**70.105**	**70.833**	**278.441**

Note: Marketing and EM&V costs are presented here to provide a complete view of the BIP program but are included in the proposed budgets for Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

BIP Labor Budget: The proposed BIP budget for SCE labor funds 1.4 full-time FTEs, including administration and overhead expenses. In addition, beginning in 2025, the BIP labor budget also includes approximately 1.4 FTEs (in 2025) to 2.0 FTEs (in 2026-2027) for BCD account management support. BCD account managers help promote the BIP program by educating eligible customers on the program. In addition, BCD also conducts rate analyses to inform customers of the benefits of participating in DR programs. While these BCD activities have traditionally been funded in SCE's GRC, with the growing importance of DR, and commensurate increase in support required of BCD, it is appropriate that they be funded in this proceeding and not in the GRC, beginning with SCE's next GRC funding cycle (2025).

BIP Non-Labor Budget: The non-labor budget includes the billing system modification described above in 2024 as well as staff training and administrative expenses.

BIP Marketing Budget: The BIP marketing budget, included in the Marketing, Education and Outreach budget (presented in Chapter VIII), includes funding to: (1) conduct outreach to obtain new customer enrollments, as program enrollment has been declining since 2018, (2) update program collateral material, (3) conduct summer readiness prior to each summer, and (4) annual window notifications. SCE shares the Commission's appetite for increasing or maintaining enrollment in BIP based upon the steps the Commission took in the Emergency Reliability Order Instituting Rulemaking (OIR) to increase enrollment and MW by adopting modifications to BIP, such as increasing the Reliability Cap to three percent, approving a 20% increase in BIP incentive rates, and allowing year-round BIP enrollment rather than a once-a-year lottery process.

BIP Incentives Budget: Testimony pertaining to BIP incentives is included in SCE-04, Chapter II.

4. Expected Load Impact of BIP Program During 2023–2027 Program Cycle

Testimony pertaining to BIP load impact is included in SCE-04, Chapter III.

C. Capacity Bidding Program

The CBP is a supply-side DR program that offers participants[30] monthly capacity payments to reduce load to a nominated amount.

1. Program Background

CBP was approved in 2006 as the successor to the California Power Authority Demand Reserves Partnership program that terminated May 2007. SCE's CBP is currently a year-round program in which participants submit monthly nominations or bids (*i.e.*, service accounts and kilowatt (kW) demand).[31] Bids are for the entire month and cannot be revoked or withdrawn during the operating month.

CBP is a relatively small DR program, with annual peak capacity nominations at approximately 15 MW during the 2018–2022 timeframe. Following the end of the Aggregator Managed Portfolio (AMP) contracts in 2017, SCE expected significant growth for CBP in the 2018-2022 cycle.

---

[30] Participants can include demand response aggregators or customers who choose to self-aggregate multiple accounts.

[31] *See* SCE Tariff Schedule CBP, Capacity Bidding Program, *available at* https://www.sce.com/regulatory/tariff-books/rates-pricing-choices.

However, due to the Demand Response Auction Mechanism (DRAM) pilot, many aggregators who might otherwise have enrolled and participated in CBP, instead moved to DRAM.

CBP provides participants monthly capacity payments based on their nominations and load reductions, if applicable, for each participating month. When CBP events are dispatched, program participants may receive additional energy payments or may be assessed energy shortfall charges based on their actual aggregate kilowatt hour (kWh) reduction (i.e., performance) during CBP events. Participants can adjust their nomination (kW) amount prior to each month and must choose to participate in either the day-ahead (DA) or day-of (DO) CBP product. Nominated accounts cannot participate in both DA and DO products for the same month.

Currently, CBP is open to all non-residential and residential customers (*i.e.*, bundled service, Community Choice Aggregation (CCA), and Direct Access customers). In its 2018-2022 Mid-Cycle Status Report Advice Letter, SCE proposed to: (1) update the CBP Day-Ahead Market price triggers to $75/MWh for all months; and (2) add a residential option to SCE's existing CBP tariff in lieu of a pilot.[32] In Resolution E-5112, the Commission rejected SCE's CBP price trigger proposal, instead adopting Day-Ahead Market price triggers of $80/MWh for May through October and $75/MWh for November through April.[33] Subsequent to SCE's submission of its 2018-2022 Mid-Cycle Status Report Advice Letter, but prior to the issuance of Resolution E-5112, the Commission approved SCE's proposal to add a residential option to its CBP.[34] Table III-8 summarizes CBP enrollment since 2018.

---

32 SCE Advice 4182-E, pp. B-16–18, E-7–9.

33 Resolution E-5112, p. 12.

34 D.21-03-056, p. 34.

Table III-8
CBP September Enrollment History[35]

Line No.	Year	Number of Enrolled Service Accounts	
		CBP DO	CBP DA
1	2018	246	30
2	2019	204	336
3	2020	307	413
4	2021	270	373

2. Proposed Program Changes

SCE proposes the following changes to the CBP in 2024.

a) Modification of CBP Operating Timeframes and Event Parameters

SCE proposes to change the hours in which CBP events may be triggered from 3-9 p.m. to 4-9 p.m. to better align with CAISO's current resource adequacy window (Availability Assessment Hours) and the availability parameters for the DR maximum cumulative capacity (MCC) bucket.[36] SCE also proposes to increase the maximum number of events allowed per month from five to six, with the same number of available hours (30 hours per month) thereby increasing the monthly availability with a maximum event duration of five hours instead of six. This change aligns the availability to the CAISO Availability Assessment Hours. Finally, SCE proposes removing the off-peak months (November through April) and making CBP a summer only program (May through October) as participation and performance in off-peak months has been low throughout the history of the program.

---

[35] *See* SCE Interruptible Load Program (ILP) and Demand Response Program (DRP) Reports for December 2018, December 2019, December 2020, and December 2021, Table I-1 in each. Reports are *available at* https://www.sce.com/regulatory/CPUC-Open-Proceedings included under the proceeding R.13-09-011.

[36] D.20-06-031, OP 19, revised the MCC buckets for demand response.

b) Modifications to the CBP Aggregator Agreements, Capacity Obligations, and Enrollment and Nomination Timelines

SCE proposes to replace the existing monthly capacity nomination schedule with an annual May-October capacity contract executed no later than January 31st of each year. Under the existing monthly schedule, aggregators may nominate a capacity obligation as few as five days before the start of an operating month, with no obligation to participate in any given month. SCE proposes to replace this monthly capacity schedule with one in which aggregators would declare the capacity they would deliver for each of the six operating months in that program year, with collateral requirements based on the maximum capacity nominated during that period at the current rate of five dollars per kilowatt ($5/kW). To accommodate this change, SCE will need to modify Form 14-777, the Capacity Bidding Program Aggregator Agreement, to include a Capacity Nomination template to be signed annually.

The current monthly customer site nomination schedule, with nominations due only five (5) days before the start of the operating month, does not provide sufficient time for SCE to: (1) register new DR resources with the CAISO, (2) update existing CAISO resources with new customer sites, and 3) place these resources on a Supply Plan once this becomes a requirement.[37] Therefore, to address these new requirements, the proposed new process for aggregators will include: a) submitting Annual Capacity Nomination for the Operating Months (May through October) 90 days prior to the first Operating Month; b) posting collateral 80 days prior to the first Operating Month; and c) submitting Add forms no later than 75 days prior to the first day of an Operating Month; and d) nomination of participating service accounts no later than 65 days prior to the first day of an Operating Month.

c) Elimination of the Day-Of CBP Product

Prior to integration of its CBP into the CAISO markets in 2015, SCE dispatched the Day-Ahead product based on actual or forecasted prices in the CAISO Day-Ahead Market, and the Day-Of product based on forecasted prices in the CAISO Real-Time Market. However, since

[37] D.21-06-029, OP 10.

integration in 2015, SCE has dispatched both the Day-Ahead and Day-Of products based on actual prices in the Day-Ahead Market only because the operating parameters of the Day-Of product do not allow it to be dispatched in the Real-Time Market. Because of this, CBP Day-Of only earns System Resource Adequacy (RA) credit, and not Local or Flexible RA credit. SCE has on multiple occasions considered necessary changes to the Day-Of product that, in combination with system changes, would allow dispatch from CAISO's Hour-Ahead Scheduling Process, but upon evaluation decided that the expenditures needed to implement these changes would be greater than the benefit or value to ratepayers, given the small amount of MW of the program. SCE therefore proposes elimination of the Day-Of product.

d) Proposed Changes to Energy Payments

The current retail energy payment structure long predates the integration of CBP into the CAISO markets in 2015. While SCE receives payment for CBP resources at the settled Locational Marginal Prices (LMPs) in the Day-Ahead Market for the full amount of energy awarded and pays shortfall penalties (if any) at the settled LMPs in the Real-Time Market, Aggregators receive payment at a fixed energy rate ($80/MWh in May-October, $75/MWh in November-April) only for energy delivered, while paying shortfall penalties at the settled Real-Time Market LMP.

In order to better align CBP energy payments with a CAISO integrated product, SCE proposes to issue energy payments to aggregators at the settled LMP for a resource's sub-Load Aggregation Point (Sub-LAP), rather than the trigger price to determine event dispatch, and for the awarded energy quantity rather than the quantity dispatched. Shortfall penalties shall remain the same as at present, with the exception that the penalty rate for the Day-Ahead Option shall be the average settled Locational Marginal Price in the Real-Time Market at the SCE Default Load Aggregation Point (DLAP_SCE) for the hour in question, and not the settled Day-Ahead Market LMP at DLAP_SCE. SCE also proposes changing the maximum kWh for retail energy payments from 150% of delivered kWh to 100% of awarded kWh to align with CAISO rules.

e) Proposed Changes to Capacity Payments

As stated in section 2(a) above, SCE proposes eliminating availability of the program in November through April. When SCE made CBP a year-round program in 2013, for each program option, it reallocated a portion of the existing May-October capacity rates to November-April so that overall annual capacity rates (in $/kW-year) would remain the same. SCE therefore proposes reallocating the existing November-April capacity rates back to May-October rates, thereby increasing rates in the summer months and making participation in the program more attractive to aggregators.[38]

Table III-9
CBP Program, Day Ahead Option
Current and Proposed Capacity Rates, 2024-2027
($/kW-month)

Line No.	Capacity Rates ($/kw-Month)						
1	Month	**January**	**February**	**March**	**April**	**May**	**June**
2	Current	$ 1.98	$ 1.66	$ 1.66	$ 1.66	$ 3.96	$ 5.94
3	Proposed	-	-	-	-	$ 4.59	$ 6.89
4	Month	**July**	**August**	**September**	**October**	**November**	**December**
5	Current	$ 20.14	$ 23.44	$ 12.54	$ 2.32	$ 1.98	$ 1.98
6	Proposed	$ 23.36	$ 27.19	$ 14.54	$ 2.69	-	-

3. Program Budget

Table III-10 shows SCE's proposed program budget and incentives for the 2024–2027 period.[39]

---

[38] The proposed capacity rates for the months of May through October equal the month's current capacity rate multiplied by the ratio of the sum of the current November-April capacity rates ($10.92) to the sum of the current May-October capacity rates ($68.34) plus the month's current capacity rate. For example, the proposed capacity rate for September equals $12.54 x ($10.92 / $68.34) plus $12.54, or $14.54.

[39] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for CBP alone is included in this application.

Table III-10
CBP Program
2024–2027 Proposed Budgets
(Nominal $ millions)

Capacity Bidding Program (CBP)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.164	.170	.185	.190	.709
2	Non-Labor Total	.019	.020	.020	.020	.079
3	**Program Total**	**.184**	**.189**	**.205**	**.210**	**.789**
4	Incentives	1.867	1.867	1.867	1.867	7.467
5	Marketing	.000	.000	.000	.000	.000
6	EM&V	.086	.086	.087	.089	.348
7	**Grand Total**	**2.136**	**2.142**	**2.159**	**2.166**	**8.603**

Note: Marketing and EM&V costs are presented here to provide a complete view of the CBP program but are included in the proposed budgets for Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

CBP Labor Budget: The proposed CBP budget for SCE labor funds approximately 1.3 FTEs, including administration and overhead expenses.

CBP Non-Labor Budget: The non-labor budget includes forecasted payments to third-party aggregators updates to SCE's CBP and third-party webpage, program fact sheets, and FAQ sheets.

CBP Marketing Budget: Third-party Demand Response aggregators are responsible for the marketing and sales of their programs to customers. Therefore, SCE does not forecast any marketing expenses related to the CBP program for the budget cycle beyond the SCE.com webpage updates noted in the non-labor budget.

CBP Incentives Budget: The CBP offers two types of incentive payments: Energy Payments and Capacity Payments. Energy Payments are only earned when events occur and are based on actual energy-use reduction. Capacity Payments are based on the load reduction amount nominated for the month and vary depending on the month's capacity price and whether require day-ahead or day-of notification. The closer the average actual energy load reduction during event hours is to the bid/nomination amount, the higher the Capacity Payment. If no event is called in a month then the full Capacity Payment is paid for that month.

4. Mid-Cycle Report Compliance Requirement

In D.19-07-009, the Commission directed IOUs to "include a proposal in their 2020 demand response portfolio mid-cycle advice letter filing, for implementing the 5-in-10 baseline for residential customers, with a 40% cap. The proposal shall include estimated costs, statistics about the accuracy of the aggregate and individual baseline, an assessment of the benefits for using the baseline, and a timeline."[40] In Resolution E-5112, the Commission approved SCE's mid-cycle advice filing (with some modifications) and reiterated the requirement above and directed that it be included here.[41] At this time, SCE has not received any CBP residential applications. Therefore, SCE is unable to provide statistics about the accuracy of the aggregated and individual baselines for CBP Residential. In lieu of this report, SCE submits a report in Appendix A on the statistical accuracy of the aggregated and individual baselines using SCE's residential participants in the SEP.[42]

Resolution E-5112 also directs SCE to provide, in this application, "a summary of the rollout of the program." On May 27, 2021, prior to the issuance of Resolution E-5112, SCE submitted Advice 4507-E, which implemented residential participation in CBP (including the 5-in-10 baseline), to implement the changes to its DR programs directed by the Commission in D.21-03-056. Following approval of Advice 4507-E by the CPUC on June 25, 2021, SCE notified all CBP aggregators by email of the changes to the program, including the launch of the residential option. SCE also updated its DR Programs website with the new tariff incorporating the changes from Advice 4507-E, including residential CBP.

5. Expected Load Impact of CBP Program During 2023–2027 Program Cycle

Testimony pertaining to CBP load impact is included in SCE-04, Chapter III.

---

[40] D.19-07-009, OP 18.

[41] Resolution E-5112, OP 1.

[42] Demand Side Analytics, Residential CBP Baseline Accuracy Assessment, (March, 2022).

D. **Smart Energy Program**[43]

The SEP is a direct load control (DLC) program of enabling technologies that reduce eligible residential customers' load during SEP triggered events.[44] Presently, enabling technologies are limited to specified Wi-Fi enabled smart thermostats, but SCE anticipates expanding the program to other enabling technologies in the future. SEP participants also have the flexibility to opt out of events at any time by resetting their thermostat's temperature. The program is available for dispatch year-round, but enrolled participants only receive program incentives (bill credits) from June through September, up to $40 annually.[45] Load reduction during SEP events during the current program cycle has been in the range of 21 to 35 MW on average.

1. **Program Background**

Following the issuance of D.16-06-029 and D.17-12-003, SCE implemented various design changes to SEP to make it a faster, flexible, and locational DR resource that can be integrated into the California Independent System Operator (CAISO) wholesale energy market. These changes included:[46]

- Renaming Save Power Day to the Smart Energy Program;
- Eliminating customers' ability to dual-participate in SEP and the Summer Discount Plan (SDP) program;
- Introducing a fixed annual payment of approximately $40 per year per service account;
- Eliminating the energy incentive payment;

---

[43] SEP was formerly known as the Peak Time Rebate Program (PTR) and the Save Power Days (SPD) program.

[44] In D.21-03-056, the Commission approved SCE's proposal to open SEP to unbundled customers (Attachment 1, p. 17). SCE expects that SEP will be open to bundled and unbundled customers by the end of the third quarter of 2022.

[45] See SCE Tariff Schedule SEP, Smart Energy Program, Capacity Payments. Current tariff schedules *are available* at https://www.sce.com/regulatory.

[46] *See* AL 3731-E and AL 3944-E for full list of SEP program design changes.

- Modifying dispatch availability to any time of the year for reliability purposes, including weekdays, weekends, and holidays, but maintaining a maximum of four hours per day and no more than 180 hours per calendar year;
- Setting specific event trigger limitations on economic events; and
- Dispatching customers by Load Control Groups that align with Sub-LAP grouping.

In 2021, the Commission issued D.21-03-056 and D.21-12-015, which authorized the following SEP changes:

- Modify the medical baseline exclusion to only restrict those with an allocation for air conditioning;
- Eliminate the restriction preventing participation by customers of Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs) by converting SEP from generation to distribution funding by 2022;
- Reinstate pre-cooling strategies where applicable;
- Increase the ME&O budget to reach a broader audience; and
- Allow SEP to be called for up to 6 hours for emergency purposes.

Issues impacting SEP customer acquisition and attrition are discussed below.

a) Customer Acquisition

As described in SCE's mid-cycle filing,[47] enrollments for program year 2018 and 2019 exceeded projections made in SCE's application for the current funding cycle.[48] Specifically, SCE projected acquiring 10,000 new enrollments annually during the 2018–2022 cycle.[49] Between program years 2018 and 2019, SCE acquired approximately 38,700 net new SEP enrollments. Program year 2020 was an anomaly year for SEP because SCE implemented a temporary enrollment freeze for one of the leading qualifying thermostat brands due to negotiations over contract requirements that took over one year to conclude. Additionally, in 2020, SCE reduced its marketing plans for SEP due to the

[47] Advice Letter 4182-E, p. B-22.

[48] A.17-01-018, consolidated with A.17-01-012 per ALJ ruling of February 16, 2017.

[49] A.17-01-012, SCE-03, p. 18, Table IV-5.

COVID-19 pandemic, relying on its approved third-party vendors and their thermostat partners to only target existing smart thermostat users. SCE communications during the spring and summer of 2020 were focused on safety and affordability and refrained from suggesting that non-smart thermostat users go out and buy a qualifying thermostat to enroll in the program. As a result of these issues, SEP acquired roughly 7,100 net new enrollments in 2020. In spring of 2021, SCE underwent its Customer Service Re-Platform project to replace its enterprise Customer Service System with SAP customer relationship and billing systems. This had a moderate effect on marketing activities during the implementation period; however, SCE did deploy late spring, summer, and holiday acquisition campaigns. These marketing activities along with the acquisition efforts performed by SEP thermostat providers led to approximately 17,500 net new enrollments in 2021.

b) Customer Attrition

During the 2018–2021 period, three factors contributed to significant SEP participant attrition. First, in 2018, to prepare SEP for CAISO market integration, SCE disenrolled approximately 6,400 customers from SEP because they were also participating in SDP.[50] All customers that were dual participating in SDP and SEP were asked, via email outreach, to select the program of their choice. Non-responders were dropped from SEP and kept on SDP because SDP provides a higher kW per customer load capacity and higher customer incentive payout.

Second, due to the expansion of CCAs in SCE's service territory and a tariff limitation restricting SEP to bundled service customers only, over 14,000 customers were disenrolled from SEP due to CCA migrations. D.21-03-056 adopted SCE's proposal to offer SEP to bundled and unbundled customers by 2022.

Third, in mid-2020, SCE launched a vendor consolidation effort to migrate 38,000 participants managed by their original thermostat provider to an SCE appointed vendor. The transition required each participant to accept new terms and conditions that would authorize the SCE appointed

[50] Consistent with the program changes approved in D.16-06-029, SCE filed Advice Letter 3731-E on January 22, 2018 to eliminate customers' ability to dual-participate in PTR-ET-DLC and SDP. Advice Letter 3731-E was approved on July 11, 2018.

vendor to manage their participation on the program. Customers were prompted to respond by the original thermostat provider with in-app notifications and email notices over a four-month period. Approximately 6,500 customers either rejected the new terms and conditions or did not respond within the deadline and, as a result, were disenrolled in March 2021. Currently, SCE contracts with two thermostat service providers who, collectively, manage eight different thermostat brands.

2. Proposed Program Changes

SCE proposes the following program changes to improve the effectiveness of the program and increase new customer acquisition and MW performance during the 2024–2027 period:

a) Increase program marketing

SCE's ME&O allocation for SEP during the 2018–2022 period averaged approximately $530,000 per year. This marketing budget limited SCE to promote SEP via digital marketing channels (e.g., email, social media and web banner ads). Although digital advertising is a valuable marketing tactic, SCE's reach of eligible customers through these channels is limited due to SCE not having email addresses for all customers. The approach to digital marketing has also resulted in SCE continually marketing to the same groups of customers while other potential enrollees do not receive communications and lack awareness about SEP. The cost for other acquisition tactics, such as direct mail letters, has been too costly for the current budget. SCE proposes a larger SEP marketing budget to reach a broader audience through additional marketing channels and strategic marketing tactics.

b) Allow program to be dispatched at lower levels of granularity

D.17-12-003 authorized SCE to dispatch SEP by Sub-LAP. As the program continues to grow, dispatching at lower levels of granularity will enable SCE to provide local load relief to affected areas while mitigating the impact to customers in surrounding areas. Therefore, SCE requests the ability to dispatch SEP at lower levels of granularity than the Sub-LAP level.

c) Remove SEP from the CAISO Day-Ahead Energy Market

SEP was integrated into the CAISO wholesale energy market in April 2019 as Reliability Demand Response Resources (RDRRs). Similar to the Summer Discount Plan, SEP also participates in the day-ahead energy market as allowed by the CAISO's tariff. SCE proposes to modify SEP integration in the CAISO wholesale energy market by removing the day-ahead economic component, while remaining integrated as an RDRR resource in the real-time market. Per the CAISO tariff, RDRRs participating as economic resources in the day-ahead market are required to register as continuous and must have the flexibility to operate anywhere between its Pmin and Pmax MW capability, based on the awarded bid quantity.[51] For example, a resource that can deliver 50 MW in its Pmax, may only be awarded for 20 MW in the day-ahead market as a continuous resource. A resource that delivers above the awarded amount may create "an inconsistency in the market which will drive some pricing problems and can also create an imbalance between what the market does and what the actual system sees."[52] Under the current program design, SEP does not have the capability to operate as a continuous resource. That is, once an SEP load control group is dispatched, it will deliver its full capacity MW output. RDRRs that can only deliver their maximum capacities are considered discrete resources and are limited to participation in the real-time market for emergency / reliability purposes.

As an RDRR discrete resource, SEP will also be placed under the statewide reliability MW cap which is currently set to three percent and scheduled to drop to two percent by 2026. SCE requests maintaining the reliability cap at three percent, otherwise, SCE will need to stop enrollments and/or limit enrollments when room under the cap becomes available.

d) Expand SEP to non-residential customers <200kW

SCE extended the smart thermostat DR concept to other programs, such as Critical Peak Pricing (CPP) in 2020 and most recently residential CBP in 2022. However, thermostat manufacturer support into other SCE DR programs is limited due to technology and operational barriers. Specifically, manufacturers like Google and ecobee do not either offer like services within the same

---

[51] Pmax maximum normal capability of a generating unit, as measured at the point of interconnection or point of delivery. Pmin is the minimum load of a generating unit. *See* CAISO, Business Practice Manual for Definitions & Acronyms, Version 19, , *available at* https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Definitions%20and%20Acronyms.

[52] *See* CAISO, RDRR Bidding Enhancements Initiative Final Proposal, (April 12, 2022), p. 9, *available at* http://www.caiso.com/InitiativeDocuments/Final-proposal-reliability-demand-response-resource-bidding-enhancements-track2.pdf.

service territory or those services come with operational restrictions that do not line up with SCE's DR program dispatch parameters. Therefore, these thermostat brands are currently excluded from participating with other SCE DR programs. To help bridge the gap, SCE proposes to expand SEP to include non-residential small-to-medium business (SMB) customers <200 kW. Expanding SEP to non-residential and eventually to support other types of enabling technologies, such as electric vehicle supply equipment (EVSE) for charging stations and heat pump water heaters, will help reach more customers and increase DR MW capacity.

3. Program Budget

Table III-11 shows SCE's proposed Smart Energy Program budget and incentives for the 2024–2027 period.[53]

Table III-11
Smart Energy Program
2024–2027 Proposed Budgets
(Nominal $ millions)

Smart Energy Program (SEP)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.462	.467	.519	.543	1.991
2	Non-Labor Total	1.688	.190	.193	.196	2.267
3	**Program Total**	**2.150**	**.657**	**.712**	**.739**	**4.258**
4	Incentives	4.027	4.556	5.017	5.418	19.018
5	Marketing	1.373	1.481	1.395	1.506	5.756
6	EM&V	.057	.057	.058	.059	.232
7	**Grand Total**	**7.607**	**6.752**	**7.182**	**7.723**	**29.264**

Note: Marketing and EM&V costs are presented here to provide a complete view of the SEP program but are included in the proposed budgets for Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

SEP Labor Budget: The proposed budget for SCE labor funds approximately 4.1 FTEs, including administration and overhead expenses.

---

[53] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for SEP alone is included in this application.

<u>SEP Non-Labor Budget</u>: The non-labor budget includes costs to pay for phone center support and administrative miscellaneous expenses that may come up during the 2024–2027 period. The non-labor budget also includes system related costs specific to SEP necessary to expand the program to non-residential customers. Additional funds are also requested to cover third-party marketplace vendor fees related to SEP pre-enrollment at point of sale. The third-party vendor fees which were funded out of the SEP budget for 2018 through 2022 will be managed and paid for under the DR Systems & Technology Support budget in Section IX.B of this Exhibit. The third-party vendor fees primarily consist of device and system costs necessary to manage customer enrollments, implement SEP events through their dispatch platforms, maintain microsites and customer notifications, all of which fall under the activities supported through DR Systems & Technology Support. The SEP marketing budget primarily includes funding for digital and direct mail advertising.

SEP Incentives Budget: SCE plans to maintain the current incentive structure for SEP in the 2024–2027 budget cycle period. That is, customers participating in SEP will earn a daily fixed summer bill credit each year (provided in their summer monthly bills from June 1 through September 30) per service account enrolled in the program.

4. <u>Expected Load Impact of SEP During 2023–2027 Program Cycle</u>

The expected load impact of SEP is included in SCE-04, Chapter III.

E. <u>Summer Discount Plan</u>

The SDP program operates as both a reliability and price responsive program. The SDP program offers bill credits to customers that allows SCE to cycle-off their air conditioning (A/C) units during curtailment events. The program is open to residential customers and small, medium, large commercial and industrial customers. SDP has a history of providing fast and reliable load shed. In 2020, SDP was dispatched for an average 30 hours per customer over 13 event days, resulting in 195 MW load reduction to support the grid and prevent rolling blackouts. However, as discussed below, there are concerns regarding attrition from the program.

1. **Program Background**

The SDP program, previously known as the Air Conditioner Cycling Program, was created in 1977 via Advice Letter 441-E. Current participating customers allow SCE to install radio frequency load control switches at their residence/business to periodically turn-off or cycle-off a customer's A/C compressor during periods of peak energy demand, system emergencies or at times of high wholesale energy prices. In return for participating in the SDP program, customers receive a credit on their electric bills each year from the first of June to the first of October. Program credits are based on the customer's air conditioner tonnage and the program option the customer chooses.

a) SDP has a history of providing fast and reliable load shed

The SDP program is one of SCE's longest standing DR programs, having provided reliability-based demand response since the early 1980s. During the 2018-2022 program cycle SCE's SDP program enrolled 36,622 residential and 622 commercial participants. Today, the SDP program represents approximately 171 MW of DR capacity with approximately 258,000 active A/C load control devices installed at customer locations. The SDP program has approximately 168,000 residential and 7,300 business customer participants.

Beginning in June 2015, SCE integrated and registered its SDP program as a RDRR into the CAISO wholesale energy market. The SDP program also participates in the day-ahead economic energy market as allowed by the RDRR tariff.

In its 2018-2022 program cycle, SCE observed a decline in participation that was driven by decreasing incentives and increased event hours. The downward trend in participation was cited in SCE's mid-cycle report (AL 4182-E), which provides evidence that reduced incentives lead to an increased rate of attrition. As noted, in 2020, SDP was dispatched for an average 30 hours per customer over 13 event days, resulting in an average 195 MW load reduction to support the grid and prevent rolling blackouts. The load impacts observed during this timeframe highlighted SDP's ability to provide fast and reliable load shed. The frequency and duration of these events, however, came at an increased cost to participating customers, resulting in approximately 17,000 residential customers (with

14 MW of DR capacity) leaving the program out of over 186,000 total participants at the beginning of 2020.

b) Attrition

(1) Increased Event Hours Have Caused High Rates of Attrition.

In 2018, over 247,000 residential customers were enrolled in SDP, representing 205 MW of DR capacity, however over the past four years (2018-2021) there has been a large decrease in customer participation in the SDP program. Increased event hours and decreased incentives through 2020 have directly affected the volume of customer attrition. As directed by the Commission in 2021, SCE made significant program changes designed to increase enrollments by removing the 20-hour economic dispatch requirement, increasing residential incentives by 25%, and offering a $50 sign up bonus through 2022. SDP was dispatched for only six hours in 2021 and SCE observed a six percent decrease in attrition that resulted from limiting hours of dispatch outside of emergency situations.

The increased number of event hours has had a significant negative effect on the program since integrating into the CAISO market. Event related attrition from 2015 to 2021 for SDP Residential resulted in over 78,000 customers leaving the program, equating to a loss of approximately 79 MW potential load reduction.[54] Historical event-related attrition for the residential program has provided some significant insights on customer performance and tolerance levels.

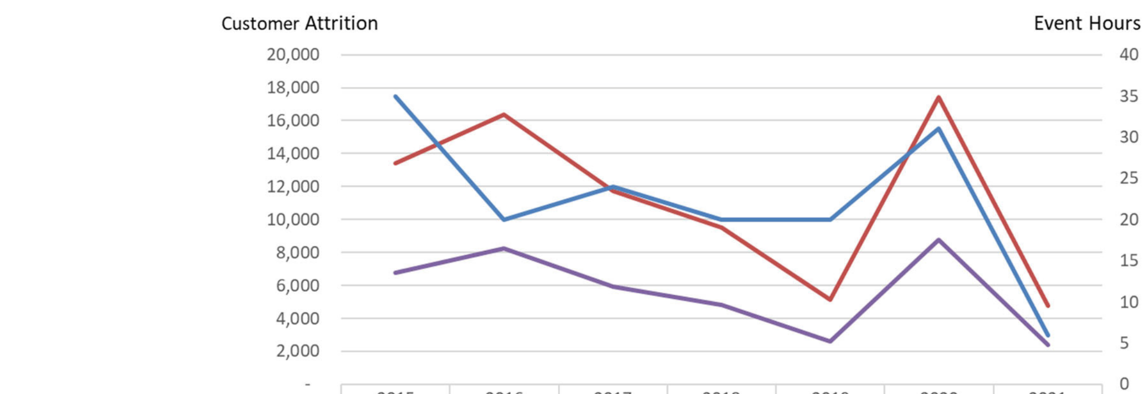
(2) Customer Attrition is Impacted by Frequency and Duration of Event Dispatch.

In its 2018-2022 Application SCE proposed a decreasing incentive structure with a goal to shift more enrollments towards the SEP, but the increasing number of emergency events refocused statewide effort toward increasing reliability and retention of existing participants. Declining incentives slowed the enrollment of new participants, but the frequency and duration of events during this timeframe had a much larger impact on attrition. Despite reducing the

54 Using the per-SA kW forecast in the PY 2014 Ex Ante Load Impact Study (August).

minimum economic dispatch requirement from 30 to 20 hours between 2016 and 2020, event related attrition continued to increase during that timeframe (as shown in Figure III-2 below). Subsequently after the 2020 heat wave events, the Commission authorized SCE to remove the minimum economic dispatch requirement, increase incentives by 25%, and offer a $50 sign-up bonus to increase participation.[55] Through increased incentives, and limited hours of dispatch SCE hopes to achieve a comfortable balance that attracts new enrollments and maintains customer satisfaction for active participants.

Figure III-2
SDP Event-Related Residential Attrition (2015-2021)



	2015	2016	2017	2018	2019	2020	2021
Total Customer Requested Attrition	13,405	16,380	11,739	9,511	5,136	17,402	4,746
Total Event Hours	35	20	24	20	20	31	6
Estimated MW Lost	13.5	16.5	11.9	9.6	5.2	17.6	4.8

c) <u>Customer End Use Interval Data is Utilized to Optimize the Program</u>

Since interval data became available in 2013 (for program year 2012), SCE has conducted targeted marketing to high usage customers most likely to perform during dispatched events. SCE only solicited new enrollment campaigns to these customers, reducing free-ridership on the program. Further with this data for enrolled customers, SCE can determine if those customers having high load usage during events demonstrated load reductions during the event hours. If a consistent pattern of non-performance was observed, SCE performed an annual site maintenance visit to make sure

[55] D.21-03-056, p. 33, Conclusions of Law (COL) 43 and Attachment 1, p. 17.

the A/C cycling switch had not been tampered with and was still in operation. Devices were replaced as necessary, or customers were removed from the program for non-compliance. These efforts have further reduced free-ridership. Finally, SCE utilized interval data to identify customers who consistently had low usage, indicating no A/C usage at the time of dispatched events. On December 7, 2016, SCE filed AL 3486-E-A to supplement to AL 3486-E, in order to implement the removal of these low usage customers beginning in 2018.

During the 2018–2022 program cycle, SCE continued to leverage interval data to ensure SDP participants were meeting the minimum electric usage threshold, an eligibility requirement that contributes to cost effectiveness of the program. During annual review completed between 2018-2022, over 11,000 customers were removed due to non-compliance with the minimum usage requirement. Annual load impact analyses performed between 2018 and 2022 show forecasted average load reduction per customer has increased over this timeframe.

d) Improved Program Performance

SCE conducts ongoing efforts to increase SDP program load impacts through targeted marketing and managing performance of active participants. This approach includes marketing to high usage customers in warmer climate zones, monitoring and removal of customers that do not meet the minimum usage requirement, and a Maintenance Replacement Project effort in which customers that do not show signs of load shed are scheduled for a site inspection which could result in device replacement or removal from the program. Annual load impact analyses performed between 2018 and 2022 show that targeted maintenance efforts have increased load impact per customer. Average residential ex-ante load impacts increased from 0.84 kW per residential customer in 2018 to 0.92 kW per residential customer in 2022.[56] Overall increased load reduction per customer validates the effectiveness of SCE's annual performance review and site maintenance efforts. Active maintenance and removal of

[56] PY2017 SCE_SDP-R_Ex_Ante_Load_Impacts (April 2018) and PY2021 SCE_SDP-R_Ex_Ante Load Impacts (April, 2022). Historical Load Impact studies are *available at* https://www.sce.com/regulatory under the documents associated with the Order Instituting Rulemaking To Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements proceeding (R.13-09-011).

customers who are unable to meet program requirements are critical to ensuring cost effectiveness of the program.

e) Customer Education and Outreach Efforts

SCE continues efforts to educate enrolled customers about the value of their continued participation in the program. SCE utilizes a four-touch retention mailer where program information is delivered to SDP customers via direct mail, email, and bill inserts. These communications happen throughout the year, providing program details, bill and SDP incentive information, SDP event readiness, tips on how to stay cool during the summer, and a year-end appreciation for program participation, and support for grid reliability. SCE leverages the DR Mobile App and the DR website to provide customers notification of dispatched events details. Real-time event information is posted on SCE.com. SCE communicates additional updates via social media platforms to share information on dispatched events and give customers a forum to provide feedback.

2. Program Changes

SCE's objective for SDP is to increase the effectiveness of the program by actively managing program performance, enrollment processing, and customer retention. SCE proposes to make program improvements that will reduce attrition in order to retain the value of the program as a resource for emergency and reliability dispatch.

a) Remove SDP from the CAISO Day-Ahead Energy Market

SCE proposes to modify SDP integration in the CAISO wholesale energy market by removing the day-ahead economic component, while remaining integrated as an RDRR resource. SCE proposed in its R.20-11-003[57] Phase II Legal Brief to remove SDP from the CAISO market altogether in order to preserve the current capacity enrolled in the program for emergency/reliability dispatch, and potentially allow for dual enrollment with SEP.[58] While the Commission was silent on this proposal, market integration has led to increased event hours and contributed to the trend in which

[57] R. 20-11-003, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.

[58] R. 20-11-003, SCE Opening Brief, p. 13 (Sep. 20, 2021).

more customers are leaving the program due to event fatigue. SDP provides SCE's highest amount of load reduction per service account for our residential segment, and it remains the most impactful residential program when needed in emergency situations. Historical data suggests that while increased incentives are attractive in promoting the program, overall customer satisfaction is driven by low frequency of events and duration. As a day-ahead, economic resource, SDP is expected to place market bids outside of grid emergency situations, but the market revenue gained from these events are minimal and do not impact the program's overall cost effectiveness. In contrast, treating SDP as an economic resource puts added stress on the customer which correlates to higher attrition rates. SCE believes that removal of the economic bidding component will alleviate customer fatigue that is generated by unnecessary dispatch, which will improve customer retention and preserve the capacity of the resource for when it is really needed in emergency situations.

In addition to customer impact and attrition resulting from unnecessary event dispatch, SDP cannot meet CAISO requirements as a day-ahead economic resource. Per the CAISO tariff, RDRRs participating as economic resources in the day-ahead market are required to register as continuous and must have the flexibility to operate anywhere between its Pmin and Pmax MW capability, based on the awarded bid quantity. For example, a resource that can deliver 50 MW in its Pmax, may only be awarded for 20 MW in the day-ahead market as a continuous resource. A resource that delivers above the awarded amount may create "an inconsistency in the market which will drive some pricing problems and can also create an imbalance between what the market does and what the actual system sees."[59] Similar to SEP, SDP does not have the capability to operate as a continuous resource. That is, once an SDP load control group is dispatched, it will deliver its full capacity MW. RDRRs that can only deliver their maximum capacities are considered discrete resources and are limited to participation in the real-time market for emergency / reliability purposes.

---

[59] *See* CAISO, RDRR Bidding Enhancements, Final Proposal, (April 12, 2022), p. 9, *available a*t http://www.caiso.com/InitiativeDocuments/Final-proposal-reliability-demand-response-resource-bidding-enhancements-track2.pdf.

As an RDRR discrete resource, SDP will also be placed under the statewide reliability MW cap which is currently set to three percent and scheduled to drop to two percent by 2026. SCE requests maintaining the reliability cap at three percent, otherwise, SCE will need to stop enrollments and/or limit enrollments when room under the cap becomes available.

3. Program Budget

Table III-12 shows SCE's proposed SDP program budget and incentives for the 2024–2027 period.[60]

Table III-12
SDP Program
2024–2027 Proposed Budget
(Nominal $ millions)

Summer Discount Program (SDP)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.991	1.029	1.232	1.260	4.511
2	Non-Labor Total	5.820	5.888	5.850	5.883	23.442
3	**Program Total**	**6.811**	**6.917**	**7.082**	**7.144**	**27.953**
4	Incentives	29.814	29.495	29.20	28.925	117.435
5	Marketing	1.808	1.809	1.811	1.813	7.242
6	EM&V	.133	.135	.136	.138	.543
7	**Grand Total**	**38.567**	**38.356**	**38.229**	**38.020**	**153.173**

Note: Marketing and EM&V costs are presented here to provide a complete view of the SDP program but are included in the proposed budgets for Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

SDP Labor Budget: The proposed budget for SCE labor funds approximately 5.9 FTEs, including administration and overhead expenses.

SDP Non-Labor Budget: The non-labor budget includes SDP device/equipment, program measurement & evaluation, device disposal fees, system enhancements, promotional offerings, administrative costs, customer service support, and claims. The SDP marketing expenses, included in

[60] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for SDP alone is included in this application.

the Marketing, Education and Outreach budget (presented in Chapter VIII), includes funding to update program website, program collateral and conduct customer education and outreach efforts, which include ongoing customer acquisition and retention campaigns highlighted in the SDP Program Background, Section III.E.1 above.

SDP Incentives Budget: SDP is requesting additional funding, beyond the base case amount calculated by SCE, to be allocated toward SDP-Commercial incentives in order to preserve the program's load reduction capability and value as a cost saving resource for business customers. SCE's base case incentive calculation projected a 63% reduction to SDP-C incentives from current levels. The incentive decrease was largely due to a reduced ex ante load impact that is being factored into the rate calculation. The average per customer load impact forecasts for SDP-C were driven down by approximately 35% when the RA window shifted from 1–6 PM to 4–9 PM[61], indicating that our commercial population has less available A/C load during this timeframe. External factors observed during the 2018-2022 budget cycle have also impacted business operations, contributing to less usage during the 4–9 PM timeframe. For example, the COVID-19 pandemic disrupted typical load patterns for all businesses and especially in schools and religious institutes, the two business types in which the majority of SDP's A/C tonnage resides.

Applying a 63% incentive reduction would negatively impact program participation as it would reduce customer interest, which leads to further attrition and lower load impact estimates and could eventually lead to discontinuation of SDP's commercial option. The majority of SDP-C participants do not meet eligibility requirements to participate in SCE DR programs outside of SDP, so discontinuation of SDP-C is not a customer friendly solution, nor is it beneficial to the state because existing MW could potentially be lost. SDP-C and SDP-R are direct load control programs and have similar characteristics in terms of when and how they can be dispatched. Both programs maintain value through the number of actively enrolled participants and ability to respond quickly to grid emergencies that may occur at any time in the day. SCE proposes that SDP-R and SDP-C be treated similarly by

[61] Per-customer load impact decreased from 2.95 kW in PY 2017 to 1.93 kW in PY 2018.

adjusting the SDP-C incentive reduction to align with the proposed 11% reduction to SDP-R incentives forecasted from 2024–2027. In order to do so, SCE requests a $14.9 million "policy adder" to address the gap in costs between the base case incentive rates calculated for SDP-C, and the proposed 11% decrease. This policy adder amount will be spread across the program cycle and is proportional to decreasing forecasted enrollments. Testimony pertaining to SDP incentives are included in SCE-04, Chapter II.

4. Expected Load Impact of SDP During 2023–2027 Program Cycle

The expected load impact of SDP is included in SCE-04, Chapter III.

IV.

CATEGORY 2: LOAD MODIFYING DEMAND RESPONSE PROGRAMS

SCE's load modifying DR program offerings are (1) the Optional Binding Mandatory Curtailment Program, and (2) the Scheduled Load Reduction Programs.

A. Optional Binding Mandatory Curtailment (OBMC)

OBMC is a program in which enrolled customers are exempted from rotating outages in exchange for providing partial load curtailments during every rotating outage period. An OBMC customer must file an acceptable binding energy and load curtailment plan with the utility, at the time of enrollment, in which the customer agrees to curtail their electricity use on its entire circuit by specified amounts.

1. Program Background

The OBMC program was first approved in D.01-04-006. The program protects large customers from the significant economic harm they might otherwise experience during a rotating outage. OBMC customers receive no payment; rather, they benefit by exclusion from rotating outages. While this does not eliminate exposure to all outages (e.g., an unplanned or forced outage or PSPS event), it eliminates the customers' exposure to Stage 3 rotating outages.[62] OBMC currently has ten enrolled customers and has not had a new customer enroll since 2009. The program is valued by these participants as a mechanism for limiting the economic impact of outages.

2. Proposed Program Changes

As described above, OBMC operates in conjunction with rotating outages and is not considered a DR program where participants earn a financial incentive in exchange for their load reduction or curtailment. As such, SCE proposes that OBMC be funded in SCE's GRC application beginning in 2025, consistent with the administration of the Rotating Outages program adopted in D.17-

[62] *See* D.01-04-006, pp. 37-39.

12-003.[63] Since SCE's GRC and DR application periods do not align, SCE requests funding for OBMC through 2024 to bridge the gap between these applications.

3. Program Budget

SCE plans to maintain this program, including its policies and procedures, in its current state through 2024, with an estimated non-labor expense of approximately $3,000.[64] If the Commission adopts SCE proposal to request funding for OBMC in its 2025 GRC, then no funding is required for the period 2025-2027. Should the Commission not adopt SCE's proposal, SCE will require $3,000 per year, for 2025-2027, to fund OBMC activities through the end of program cycle. Table IV-13 shows SCE's proposed OBMC program budget for the 2023–2027 period.

Table IV-13
OBMC Program
2024–2027 Proposed Budget[65], [66]
(Nominal $ millions)

Optional Binding Mandatory Curtailment (OBMC)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	-	-	-	-	-
2	Non-Labor Total	.003	-	-	-	.003
3	**Program Total**	**.003**	**-**	**-**	**-**	**.003**
4	Incentives	-	-	-	-	-
5	Marketing	-	-	-	-	-
6	EM&V	-	-	-	-	-
7	**Grand Total**	**.003**	**-**	**-**	**-**	**.003**

---

63 *See* D.17-12-003, OP 8.

64 Due to the size and lack of activity of this program, SCE does not forecast labor expenses for 2024–2027.

65 Table IV-13 assumes that the Commission adopts SCE's proposal to fund this program in it GRC beginning in 2025.

66 The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for OBMC alone is included in this application.

B. Scheduled Load Reduction Program (SLRP)

SLRP is a statewide legislated[67] load reduction program that incentivizes eligible customers (i.e., those with average monthly demand greater than 100 kW) to reduce their energy usage during pre-scheduled periods during the summer.[68] This program is effectively dormant, with no enrollment since 2010 due to program design that makes earning incentives difficult for customers.

1. Program Background

As this program is ordered by statute, the Commission determined in 2006 that it did not have the authority to close the program.[69] SCE does not anticipate any participation during the 2023–2027 cycle.

2. Program Changes

SCE does not propose any changes to the SLRP program in this funding cycle.

3. Incentive Structure/Funding

A customer electing to participate in the SLRP would elect a load reduction strategy through one of three options, and at least 15% of their demand would be compensated on a per-kWh credit on their bills for the amount reduced.

4. Program Budget

Table IV-14 shows SCE's proposed SLRP program budget and incentives for the 2024–2027 period.[70] Based on the lack of enrollment in this program, SCE proposes a non-labor budget of approximately $3,200 per year as shown in Table IV-14.

---

[67] *See* Cal. Pub. Util. Code § 740.10 (requiring each utility to establish a Scheduled Load Reduction Program in its respective service territory).

[68] To be eligible, a customer must have an average monthly demand of 100 kW or greater and commit to a least a 15% reduction in load (based on the customer's maximum demand during the previous 12 months). *See* Schedule SLRP – Scheduled Load Reduction Program, Applicability. Current tariff schedules *are available* at https://www.sce.com/regulatory.

[69] *See* D.06-03-024, COL Paragraph 2.

[70] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for SLRP alone is included in this application.

Table IV-14
SLRP Program
2024–2027 Proposed Budget
(Nominal $ millions)

Scheduled Load Reduction Program (SLRP)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	-	-	-	-	-
2	Non-Labor Total	.003	.003	.003	.003	.013
3	**Program Total**	**.003**	**.003**	**.003**	**.003**	**.013**
4	Incentives	-	-	-	-	-
5	Marketing	.002	.002	.002	.002	.008
6	EM&V	-	-	-	-	-
7	**Grand Total**	**.005**	**.005**	**.005**	**.005**	**.020**

V.

CATEGORY 3: DEMAND RESPONSE AUCTION MECHANISM PILOT AND DIRECT PARTICIPATION ELECTRIC RULE 24

SCE's Category 3 Demand Response program offerings are (1) the Direct Participation Electric Rule 24 program, and (2) the Demand Response Auction Mechanism (DRAM) pilot

A. Direct Participation Electric Tariff Rule 24

SCE's Rule 24 establishes the administrative and technical mechanisms that allow third-party DR providers (DRPs) to bid DR resources directly into the CAISO wholesale energy market. Rule 24 establishes the terms and conditions for entities that seek to take part in Direct Participation Demand Response Service. It also allows DRPs or retail customers to participate directly in the CAISO wholesale energy market for compensation by the CAISO in accordance with market awards and established dispatch instructions. DRAM sellers also aggregate load and bid that load into the CAISO market through Rule 24.

SCE currently has 20 registered DRPs in operation within its service territory and 15 DRP's have active Rule 24 data authorizations, with over 62,000 SCE customers having active CAISO registrations based on their participation in a wide variety of programs offered by these DRPs.

1. Program Background

D.15-03-042 authorized the IOUs to recover costs for implementing the initial step of direct participation by DRPs in the CAISO energy markets. The Commission established a target of 14,000 customer registrations for SCE during the initial step and noted that the target should be a dynamic ceiling that should rise over time.[71] D.16-06-008 authorized SCE to spend funds to raise its Rule 24 registration cap to 42,000[72] and outlined a process for requesting future increases to that cap.[73] D.16-06-008 also ordered the IOUs to develop a "Click-Through" process allowing customers to

---

[71] D.15-03-042, p. 36 and OP 10.

[72] D.16-06-008, p. 19 and OPs 6 and 7.

[73] *Id.*, OP 11.

authorize a DRP to receive their Rule 24 data.[74] Energy Division (ED) subsequently approved SCE's request of $3.5 million to raise the Rule 24 cap to 100,000 registrations by 2019 to support Rule 24 operations from 2018 to 2022.[75]

SCE's Click-Through Application (A.18-11-016), filed in compliance with Ordering Paragraph (OP) 29 of Resolution E-4868, included proposals and cost estimates related to click-through improvements and additional enhancements to data delivery processes. In 2019, SCE implemented further improvements to these processes based on feedback from its participation in Customer Data Access Committee (CDAC) meetings and feedback from DRPs. On November 13, 2020, SCE submitted updated testimony discussing actions SCE has taken to support the click-through authorization processes and to provide updates on proposed budgets for further enhancements to click-through and related data delivery obligations consistent with Resolution E-4868. At the time of the filing of this DR Application, the Commission has not issued a decision on SCE's Click-Through Application.

2. Proposed Program Changes

Consistent with D.16-06-008,[76] SCE proposes to increase the CAISO registration cap to 225,000 (from the current cap of 100,000) for the 2023–2027 funding cycle. As shown in Table V-15, CAISO registrations increased by 57% to over 32,000 and then continued to increase at an annual rate of approximately 20% from 2019 to 2021. SCE anticipates that its CAISO registrations will reach the existing active CAISO registration cap of 100,000 by 2025 or earlier if registrations continue to increase at this rate.

a) CAISO Registrations

To support third-party direct participation, SCE provides customer usage data to third-party DRPs in order to settle transactions with the CAISO. For each customer that participates

[74] D.16-06-008, p. 8 and OP 1.

[75] SCE Advice 3553-E submitted on February 7, 2017 was approved by ED on November 27, 2017 with an effective date of February 7, 2017.

[76] D.16-06-008, OP 12.

with a DRP the IOUs must create an individual customer data authorization via a paper Customer Information Service Request (CISR), or use the Click-through authorization process to provide usage data to the DRP(s) the customer authorizes to receive their data. If the customer is eligible to participate directly with a third-party DRP, the DRP registers the customer's account in the CAISO. SCE performs the Utility Distribution Company (UDC) validation within the CAISO Demand Response Registration System (DRRS) to approve or deny customer account registration requests submitted by DRPs. If the customer account is approved, SCE adds an account identifier to identify third party DRP enrollment and reprograms the customers' meters to 15-minute intervals, as needed.

SCE is requesting additional funding to provide for a total of up to 225,000 active CAISO registrations, as reflected in Table V-15 below, to ensure adequate resources and capabilities to support DRAM and non-DRAM DRP participation through 2027. As of February 28, 2022, over 62,400 SCE customers have active CAISO registrations. As noted, SCE projects that its CAISO registrations will reach the existing cap of 100,000 by 2025 or earlier if registrations continue at the same rate. SCE is anticipating a 24% growth rate to remain constant through 2027, but this forecast does not include the forecasts from DRPs and DR stakeholders that are anticipating a significant increase of CAISO registrations as they expand their offerings to include new DR technologies[77] and accelerate the installation of smart thermostats[78] to ensure reliable electric service in the event of extreme weather conditions.

---

[77] *See, e.g.*, OHM Connect Press release *available at* https://assets.website-files.com/53cda9eccbc8e0894bcf7766/5fce6f871f4224502c080707_news-sip-ohmconnect-press-release-12.07.2020.pdf: ("The 550 MW Resi-Station project will be funded by SIP and developed in partnership with OhmConnect and will comprise hundreds of thousands of actively engaged customers with a fleet of in-home smart devices delivering targeted energy reductions,…[¶] In order to scale up Resi-Station and provide savings to California residents, SIP and OhmConnect are partnering with Google to offer Nest thermostats to hundreds of thousands of participants….").

[78] *See*, e.g., R.20-11-003, DR Coalition, January 11, 2021 testimony, p. 5 lines 3-7; DR Coalition Opening Brief, p. iii and p. 11 (February 5, 2021).

Table V-15
Rule 24 CAISO Registrations
2022 to 2027 CAISO Active Registration Forecast

Line No.	Description	Actual				Forecast					
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	CAISO Registrations (End of year total)	32,038	38,235	44,949	61,328	76,047	94,298	116,929	144,993	179,791	222,940
2	Growth Rate % (Year-over-Year)	n/a	19%	18%	36%	24%	24%	24%	24%	24%	24%

To support this growth in active CAISO registrations, SCE forecasts a need for additional Rule 24 program staff to support the activities required to manage CAISO registrations, analyze DRP reported data issues, and technical support needed to resolve reported data delivery issues. The sections below detail SCE's proposed Rule 24 cap increase to 225,000 active CAISO registrations to support that increase, and budgets necessary for performing those activities.

b) Rule 24 DRP & Data Authorizations

Pursuant to Electric Tariff Rule 24, SCE is obligated to provide all Revenue Quality Meter Data to the Seller according to the standards adopted in the Direct Access Standards for Metering and Meter Data and CAISO requirements.[79] Additionally, per D.19-12-040, SCE is required to follow DRP communication protocols that provide a standardized data issue template for DRP's to report Rule 24 data issues, and requires regular meetings and communications with DRPs regarding the status of reported data issues. SCE currently has 20 registered DRPs in operation within its service territory, and 14 DRPs have active Rule 24 data authorizations. As of February 2022, there are approximately 111,000 active Rule 24 customer data authorizations.[80] SCE forecasts the need to support over 400,000 Rule 24 Data Authorizations by 2027, as shown in Table V-16 below. The forecasted number of data authorizations assumes SCE will receive data authorization requests up to that year's cap, for each year over the 2023–2027 period. It is also assumed that two data authorizations will be

79 SCE Rule 24 Section C.2.h.

80 SCE currently has more than 161,000 Data Authorizations but notes that there are approximately 50,000 duplicate authorizations. As part of the Click Through Application A.18-11-016, SCE has requested funding to enhance its Click Through system to not allow duplicate authorizations when the customer, location and DRP are all the same.

submitted for each service account, which is consistent with the number of Rule 24-related data authorizations submitted for each service account.

Table V-16
Rule 24 Data Authorizations
2022 to 2027 Rule 24 Data Authorizations Forecast

Line No.	**Description**	**Forecast**					
		2022	**2023**	**2024**	**2025**	**2026**	**2027**
1	Rule 24 Data Authorizations	137,762	170,825	211,823	262,660	325,699	403,867
2	CAISO Registrations (End of year total)	76,047	94,298	116,929	144,993	179,791	222,940
3	Growth Rate % (Year-over-Year)	24%	24%	24%	24%	24%	24%

3. <u>Incentive Structure / Funding</u>

The Rule 24 program operations/administration budgets are currently funded in SCE's Demand Response Programs Balancing Account (DRPBA). SCE requests to continue cost recovery for Rule 24 Program funding through the DRPBA.

4. <u>Program Budget</u>

Table V-17 below summarizes SCE's 2024–2027 proposed funding for Direct Participation Electric Rule 24 activities.[81] The budget reflects the increased CAISO authorization cap proposed in Section V.A.2 above with additional details provided below.

[81] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for Direct Participation Electric Rule 24/32 alone is included in this application.

Table V-17
Rule 24 Program Budget
2023–2027 Proposed
(Nominal $ millions)

DR Rule 24						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.717	.737	.764	.785	3.003
2	Non-Labor Total	.221	.223	.227	.181	.852
3	**Program Total**	**.938**	**.961**	**.990**	**.966**	**3.855**

a) SCE Labor

Direct Participation Electric Rule 24 activities require seven FTEs, including administration and overhead expenses, to support account management activities for up to 25 DRPs and up to 400,000 data authorizations. Labor includes account management, project management, business operations support and revenue services support personnel which perform various functions including but not limited to performing and maintaining DRP data authorizations, validating, processing, and executing DRP establishment package (precursor to DRP registering with the CPUC and CAISO), supporting resolution of data issues and other analytical activities for Rule 24 including monitor/perform quality control of Rule 24 data delivery, and supporting execution of Rule 24 Program operational processes and projects to support CAISO registrations, Rule 24 data delivery, and other Rule 24 related issues.

b) Non-Labor

SCE's proposed Direct Participation Electric Rule 24 budget included non-labor expenses for ongoing costs associated with its cloud-based data platform for Rule 24 data authorizations and SCE.com.[82] and system enhancements due to CAISO DRRS upgrades. During the current DR program cycle, the CAISO implemented system enhancements to its DRRS system. SCE is requesting funding to build an application programming interface (API) to integrate SCE's system with the

[82] SCE requested authorization to recover the costs to transition its on-premises data warehouse to a cloud-based platform in A.18-11-015.

CAISO's DRRS to retrieve DRP Registration and Resource ID data which will support SCE's ability to audit DRAM and ELRP invoices by validating DRPs' CAISO Resource IDs and registrations. This interface will require system enhancements and database development to maintain the data.

B. Demand Response Auction Mechanism Pilot

1. Program Background

The DRAM has its origins in the Order Instituting Rulemaking To Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements (OIR (R.)13-09-011), which encompasses, among other issues, how the Commission should determine the appropriate policy on Resource Adequacy (RA) capacity payments for DR. The DRAM pilot, initiated following the issuance of D.14-12-024, was established to test (a) the feasibility of procuring DR Supply Resources for system RA with third party direct participation in the CAISO markets through an auction mechanism, and (b) the ability of winning bidders to integrate their DR Resources directly into the CAISO market. As clarified by the Commission, and understood by the DRAM working group, the proposed design was non-precedential, and should test the viability of the DRAM procurement mechanism. Stakeholders made mutual concessions on the basis that they would have the ability to assess whether the DRAM pilot should be made permanent in a regular program.[83]

The DRAM is designed as a pay-as-bid auction of monthly (system capacity, local capacity, or flexible capacity) RA associated with a DR product located in the IOU service area, with the product offered directly into the CAISO wholesale energy market. The IOUs purchase the RA only and have no claim or rights on revenues the winning bidders may receive from the CAISO energy market. DRAM Request for Offer (RFO) solicitations were launched starting in 2015 for the 2016 RA delivery year and have been authorized through the 2023 RA delivery year.

In D.19-07-009, the Commission concluded that while DRAM had been "successful in engaging new customers and third-party demand response providers and in offering competitive bidding prices for resource adequacy," the program needed "several immediate critical changes to address

---

[83] SCE Advice 3208-E, p. 3.

shortcomings in performance, reliability, and offering competitive prices in the wholesale energy market." Although the Commission approved a four-year continuation of DRAM,[84] it stated that "we cannot expand the role of the Auction Mechanism or adopt it as a permanent mechanism until improvements are evident."[85] The Commission adopted a two-step approach to improving DRAM, involving (1) the adoption of specific "critical improvements," and (2) "an iterative approach to continuous improvements of the Auction Mechanism that begins with a series of working group meetings leading to a second decision, as described in OP 12, and evolves into an informal refinement process led by the Commission's Energy Division . . . ."[86]

In the same decision, the Commission directed the IOUs to contract with a consultant to evaluate the DRAM pilot and issue a final report by December 1, 2021.[87] On August 31, 2021, SCE submitted a request by the consultant, Resource Innovations (formerly Nexant), to extend the deadline for the final evaluation report to April 1, 2022. On September 30, 2021, the Executive Director granted this request. On March 25, 2022, SCE submitted a request by Resource Innovations for a further extension of this deadline until May 23, 2022, and the Commission's Executive Director approved it on April 1, 2022.

2. Proposed Program Changes and Proposed Budget

Given that the DRAM evaluation is not final and the future of the pilot is uncertain, SCE is not requesting a budget for DRAM at this time. In R.20-11-003, the Commission declined to approve a second DRAM auction in 2022, and noted that questions have been raised by a number of parties, including the CAISO, about whether DRAM is providing reliability services as expected and in proportion with the pilot's contracts in recent years. Pending a Commission decision based on its review of the final DRAM evaluation report, and in light of the Commission's prior hesitation to adopt DRAM as a regular program, and questions raised by other parties about the program, SCE does not

---

[84] D.19-07-009, p. 2.

[85] *Id.*, p. 9.

[86] *Id.*, OP 1.

[87] *Id.*, OP 16.

request a budget for DRAM at this time. If the Commission determines that there are demonstrated improvements and deems the pilot successful in the areas of performance and reliability, SCE may file supplemental testimony seeking additional funding to continue the DRAM pilot beyond 2023.

3. Customer Information Working Group Report

On December 18, 2020, the Commission issued Resolution E-5110 authorizing the Energy Division to initiate a Customer Information Working Group (CIWG) to study The California Efficiency + Demand Management Council's proposal from the DRAM Working Group t and produce a report by June 1, 2021.[88] The Resolution also ordered the IOUs to include the Customer Information Working Group Report in their 2023-2027 DR Portfolio Applications.[89] Since the Customer Information Working Group was never initiated, there is no report to include in this application.

---

[88] Resolution E-5110, OP 5, p. 49, *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M355/K564/355564729.PDF.

[89] *Id*., OP 6, p. 50.

VI.

CATEGORY 4: EMERGING AND ENABLING TECHNOLOGIES

This chapter presents SCE's request for funding of its Emerging and Enabling Technologies which include SCE's Technology Incentive Program (TIP) and SCE's Emerging Markets and Technology program.

A. Technology Incentive Program (TIP)

The TIP serves as an umbrella for SCE's technology incentive programs—i.e., programs that provide SCE customers with incentives for installing selected technologies that facilitate related DR programs. Currently, SCE manages two incentive programs: the Programmable Communicating Thermostat Incentive Program and the Automated Demand Response Technology Incentive Program (Auto-DR) as described below.

1. Programmable Communicating Thermostat (PCT) Incentive Program

The PCT Incentive Program provides eligible residential and small and medium business (SMB) customers with a one-time $75 incentive in the form of a bill credit. To qualify, customers must install and register an eligible thermostat supported by one of SCE's authorized thermostats service providers and must be enrolled in a qualifying DR program.

a) Program Background

The PCT Incentive Program was approved in D.17-12-003.[90] Currently, PCT incentives are available for eligible customers participating in Smart Energy Program (SEP), Critical Peak Pricing (CPP), and third-party DR programs such as the Capacity Bidding Program for residential customers (CBP-Residential) and the DRAM pilot.

For SEP, the PCT incentive offer was already built into the SEP enrollment process involving its authorized thermostat vendors. As part of this process, SCE's authorized thermostat vendors verify thermostat installation and online connectivity in the home for DR dispatch capabilities during the SEP enrollment phase. Once the enabling technology and customer's service

---

[90] D.17-12-003, p. 82 and OP 32.

account are successfully registered and enrolled, SCE will issue a one-time $75 PCT incentive in the form of a bill credit.

SCE spent part of 2018 collaborating with program stakeholders and other IOUs (PG&E and SDG&E) to establish guidelines for administering the $75 PCT incentive for the other qualifying DR programs (i.e., CPP, CBP, and DRAM Pilot). SCE initially worked to implement a third-party technology solution to implement an automated rebate process. Unfortunately, this third-party vendor technology solution required more time than expected to develop and implement. In the interim, SCE implemented a temporary solution in September 2018 to offer the $75 PCT incentive to residential DRAM Pilot participants. The solution was limited to the residential sector because SCE used an existing Energy Efficiency thermostat rebate process that was only available to residential customers through its Plug Load Appliance (PLA) program.

In the second quarter (Q2) 2020, SCE implemented the third-party vendor technology solution to implement an automated rebate process similar to SEP that can serve non-residential customers and verify device connectivity. Using this solution, customers can apply for the PCT incentive via an online form through the authorized vendor's microsite and will not be required to supply a proof of purchase receipt. Furthermore, SCE has the capability to adjust the cooling temperature setpoint on participating thermostats by up to four degrees for CPP and CBP-Residential customers during DR events to help reduce energy usage. Customers may opt-out of this automated service at any time without necessarily opting out of the DR program.

Between 2018 and 2021, SCE paid about $4 million in PCT incentives to almost 54,000 customers.

b) <u>Proposed Program Changes</u>

For the 2024-2027 period, SCE plans to continue offering the $75 PCT incentive for qualifying DR programs authorized by the Commission under the TIP. SCE will continue to work with authorized thermostat service providers to support smart thermostats that SCE customers are likely to own for their home or business. SCE also proposes to use the PCT incentive and apply an instant discount at point of sale.

In D.21-03-056, the Commission supported SCE's proposal for new acquisition opportunities to increase customer enrollment in SEP which included point-of-sale enrollment / DR pre-enrollment. SCE's Marketplace is a platform that can offer this feature. SCE Marketplace is an automated appliance and product recommendation website administered through an authorized third-party vendor who hosts and operates the SCE branded platform. Marketplace currently includes information about smart thermostats including which brands and models qualify for the $75 PCT incentive. In the Emergency Reliability OIR Phase 2 Testimony filed on September 1, 2021, SCE proposed to have the flexibility within the PCT Incentive Program to apply the PCT incentive in the SCE Marketplace as an instant rebate for qualifying customers who choose to pre-enroll in SEP.[91] In the Commission's Phase 2 Decision (D.21-12-015), the Commission did not address SCE's proposal, so SCE re-proposes this change for the 2024–2027 period. The modification expands SCE's new enrollment acquisition strategy by removing an adoption barrier some customers may have with paying the full upfront cost of a thermostat. Customers who choose to forgo the DR pre-enrollment will not qualify for the instant rebate but may be eligible to receive the PCT incentive as an SCE bill credit following successful enrollment in SEP through the traditional enrollment flow. Logistically, SCE will pay the cost of the instant rebate to the Marketplace vendor with the customer being the beneficiary of such transaction. SCE recognizes D.18-11-029 authorized SCE to limit Auto-DR incentive payments specifically to customers and not any third parties. Although Auto-DR and the PCT Incentive Program are under the same umbrella of the TIP, the PCT Incentive Program is a separate program from Auto-DR and was not considered in D.18-11-029. Therefore, SCE proposes to implement this program modification specifically for the PCT Incentive Program and be able to utilize program funds to provide instant rebates via Marketplace to qualifying customers.

[91] SCE's Direct Testimony (SCE-04) in Phase 2 of R.20-11-003, p. 27.

c) Incentive Structure / Funding

SCE proposes $2.075 million annually for the PCT program budget and incentives for the 2024-2027 period which is included in Table VI-18 below. The budget is based upon a $75 PCT incentive per qualifying account.

2. Automated Demand Response Technology Incentive Program

The Automated Demand Response (Auto-DR) Technology Incentive Program provides eligible SCE non-residential customers with incentives for the purchase and installation of Auto-DR enabling technologies.

a) Program Background

The Auto-DR technology enables customers who participate in DR programs to automatically reduce electricity usage during a DR event. Customers pre-program their levels of DR participation, referred to as "shed strategies," and the Auto-DR system or technology enables the facility or building to automatically participate in a DR event. The system provides the customers increased flexibility (e.g., customizable load shed strategies) and ease-of use with no manual response or intervention. The Auto-DR program provides incentives to customers for installing automated load control equipment or systems, such as an energy management system (EMS), at a non-residential customer site. Customers must have an interval meter and be a participant in at least one qualifying DR program. The Auto-DR program currently offers Express and Customized solutions options for customers. Auto-DR Customized Control Incentives are available to medium and large commercial customers who install or retrofit an Energy Management Control Systems (EMCS).

b) Program Changes

In 2020, the IOUs jointly hired Energy Solutions to conduct research on the Auto-DR program and the IOUs held workshops with stakeholders. Based on the findings of the Energy

Solutions research project[92] and the various workshops, SCE proposes the following changes to the Auto-DR program to mitigate attrition and increase program enrollment.

(1) Extend the changes to customized incentives adopted in D.21-12-015

SCE proposes to extend the changes approved in D.21-12-015 through 2027. The Decision authorized the IOUs to pay upfront 100% of the eligible incentives for a customized Auto-DR project on the condition that the customer's enrollment commitment to participate in an eligible DR program is extended from three years to five years for 2022 and 2023 only. The authorized changes address program design concerns identified in the Energy Solutions research project and in various workshops. While authorizing the changes for 2022 and 2023 provides immediate and short-term solutions to prevent customer attrition, the authorized changes have been repeatedly identified as reasons that have led to customer attrition over the years. Therefore, SCE proposes extending the changes through 2027 to make the program design as desirable to customers as possible to prevent continued stagnation of customer enrollment.

The Energy Solutions research project found that applications decreased substantially due to changes in incentive structure and the implementation of the 60/40 incentive structure.[93] It also showed that most Auto-DR customers maintained their DR program enrollment longer than the existing three-year requirement.[94] Energy Solutions found that once an account is enrolled in a DR program after receiving an Auto-DR incentive, they tend to remain enrolled for at least three years, and almost 60% of accounts stayed enrolled in DR for five or more years after incentive payment. These results show that the Auto-DR Incentive Program is a strong driver of sustained

---

[92] Energy Solutions, Automated Demand Response Non-Residential Incentive Structure Research Project Report, (Aug. 2020), *available at* https://www.etcc-ca.com/reports/searchm was included as Attachment 2 to the IOUs' joint updates to the Auto Demand Response Control Incentive Guidelines and Adopted Policies, SCE Advice 4278-E, PG&E Advice 5931-E, and SDG&E Advice 3597-E, submitted on August 28, 2020.

[93] *See* Energy Solutions, Automated Demand Response Non-Residential Incentive Structure Research Project Report August 6, 2020, p. 6 ("Historically, participation in paid ADR MW peaked in 2012, after which applications decreased substantially. Research indicated the trend was due to changes in incentive structure.", *available at* https://energy-solution.com/wp-content/uploads/2020/11/Automated_Demand_Response_Non-Residential_Incentive_Structure_Research_Project_Report.pdf.

[94] *See id.*, p. 6.

engagement with DR programs and that most customers that receive the incentive do become ongoing DR participants.[95]

In summary, the research project showed that extending the incentive structure changes for customized projects offers a low risk, high reward solution to the reduction in application submittals in recent years. SCE notes that to mitigate the risk of a customer not meeting the time commitment, SCE is entitled to a refund from the customer of a prorated amount of the incentive already paid if the customer fails to remain enrolled in a qualifying DR program for the required timeframe.

(2) Research Expanding Express Control Incentives

One of the recurring barriers to entry regarding the current Auto-DR program is the lengthy application process.[96] Auto-DR Express Control Incentives use predetermined (deemed) kW savings on standard lighting and heating, ventilation, and air conditioning (HVAC) technologies and measures. The application process for Express Control Incentives is a simpler, shorter process due to using deemed kW savings, which do not need to be measured for each individual project. Express Control Incentives are currently only available to certain business sectors for customers with less than 500 kW of peak demand. SCE proposes to conduct additional research with PG&E into expanding Express Control Incentives to offer additional measures where customers can expect a simpler and shorter application process and also research expanding Express Control Incentives to other business sectors. SCE anticipates this modification will lead to faster distribution of incentives to more customers. For this co-funded research project, SCE requests $250,000 to examine the possible modification or expansion of the Auto-DR Express Control Incentive Program.

---

95 *See id.*, pp. 42-43.

96 *Id.*, p. 56.

(3) Add the Base Interruptible Program, 15-minute option (BIP-15) as a Qualifying DR program eligible to receive Auto-DR incentives

SCE proposes adding BIP-15 as a qualifying DR program eligible to receive Auto-DR incentives. In D.18-11-029, the Commission confirmed that reliability demand response resources (RDRR) bid in the CAISO market through the Auction Pilot should not be eligible to receive Auto Demand Response control incentives.[97] These resources are reliability resources and the Commission has stated that "reliability programs are rarely dispatched and should not be eligible for these incentives."[98] However, the frequency of BIP dispatches has recently increased, with eight events occurring in 2020 and dispatches are expected to remain elevated due to capacity shortages and changing grid conditions attributed to climate change that are likely to continue in the coming years. SCE proposed to limit Auto-DR incentives to BIP-15, which requires the BIP participant to reduce their load within 15 minutes of receiving the event notification, for the reason that when a customer installs Auto-DR controls their load will immediately drop as soon as they receive a signal from SCE making BIP-15 the logical option for Auto-DR participants.

Currently, Auto-DR qualifying DR programs are the Capacity Bidding Program (CBP), Critical Peak Pricing (CPP), DRAM proxy demand resources (PDRs), and Real-Time-Pricing (RTP). Since SCE is not requesting DRAM funding beyond 2023 at this time, it is not currently anticipated that DRAM will be a qualifying program option after 2023.[99] Adding BIP-15 as a qualifying program will provide another viable option for customers currently enrolled in or who were planning on in DRAM. SCE has historically seen customers / aggregators on DRAM move to BIP or CBP when their DRAM contracts ended. Allowing BIP-15 as a qualifying program would open the Auto-DR option to these large MW, reliable customers, and fast-acting customers. Auto-DR can automate the processes of these BIP customers, allowing their available capacity to be even more reliable and faster.

---

97 D.18-11-029, Decision Resolving Remaining Application Issues for 2018-2022 Demand Response Portfolios and Declining to Authorize Additional Demand Response Auction Mechanism Pilot Solicitations, OP 6.b.

98 *Id.*, p. 46.

99 In the event DRAM continues beyond 2023, SCE may request supplemental funding for Auto-DR.

Finally, automation may allow some customers previously not suited for BIP to enroll in BIP now that the load drop would be automated.

SCE anticipates an additional 10 MW of Auto-DR applications with DRAM as the qualifying program to be approved and paid before the end of 2023. To ensure the continued availability and reliability of these MW beyond 2023 (and DRAM), BIP-15 should be added a qualifying program to offer these customers another option to move their automated load reduction.

SCE requests $625,000 to implement the addition of BIP-15 as a qualifying DR program for Auto-DR incentives. The cost includes updating multiple systems to accommodate new program enrollment rules.

(4) Incentive Structure/Funding

SCE does not propose any changes to the Auto-DR Program incentive structure which are Auto-DR Customized Control Incentives are $200/kW (based upon the verified load reduction), not to exceed 75% of total eligible costs, and Auto-DR Express Control Incentives are $300/kW (based upon the measure(s) deemed kW value), not to exceed 100% of total eligible costs.

3. Program Budget

Table VI-18 provides SCE's 2024–2027 proposed funding for the Technology Incentive Program.[100] The proposed budget for SCE labor funds approximately 4.1 FTEs, including administration and overhead expenses.

The non-labor budget funds engineering support expenses, and OpenADR membership as well as staff training and administrative costs. In addition, the non-labor budget funds the proposed research into expanding Auto-DR Express Control Incentives and implementation of BIP-15 as a qualifying Auto-DR program (both described above). The incentive budget for 2024–2027 includes $8.3 million for PCT incentives and $9.6 million for Auto-DR incentives. The marketing budget primarily includes funding for costs associated with updating the PCT and Auto-DR webpages on

[100] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for TIP alone is included in this application.

sce.com, updates to the Auto-DR Guidelines, and informational materials, such as fact sheets and Frequently Asked Questions (FAQs).

Table VI-18
Technology Incentive Program
2024-2027 Proposed Budget
(Nominal $ millions)

Technology Incentive Program						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.517	.524	.564	.580	2.185
2	Non-Labor Total	1.141	.272	.279	.286	1.977
3	**Program Total**	**1.658**	**.796**	**.843**	**.866**	**4.162**
4	Incentives	4.475	4.475	4.475	4.475	17.90
5	Marketing	.020	.020	.020	.020	.080
6	EM&V	-	-	-	-	-
7	**Grand Total**	**6.153**	**5.291**	**5.338**	**5.361**	**22.142**

B. Emerging Markets and Technology

SCE's Emerging Markets and Technology (EM&T) program facilitates the development and deployment of innovative and flexible demand response-enabling technologies, software, and system applications that encourage cost-effective customer participation and sustainable performance in SCE's DR programs, incentives, and time-variant rates. The program funds laboratory research and testing services, product demonstrations, market studies, assessments of advanced communications protocols, and scaled field deployments of DR-enabled end use systems that help high-tech startups and commercial consumer markets adopt DR methods and standards.

1. Program Background

SCE endeavors to support development and availability of innovative cost-effective technologies, thereby enabling customers to manage their energy costs though the adoption of flexible energy usage strategies. The EM&T program provides a delivery channel to accelerate new products and services for DR programs and for the wider DR and energy industries, as California often leads the way for the rest of the world.

The EM&T program activities are also designed to identify and mitigate barriers that impede or restrict SCE customers and the overall consumer industry from understanding and adopting effective DR behaviors and technology measures. The program's technology adoption influence strategy includes delivering upstream industry market facilitation to bring DR awareness to the consumer industry so that there is a flow of "off the shelf" systems that customers can adopt. This includes, through technology-driven DR standards advocacy, collaborating on innovative demonstration projects and joint research studies with state agency grant awardees and research firms to bring innovation to market as it evolves year after year.

Throughout the 2018-2022 program cycle, the SCE EM&T program has continued the advancement and deployment of innovative demand response-enabling technologies and enhanced their value for all of SCE's customers through not only its direct research activities, but also through leveraging external collaborative cost-sharing partnerships. The diverse portfolio of emerging technologies, software, and innovative solutions within the EM&T program help SCE support the State's efforts to increase demand flexibility and reduce greenhouse gas emissions solutions.

The EM&T program works collaboratively with other California IOUs with similar DR programs, as well as local academic institutions, national laboratories, trade allies, and public agencies, to investigate innovative applications and software that could enable increased customer participation in SCE's DR program portfolio. The EM&T program actively shares its activities through many research and non-profit DR affiliate organizations, including the Electric Power Research Institute (EPRI), OpenADR Alliance (OADR), Peak Load Management Alliance (PLMA), Association of Energy Services Professionals (AESP), Smart Electric Power Alliance (SEPA), and collaborates with many partners and scan a wide variety of sources to identify suitable project candidates.

The EM&T program executes its core investment strategies to align with the guidance from D.17-12-003, and the learnings and results from each activity, study, and assessment type are shared via multiple technology transfer channels with DR stakeholders, research organizations, and policy makers. These strategies facilitate DR-enabling technology education, in-situ field testing, capture of customer perspectives, understanding of market barriers, promotion of technology transfer, and, ultimately, customer and program adoption.

The five EM&T core investment strategies are:

- Intake and Curation: Identifies studies, projects, or collaborations for inclusion in EM&T's portfolio and selects which ones to fund based on a well-informed understanding of the broader industry context. EM&T interacts with a range of entities in the DR markets ecosystem—manufacturers, other utilities, industry organizations, universities, research labs and others to assess opportunities that best fit the program.
- Market Assessments: Create a better understanding of the emerging innovation and developments of new consumer markets for DR-enabling technologies and an awareness of consumer trends for smart devices. Assess both the viability of a technology and the customer markets by reviewing the overall delivery channels and upstream opportunities to engage manufactures distributors and end point sales to better understand market facilitation.
- Technology Assessments: Assess and review the performance of DR-enabling technologies through lab and field tests, and demonstrations designed to verify or enable DR technical capabilities to help manufacturers meet the needs of the DR programs.
- Technology Transfer: Advance DR-enabling technologies to the next step in the adoption process, including raising awareness, developing capabilities, and informing stakeholders during the early stages of emerging technology development for potential DR program and product offerings.
- Strategic Advocacy: Support key market actors to integrate DR-enabling emerging technologies into their decisions, including promoting DR-enabling technologies for program adoption and supporting the development of open industry standards.

The EM&T program has also leveraged other funding sources to enhance and sustain DR innovation for future energy markets in California. EM&T recognizes the cost-efficiency opportunities offered by collaborating on research of DR-enabling technologies performed by both the State and national research programs and will continue to leverage these collaboration opportunities to bring that research and learnings to the SCE DR programs.

2. <u>Program Changes</u>

In the 2023–2027 DR program cycle, the EM&T investment portfolio will build on its previous achievements and address the increase in State research priorities to examine new opportunities to enable customer demand flexibility and integrate renewables and decentralized energy resources. The EM&T program will pursue an aggressive research agenda in keeping with state policy needs and industry progress, and position SCE to develop the advocacy for technologies that support innovative "new models of DR."

The EM&T program will increase its efforts to identify, develop, and demonstrate new and innovative pre-commercial technologies that ultimately will be deployable commercially at scale to improve the reliability of the state's electric grid. The program will conduct applied research and technology demonstration and deployment projects in California that will adopt the CEC's Load Management Standards to increase the use and market adoption of advanced, interoperable and flexible DR technologies and strategies as grid resources and facilitate integration of mass market DERs. Through its partnership with other IOUs, the program will continue to research, test and demonstrate these new flexible load technologies and strategies and collaborate with other research initiatives funded at the State and national levels.

The deliverables from the EM&T program such as reports and webinars will continue to develop "market ready" solutions that can mitigate the uncertainty risk for California utilities to cost-effectively apply these load flexibility technologies and strategies, thereby dramatically increasing their adoption, deployment, integration and use. This, in-turn, will lead to greater end use load flexibility and enhanced, cost-effective system reliability, which ultimately benefits all California ratepayers. Reports and webinars will be conducted throughout the program's term to communicate the effects of targeted technologies and associated strategies assessed and reviewed in a regular basis, and market assessments will also consider the effects of technologies on the local distribution infrastructure when adopted at greater scale in the future.

With the diverse and dynamic research portfolio that it manages today, the EM&T program is positioned to support DR innovation in future years as California faces policy and regulatory changes, as well as address the challenges of customer enabling technologies for new innovative dynamic rates that are in the process of being piloted in California.

The EM&T program will also continue its work with the limited income (LI) customers, by leveraging lessons learned from SCE's current technology demonstration work in disadvantaged communities (DACs) and environmental social justice (ESJ) communities. This includes continuing demonstration projects, identifying technology pathways for market adoption and building on existing analysis of likely new forms of flexible rate designs to anticipate and mitigate adverse impacts on the DAC and/or LI communities. Examples of these include facilitating the assessment of enabling DR technologies for low income and transitional housing developments with both building developers and other research organizations such as with EPRI and the California Energy Commission.

The EM&T program will also continue in its efforts to connect clean energy entrepreneurs with the funding, training, resources, and expertise needed to help turn innovative concepts into commercially viable DR products and services that benefit consumers, energy service providers, and society overall. Anticipated growth by the EM&T program in end use technology research will fund an investment portfolio of a wide range of pre-commercial innovations to support the deployment of new, commercially-available, signal-responsive products such as refrigeration equipment, air conditioners, water heaters, heat pumps, HVAC and thermostat controls, plug load control devices, battery storage and EV charging systems—and other end-use technologies in residential and commercial buildings.

Since a key function of the EM&T program is to support California's increasing and urgent goals for decarbonization and renewables integration, continued investments in research and innovation are necessary to accelerate technology performance and implement cost improvements that can make new emerging technologies and software easier, faster and readily available to electricity ratepayers to enhance their performance in DR programs.

For 2023–2027, additional efforts and funding are needed to specifically catalyze advancements to support the cost-effective implementation of the CEC's Load Management proceeding, legislation such as SB 100, California's Title 24 new construction, and future state and local jurisdictional policies in areas including renewable and zero-carbon generation, long-duration energy storage, and large-scale load flexibility. Intaking more innovative new ideas for EM&T projects and activities are essential to increase customer end-use demand flexibility, ultimately providing an increased price elastic response to current and future retail rate designs, which will enhance grid stability and take advantage of new electric loads to help resolve reliability issues related to achieving California's renewable generation and decarbonization goals. To meet these goals in the 2023–2027 program cycle, the EM&T program has updated the following key portfolio investment tactical activities in line with its five investment strategies to meet the needs of customers and State policy drivers:

- Increase efforts to assess and advocate for advanced signal-responsive (price, marginal greenhouse gas emissions, etc.) and interoperable technology solutions that enable commercialization and market adoption of flexible demand resources, innovative real-time pricing models, and transactive energy approaches to automated customer energy management;
- Review and test the performance and costs of innovative and emerging DR enabling technologies to provide a clear value proposition and business use cases for customers, building owners, ratepayers, load serving entities, and grid operators in concert with manufacturers and distributors;
- Develop scalable flexible software technologies that address the challenges of increasing signal-responsiveness and meet the needs of multiple actors—including customers across all sectors, grid operators, utilities and other load serving entities, and service providers (aggregators);
- Share technical knowledge developed through the research activities with a larger audience of DR and DER stakeholders as well as rate designers and other energy service providers in California to accelerate standardization, adoption, reduce customer and infrastructure costs, increase electrical grid benefits, and reduce greenhouse gas emissions;
- Demonstrate advanced technologies and operational strategies that increase demand flexibility with a goal of mass-market technology advancement that is not limited to single-end use

enabling technologies, develop mass market customer interfaces and experience understanding, and document the performance, consumer acceptance, and the value of the economic and environmental benefits to the customer and the system, of flexible demand technologies and strategies that enable mass market demand response;

- Facilitate the integration, aggregation, and scalability of flexible and interoperable demand response technologies with energy efficiency measures through integrated demand side management (IDSM), distributed generation balancing, storage management, and electric transportation vehicle to building (V2B) strategies with the goals of optimizing customer load shapes, bills, and productivity while reducing greenhouse gas emissions and providing operational savings to the wholesale markets and retail providers;

- Actively pursue additional research into new models of transactive dynamic rate design and real time subscription tariff elements and conduct comprehensive studies that fully assess the costs and benefits of real-time rates, including the required infrastructure, manufacturer interest, and customer impacts. The research efforts will further examine the ideas in the 6-step Distributed Energy Resource (DER) & Demand Flexibility roadmap described by Energy Division Staff at the May 25, 2021 workshop on Advance DER and Demand Flexibility Management.[101] In addition to the current Dynamic Rate Pilot (aka UNIDE/TeMix) that is in active deployment and authorized by D.21-12-015,[102] the EM&T program will also continue to expand upon this research and examine new economic options for both transactive price models and real time pricing with other parties and stakeholders, and to demonstrate how new forms of distributed energy resources can act as both customer assets and grid interactive resources.

Discovering new flexibility technologies and strategies for customer energy management and realizing their potential for adoption and market transformation through codes & standards, policy

[101] Advanced DER and Demand Flexibility Management Workshop *available at* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

[102] *See* D.21-12-015, OPs 59 and 60, and Attachment 1, p. 10.

enhancements and regulatory action will be an important outcome of the resulting technology research and development activities within the EM&T program. As utility pricing and incentive structures more accurately align customer incentives with grid needs, the additional investment in research and development provided by the EM&T program will continue to refine end-use automation technologies and influence retrofit and new construction building design, to achieve retail load flexibility at the scale needed to successfully transition California to a 100% carbon-free energy system by 2045.

Pursuant to D.21-12-015, the Commission directed SCE to conduct a three-year (2022-2024) dynamic rate pilot using a rate calculation platform developed by TeMix.[103] SCE's authorized budget of $2.5 million[104] was based on TeMix's proposed unified, universal, dynamic economic (UNIDE) program, an extension of the TeMix Retail Automated Transactive Energy System (RATES) platform piloted by California Energy Commission (CEC) Electric Program Investment Charge (EPIC) grant EPC-15-054 and demonstrated in SCEs territory as a subscription-based transactive retail pricing model,[105] which included approximately 100 retail customers on the SCE distribution grid[106] and budgeted for $3.2 million.[107] SCE is requesting an additional $1.25 million to expand the scope of the Dynamic Rate / UNIDE pilot per the Commissioner's encouragement in D.21-12-015 to include "SCE residential, commercial, and industrial customers with smart-enabling price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads."[108]

---

103 *See* D.21-12-015, p.96. On January 5, 2021, SCE submitted Advice 4684-E describing the scope, partners, shadow bill implementation, dates, and tariff design for the dynamic rate pilot.

104 *Id*., Attachment A, p. 10.

105 *See* R.20-11-003, Reply Testimony of Southern California Edison Company Phase 2, p. 8.

106 *See* CEC's, Final Project Report: Complete and Low-Cost Retail Automated Transactive Energy System (RATES), p. 49, *available at* https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-038.pdf.

107 *Id*., Appendix J, p. J-2.

108 *See* D.21-12-015, Attachment 1, p. 11.

3. Program Budget

SCE's proposed EM&T budget for 2024 through 2027 is shown in Table VI-19 below.[109] This budget request includes both labor and non-labor costs to manage and deliver the advanced technical EM&T research portfolio of engineering projects that have been identified in the testimony preceding this section. In addition, SCE will (1) broaden its portfolio of projects and demonstrations, through the coordination with other agencies and state-funded DR research projects, such as the CEC's EPIC 4 awards for advanced innovative demand response emerging technology; (2) support the CEC's load management and SB49 flexible rulemakings for enhancing new models of dynamic pricing and secure communication standards; and (3) increase the level of market facilitation and research development with EPRI, LBNL, NREL, and other utilities and CCAs through partnerships for DR/DER/DRP technology assessments. These co-funding and cost sharing activities involve other externally funded research activities that include the Department of Energy, non-profit grants, and private sector funding.

SCE's proposed labor budget funds one FTE dedicated to the EM&T program management and multiple part time project support and management personnel totaling approximately 2.7 FTEs per year.

Table VI-19
Emerging Markets and Technology
2024-2027 Proposed Budget
(Nominal $ millions)

Emerging Markets and Technology						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.461	.450	.482	.496	1.890
2	Non-Labor Total	4.725	3.40	3.450	3.450	15.025
3	**Program Total**	**5.186**	**3.850**	**3.932**	**3.946**	**16.915**

[109] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for EM&T alone is included in this application.

VII.

CATEGORY 5: PILOTS

This chapter presents SCE's proposal for DR Pilot programs to be conducted in this funding cycle. In D.12-04-045, the Commission established the requirement that all future DR applications to include a pilot plan for all proposed DR pilots.[110] For this DR application SCE is proposing two pilots: the Mass Market DR Pilot and the Flexible DR Pilot.[111] In addition, SCE describes its proposals for the Emergency Load Reduction Program and its Charge Ready DR pilot.[112]

Pilots are important components in SCE's DR portfolio as they help inform future program design required to achieve more effective programs and/or programs that reach a larger number of participants. In this program cycle, SCE's proposed Mass Market DR (MMDR) pilot is critical to expanding DR programs beyond large commercial and industrial customers to include areas of electrification and smart technology advancements in the residential and small commercial customers. SCE's Flexible DR Pilot is designed to determine the ability of operators of water and wastewater systems to provide both energy storage capacity during periods of excess renewable energy and consumption during periods of excess generation by renewable resources.

A. Emergency Load Reduction Program (ELRP) Pilot

The ELRP, which includes the Residential ELRP or Power Saver Rewards Program, is a voluntary, non-penalty, bidding pilot program that offers incentives to participants for their Incremental

---

[110] D.12-04-045, OP 80. Specifically, the Commission requires a pilot plan for each proposed pilot that includes: a) problem statement; b) how the pilot will addresses a DR goal or strategy; c) specific objectives and goals; d) a clear budget and timeframe; e) relevant standards or metrics; f) methodologies to test the cost-effectiveness of the pilot; g) an Evaluation, Measurement and Verification plan; h) and a strategy to identify and disseminate best practices and lessons learned.

[111] In addition to the pilot programs described in this section, SCE is also conducting its Demand Response Pilot in Disadvantaged Communities authorized in D.17-12-003. While the Commission approved SCE's request to extend this pilot through Q1 of 2024 (*see* Advice 4454-E), SCE is not seeking funding in addition to the $1 million authorized in D.17-12-003. SCE is also conducting the ELRP pilot as authorized in D.21-03-056 and modified by D.21-06-027 and D.21-12-015.

[112] In addition to the pilot programs described in this Chapter, the Commission directed that SCE conduct a dynamic rate pilot to be included in its Emerging Markets and Technologies program. (*See* D.21-12-015, p. 96). As described in the EM&T program above (Section VI.B), SCE is also requesting additional funding for this Dynamic Rates/UNIDE pilot.

Load Reduction (ILR) during an ELRP Event. ELRP consists of two groups (Group A and B) each with various sub-groups as follows:

- Sub-Group A.1. – Non-Residential Customers
- Sub-Group A.2. – Aggregators of Non-Residential Customers, including BIP Customers
- Sub-Group A.3. – Non-Residential Customers with Rule 21 Exporting Distributed Energy Resources
- Sub-Group A.4. – Virtual Power Plant (VPP) Aggregators
- Sub-Group A.5. – Vehicle Grid Integration (VGI) Aggregators
- Sub-Group A.6. – Residential Customers (Power Saver Rewards Program)
- Sub-Group B.1. – 3rd Party Demand Response Providers (DRPs) with Proxy Demand Resources (PDRs)
- Sub-Group B.2. – Capacity Bidding Program (CBP) Aggregators

1. Program Background

As a result of a prolonged heat storm in mid-August 2020 that required CAISO to initiate rotating outages, the Commission initiated the Emergency Reliability Rulemaking (R.20-11-003) to "ensure reliable electric service in the event that an extreme heat storm occurs in the summer of 2021."[113] In D.21-03-056 the Commission directed the establishment of the ELRP pilot to prepare for the potential for extreme weather in the summers of 2021 and 2022 "as a tool that can provide emergency load reduction and serve as an insurance policy against the need for future rotating outages."[114] D.21-03-056 authorized an initial pilot period of the 2021-2025 for the ELRP pilot with "years 2023–2025 subject to revision in the [November 2021] DR application proceeding."[115] In D.21-06-027 the Commission modified ELRP to have both day-of and day-ahead triggers for Group A.[116] In

[113] OIR to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021 (R.20-11-003), p. 1.

[114] D.21-03-056, OP 7.

[115] *Id.*, p. 19.

[116] D.21-06-027, OP 2.

December 2021, the Commission issued D.21-12-015 which made additional modifications to the ELRP pilot and expanded eligibility for customers and aggregators, as well as, increasing the incentive rate to $2 per kilowatt-hour ($2/kWh).[117] In D.21-03-056 and D.21-12-015, the Commission authorized the IOUs to propose annual modifications and improvements to the ELRP through an annual advice letter process. SCE will continue to utilize the advice letter process to propose future modifications and improvements to the ELRP. Pursuant to D.21-12-015, SCE requests funding for ELRP in this application.

2. Proposed Changes

Per D.21-03-056 and D.21-12-015, ELRP is a five-year pilot (2021-2025) to "allow the large electric IOUs and CAISO to access additional load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages while minimizing costs to ratepayers."[118] SCE describes the proposed changes and budgets for ELRP for three distinct timeframes (2023, 2024–2025, and 2026–2027) below.

a) 2023

Funding for ELRP for 2023 has already been approved and authorized by the Commission in D.21-12-015. For 2023, SCE does not propose any changes to the program and does not anticipate the need for additional funding beyond what has already been authorized in that decision.

b) 2024–2025

For the 2024-2025 period, SCE proposes to extend ELRP with no changes to the structure or incentives of the program. As described in Exhibit SCE-01 of this Application, SCE is concerned that Flex Alert's paid marketing efforts are not optimal for increasing DR enrollment and participation for Residential ELRP and may lead to customer confusion. Therefore, SCE proposes to discontinue funding for Flex Alert Marketing, Education and Outreach (ME&O) beginning in 2024.[119] Doing so will enable SCE to develop personalized messaging focused on SCE's ELRP and encourage

[117] D.21-12-015, pp. 31-42, and Attachment 2, pp. 2-10.

[118] D.21-03-056, p. 18.

[119] SCE plans to continue to rely on Flex Alert triggers for the residential ELRP during this period.

enrollment and participation. In addition to funding for administration, systems, measurement and evaluation (M&E), and incentives, SCE's proposed budget also includes funding for ME&O.

During the summer when customer participation is critical, SCE's ME&O efforts will be to educate customers on the actions they need to take when ELRP events are triggered and the benefits of doing so. To achieve this goal, SCE will leverage customer segmentation, predictive modeling, personalized messaging, and marketing automation to implement a targeted marketing outreach and education campaign through a combination of TV, radio, digital media advertising in up to three languages, SCE.com, social media, and direct communications as appropriate. SCE also plans to partner with key CBOs to better address limited income and DAC customers. SCE estimates the cost of the campaigns to encourage customer participation will total approximately $3.5 million per year for the 2024–2025 period. This estimate is based on similar efforts SCE conducted for the Time of Use (TOU) Awareness and Rate Options campaigns.

Before and after the summer months, SCE's efforts will focus on customer retention and acquisition. SCE estimates that approximately two million residential customers will be defaulted onto the program in 2022. To maintain this level of enrollment, SCE plans to conduct ongoing ME&O activities to retain enrolled customers as well as encourage new enrollments. Specifically, SCE expects to utilize email, social media, and other outreach tactics at a non-labor cost of approximately $600,000 per year during this period.

SCE estimates that market research, content creation, and other marketing support necessary to conduct the activities above will total approximately $675,000 in non-labor expenses per year during this period.

In addition to continuing to operate ELRP pilot as envisioned in D.21-03-056 and D.21-12-015, SCE proposes to transition Charge Ready DR pilot customers as described in Section VII.D below.

SCE also intends to evaluate and develop a plan to transition certain ELRP customers and aggregators to a capacity DR programs or solicitations such as CBP or all source RFO solicitations, if possible.

c) 2026–2027

SCE anticipates that the ELRP will be successful in engaging and educating many new customers to DR, especially low income and DAC customers. This creates an opportunity to provide additional DR capacity by transitioning ELRP customers to other DR programs. Therefore, for the 2026-2027 period, SCE proposes to continue to offer ELRP to directly enrolled customers (e.g., ELRP sub-groups A.1., A.3., and A.6.) and transition ELRP to an emergency reliability resource. For instance, SCE proposes to eliminate the pilot's minimum dispatch duration and reduce the annual dispatch limit from 60 hours to 30 hours. Second, SCE proposes to reduce the incentives from $2 per kilowatt-hour ($2/kWh) to $1/kWh. Finally, SCE proposes to use different triggers for ELRP beginning in 2026 and cease the use of Flex Alerts as the program trigger for Residential ELRP.

During the 2026–2027 period, SCE will continue its marketing efforts described above. However, due to the transition and program changes beginning in 2026, SCE does not anticipate the need for the same level of marketing, education and outreach (ME&O) as in the 2024–2025 period. As a result, SCE forecasts non-labor ME&O cost of approximately $2.5 million per year.

In Section VII.B below, SCE proposes conducting a Mass Market DR pilot during the 2024–2027 period to study program design elements that would enhance mass market participation in DR programs. Though that effort is intended to inform the design of a new DR program to be launched in 2028, SCE anticipates that lessons learned in the MMDR pilot may be applied to the ELRP pilot during the 2026–2027 period. Hence, in addition to those identified above, SCE may propose changes to ELRP via the annual Tier 2 advice letter established in D.21-12-015[120] based on the interim results from the MMDR pilot as early as 2025.

3. Proposed Budget

SCE's proposed ELRP budget for the period 2024–2027 is presented in Table VII-20 below. The proposed budget for SCE labor funds approximately 6.4 FTEs required to manage the program, including administration and overhead expenses.

[120] *See* D.21-12-015, OP 22 and Attachment 2, p. 20. The December 31 filing date for this advice letter was changed to January 15 in D.21-12-069, OP 1.

The non-labor expenses in the proposed budget includes third-party program implementation, EM&V, and aggregator administration costs for the 2024-2027 period. In addition, the proposed budget includes funding for SCE's ME&O activities as described above.

Table VII-20
Emergency Load Reduction Program Pilot
2024-2027 Proposed Budgets
(Nominal $ millions)

Emergency Load Reduction Program (ELRP)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	1.576	1.746	1.162	1.197	5.680
2	Non-Labor Total	11.009	11.063	5.661	5.755	33.488
3	**Program Total**	**12.584**	**12.809**	**6.823**	**6.952**	**39.168**
4	Incentives	60.0	60.0	9.30	9.30	138.60
5	Marketing	5.032	5.074	2.534	2.574	15.213
6	EM&V	.352	.355	.360	.366	1.433
7	**Grand Total**	**77.968**	**78.238**	**19.017**	**19.191**	**194.415**

Note: Marketing and EM&V costs for pilots are included here and not in Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

B. Mass Market Demand Response (MMDR) Pilot

SCE is proposing to conduct a DR pilot to determine the program design elements for an SCE-offered mass market demand response program to be launched in the DR cycle beginning in 2028.[121]

1. Background / Problem Statement

The continued effects of global warming with the increased probability of extreme weather, advancements towards electrification, renewable penetration, and steep ramping are all contributing to a changing industry that requires programmatic solutions designed well in advance of achieving California's Clean Energy ambitions. DR is a vital component in the achievement of California's 2045 decarbonization goals through lowering customer consumption and keeping consumer

[121] In this context, mass market refers to residential and small non-residential customers.

costs affordable.[122] DR program optimization and growth opportunities reside in the mass market sector, which includes residential and small commercial customers.

"We expect major changes in how customers will use electricity, which will place unprecedented demands on the grid. Beyond an expected increase of 60% in electricity demand and 40% in peak load by 2045, electrification of mobility and mass adoption of distributed energy resources (DERs) like solar and batteries will make electricity demand more variable — yet increase customers' expectations for reliability and resilience."[123] With this in mind, it is critical to advance and innovate our current demand response offerings into solutions that solve for both the safe and reliable delivery of service while providing economic benefits to customers as electricity costs increase.

2. Alignment with DR Strategy

SCE has delivered valuable mass market demand response programs for over 35 years, but it is necessary for the evolution and optimization of its current portfolio to improve and learn the demand flexibility and load modifying capabilities of its current and future enrollees. Furthermore, system emergencies during the summer of 2020 and the continued need for demand response to solve for capacity and/or grid issues have demonstrated the value that DR plays in ensuring reliability and resiliency.

As electrification increases and customer access to technology solutions become more readily available, it will be necessary to evolve mass market demand response so that it is able to:

a. Scale to mass adoption (allowing for increased participation while decreasing individual customer sacrifice).
b. Allow a flexible, technology agnostic approach not limited to one device / one service account participation.

---

[122] SCE's, Pathway 2045: Update to the Clean Power and Electrification Pathway, (Nov. 2019) *available at* https://download.newsroom.edison.com/create_memory_file/?f_id=5dc0be0b2cfac24b300fe4ca&content_verified=True.

[123] SCE, Reimagining the Grid, (Dec. 2020), *available at* https://download.newsroom.edison.com/create_memory_file/?f_id=5fcfb5f62cfac23b06eb7d39&content_verified=True.

c. Be flexible in its utilization to respond to the dynamic grid and system conditions by accommodating varied dispatchability, high price mitigation and shifting of load in response to changing load curves and ramping conditions,

d. Maintain a customer focus through design simplification that increases customer participation and is available for multiple customer classes, while providing necessary economic relief as electricity utilization increases.

As a result of increasing electrification, SCE anticipates significant impacts to the grid which will require innovative and dynamic demand response solutions to mitigate against potential resource constraints and ensure reliable service to our customers.

3. Goals & Objectives

a) Determine future economic viability: customer retail payment, technology rebates for a cost-effective design

In the MMDR pilot, SCE will determine how the level of customer incentivization should be quantified and compared to existing available DR programs; determine if incentive levels should vary by technology or should incentive payments be technology-agnostic, based on reduction at the meter; and study technology rebate to determine a) the efficacy of driving DR participation and b) the feasibility of implementing a deemed approach to evaluating enabling technologies as they become widely available.

b) Determine load reduction capabilities of multiple end use devices participating in a single program

SCE will evaluate the dynamic dispatchability when customers are participating in DR events with multiple end use devices. Flexible dispatch strategies will be studied to enable SCE to respond to varying conditions thereby, optimizing the value and benefits of the program/pilot while being able to dynamically respond to circumstances when needed.

c) Conduct measurement and evaluation of performance.

In the MMDR pilot, SCE will conduct a M&E study that will determine the efficacy of the DR program dispatch and performance using a third party. This study will compare and contrast performance against different baseline methodologies, technologies, and customer segments and demographics.

d) User Experience and Customer Feedback

In the MMDR, SCE will study customer awareness, knowledge and understanding of their demand response options. This effort will also include market research to determine customers' decision-making process and overall experience in the pilot in order to inform future program design for mass market customers.

e) Resource Utilization

Finally, SCE will study the best fit for demand response utilization to determine whether the Next Generation of DR for mass market is most beneficial for CAISO market utilization to mitigate high prices, load management utilization to attempt to modify the duck curve, utilization to mitigate grid challenges or the right combination and flexibility for multiple uses will be evaluated as part of this process.

4. Standards and Metrics

It is our objective to take the lessons learned from this pilot to create an easily understandable program that provides economic support to customers and increases automation of customer participation during load reduction events. Achieving these goals is an important step towards the advancement of Pathway 2045 and meeting the needs of the Grid of the Future as described in "Reimagining the Grid."[124]

The results of this pilot will serve as the basis for SCE mass market demand response offerings in the future. To be successful, future programs must have the ability to scale and adapt while increasing the demand flexibility of our mass market population. A successful mass market program must reduce the risk to, and sacrifice of, individual customers that cause distrust and attrition in order to achieve and maintain increased adoption and participation.

---

[124] *Id.*

During the MMDR pilot, SCE will test vendor and technology capabilities, customer adoption and programmatic design of a future technology agnostic offering under one tariff. This will align to the availability of new systems, technology, and connected devices (i.e., wide adoption of connected devices and significant advancements towards electrification) in 2028-2032.

5. Method to Test Cost Effectiveness

The MMDR pilot will not be evaluated for cost-effectiveness. Rather, the objective of this pilot is to determine the design elements of a single tariffed, technology agnostic mass market program to be offered in the next program cycle. While the standard requirements to determine cost effectiveness of a program will be considered in that future design, as described in SCE-01, SCE urges the Commission to consider other benefits (e.g., contributions to grid reliability) when assessing future DR programs.

6. Measurement and Evaluation Plan

The main objectives of the evaluation study will be to report on the number of customers targeted (per customer segment), the number of customers enrolled, the number of events called, the number of event participants, and the event performance of participants. Additionally, SCE will seek participant feedback that includes customer awareness, knowledge and understanding of available pilot options, customer decision-making processes, why they enrolled or declined to enroll, their experience on the program, plan for responding to events, and the role of smart enabled technology in responding to and decreasing customers' energy costs. See Section IX.A.3.a) for detailed EM&V plans for the MMDR pilot.

7. Implementing Lessons Learned

Utilizing the comprehensive approach to program design described above will enable SCE to develop the next generation of effective customer-centric mass market demand response programs, that will accommodate changing market and system conditions.

Table VII-21
Mass Market DR Pilot
Overview of Planned Activities

Line No.	Description	2023	2024	2025	2026	2027
1	Key Activities	• Finalize detailed pilot strategies • Develop marketing / acquisition strategy & materials • Implement system changes	• Acquire participants • Test dispatch strategies • Gather participant feedback • Conduct EM&V	• Acquire participants • Test dispatch strategies • Gather participant feedback • Conduct EM&V	• Acquire participants • Test dispatch strategies • Gather participant feedback • Conduct EM&V • Submit full program proposal (November 2026)	• Maintain, optimize, & acquire
2	Residential Pilot Enrollment	0	1,700	2,300	3,100	4,100
3	Small Business Pilot Enrollment	0	350	600	850	1,100

8. Proposed Budget and Timeline

The MMDR Pilot is designed as a five-year pilot that will inform the design of a new mass market DR program in 2028. The proposed budget for the Mass Market Demand Response Pilot is presented in Table VII-22 below. The proposed budget for SCE labor funds approximately 0.5 FTEs, including administration and overhead expenses.

The non-labor budget funds system modifications, marketing, and EM&V studies.

Table VII-22
MMDR Pilot
2024-2027 Proposed Budget
(Nominal $ millions)

Mass Market Demand Response (MMDR) Pilot						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.073	.074	.079	.081	.307
2	Non-Labor Total	.037	.037	.038	.039	.151
3	**Program Total**	**.111**	**.112**	**.117**	**.119**	**.458**
4	Incentives	.091	.036	.061	.056	.244
5	Marketing	.127	.060	.085	.080	.352
6	EM&V	.100	.101	.102	.104	.407
7	**Grand Total**	**.429**	**.308**	**.365**	**.359**	**1.461**

Note: Marketing and EM&V costs for pilots are included here and not in Categories 6 (Marketing, Education & Outreach) and 7 (Portfolio Support).

C. Flexible Demand Response (Flex DR) Pilot

SCE proposes the Flexible DR Pilot to determine the potential for operators of water and wastewater systems to fill a critical role in California's resource strategy by providing energy storage capacity during periods of excess renewable energy, while discharging during periods of peak demand.

1. Background/Problem Statement

As California continues to struggle with critical energy supply and infrastructure challenges, SCE will seek to identify and address the points of highest stress and develop the most effective solutions needed to meet those challenges. At the top of this list is California's water-energy relationship: water-related energy use and peak demand are growing rapidly in many parts of the state, stressing already constrained electricity delivery systems. When the electric infrastructure becomes stressed beyond its limits, water system reliability quickly plummets and threatens public health and safety.

California has invested billions of dollars in renewable resource acquisition to put the State on a path to 100% carbon-free electricity, but often excess renewable energy is either unused by the wholesale market or its generation is shut down by grid operators. Curtailments of renewable energy are antithetical to State policy. As renewables continue to grow at a rapid pace, near-term solutions are needed to bridge the technology gap. Fortunately, cost-effective remedies exist today in the State's water and wastewater systems that can, when properly configured and operated, become virtual electric batteries through changes in their operations known as "flexible demand response."

The water sector is the perfect electric reliability partner. Not only does water depend on reliable electric service to meet its mission critical goals but the water and wastewater utilities' service areas span hundreds of miles, usually contiguous with electric transmission and distribution infrastructure. Where there are communities and businesses that need reliable electric service, those same people and businesses need reliable potable water and water treatment services. Importantly, water-related flexible electric resources exist today and there is a substantial opportunity to develop these long term "flexible demand response" solutions by influencing the billions of dollars in upgrades and expansions being invested by the water sector and the State every year to build drought resilience.

2. <u>Alignment with DR strategy</u>

Water-energy efforts to-date through energy efficiency programs have focused on saving water to save energy. No substantial efforts have yet tackled leveraging flexibility inherent in the design and operations of water and wastewater systems to provide "flexible demand response", both to increase electric demand during periods of over-supply and to decrease electric demand during periods of under-supply. This Pilot proposes to develop a flexible demand response ("Flex DR") program that will encourage SCE's water sector customers to consider integrating opportunities to provide solutions to the challenges of renewable curtailment and the need for demand side flexibility into their long-term planning and capital investment processes.

When responding to grid signals, water sector customers can provide the price-responsive reliability demand-side resources that also meet the needs for renewable over-generation mitigation and local grid optimization of supply and demand into their long-term capital planning and day to day operations of water transmission, treatment, and pumped storage systems. This includes changes to the quantity and/or timing of pumping and processing, to include opportunities to either reduce load when needed to support electric reliability or shifting operations to mitigate the curtailment of renewables due to insufficient demand by increasing usage. (Note: For purposes of this Pilot, the definition of "pumped water storage" is very broad: essentially any water or wastewater function that involves pumping to end use (demand) and/or storage.)

3. Pilot Objectives

The Pilot will have the following key objectives:

1. Demonstrate the technical viability and economic value for SCE and its customers, stakeholders, and constituents of leveraging the flexibility in California's water system to provide cost-effective electric reliability support to SCE's grid operations.
2. Apply results of pilot demonstrations to the design of a cost-effective Flexible Demand Response ("Flex DR") program and potentially make tariff and program changes (for pumped water storage that coordinate their real time operations with local grid needs).
3. Improve future efforts for optimized distribution planning, including water sector capital investment infrastructure forecasting to support cost effective and widespread flexible resources as they come in line, optimize grid infrastructure investments by facilitating water sector input about planned developments, DER siting plans, and resiliency needs.
4. Enable water sector customers in the pilot to provide demand flexibility of approximately 4MW to 8MW of peak load shift.[125]

In 2017, SCE developed an approach for a water flexible DR program in its Overgeneration Pilot[126] with the assistance of SCE's water and wastewater utility customers, with the aim of leveraging the flexibility in water systems to provide near-term, cost effective electric reliability support. One combined water and wastewater agency stated during that time that it believed it could

---

[125] These figures assume that at least ten large water sector customers participate in the Flex DR pilot with a total of 40 MW to 80 MW of demand and a 10% demand shift potential.

[126] *See* Water Energy Innovations (WEI), Water Sector Over-Generation Mitigation and Flexible Demand Response Phase 2 Program Recommendations *available at* https://waterenergyinnovations.com/projects/water-sector-over-generation-and-flexible-demand-response/.

provide as much as 17 MW of over-generation mitigation support (approximately 85% of its annual peak electric demand) if cost savings and incentives were both sufficient and dependable to make the needed operational changes.[127] The SCE water sector customers and other pilot participants at that time through in person interviews also asserted that much more could be possible if SCE could provide relief from the impact of tariff demand charges, which limit flexible operations, and include incentives that could be counted on over a prescribed multi-year term that would enable the water sector to include consideration of such incentives in their capital improvement plans.

Key recommendations and findings from the Overgeneration Pilot[128] that support SCE's Flex DR pilot proposal include:

- **California's Water Sector is Replete with Flexibility**. Water sector flexible electric resources tend to flourish at existing sites with flexible capacity but can be developed at other sites with some capital investment and/or operational changes.
- **Existing Demand Response Programs need revision.** Meter-specific DR programs cannot accommodate the network design of water and wastewater utilities. Operational changes for DR participation may result in electric system impacts upstream, downstream, and/or laterally from a DR action taken at one particular meter premise. As a consequence, responding to DR events at the individual meter level may not achieve the desired electric impact at the targeted location. Other aspects of conventional DR and other energy programs' participation requirements (e.g., the consequences of demand charges in the context of a Flexible DR need) create barriers to water sector participation and sub-optimal program performance results given the emerging and ever-increasing need for flexible grid resources.

[127] *Id.*, Appendix A, p. A-1.

[128] *See* reports included at WEI, Water Sector Over-Generation Mitigation and Flexible Demand Response *available at* https://waterenergyinnovations.com/projects/water-sector-over-generation-and-flexible-demand-response/.

- **Water and wastewater utilities can do much more**. Water and wastewater utilities emphasized an urgent need to more clearly understand the electric system impacts that are in need of being targeted to maintain local reliability. With unambiguous information, water sector engineers, planners, operators, and their technical service providers can help SCE identify opportunities to provide electric reliability support, both on short- and long-term bases.
- **The water sector is driving development of in-house SCADA systems**. Of their own accord, many water and wastewater utilities are integrating real-time electric data into their SCADA systems and decision-making tools to further improve their ability to manage the time and cost of their energy use. These tools will be valuable in helping them determine how, when and where they can provide electric reliability support over a longer term horizon in parallel with electric system planning needs.
- **Building a culture of change and innovation requires training and buy-in**. First-line water utility operators have a pivotal role in energy management, but they need appropriate tools and training, and they need a supportive organizational leadership culture that values and recognizes initiative and results. Acknowledging the considerable value that water sector operators can bring to the Flex DR pilot through improved real-time decision making will help to build the needed organizational buy-in and support.
- **The appropriate relationship is that of an "Electric Reliability Partner" with SCE**. To fully leverage the flexibility inherent in water and wastewater utilities' systems and to influence the billions of dollars in ongoing investment in water sector infrastructure, an open and collaborative dialogue between the water and electric sectors is urgently needed. This starts with a collaborative dialogue about the shared values of reliability, and how each can partner with the other to bring value and reduce operational costs.

- **The path forward is a new water-electric partnership known as "Flex DR."** Water and wastewater utilities emphasized in the Overgeneration Pilot that they are not interested in shifting a few MW a few hours a year – they are interested in playing a major role in defining a new, electric reliability operations protocol that will help define the water sector's energy future, both as a reliability partner with the local electric utility, and as an infrastructure collaborator for long term investment. This is what they consider the new and urgently needed path forward. Of the positive lessons learned and opportunities for improvement recommended from the participants in the Overgeneration Pilot, there are multiple barriers to demand flexibility that the Flex DR pilot will explore and develop strategies for improving the ability for water agencies to participate in a new Flex DR program.

This proposed Flex DR Pilot will consider and utilize the learnings from the 2019 Overgeneration Pilot report with the assistance from the leading water and wastewater utility customers of SCE that participated in the Overgeneration Pilot. These customers are primed and ready to demonstrate innovative water sector "flexible DR" strategies (the 2017 Overgeneration Pilot did not include any demonstrations of flexibility). Proving the ability of these supportive water sector utilities to provide over-generation mitigation and local grid reliability support via pumped storage and operational changes is vital to successful development and implementation of a cost-effective Flex DR program.

The timing is opportune for a Flex DR pilot program of this scope and the groundwork has been prepared for the next phase of development. California is once again in a major drought and the State's water sector is actively engaged in preparing for substantial system and operational changes. Expedience is needed to influence the capital investment by water and wastewater utilities for upgrades and expansions that build drought resilience while meeting load growth. When design, development, and operations of water and wastewater systems are enabled and synchronized with the needs of the electric grid, cost effective benefits accrue to both water and electric ratepayers.

Since designing, developing, and implementing a new water sector industry-wide approach for water-energy reliability is not a trivial undertaking, SCE recommends that a "walk before running" approach through the implementation of this Pilot would be the most prudent. Fortunately, SCE has maintained a close collaboration with its water sector customers to focus on opportunities to align the water and electric sectors' needs and interests since the initial effort in 2019,[129] and the water industry is primed for the next step.

To add to the sense of urgency, the recent wholesale market reliability issues from the summer of 2020[130] are stark reminders of the need for the water sector to work with SCE to enhance local grid resilience while concurrently supporting regional electric system reliability. The critical nature of the current statewide drought must, of necessity, be front-and-center in considering potential opportunities and in strategic program design. Since "time is of the essence" for both the water and electric sectors, a three-pronged approach would be prudent:

a. Expedite the near-term development of water sector Flexible Electric Resources.

b. Integrate development of Flexible Electric Resources into future water sector resources, infrastructure, and operations.

c. Develop a Flex DR program design that could improve upon existing rate designs and enhance existing DR programs for capturing the "low hanging fruit" benefits in the water sector (i.e., existing customers who have identified opportunities to increase their flexible DR potential from the 2019 study[131]).

4. Standards and Metrics

As repeatedly asserted by water and wastewater utilities and evidenced in the sector's current limited participation in existing "shed" type of Demand Response programs, the fact that water

---

[129] Reports are available at Water Energy Innovations website, *see* Water Sector Over-Generation and Flexible Demand Response, *available at* https://waterenergyinnovations.com/projects/water-sector-over-generation-and-flexible-demand-response/.

[130] *See* CEC News Release, CAISO, CPUC, CEC Issue Final Report on Causes of August 2020 Rotating Outages, *available at* https://www.energy.ca.gov/news/2021-01/caiso-cpuc-cec-issue-final-report-causes-august-2020-rotating-outages.

[131] Reports are available at WEI website, *see* Water Sector Over-Generation and Flexible Demand Response, *available at* https://waterenergyinnovations.com/projects/water-sector-over-generation-and-flexible-demand-response/.

agencies can provide flexible DR capacity doesn't necessarily mean that water or wastewater can be operated at much higher levels for shorter durations of time. In addition to public health and safety concerns such as water quality, water and wastewater utilities must always operate their systems prudently, and in accordance with the best cost containment procedures given the existing electricity rates.

However, the decision as to whether and how to operate depends on many factors including the age, condition, and capacity of pumps and pipelines, and whether there is sufficient storage to hold the additional water being pumped until it is needed to meet demand. With proper planning and forecasting in coordination with the local grid needs, more flexible DR capabilities may be enabled when there is a close coordination between day ahead and week ahead grid operational schedules and water and wastewater system operations.

The water sector in California can shift its current daily energy loads (energy consumption moved into the middle of the day) by up to ~1000 MWh in the summer and ~2600 MWh in the winter. Annually it can shift between 750-1100 GWh. This equates to roughly 1/3 of the total energy use in the sector being shifted from current demand profiles. This flexibility also allows it to reduce its contribution to daily peak demand by >300MW, an approximately 80% reduction in its current contribution to the grid demand during the peak demand time period.[132]

5. Cost Effectiveness

The Pilot will not be evaluated for cost-effectiveness. Rather, the objective of this Pilot is to test the ability of water and wastewater utilities to change the quantity of their electric demand, both up and down, at specific times and in response to specific signals. The technical responses will be monitored and validated by SCE staff and/or technical consultants in close collaboration with water sector engineers. The costs of configuring the water and wastewater systems to be able to provide these types of changes in electric demand will be documented by the water sector participants and validated

[132] Conversation with the UC Davis Center for Water Energy Efficiency and their recent work for the California Energy Commission under GFO 16-305 and U.C. Davis Center for Water-Energy Efficiency, Advancing Demand Response in the Water Sector, *available at* https://cwee.ucdavis.edu/research/demand-response-water/.

by independent evaluators and a technical review committee. These costs of water system changes may include implementation of equipment that allows real-time control of water sector electric loads by SCE. While the standard requirements to determine cost effectiveness of a program will be considered in that future design, as described in SCE-01, SCE urges the Commission to consider other benefits that will be derived from the Pilot (e.g., contributions to grid reliability) when assessing future DR programs.

6. Measurement and Verification

Success factors for the Pilot will be jointly developed by water sector participants, SCE, and the Pilot Program's Technical Advisors. Surveys will be conducted after each pilot program task and/or phase to obtain feedback that can be used to refine proposed program elements. Ultimately, the overarching goal is to develop a program design that will successfully increase development and deployment of water sector Flexible Electric Resources. Water sector participation in, and commitment to, the recommended program design is essential. Based on previous responses and feedback from the water sector participants, it is anticipated that the empirical outcomes of the Pilot such as the amount of shift of energy or electrical demand may require an *ex post* assessment as well as a process evaluation, for which the criteria may be identified by the advisory team when the Pilot is initiated.

7. Implementing Lessons Learned

Through meetings, interviews, case studies, and workshops,[133] water and wastewater utilities conveyed the following common messages:

a. Mission-critical goals have priority. Water and wastewater utilities must assure they are meeting their mission-critical priorities before considering discretionary initiatives. Although energy is one of their largest costs and reducing costs is important to keeping utility services affordable for their customers, it is usually 3rd or 4th on their list of priorities. This will be a serious consideration in the pilot when designing a Flex DR program to enable the flexibility needed by the electric utility.

[133] *See* WEI, Water Sector Over-Generation Mitigation and Flexible Demand Response Phase 2 Program Recommendations, p. 68 *available at* 20191025-FINAL-Overgen-Ph2-Report-COMPLETE-2-Sided-Print.pdf (pagedesign.us).

Although the water sector would like to participate in new programs that are developed, they must always have the option to decline to participate and not be "locked in" if doing so might incur a risk to their mission-critical operations.

b. Energy reliability is a critical element of water reliability. The water sector is acutely aware of the critical relationship between reliable energy service and their ability to provide reliable water and wastewater utility services. It is top of mind whenever there is a disruption to electric service, whether through an electric utility outage or a natural disaster such as earthquakes. Most recently, water and wastewater utilities affected by fire - whether due to an actual fire or electricity being turned off to reduce fire risks – are urgently revisiting their emergency operations protocols and preparedness, including the quantity and types of emergency power needed at each site deemed "critical" to their ability to provide services.

c. The water sector is willing and ready to support electric system reliability. Driven by a need to assure that they be resilient after the most common types of outages, water and wastewater systems are designed with redundancy at many locations so that they can continue to provide mission critical services under most contingencies. Consequently, most water and wastewater utilities have flexible DR capacity in some parts of their system. When not needed for water or wastewater emergencies, some flexible DR capacity can be used to provide electric reliability support.

Water and wastewater utilities are constantly planning and always looking forward to the next increment of investment that will be needed for new, upgraded, and/or expanded facilities. Water and wastewater utilities can and should integrate electric reliability into their plans. In fact, they do that now since energy reliability is integral to continued provision of reliable water and wastewater services. The water sector can better coordinate these plans to also meet the needs of their electric utility if those needs are clearly understood, and that will be one of several core outcomes of the Flex DR pilot.

Through case studies, meetings, and interviews with water and wastewater utilities by SCE in the last few years, principles for a Flex DR program were developed to leverage the flexibility inherent in California's water systems for near-term cost-effective electric reliability support.[134] Key to this program's success is the recognition that California's water sector is not merely an electric customer - it is a natural and inevitable electric reliability partner with substantial capabilities to provide over-generation mitigation as easily as it has historically provided relief during periods of under-generation (aka "under-supply"). When design, development and operations of water and wastewater systems are synchronized with the needs of the electric grid, cost-effective benefits accrue to both water and electric ratepayers.

The Flex DR program intends to share its lessons learned via stakeholder discussions and public webinars with both the water sector and support industries. These discussions may take the form of virtual meetings, in-persons workshops, and/or technical whitepapers.

8. Schedule and Budget

The Flex DR pilot is planned to commence in 2023 with interim deliverables scheduled to be provided throughout the term of the Pilot. Key activities would depend on the cadence and schedule of the availability of resources both within the water sector (acknowledging their key priorities) and the need for acceleration of activities in early 2024 due to system and program needs. Funding will be authorized for five years.

The budget requested, shown in Table VII-23 includes labor, administration, external contract evaluation resources, costs for coordination and meeting activities with water/wastewater stakeholders, and several compensation strategies for enabling technologies, fixed and variable payments for performance incentives, and risk premiums for incremental operational capital costs or risk for participating in the Flex DR pilot activities. The labor budget funds approximately 0.7 FTEs, including administration and overhead expenses, to manage the pilot. Budgeted non-labor expenses include enabling technologies, hydrological analyses and demand charge deferral payments to water

[134] *See* Preface of the report Water Sector Over-Generation Mitigation and Flexible Demand Response Phase 2 Program Recommendations, *available at* 20191025-FINAL-Overgen-Ph2-Report-COMPLETE-2-Sided-Print.pdf (pagedesign.us).

stakeholders. Key interim deliverables are expected before the end of 2024 and 2025, while the full Flex DR program can be extended through 2027.

Table VII-23
Flex Demand Response Pilot
2024-2027 Proposed Budget
(Nominal $ millions)

Flex DR Pilot						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.363	.378	.398	.401	1.541
2	Non-Labor Total	.775	1.014	1.080	.645	3.515
3	**Program Total**	**1.139**	**1.393**	**1.478**	**1.046**	**5.056**
4	Incentives	.125	.250	.250	.175	.800
5	**Grand Total**	**1.264**	**1.643**	**1.728**	**1.221**	**5.856**

D. Charge Ready Demand Response Pilot

1. Background

On October 30, 2014, SCE filed A.14-10-014 proposing its Charge Ready Program and Market Education Programs. In its testimony, SCE proposed that "[all] Customer Participants with Level 2 charging stations must agree to participate in future demand response programs designed in connection with the Program and approved by the Commission."[135] In D.16-01-023, the Commission adopted the Proposed Settlement which authorized SCE to implement a Charge Ready Pilot program ("CRPP"), and directed SCE to establish a demand response (DR) program, in which all Charge Ready customers with installed Level 2 EVSE are required to participate.[136]

On January 17, 2017, SCE served testimony in support of its application for approval of its 2018-2022 DR programs and budgets (A.17-01-018). SCE's testimony included a chapter describing the DR pilot for the CRPP. On December 21, 2017, the Commission issued D.17-12-003, the *Decision*

135 A.14-10-014, SCE-01, Volume 03, p. 18.

136 D.16-01-023, p. 35.

Adopting Demand Response Activities and Budgets for 2018 through 2022, authorizing $429,953 for SCE's two-year Charge Ready DR Pilot.[137]

On November 13, 2019, the Commission approved the extension of the Charge Ready DR Pilot for one additional year, through 2020, to coincide with the extension of the CRPP.[138] On July 2, 2020, SCE submitted AL 4244-E requesting to extend the Charge Ready DR pilot through the end of 2022, to allow for further analysis of peak period grid impacts from the Charge Ready DR events and to minimize impacts on SCE's implementation of its Customer Service Re-Platform Project. On April 20, 2021, AL 4244-E was approved by the Commission's Energy Division Deputy Executive Director Randolph, "contingent upon SCE providing additional analysis of its Charge Ready demand response (DR) pilot implementation to date and based on the understanding that SCE will submit a proposal for a full-scale DR program to serve Charge Ready customers in the Fall of 2021."

On July 21, 2021 SCE submitted a report and additional event analysis of the Charge Ready DR Pilot through 2020 to Energy Division. SCE submitted a supplemental report on December 16, 2021 that included analysis and data for Charge Ready DR events held during 2021. A call with Energy Division staff representing both Demand Response and Transportation Electrification occurred on November 2, 2021 to discuss future options for Charge Ready DR. During this meeting, SCE received verbal confirmation regarding SCE's plan to include its plans for Charge Ready DR pilot in this DR Application as a sub-group in ELRP. SCE followed up with a request to Energy Division on November 15, 2021 to submit a proposal for a DR program for Charge Ready Customers in this DR Application, which SCE provides below.

2. <u>Proposal</u>

SCE proposes to transition all Charge Ready DR pilot customers to ELRP by May 2023. SCE expects that current authorized ELRP funding will be sufficient for the additional admin and incentive costs related to this transition and does not request additional funding in this DR Application

[137] D.17-12-003, OP 40, p. 196.

[138] The Commission approved AL 4055-E, which was submitted on August 15, 2019.

for this effort. Transitioning customers from the Charge Ready DR Pilot to ELRP will allow time for other planned or in-progress pilots and projects related to dynamic pricing and to collect and analyze additional data that should be considered when determining the best long-term solution for EV's as a DR resource.[139] The data collected as a result of customer participation in other pilots, dynamic pricing pilots, and ELRP will provide information about barriers to participation, alternative options for utilizing EV's as a DR resource, and a better understanding of customers and/or aggregators interest in using EV's for DR. As described in Section VII.A above, SCE proposes to extend ELRP, with modifications, through 2027. The Charge Ready-specific results and lessons learned during ELRP will enable SCE to develop a permanent DR program for EVs in its next program cycle.

[139] Other efforts that will inform future EV DR programs include the proposed VGI pilot and the Dynamic Rates/UNIDE pilot.

VIII.

CATEGORY 6: MARKETING, EDUCATION & OUTREACH

This chapter presents SCE's request for funding for its Marketing, Education, & Outreach (ME&O) activities, other than those associated with pilots presented in Category 5 (Chapter VII).[140] In D.12-04-045, the Commission directed the IOUs to consolidate all marketing funding into the Marketing, Education, & Outreach (ME&O) Budget Category.[141] In D.17-12-003 the Commission reduced the number of budget categories from ten to seven and retained the ME&O budget category.[142] ME&O activities for DR programs are typically program-specific actions that aim to promote awareness, notify changes, and increase enrollment in a program or aid program retention by communicating event preparedness information and or program changes. The objective of SCE's proposed ME&O activity is to build awareness, educate, and enroll customers in SCE's DR programs. SCE's DR ME&O activity will also increase consumer awareness of how DR programs reduce stress on the environment and energy grid; help customers manage energy use and cost with the end result of driving increased program participation.

A. Key components of SCE' s ME&O Strategy

Though the SCE's ME&O activities vary depending on the characteristics of each program, SCE applies a uniform strategic framework as described below.

Customer Segmentation and Targeting: Through external research and internal customer data, SCE has identified multiple customer groups who can benefit from DR programs. Both residential customers and businesses customers play an important role in helping California meet its energy goals and SCE manage the grid. Where appropriate, SCE has prioritized a focus on low-income customers and residents of Disadvantaged Communities, who face higher barriers to receiving clean, safe, and affordable utility service, to support the fair treatment of all races, cultures, and incomes. SCE continues

---

[140] ME&O costs individual programs are budgeted in in Category 6 and included in individual program budget tables for reference only. ME&O for pilots, however, are included in Category 5 and not in Category 6.

[141] D.12-04-045, p. 91.

[142] D.17-12-003, OP 54.

to embrace and support an equity focus for its program offerings, including the DR programs in this Application. To achieve this goal, SCE will partner with key Community Based Organizations (CBOs) to distribute in-language program materials (e.g., presentations, talking points, turn-key social media messages, and program fact sheets) and educate them on program availability for people in their communities.

Marketing Strategy: Achieving the objectives of the DR portfolio will require an integrated and proactive customer engagement and recruitment effort. To help build foundational knowledge of the benefits of DR programs, SCE will implement targeted, effective communications to cross-promote DR programs and incentives that can improve a customer's potential to save on their energy bills. SCE plans to develop and use customer segmentation and predictive modeling to drive an equitable targeting strategy to reach priority customer populations during DR program enrollment.

Automated Personalized Communications: SCE will use customer data captured during program enrollment to develop comprehensive customer profile segments and activate targeted lead nurturement campaigns that 1) match customers to other available DR programs, 2) provide next steps enrollment information, frequently asked questions, and links, and 3) encourage customers to take the next step in their DR program enrollment journey to maximize their savings potential.

Digital Customer Experience Enhancements: SCE intends to integrate and improve the digital customer experience on SCE.com and the MySCE App by ensuring the integration of operational and customer data with marketing systems, simplifying and streamlining the user experience to include program changes and new pilots, offering enhanced self-service solutions, program enrollment management capabilities, and consolidating multiple applications and functions into the main MySCE App.

B. Tactical Implementation of ME&O

SCE will use tactical approaches that leverage the most effective communications channels, targeting customer groups, and connecting with hard-to-reach, low-income, and Disadvantaged Communities in their preferred language. Some examples of the tactics that will be considered and evaluated are CBO outreach and engagement, direct mail, public relations, social media, email marketing, paid search, content marketing in education materials, digital customer experience enhancements through SCE.com and the MySCE App, and automated personalized communications.

C. Proposed Budget

Pursuant to the requirements of D.12-04-045,[143] ME&O budgets for individual programs are incorporated into this section for budget and reporting purposes except for pilots such as ELRP and the MMDR pilot. The ME&O funds for the ELRP and MMDR pilots are included in their respective program budgets.[144] Table VIII-24 below provides SCE's proposed ME&O budget for SCE's DR resource programs.[145]

The proposed budget for SCE labor funds approximately 2.4 FTE per year to manage and oversee marketing plans and strategies for both SCE's residential and non-residential DR programs. In previous program cycles, SCE did not request labor funding in its DR applications due to the minimal SCE labor required to manage its DR marketing efforts during those cycles.[146] As SCE expands its marketing activities to support the growth in SCE's DR programs during this program cycle, the effort and resources required to manage ME&O activities has increased. Specifically, SCE resources are required to develop and implement strategies for the residential programs, such as the Summer Discount Program (SDP) and Smart Energy Program (SEP), develop an integrated marketing strategy to deliver targeted and personalized communications to SCE's customers, as well as campaign strategies to drive enrollment in DR program. SCE's labor budget also includes resources to manage marketing campaign for non-residential programs, such as SDP, Base Interruptible Program (BIP) and Agricultural and Pumping Interruptible (AP-I) Program. In addition, SCE has also budgeted for resources to improve the DR customer experience on SCE.com and MySCE app through based on customer research,

[143] D.12-04-045, p. 91.

[144] *See* Section VII.A for the ELRP pilot and Section VII.B for the MMDR pilot.

[145] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level.

[146] Actual labor costs incurred during these cycles, however, were properly recorded for recovery in the DR Program Balancing Account (DRPBA).

benchmarking other utilities, working with the development team to create new features, and creating an ongoing measurement framework to determine performance of the applications.

SCE's non-labor forecast funds targeted communication campaigns, digital marketing and related outreach, increased education, and encouraging program participation. These costs also include the implementation of marketing outreach and related collateral, as well as the development of automated personalized communications to targeted DR participants.

Table VIII-24
Marketing, Education and Outreach (ME&O)
2024-2027 Proposed Budget
(Nominal $ millions)

Marketing, Education and Outreach						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.321	.330	.339	.349	1.340
2	Non-Labor Total	3.635	3.713	4.376	4.486	16.210
3	**Grand Total**	**3.956**	**4.043**	**4.716**	**4.835**	**17.550**

IX.

CATEGORY 7: PORTFOLIO SUPPORT (INCLUDES EM&V, SYSTEM SUPPORT, AND NOTIFICATIONS)

This Chapter presents the DR portfolio support activities including evaluation, measurement, and verification (EM&V) DR support activities for the 2023–2027 funding cycle, consistent with D.17-12-003.[147]

The overarching goal of DR EM&V is to assess the efficacy of DR resources. EM&V studies provide the Commission, the CEC, the IOUs, CAISO, and other interested parties with a rigorous, systematic quantification of demand reduction achieved and provide program administrators with a stable view of the DR environment against which to plan. During the 2023–2027 program cycle, SCE will conduct DR load impact evaluations under the protocols adopted in D.08-04-050, process evaluations, and baselines or other evaluations as necessary.

A. Evaluation, Measurement & Verification (EM&V)

1. Overview

After-the-fact (*ex post*) program evaluation is essential to the development of effective DR programs in California. Measuring DR program performance against the costs of program administration requires rigorously designed impact evaluation studies. These evaluation findings are then used to determine the magnitude of the programs' historical load impacts and to forecast expected load impacts in future periods. The results of these evaluations are applied in DR cost-effectiveness calculations and in the annual RA planning process conducted at the CPUC, CEC and CAISO. In the last five years SCE collaborated with PG&E and SDG&E to complete over 15 statewide program evaluation and load impact studies for DR programs. Programs evaluated included the Base Interruptible Program (BIP), Summer Discount Plan (SDP) Program, Smart Energy Program (SEP), Agricultural & Pumping Interruptible (AP-I) Program, Critical Peak Pricing (CPP), Real-Time Pricing (RTP), and residential time-of-use (TOU). The evaluation study plan is shared with the DRMEC before

---

[147] D.17-12-003, OP 54, requires that EM&V, system, and notifications activities be included in the Portfolio Support category.

study initiation, which is composed of representatives from the CPUC, the CEC, and the IOUs, and is made publicly available by sending to the service list(s) of the current DR and RA proceeding(s). Following review and comment by the DRMEC, downloadable copies of the final reports were made publicly available on the California Measurement Advisory Council (CALMAC) Web site.

On April 24, 2008, the Commission issued D.08-04-050 which approved the Load Impact Protocols for evaluating IOU-administered DR programs. The Load Impact Protocols establish requirements for the measurement of DR load impacts and provide guidelines to ensure accurate, reliable, and unbiased load impact evaluations and estimates suitable for long-term resource planning. In D.08-04-050, the Commission confirmed its desire for the IOUs to apply the DR load impacts and cost-effectiveness protocols in their future DR applications. Under the guidelines of the protocols, all program evaluation plans must be reviewed by the DRMEC and the results of the completed load impact reports must be submitted by April 1 each year, unless otherwise directed by the Commission. Besides providing methods and guidance for estimating DR load impacts (Protocols 4-24), Protocols 26-27 specify requirements for Evaluation Reporting and a Process Protocol that specifies requirements for (1) evaluation planning, review and comment process, (2) review of interim and draft load impact reports, (3) review of final load impact reports, and (4) procedures for resolving disputes over evaluation plans and results. According to the protocols, DR program evaluation planning, scheduling and prioritization will continue to be carried out under the guidance of the DRMEC.

2. Program Activities

This section describes SCE’s proposed EM&V activities and budget requirements for DR programs proposed for 2023–2027.

a) Load Impact Evaluations

Under the guidelines established by the DR Load Impact Protocols, SCE proposes to conduct evaluation research designed to support DR program administration, day to day operations, RA, and long-term resource planning. SCE’s evaluation activities will continue to focus on programs with large load reduction capability and those that are expected to expand significantly. Where considered appropriate, DR programs of similar design will be evaluated on a statewide basis, reducing total study costs. Under the oversight of the DRMEC, SCE proposes to evaluate the following statewide and local DR programs during the 2023–2027 program cycle: BIP, CBP, AP-I, SEP, and SDP (Residential and Commercial). Consistent with the guidelines offered in the Load Impact Protocols, SCE's evaluations will focus on both *ex post* findings and ex ante estimations. Ex post load impacts are summarized for all programs that experienced events during the program year. These impacts determine what savings or load reductions were achieved over a historical period, based on the conditions in effect. Because historical performance is tied to past conditions such as weather, price levels, and dispatch strategy (e.g., localized dispatches), ex post load impacts may not reflect the full option value of a DR resource.

Ex ante load impacts are estimated for each DR program and for SCE's DR portfolio. Ex ante load impacts are forward-looking and reflect the load reduction capability of a DR resource under a standard set of conditions. These impacts summarize the load reduction that can be expected from SCE's DR programs if dispatched individually or jointly. At the portfolio level, load impacts avoid double counting impacts from dually enrolled customers. Ex ante load impacts are estimated under normal (1-in-2 year) and extreme (1-in-10 year) weather conditions. Estimates have also been developed for two sets of weather conditions, one based on SCE-specific peaking conditions and one based on CAISO system peaking conditions and both these system conditions are reported in the final load impacts.

b) Process Evaluations

Besides load impact studies, SCE recognizes the need to conduct program process evaluations and general market surveys, both of which can play an important role in program planning and the evaluation process. Process evaluations are an essential component of instituting a well-managed program operation. Process evaluations not only assess the way a program is designed, operated, and delivered as authorized, but also document program operations for stakeholder visibility. As such, these are also useful in identifying opportunities to improve program efficiency and performance in acquiring energy resources; as well as complement load impact assessments by adding program performance insights. Process evaluations should be conducted periodically, to provide sufficient time for processes to develop and demonstrate efficiencies, improvements, and benefits. Mature DR programs that deliver consistent load impact results should be evaluated less frequently. Alternatively, newly implemented, substantially redesigned programs, or programs that appear problematic warrant more frequent attention.

During the 2018–2022 period, process evaluations were conducted for CPP, SDP (Residential and Commercial), and SEP programs to document and assess significant program changes and impacts, including: customer satisfaction and understanding of CPP following waves of default, as well as of SEP under separate vendors. The evaluation team also devoted resources to topics of interest to DR program stakeholders, including effectiveness of current and future event notification methods (i.e., DR App) and marketing strategies. Draft findings were discussed with program stakeholders, and then documented in written reports. Findings will be useful for SCE to guide future program design, customer outreach, marketing efforts, and will also inform customer attitudes regarding incentives and event durations.

Similar to the 2018-2022 cycle, the decision to evaluate should be based on a needs assessment for all eligible DR Programs. Program evaluators, working cooperatively with program managers and regulatory support, should have a good deal of discretion over the design, scope and frequency of process evaluation and market assessment studies, as one-size-fits-all does not apply. The evaluation planning process should recognize that evaluation is a decision-making tool and scheduling should be determined in concert with the stakeholders. Process evaluations account for $1.139 million of SCE's EM&V non-labor budget category over the 2024–2027 period.

3. <u>EM&V Support on Pilots, Tariffs, and Other Programs</u>

In addition to load impact and process evaluations, the EM&V team also supports other programmatic activities within SCE. Brief descriptions of some of the activities that EM&V will support over the 2023–2027 period are provided below:

a) <u>Mass Market Demand Response Pilot</u>

SCE is proposing a Mass Market Demand Response pilot which is aimed to test and evaluate innovative methods to engage and sustain customers' participation in DR events using multiple rate and program design options. Main objectives of the EM&V work supporting this pilot will be centered on quantifying impacts due to participation in associated DR events as well as understanding customers' experience with the pilot in order to improve its design and provide feedback for future program rollout. Non-labor costs for the Mass Market DR Pilot study is requested and funded within the Mass Market DR Pilot budget request included in Section VII.B, but the SCE M&E labor to manage these studies are funded within the EM&V budget.

b) Dynamic Rates Pilot

The pilot will be evaluated with methods similar to SCE's existing Real Time Pricing Rate. The evaluations will examine how being on the Tariff affects the customers' load shift. To assess the impact of the tariff, load profiles will be constructed for what the customer would have done had they not been on the RTP tariff. The appropriate counterfactual is the customer's consumption patterns on the otherwise applicable tariff (OAT). This counterfactual will be modeled using a price model that estimates the relationship between the price each customer is exposed to and their load. From that model reference loads can be constructed by predicting what customers would have done on the OAT using individual customer regressions. Any peak or off peak changes in load within the customers that are on the tariff, compared to those on the shadow bill, will then be quantified. These load impacts will be indicative of possible grid and GHG benefits due to the program. SCE also expects to learn more about customer behavior which will help SCE tailor the rate design and future communication to the customers. In addition, SCE plans to solicit competitive bids so that the costs of the evaluations are kept reasonable.

c) Emergency Load Reduction Program (ELRP) Pilot

The ELRP pilot is a statewide pay-for-performance (non-punitive) demand response pilot that pays customers for incremental load reduction that occur during system emergencies during the summer months. The goal of the program is to help the IOUs and CAISO avoid outages while controlling costs to ratepayers. The Pilot provides payments based on the total incremental energy reduction over the event period with no capacity payments. ELRP is out of market (no RA, CAISO, or

CEC obligations) with the goal of providing access to additional, emergency DR load reduction during times of high grid stress.

SCE is currently conducting a joint evaluation of its ELRP program with PG&E for DR events that have been called for Program Years 2021 and 2022. The 2023–2025 load impact evaluations of the ELRP will be conducted in a manner that conforms to the Load Impact Protocols (LIP) adopted by the CPUC in D.08-04-050. Non-labor costs for the ELRP load impact study are requested and funded within the ELRP budget request included in Section VII.A, but the SCE M&E labor to manage these studies are funded within the EM&V budget.

d) <u>Prohibited Resources (PR)</u>

Annual PR audits have been performed since 2019 by a third-party Verification Administrator, Nexant/Resource Innovations, pursuant to Resolution E-4906. These annual audits assess on a sample basis compliance with the Prohibited Resources (PR) restriction originally set forth by D.16-09-056. These PR audits are cost-shared by the IOUs and funded out of its 2018–2022 authorized funding, funding for PR was not considered beyond 2022.

Separately, on October 18, 2018, each IOUs filed its PR Application (A.18-10-008 et al) pertaining to PR loggers/meters. Also, there was a “test year” deployment of meters/loggers in 2019. Together with the audits, the Applications, and the test year date, the CPUC was expected to make a determination about the permanent framework for PR compliance. Presumably, such a durable framework could include a permanent deployment of meters/loggers and/or ongoing annual verifications.

While a Prehearing Conference was held on January 20, 2019, with a schedule for the balance of 2019, certain regulatory activities subsequently were deferred to early 2020, but at the time of this filing, the CPUC has not made a determination about a permanent PR compliance framework. Because of this lack of finality, the PR Application proceeding has been extended a number of times with the current expiration to occur in October 2022, which is beyond the timing of the IOUs’ 2023 Bridge and 2024-2027 funding Applications, SCE includes a funding request for PR verification in this Application.

Since the annual PR verification audit normally begins in September of each year and concludes by around the end of the first quarter of the following year, the 2022 verification audit would include expenditures that will be incurred in early 2023. SCE should have the authority to pay PR audit invoices in 2023 for the 2022 audit as part of its 2018–2022 authorized funding but seeks explicit CPUC approval with regard to the timing of payments and authority for payments to be made in the subsequent calendar year in which the PR audit is performed (e.g., costs would be incurred and paid in 2023 related to the 2022 PR audit).

Also, pending the outcome and decision of SCE's PR Application, should the CPUC decide that annual PR verification audits should continue indefinitely, SCE requests funding for these PR verification audits in this Application. Per Resolution E-4906, it was determined that $375,000 in total was an appropriate amount for the annual PR verification; therefore, SCE requests its respective amount in this Application based upon a 40/40/20 split between SCE, PG&E, and SDG&E, respectively. For the 2023 Bridge Year, SCE requests Commission authorization to use approved funding from its authorized 2023 Bridge Year Funding and allow SCE to shift funding from its DR programs in Budget Category 1 to its EM&V program budget in Budget Category 7 through a Tier 1 Advice Letter to fund this activity, because funding approved in D.17-12-003 did not include incremental funding for PR verification audits. SCE's request to allow fund shifting through a Tier 1 Advice Letter is reasonable because the purpose and use of these funds are not controversial and the fund shift amount is low ($150,000).[148] For the 2024–2027 DR funding cycle, SCE requests a total of $600,000 for its proportional share of the PR verification audit.[149] It should be noted that the $375,000 annual budget amount is limited to the current annual verification process as approved by the CPUC via PG&E AL 5138-E-A et al (joint IOU filing). The approved verification relies on a sample audit process and does not cover the universe of all prohibited resources. Moreover, this budget excludes considerations for

---

[148] PR Verification Audits are estimated to be $375,000 annually. SCE's share is 40% or $150,000 ($375,000 x 40%).

[149] Resolution E-4906 established an annual budget $375,000. This amount multiplied by four years and SCE's 40% proportional share yields $600,000 for 2024–2027. (($375,000 x 4) x 40%) = $600,000.

any additional requirements which could be imposed up to and including the deployment of meters/loggers if paid for by the utilities.

e) Bottoms-Up DR Potential Study

SCE proposes to collaborate with PG&E and SDG&E to fund and conduct a Bottoms-Up DR Potential study. The objectives of this study are to identify disaggregate end-use loads that are flexible to be deployed to help address operational and planning needs, determine whether existing programs are adequate to manage these loads or whether modifications to existing programs or new programs need to be developed, and develop a supply curve of the identified loads. This study would also consider customers' attitudes, and knowledge regarding their energy usage to identify how to increase customer and engagement throughout the customer journey. 'This study is necessary to develop a comprehensive load management strategy that may include a broad range of rates, programs, pilots, and technology incentives that produces grid benefits while also providing customer a positive experience. SCE expects to conduct this study in time to inform its application for the next program cycle. SCE has included $1.2 million as its share of this study in its proposed budget for EM&V activities.

f) CAISO Market Integration Study

In SCE-01, SCE proposed conducting an independent performance assessment to determine whether the Commission's goals for integrating DR programs into the CAISO market are being met and identifying opportunities to improve the integration of supply-side resources. SCE proposes that this effort be jointly funded by the IOUs and estimates a total cost of $3 million for the study. Accordingly, SCE has included $1.2 million as its share of this study in its proposed budget for EM&V activities.[150] SCE proposes that the funding initially be used to contract with a lead independent consultant or consultants. The consultant(s) would be responsible for project management of the study, including coordination with an advisory group made of stakeholders and completion of a final report, including recommendations, by the established due date. The advisory group, in conjunction with the

[150] SCE anticipates the three IOUs would share funding of this study at a breakdown of 40% for SCE, 40% for PG&E, and 20% for SDG&E. SCE's 40% share of $3 million is $1.2 million.

consultant, would be responsible to identify the scope and research goals for the study and to provide data and technical assistance as appropriate.

g) Other Pilots, Programs and Activities

SCE also intends to study emergent DR issues and conduct studies to evaluate outcomes. SCE anticipates conducting studies to aid in understanding the cost-effectiveness of DR programs, understanding baselines and other issues in the wholesale and retail settlements, and understanding impacts of newer technologies such as Virtual Power Plant (VPP) and electric vehicles. SCE also intends to study and evaluate DR market integration and whether its goals have been met.

For example, in D.19-07-009, the Demand Response Retail Baseline Working Group was established, with facilitation by the Commission's Energy Division. The working group was charged with developing proposals to address baseline issues. Per the Decision, SCE includes a copy of the DR Retail Baseline Working Group Final Report in Appendix B.[151]

4. Program Budget

SCE's proposed budget to manage, administer and perform EM&V activities for the period 2024–2027 funding cycle is shown in Table IX-25 below.[152] This budget includes funding for approximately 3.2 FTEs, including administration and overhead expenses, for overall management of the EM&V function as well as project management of evaluation studies conducted during this period. The non-labor portion of the proposed budget includes funding necessary to conduct load impact and process evaluation studies and PR verification audits as described above.

---

[151] *See* D.19-07-009, p. 85, OP 19. *See also*, Retail Baseline Working Group Final Report, (March 1, 2021).

[152] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for EM&V alone is included in this application.

Table IX-25
EM&V
2024-2027 Proposed Budget
(Nominal $ millions)

Evaluation, Measurement & Verification (EM&V)						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	.487	.473	.492	.507	1.959
2	Non-Labor Total	3.448	1.057	1.071	1.089	6.665
3	**Grand Total**	**3.935**	**1.530**	**1.564**	**1.595**	**8.624**

B. <u>DR Systems & Technology Support</u>

Well-functioning technology systems are vital to efficient operation of SCE's DR portfolio. The activities and funding associated with these systems are contained in SCE's DR Systems and Technology Support area. During the 2023-2027 DR cycle, SCE intends to continue to focus on maintaining secure systems that comply with up to date cybersecurity standards, provide customers an easy and seamless method to enroll into SCE's DR programs, effectively dispatch all DR programs by sending accurate signals and notifications (i.e., phone, text, email, and Mobile App push alerts), display accurate event information on both web and mobile web platforms, and calculate wholesale and retail settlements accurately.

In preparation for SCE's vision of the future of DR as described in this testimony, the DR Systems and Technology Support funding will be used to evaluate and enhance CAISO wholesale market integration efforts and ensure accurate dispatches and accurate settlements, support modification of the DR programs to improve cost effectiveness (e.g., enabling dispatch of DR programs at granular levels, such as the substation and circuit levels), and integrate with systems operated by SCE's Grid Control Center to improve the operation of DR program activities. The System and Technology team also tests, evaluates, and onboards new smart technologies into SCE's DR portfolio by working with internal and external stakeholders.

1. **Background**

In SCE's 2009-2011 DR Application, SCE consolidated most of the DR system costs into a new budget item called Demand Response System Infrastructure. Prior to the 2009-2011 program cycle, SCE included the systems costs within each individual DR program. This section describes the activities and costs associated with the system infrastructure efforts required to support the DR portfolio. The following guiding principles apply to the allocation of systems and technology costs:

- When a cost component is ascribed to a specific program, it will be noted and requested in that specific program's section of this Application.
- When a cost component cannot be ascribed to a specific program, it will be identified and included in this budget.
- All direct labor associated with system maintenance and project implementation will be included in this budget.
- All systems costs for Hosting & Maintenance are requested in this budget.
- Project costs associated with technology upgrades for DR funded outside of this Application will normally be funded by that pilot or program. Examples are SCE's Local Capacity Resource Contracts, Distribution Deferral Contracts, and Preferred Resource Pilot Programs.

2. **Systems Summary**

SCE utilizes many complex systems to manage its diverse portfolio of DR programs. These systems may be developed and owned by SCE or outsourced to third party vendors. The systems that SCE utilizes to enable DR can perform one or more of the following functions:

- Customer Enrollment Management Systems & Reporting Environments – Systems that track customer program enrollment, program termination, device/enabling technology information, service orders, and ongoing eligibility requirements.

- Customer Contact and Notification Systems - Systems that track customer contact preferences and/or notify customers of DR events via email, phone, TTY, and/or text message.
- DR Bidding Platforms – Systems that allow customers and aggregators to nominate monthly and event-based kW reduction commitments.
- Load Control and Event Dispatch Platforms including End User Technology - Systems that communicate to Load Control and Event Dispatch End user technologies that provide information before, during, and after DR events. Devices, enabling technologies and displays located at the customer's homes and businesses that notify customers of DR events and can automatically curtail load. Examples include Auto-DR clients, Smart Thermostats, AC cycling devices, Agriculture and Pumping direct load control devices.
- Customer Web pages for Program Education and Event Notification – Web pages that provide DR program content and current and historical event information.
- Billing, Rebate and Event Settlement Systems – Systems that settle program and tariff performance and provide credits or bills to customers. Systems that track workflow, projects and costs for DSM technology incentives such as Auto-DR.
- Meter Data Systems – Systems that track customer usage information that is utilized to determine monthly bills, credits, and load reduction during DR events.
- Integration Technology – Secure servers that allow data to be shared across various unconnected DR systems hosted by SCE and external vendors.

Table IX-26
Summary of Systems and Functions

Line No.	Function	System							
		OnSolve	CSE Platform	Honeywell DRAS	APX Platform	DR Databases	SAP	Resideo / EnergyHub	CAISO Market Integration
1	Customer Enrollment Management Systems				Yes	Yes	Yes		Yes
2	Customer Contact and Notification	Yes			Yes				
3	Demand Response Bidding Platform				Yes	Yes			Yes
4	Load Control and Event Dispatch (incl. End-User Technology)		Yes	Yes	Yes			Yes	
5	Customer Web Pages for Program Education and Event Information			Yes	Yes				
6	Billing, Rebate, and Event Settlement Systems				Yes	Yes	Yes	Yes	Yes
7	Meter Data Systems				Yes		Yes		Yes
8	Integration Technology		Yes	Yes	Yes	Yes	Yes	Yes	Yes

3. <u>Vendor Partnerships for Systems Hosting & Licensing</u>

SCE partners with multiple vendors to support its DR portfolio. At the time of this application, the following vendors are contracted with SCE to provide technology services for dispatching demand response events. SCE may choose during this funding cycle to consolidate, eliminate, replace, retain, or enhance the services provided by these and other unspecified technology vendors to ensure quality and cost competitiveness.

- Corporate Systems Engineering (CSE) – CSE is the supplier of SCE's Alhambra Control Platform that communicates via FM radio to approximately 500,000 direct load control switches for the SDP and AP-I program.
- APX – The APX Bidding and Event Dispatch Platform is a web-based system to support the enrollment and monthly nominations for aggregator programs as well as executes the dispatch of events for SCE's portfolio.
- Honeywell – Honeywell is the supplier of the Demand Response Automation Service (DRAS) that enables SCE's Open ADR capabilities. It provides a web portal for customers and aggregators to receive event notifications, adjust shed signals, and

enable automated response from their energy management systems (EMS). Honeywell also hosts on behalf of SCE the DR Event Website that displays on a website and mobile website any scheduled, active and terminated events for all of SCE's DR programs. Honeywell developed a mobile app for IOS and Android smartphones that allows customers to download and configure the app to send push notifications and alert them of DR events.

- Resideo – Resideo is one of the vendors with an enrollment and control platform for managing smart thermostats to be controlled during SEP and TIP programs events. These set of the smart thermostats are not managed by EnergyHub.
- EnergyHub – EnergyHub is the second vendor with an enrollment and control platform for managing smart thermostats to be controlled during SEP and TIP programs events. These set of smart thermostats are not managed by Resideo.
- OnSolve – Backup Notification system that contains customer contact information for all of SCE's DR programs, including phone, text and email
- SCE will be conducting a Request For Proposal (RFP) to onboard a third party vendor in 2022 to support CAISO wholesale market integration. The third party will be responsible for registering all of SCE's CAISO market integrated programs with the CAISO Demand Response Registration System (DRRS), resource creation and performing CAISO wholesale settlements. The budget requested for the hosting and licensing are estimates provided by a third-party vendor

4. <u>Demand Response System Enhancements, Maintenance and Technology Projects</u>

In addition to the hosting and licensing fees paid to SCE's DR systems vendors, additional enhancements are made to these systems on an annual basis. Enhancements are made for a variety of reasons including integration with system or program updates at CAISO, improvements to cybersecurity, compliance with web accessibility, compliance with CPUC decisions, updates to system integrations, and other improvements to the overall performance or customer satisfaction of DR programs.

5. **Program Budget**

Table IX-27 shows SCE's proposed budget for DR Systems and Technology Support activities for the 2024-2027 period.[153]

Table IX-27
DR Systems and Technology Support Budget
2024-2027 Proposed Budget
(Nominal $ millions)

DR Systems & Technology Support						
Line No.	**Description**	**2024**	**2025**	**2026**	**2027**	**Total (2024-2027)**
1	SCE Labor Total	1.963	2.025	2.139	2.205	8.333
2	Non-Labor Total	8.466	8.720	8.981	9.250	35.417
3	**Grand Total**	**10.429**	**10.745**	**11.120**	**11.456**	**43.750**

The proposed DR Systems and Technology Support budget for labor funds approximately 16 FTEs, including administration and overhead expenses. The proposed non-labor budget includes costs for DR system enhancements, hosting and maintenance. The DR Tech Ops team has developed estimated budgets for each system for the 2023–2027 program cycle. The overall DR systems and technology budget has increased for several reasons:

- Vendor Hosting and device fees for the SEP were previously listed as part of the SEP budget. However, since the devices supported by these vendors have been expanded to other DR programs (i.e., CPP, DRAM, and CBP), these costs have been consolidated in the DR system and technology budget. SCE pays a per-device fee to its vendors to help manage the participation of these devices in DR programs.
- CAISO Registration, Bidding and Settlements are in the process of being transitioned from SCE's Energy Procurement and Management team to the DR Systems and

[153] The bridge year (2023) budget is summarized in Exhibit SCE-02 at the Category level. No specific bridge year request for DR Systems and Technology Support alone is included in this application.

Technology team. SCE will partner with a new vendor to improve automation and integration of these essential functions.

- System vendor fees have increased due to a combination of factors including additional system capabilities added to improve the dispatch, notification and settlement of DR programs.
- The shift to more Software as a Service (SAAS) and cloud-based solutions has resulted in more flexible, secure and redundant systems without the need to manage and continually upgrade hardware, but has resulted in increased total costs due to cloud hosting and maintenance fees.

Appendix A

SCE Residential CBP Baseline Accuracy Report

REPORT

Residential CBP Baseline Accuracy Assessment

Prepared for:

Southern California Edison

By:

Savannah Horner

Adriana Ciccone,

Demand Side Analytics

March 2022

TABLE OF CONTENTS

Figures

Tables

1 INTRODUCTION AND KEY FINDINGS

SCE engaged Demand Side Analytics (DSA) to evaluate the different demand measurement methods, also known as baseline methods, for a Residential Capacity Bidding Program (CBP) at SCE pursuant to California Public Utilities Commission (CPUC) Resolution E-5112[1], Ordering Paragraph 2. This analysis focuses on the performance of aggregate and individual Residential baselines, using existing Residential customer meter data.

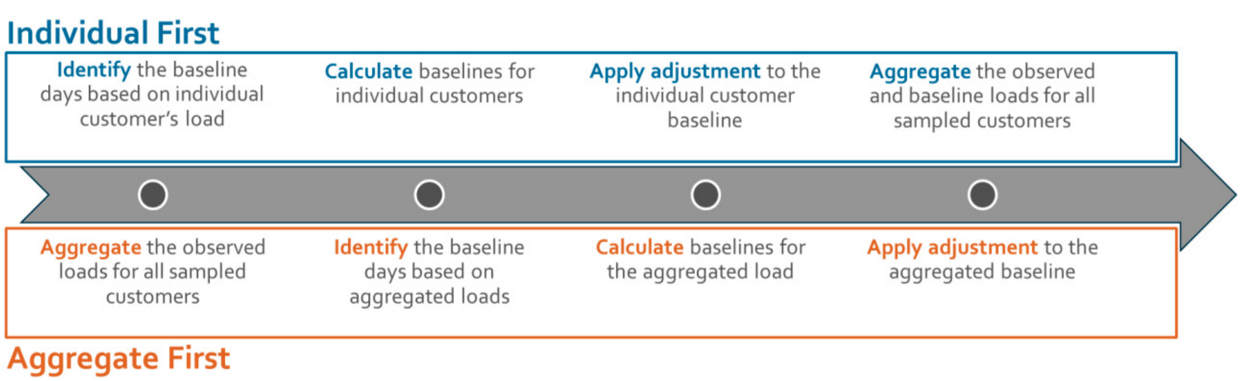
Although SCE's CBP tariff allows for Residential customer participation, at this time no aggregators have proposed a Residential aggregation. Without actual SCE CBP Residential customers, this study was conducted based on Residential customers who are similar to SCE's Smart Energy Program (SEP) participants, as these customers are thought to be representative of likely Residential CBP participants. The assumption is that these Residential customers would be called at the same time as SCE's Commercial CBP-DA customers.

The focus of this analysis is quantifying the difference in accuracy (or bias) and precision (or noise) for two different aggregation methods, using the high 5-of-10 baseline. The two aggregation methods are defined as:

1. **Aggregate first approach:** All customer loads are aggregated before the baseline calculation. The baseline days are identified based on aggregated loads from eligible days, and the baseline adjustment is applied to the aggregated baseline.
2. **Individual first approach:** Baselines are calculated for individual customers first. The baseline days are identified based on each individual customer's load, and baseline adjustments are applied to individual baselines. The baseline days may be different from customer to customer. The final baseline is the sum of all individual customer baselines.

The differences in the process of the two aggregation methods are further detailed in Figure 1.

Figure 1: Difference between Aggregate First and Individual First Methods

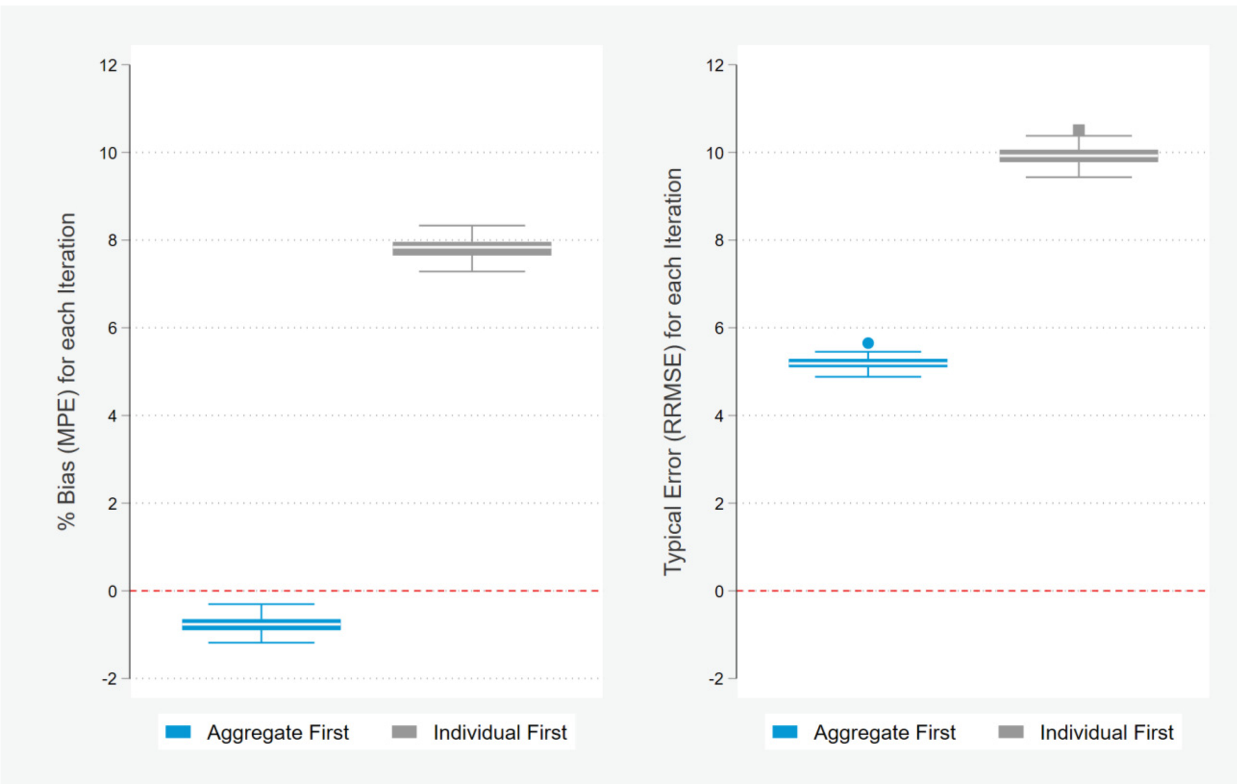


[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334549.PDF

Each of the two aggregation types are then evaluated across a number of customer sample sizes on different "pseudo-event" days. In this assessment, we use the actual event days of the Commercial CBP-DA program because the population of interest, SEP control customers, were not dispatched on these days. Because demand reductions are zero on these pseudo-event days, any difference between the baseline and the actual loads is error.

A summary of the accuracy and precision metrics for the two baseline types assessed are shown in Figure 2. In both measures of accuracy and precision, baselines composed of aggregated loads outperform results where baselines are computed for individual customers and then aggregated. Clearly, the "individual first" method is biased upwards. This upward bias is the result of two specific considerations of the "individual first" method; baseline day selection and adjustments.

Figure 2: Overview of Accuracy Results for Samples of 2,000 Customers



The results of this analysis suggest five key findings:

KEY FINDINGS

1	**The "aggregate first" method outperforms the "individual first" method.** Aggregating loads first reduces the noise of individual customer load when picking baseline days and applying the adjustment.
2	**The inaccuracy exhibited by the "individual-first" method is not resolved by moving to larger sample sizes.** Each individual customer's baseline is biased upwards prior to aggregating any number of customers together.
3	**Individual customer level results are inherently more volatile than aggregated results.** The accuracy assessment was conducted at the portfolio level to reflect settlements with aggregators. Often, aggregators apply baselines for settlement to individual customers. Volatility of baselines and settlement error is larger at the individual customer level.
4	**Longer event windows tend to produce smaller errors.** This is the case under both aggregation methods.
5	**The precision and accuracy of SubLAP performance is a function of the size of the SubLAP.** SubLAPS like High Desert and Low Desert have fewer customers and are less accurate, as well as less precise.

Based on these findings, if Residential SCE customers begin participating in the CBP program, DSA suggests the following recommendations for program design.

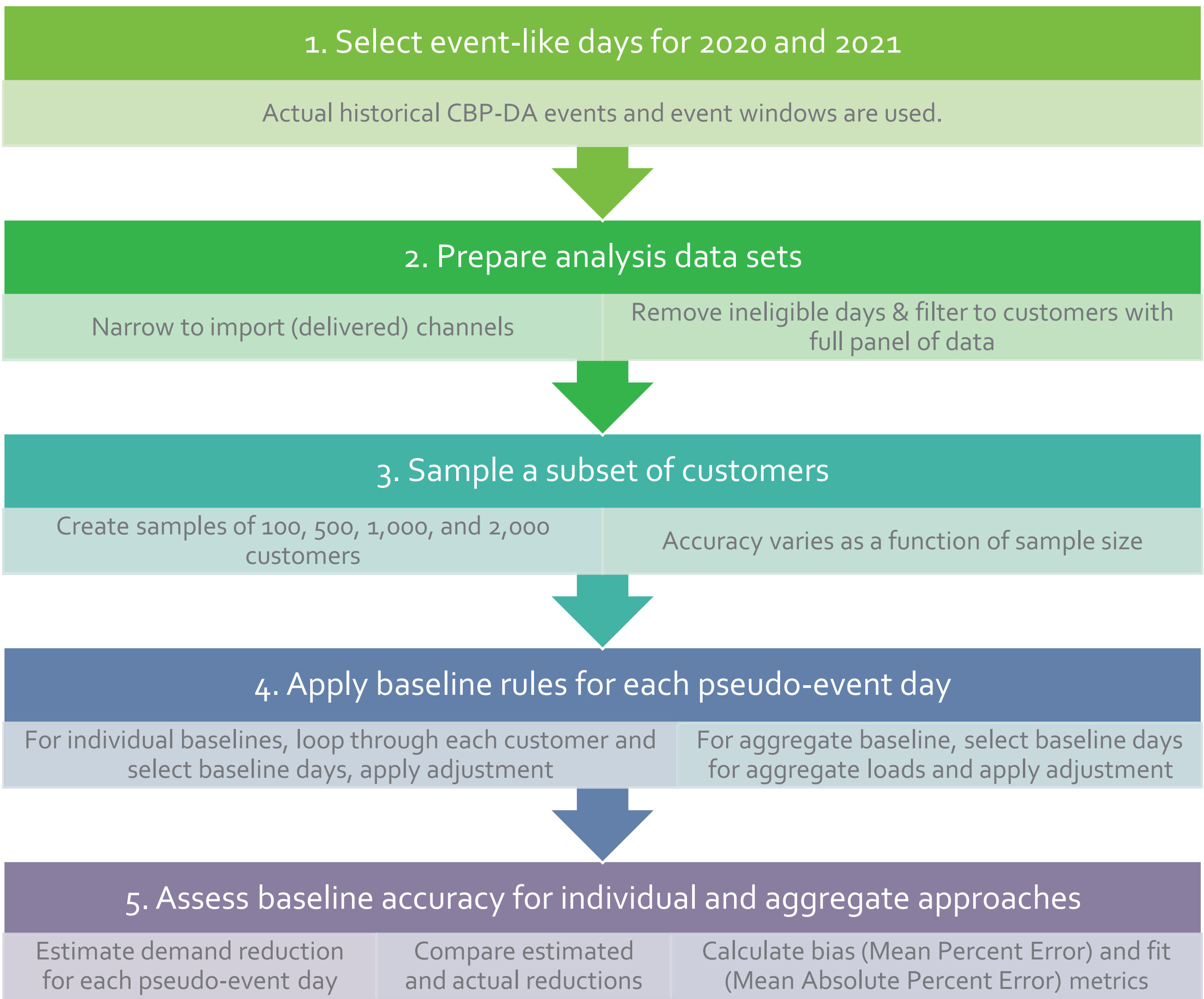
RECOMMENDATIONS

1	**Calculate settlement using the "aggregate-first" method.** It is unbiased and more precise than the "individual-first" approach, which tends to overestimate impacts.
2	**Settlement should be calculated for each portfolio resource at the SubLAP level to align with CAISO.** As CAISO settlements are done at the SubLAP level, this is a natural grouping for program aggregation.
3	**Aggregators should have no less than 100 customers per SubLAP to avoid noisy settlement results.** Groups of fewer than 100 customers are prone to both higher bias and lower precision **.**
4	**Settlement between aggregators and individual customers should be left to aggregators.** The aggregator is responsible for the relationship and settlement with the individual customer.

2 METHODOLOGY

Quantifying the error of any given baseline requires knowledge of what the load would be absent any intervention. When no intervention occurs, it is possible to determine if each baseline method correctly measures energy use and, if not, by how much it deviates from the known values. Figure 3 lays out the analysis process that allows us to calculate this baseline accuracy.

Figure 3: Process Overview



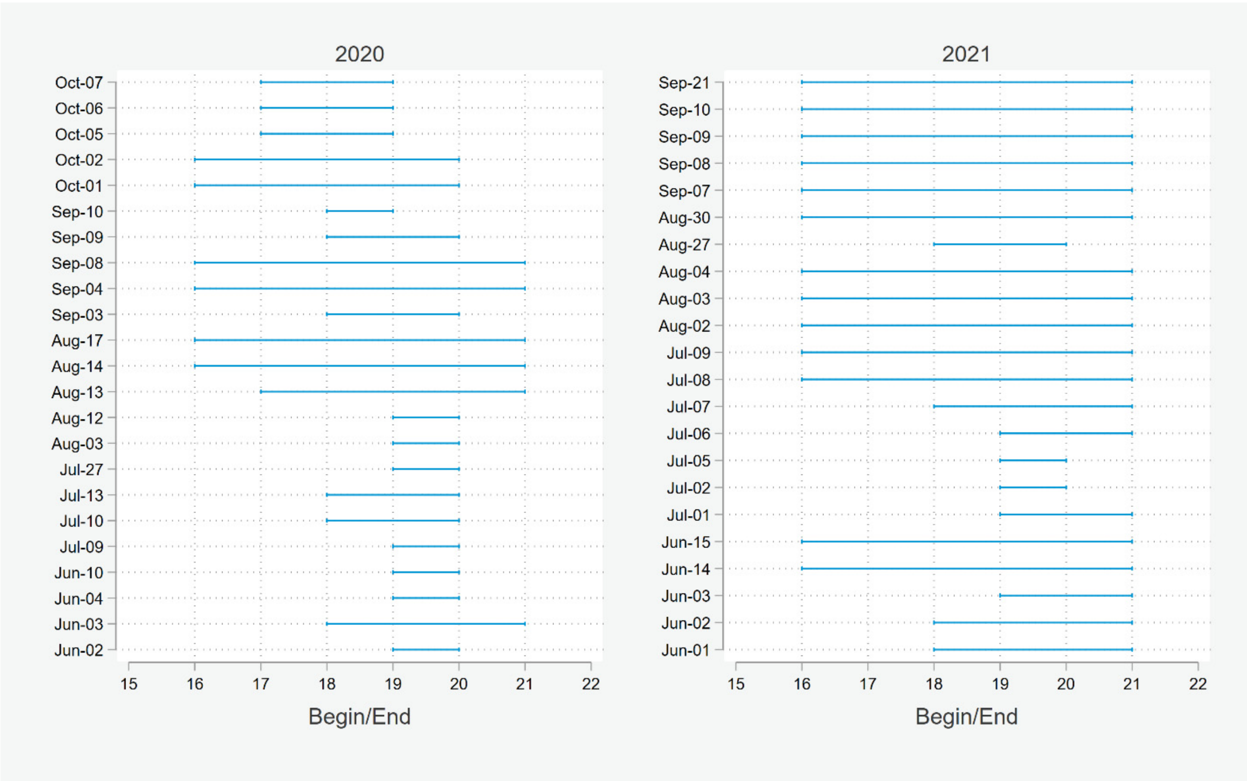
We describe these key methodological steps in more detail below.

2.1 SELECT EVENT-LIKE DAYS FOR 2020 AND 2021

The Residential CBP program would be dispatched at the same time as the existing Commercial program, so we select days where Commercial CBP day-ahead events were called as the pseudo-event days for evaluating the baseline accuracy. This ensures that the characteristics specific to CBP event days are captured, whether the dispatch was for economic or reliability reasons. Specifically, we use the summer event days in 2020 and 2021, across the 4 PM to 9 PM event window. Both years are included in the analysis so that we are able to assess how the baselines perform across different temperature conditions, since the 2020 summer was more extreme than 2021.

Across both years, we use a total of 45 pseudo-event days. The start time, duration, and date of these pseudo-event days are detailed in Figure 4. The most common pseudo-event day window spans the whole 4 PM to 9 PM period, while the second most frequent window lasts only one hour from 7 PM to 8 PM.

Figure 4: Pseudo-Event Day Details



2.2 PREPARE ANALYSIS DATASETS

We use Residential SEP control customers as stand-ins for Residential CBP participants, since these customers did not participate in any DR programs and will not be affected by the Commercial CBP day-ahead events. This population is also used because the current SEP participants serve as a good proxy for Residential customers that would participate in a CBP program. To match CAISO baseline settlement rules, we model baselines using only the delivered load of these customers. Table 1 details the data sources that are used to construct the analysis dataset.

Table 1: Data Sources and Specifications

Data Type	Data Source	Specifications
Customer Characteristics	SCE Residential customer characteristics for customers not enrolled in any DR	**Total Customers**: 39,521 **Key Variables**: Customer IDs, NEM status, Climate Zone, SubLAP
Customer Meter Data	Hourly interval data (import/delivered channels only)	**Date Range**: May 2020 – October 2020; May 2021 – September 2021
Events	List of historic CBP-DA events	**Event Range**: Summer 2020 and 2021 **Event Window**: any between 4 – 9 PM **Total Events**: 45 events

We weight the control customers to match the SEP participant distribution of SubLAP, NEM status, and climate zone to create an analysis dataset that mirrors the participant population (Table 2).

Table 2: Control Customers and SEP Participant Modelling Ratio

Segmentation Variable	Segment Description	Control Customers	SEP Participant Ratio
NEM	NEM Customer	8,573	24.85%
	Non-NEM Customer	30,948	75.15%
SubLAP	Central	13,432	40.63%
	High Desert	3,537	2.79%
	Low Desert	245	0.10%
	North	9,316	10.59%
	Northwest	3,362	1.32%
	West	9,629	44.57%
Climate Zone	5	1,399	0.06%
	6	4,813	11.86%
	8	5,385	32.62%
	9	5,410	13.57%
	10	4,316	29.00%
	13	4,610	3.95%
	14	4,627	4.13%
	15	4,208	3.05%
	16	4,753	1.76%

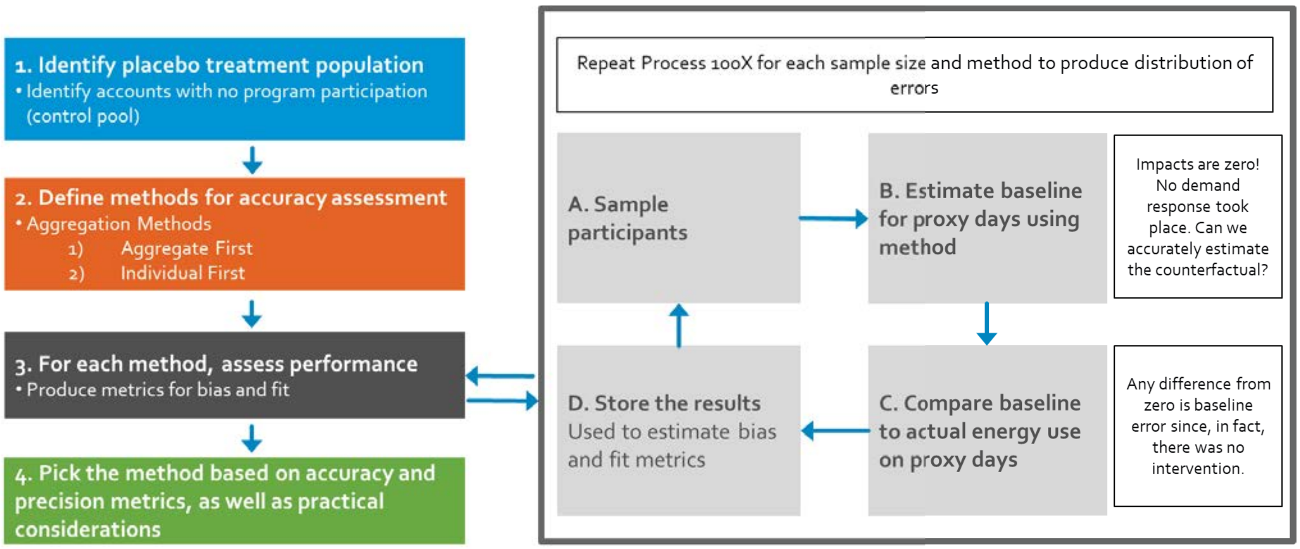
The final step in creating this analysis dataset involves removing ineligible baseline days, which are outlined below:

- **ISO Holidays.** This excludes Presidents Day, Columbus Day, and Veterans Day.
- **Weekends.** In the last two years, no weekend events have been called under the CBP program, so we remove all weekends from the analysis dataset.
- **Events.** The customers we model are all control customers, so there are no event days to exclude from the analysis dataset.

2.3 SAMPLE SUBSET OF CUSTOMERS

Figure 5 summarizes the approach we use to assess the accuracy and precision of the baselines. The approach is effectively a competition, where the answer is known, and both methods are tested repeatedly for different samples of participants, a procedure known as bootstrapping, to identify the methods that are unbiased and accurate.

Figure 5: Accuracy Assessment Framework



Implementing a demand response program means dealing with customer churn and granular dispatch of participants. As the number of participants increases, their loads tend to converge towards a more representative value, with larger and lower load profiles averaging out. At smaller sample sizes, baseline accuracy will be more dependent on outliers or influential customers in the participant sample; the converse is true once sample sizes are large.

To reflect how any baseline accuracy study is underpinned by assumptions about how many and which customers are participating, the bootstrapping exercise was conducted prior to beginning the baseline calculation. Essentially, for each target sample size (100, 500, 1,000, and 2,000 customers), 100 independent random samples of customers were pulled from the Residential SEP control pool population and saved. This allows the results shown below to reflect the baseline accuracy results across a wide range of possible participation scenarios.

2.4 APPLY BASELINE RULES FOR EACH PSEUDO-EVENT DAY

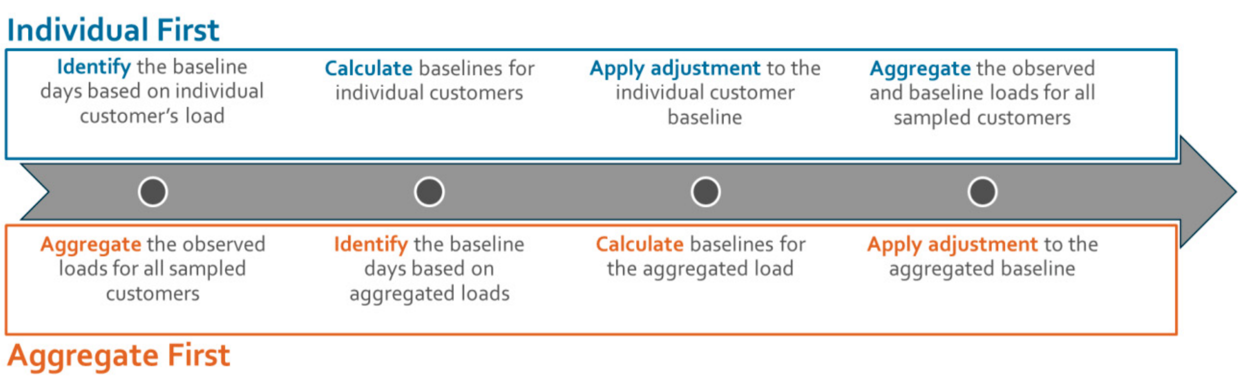
The baseline specification for Residential customers on weekday events is a high 5-of-10, day-matching baseline. The adjustment specifications of this baseline are detailed in Table 3.

Table 3: Baseline Adjustment Specifications

Adjustment Category	Value	Description
Type	Multiplicative	To get the adjusted baseline, the unadjusted baseline is multiplied by the ratio of the unadjusted baseline to the observed loads in the adjustment window.
Cap	40% cap	The adjustment ratio cannot exceed 40% in either direction.
Window	2 hour pre/post period adjustment	This specifies which hours are considered the basis for the same-day adjustment.
Buffer	2 hour pre/post adjustment buffer	This specifies the amount of time before or after an event before the adjustment window is in place.

Once participants are sampled, we apply this baseline in two different fashions; the "individual first" method and the "aggregate first" method. The differences are detailed in Figure 6.

Figure 6: Difference between Aggregate First and Individual First Methods

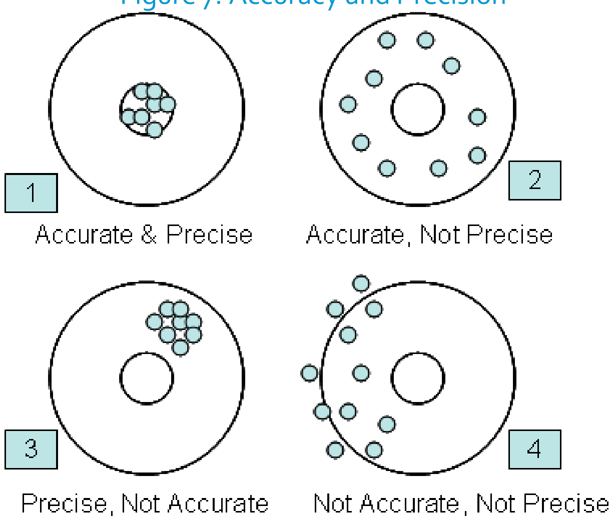


Essentially, the "aggregate first" method aggregates the load for each sample size and iteration and then applies the baseline methodology, while the "individual first" method computes the baselines for each customer and then aggregates according to the saved list of sampled customers for each target size and iteration. This means that for any given sample and iteration, the "aggregate first" and "individual first" results are based on the same set of participants. The only difference in results is due to the baseline aggregation method itself. The aggregation in the "aggregate first" method is done first at the SubLAP level, as this is the level relevant for CAISO settlement. These values are then aggregated based on the relative size of the SubLAP populations to the program level for comparison with the "individual first" approach.

2.5 ASSESS ACCURACY FOR INDIVIDUAL AND AGGREGATE APPROACHES

The terms accuracy (or bias) and precision (or noise) have very specific meanings in statistics. Accuracy refers the tendency for a baseline to over- or under-predict the true value consistently. Precision indicates how close a baseline is to the true value. Figure 7 illustrates the difference between these two terms. The best baselines are both accurate and precise (top left panel). In general, baselines with higher accuracy and lower precision (top right panel) are preferred to those with higher precision but lower accuracy (bottom left panel) because biased estimates are very undesirable, no matter how precise they are.

Figure 7: Accuracy and Precision



Accuracy and precision can be measured in several ways. In this analysis, we measure bias through the mean percent error (MPE). MPE measures the percentage by which the baseline under- or overestimates the observed demand on average. We measure precision using the normalized root of the mean square error (referred to as RRMSE). This metric normalizes the root mean square error across loads of different magnitudes by dividing it by the average of the actual observed demand. These metrics are described in more detail in Table 4.

Table 4: Bias and Fit Metrics

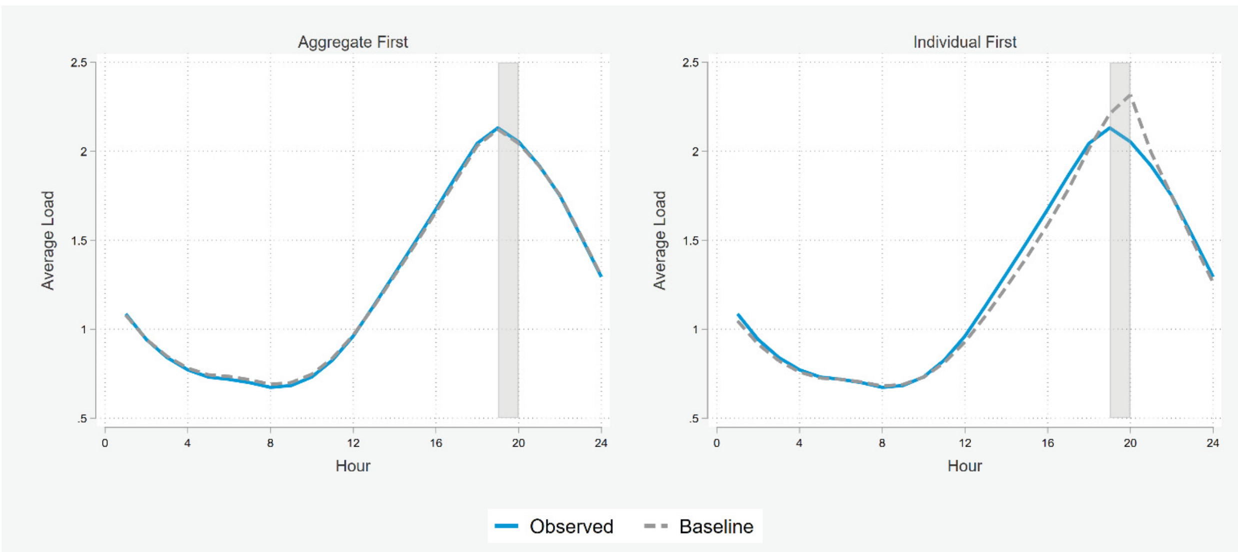
	Bias (Accuracy)	Precision (Noise)
Metric	**Mean Percentage Error (MPE)** This metric indicates the percentage by which the measurement, on average, tends to over or underestimate the true value. A negative value indicates a tendency to under-predict and a positive value indicates a tendency to over-predict.	**Relative Root Mean Square Error (RRMSE)** The root mean squared error is a measure of how far the estimated values are from actual values. Technically, it measures the spread of errors, weighing bigger errors more heavily than small ones. The RMSE is normalized by dividing it by the average of the actual values.
Mathematical Expression	$MPE = \frac{\frac{1}{n}\sum_{i=1}^{n}(\hat{y}_i - y_i)}{\bar{y}}$	$RRMSE = \frac{\sqrt{\frac{\sum(\hat{y}_i - y_i)^2}{n}}}{\bar{y}}$

3 RESULTS

3.1 PROGRAM RESULTS

As described above, the best baselines will have both low bias and high precision. Since the sample pool did not participate in a demand response event on the pseudo-event days, we expect that the baseline should closely mimic the observed load if it is unbiased. Figure 8 shows the average observed load and baselines across iterations for the two aggregation methods, using one of the most common event windows from 7PM – 8PM. The left panel on the graph represents the "aggregate first" baseline method; the right panel represents the "individual first" method.

Figure 8: Bias of Aggregate First and Individual First Methods (7PM – 8PM Event Window)



Clearly, the "individual first" baseline method is biased upwards. This upward bias is the result of two specific considerations of the "individual first" method; baseline day selection and adjustments. In the "individual first" method, the set of five baseline days are selected for each individual customer. This differs from the "aggregate first" method since this method selects baseline days on the basis of aggregate loads, at which point the volatility of individual customer loads have been cancelled out due to aggregation. After the selection of the five baseline days, same-day adjustments in the "individual first" method are then applied based on the load of that specific customers. Because individual customer loads are noisy, large day-of adjustments for individual customers can also bias the results upward. In combination, the baseline day selection and the multiplicative adjustment bias the "individual first" method upward in a way that the "aggregate first" method does not.

Shown above, Figure 8 uses one of the nine event windows to contextualize the performance of both aggregation methods. To analyze the bias and precision of the full accuracy assessment, we remove the variability of event duration and group the performance across pseudo-event days. Figure 9 graphs the bias against the precision for each of these observations. The four colors of markers correspond to the four different sample sizes. Each sample size contains 100 markers that represent results for different subsets of customers – one for every iteration of bootstrapping. The best-performing baselines are unbiased (MPE close to 0) and highly precise (RRMSE close to 0). The blue regions in the graph below highlight the range of acceptable MPE and RRMSE results for candidate baselines.

Looking at the horizontal and vertical positions of the markers, it is clear that the "individual first" method has lower precision and consistently higher bias (~8%), even at the largest sample sizes. In other words, using the "individual first" method overstates the actual load by 8% on average. The "aggregate first" has lower bias and higher precision, especially as the sample size increases.

Figure 9: Precision vs Bias Relationship by Aggregation Method

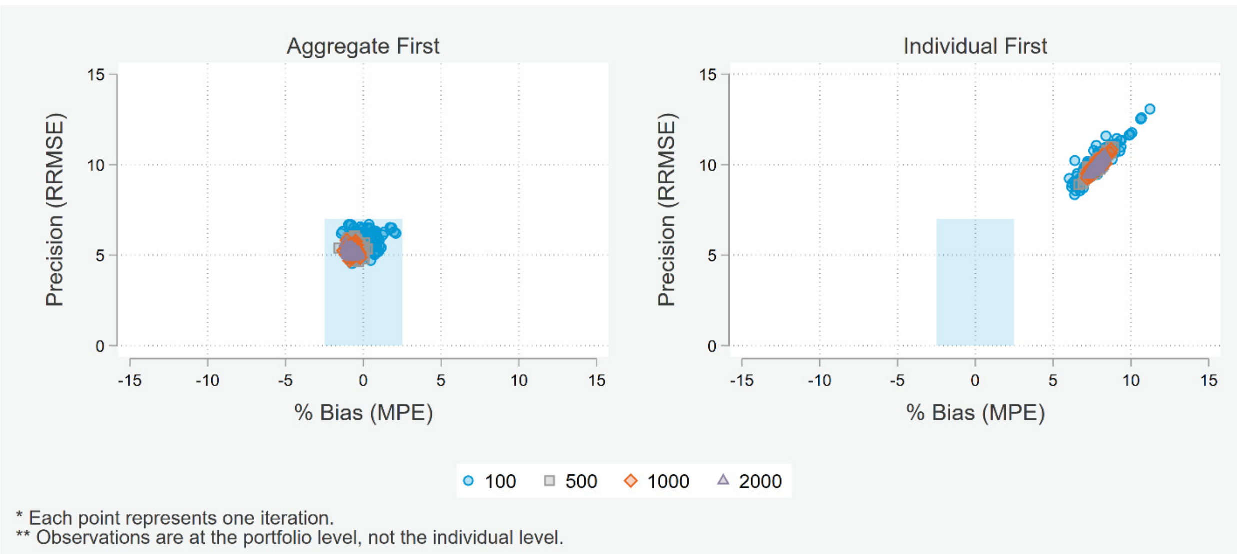


Table 5 shows the average bias and precision for each sample size and method, which just depicts the central tendency across the iterations in Figure 9.

Table 5: Point Estimates of Precision and Bias by Aggregation Method

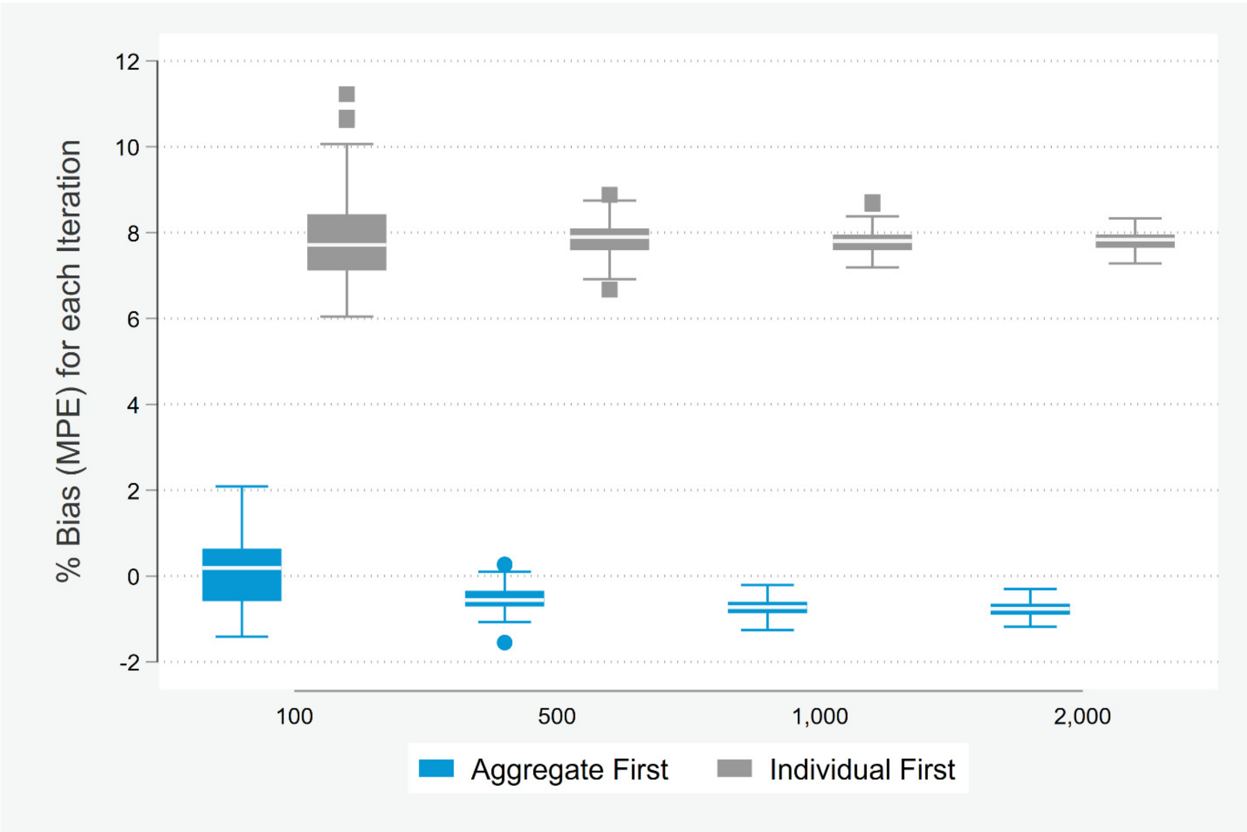
Sample Size	Bias (%)		Precision (%)	
	Individual First	Aggregate First	Individual First	Aggregate First
100	7.9%	0.1%	10.2%	5.8%
500	7.9%	-0.5%	10.0%	5.3%
1,000	7.8%	-0.7%	9.9%	5.2%
2,000	7.8%	-0.8%	9.9%	5.2%

Although the point estimates are helpful, we use boxplots to understand the distribution of the data. Boxplots summarize key metrics of distribution, which include the median value (identified by the horizontal, white line), the middle 50% of the data (the blue/grey box), and outliers (the dots present outside the extension of the box).

Figure 10 graphs this distribution of bias for each sample size to get a clearer understanding of how bias changes as the sample size increases. Two observations are clear:

1. **The spread of the bias decreases as the sample size increases.** This means we see the distribution tighten around the median value with larger sample sizes.
2. **The bias of the "individual first" method does not converge on zero.** In every iteration and sample size, the "aggregate first" method outperforms the "individual first" method.

Figure 10: Distribution of Bias by Sample Size



A similar trend to Figure 10 is present when examining the distribution of the typical error, or the RRMSE, across sample sizes.

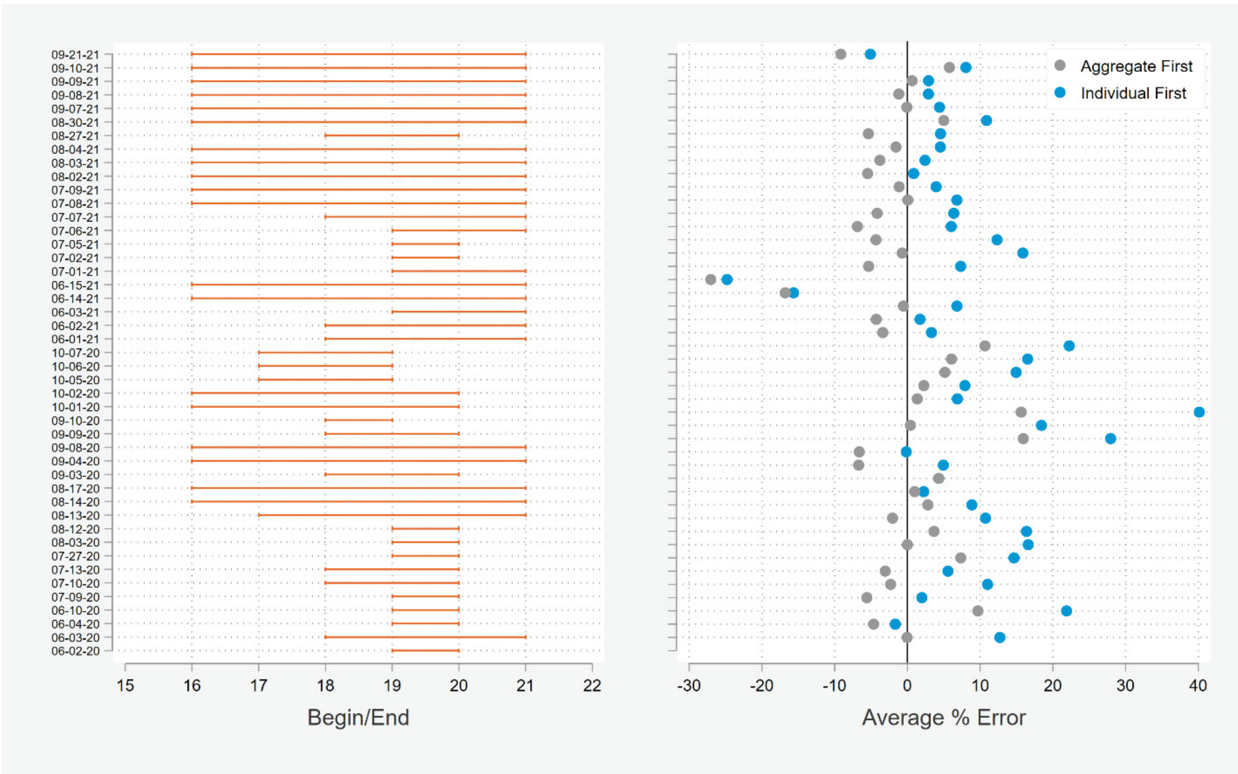
Up until this point, we have been looking at the baseline performance across two summers of events. However, this masks volatility in performance from event to event. Shown in the right panel of Figure 11 is the average error for each of the 45 psuedo-event days for the samples of 2,000 customers. An error of zero would indicate that the baseline perfectly predicts the observed load, while positive errors indicate that the baseline is over-predicting and negative errors indicate that the baseline is under-predicting. In addition to error, we include the event start time and duration in the left panel to illustrate the effects of event start and duration on the performance of the baselines.

It is clear that noise exists across these pseudo-event days, which is averaged out when we look at the iterations in Figure 9. This variability indicates:

1. For all event days, the "individual first" method is biased upwards when compared to the "aggregate first" method.

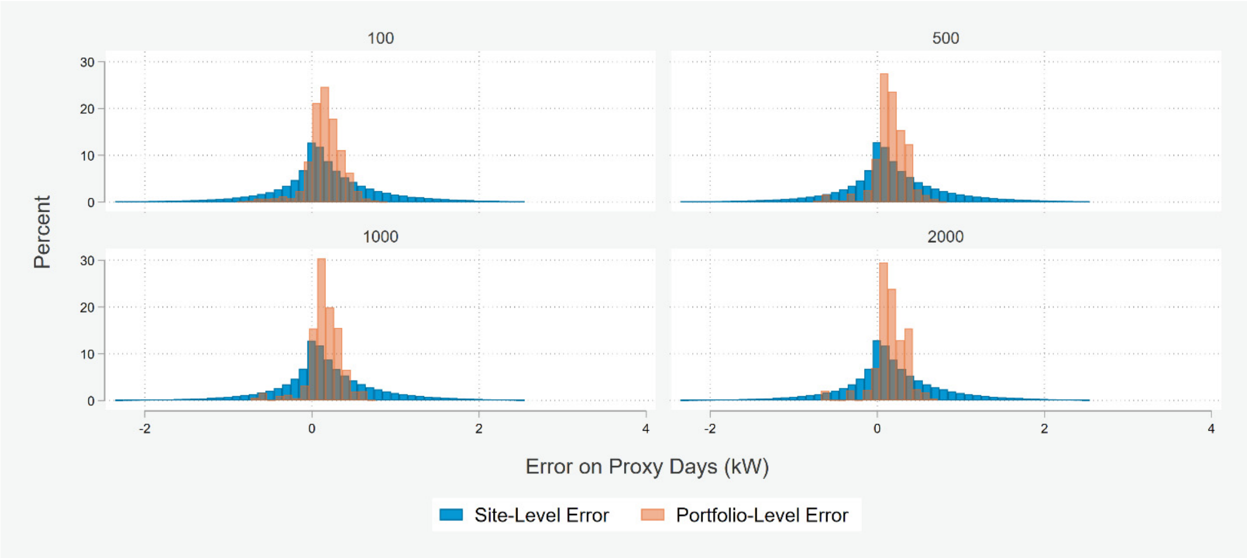
2. The "aggregate first" method is centered on zero error.
3. The "individual first" method performs better with longer event durations.

Figure 11: Event Day Error for Samples of 2,000 Customers



Similar to the noise present across pseudo-event days, noise is also present in the customer level results. While the "aggregate first" method strictly produces error on the portfolio level, the "individual first" method can produce site-level and portfolio-level error. To illustrate this, we plot the "individual first" site-level errors against the "individual first" portfolio-level errors in Figure 12. This makes it clear that the range of errors for individual sites is larger than the range of errors at the portfolio-level, which underscores that individual customer results are inherently more volatile than aggregate results. This volatility directly reduces settlement accuracy.

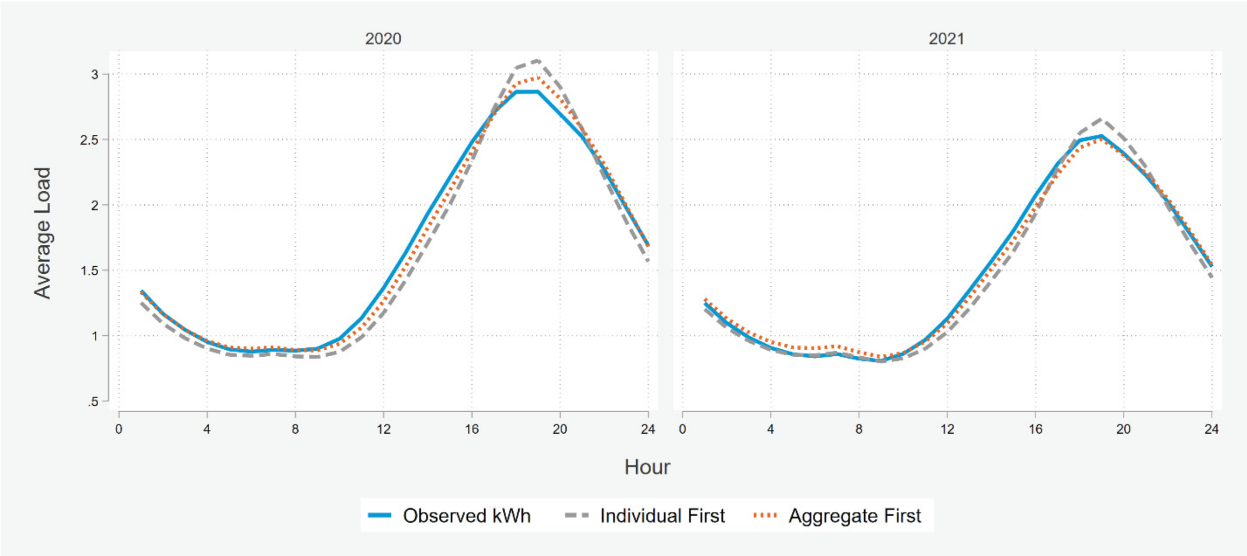
Figure 12: Site-Level and Portfolio-Level Errors for the Individual First Method



3.2 RESULTS FOR THE TOP 5 EVENT DAYS PER SUMMER

Examining the top five days of each year, selected based on CAISO system loads, allows us to explore how the baseline methods perform on more extreme years (2020) and more mild years (2021). Figure 13 plots the average performance across the top five event days per summer for the two baseline methods. The summer of 2020 tends to produce baselines that over predict for both the "individual first" and the "aggregate first" methods, but the "aggregate first" method still predicts closer to the actual load. The upward bias both methods produce in the summer of 2020 is likely a product of more extreme weather conditions and shorter event windows.

Figure 13: Baseline Performance on the Top 5 Event Days per Summer



When we break down this performance by individual event days in Table 6, it becomes clear that on almost all of the top 5 event days the "aggregate first" method performs better.

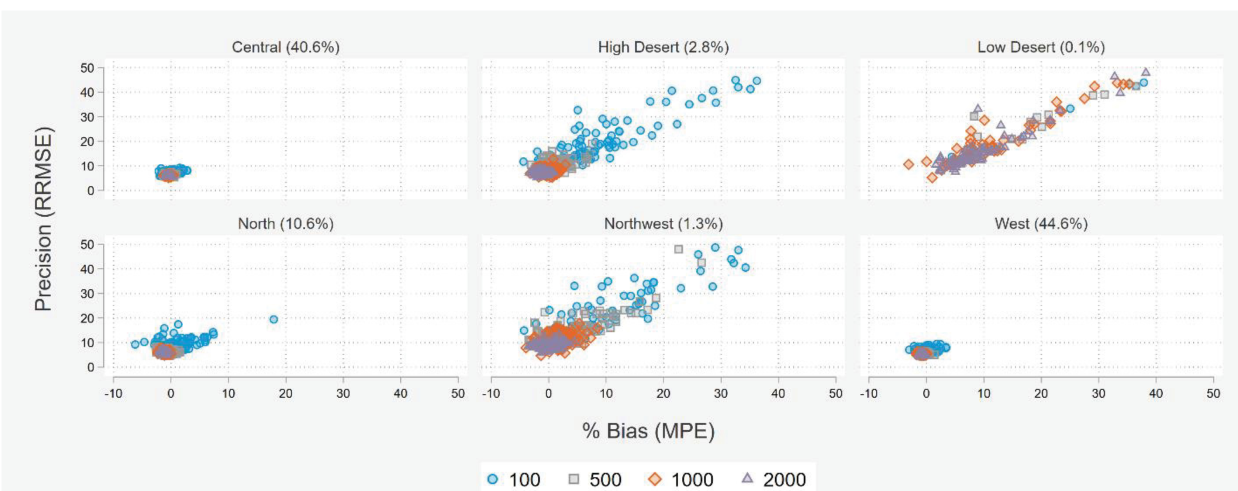
Table 6: Point Estimates of Bias on the Top 5 Event Days by Summer

Year	Date	Event Start	Event End	Individual First Bias (%)				Aggregate First Bias (%)			
				100	500	1,000	2,000	100	500	1,000	2,000
2020	13-Aug	18	21	8.8%	9.2%	9.0%	8.9%	3.3%	3.2%	2.9%	2.8%
	14-Aug	16	21	1.9%	2.3%	2.2%	2.2%	0.9%	1.1%	0.9%	1.0%
	17-Aug	16	21	4.2%	4.5%	4.2%	4.3%	3.9%	4.4%	4.1%	4.3%
	1-Oct	16	20	6.9%	6.9%	6.8%	6.9%	1.8%	1.5%	1.3%	1.4%
	2-Oct	17	20	7.9%	8.1%	7.8%	7.9%	2.7%	2.6%	2.2%	2.3%
2021	9-Jul	16	21	3.7%	3.9%	4.0%	4.0%	-0.8%	-1.1%	-1.1%	-1.1%
	27-Aug	19	20	4.2%	4.5%	4.6%	4.6%	-5.1%	-5.4%	-5.3%	-5.4%
	7-Sep	16	21	4.6%	4.6%	4.4%	4.4%	0.4%	0.2%	0.0%	-0.1%
	8-Sep	16	21	3.0%	2.8%	2.9%	2.9%	-0.7%	-1.0%	-1.2%	-1.2%
	9-Sep	16	21	2.8%	3.0%	2.8%	2.9%	0.5%	0.8%	0.5%	0.6%

3.3 SUBLAP RESULTS

Since SCE would settle the Residential CBP program at the SubLAP level, it is also important to understand how individual SubLAPs perform with the high 5-of-10, day-matching baseline. We compare the accuracy and precision produced by the aggregate-first method for individual SubLAPs in Figure 14. In this figure, the reported sample sizes are based on the full sample for each iteration, so the results for each SubLAP are shown for the proportion of the participant population within that particular SubLAP. For example, in the sample of 1,000 customers, 406 customers would be from Central and 28 would be from High Desert. Given this distribution of customers in the sample, it is clear that results for SubLAPs that represent a smaller portion of the total population tend to be less accurate and less precise.

Figure 14: Precision vs Bias Relationship by SubLAP



* Sample size is based on the program, not the SubLAP.
** Observations are at the portfolio level, not the individual level.

4 CONCLUSIONS AND RECOMMENDATIONS

The results of this analysis suggest five key findings:

1. **The "aggregate first" method outperforms the "individual first" method.** Aggregating loads first reduces the noise of individual customer load when picking baseline days and applying the adjustment.

2. **The inaccuracy exhibited by the "individual-first" method is not resolved by moving to larger sample sizes.** Each individual customer's baseline is biased upwards prior to aggregating any number of customers together.

3. **Individual customer level results are inherently more volatile than aggregated results.** The accuracy assessment was conducted at the portfolio level to reflect settlements with aggregators. Often, aggregators apply baselines for settlement to individual customers. Volatility of baselines and settlement error is larger at the individual customer level.

4. **Longer event windows tend to produce smaller errors.** This is the case under both aggregation methods.

5. **The precision and accuracy of SubLAP performance is a function of the size of the SubLAP.** SubLAPS like High Desert and Low Desert have fewer customers and are less accurate, as well as less precise.

Based on these findings, if Residential SCE customers begin participating in the CBP program, settlement should be based on an "aggregate first" baseline method, which outperforms and is less volatile than an "individual first" baseline settlement method. The natural level for aggregation is the one used for settlement with CAISO, which is at the SubLAP (a geographic area) level, but it is important to recognize that calculating baselines at the SubLAP level leads to less aggregation and less precise baselines. DSA recommends aggregating no less than 100 customers together in a given SubLAP, due to these smaller SubLAPs exhibiting greater variability. DSA has the following recommendations for the design of the Residential CBP Program:

	RECOMMENDATIONS
1	**Calculate settlement using the "aggregate-first" method.** It is unbiased and more precise than the "individual-first" approach, which tends to overestimate impacts.
2	**Settlement should be calculated for each portfolio resource at the SubLAP level to align with CAISO.** As CAISO settlements are done at the SubLAP level, this is a natural grouping for program aggregation.
3	**Aggregators should have no less than 100 customers per SubLAP to avoid noisy settlement results.** Groups of fewer than 100 customers are prone to both higher bias and lower precision **.**
4	**Settlement between aggregators and individual customers should be left to aggregators.** The aggregator is responsible for the relationship and settlement with the individual customer.

APPENDIX

Table 7: Point Estimates of Precision and Bias by Event Year

Year	Sample Size	Bias (%)		Precision (%)	
		Individual First	Aggregate First	Individual First	Aggregate First
2020	100	12.47	3.46	12.88	6.15
	500	12.43	2.68	12.66	5.36
	1,000	12.39	2.48	12.58	5.20
	2,000	12.39	2.40	12.57	5.19
2021	100	3.06	-3.35	7.38	5.48
	500	3.08	-3.86	7.21	5.26
	1,000	2.98	-4.09	7.15	5.25
	2,000	3.02	-4.08	7.16	5.20
All	100	7.87	0.13	10.19	5.82
	500	7.86	-0.52	10.00	5.31
	1,000	7.79	-0.73	9.93	5.23
	2,000	7.81	-0.77	9.92	5.19

Table 8: Point Estimates of Bias on the Top 5 Events per Summer

Year	Date	Event Start	Event End	Individual First Bias (%)				Aggregate First Bias (%)			
				100	500	1,000	2,000	100	500	1,000	2,000
2020	13-Aug	18	21	8.79	9.16	8.99	8.86	3.33	3.16	2.86	2.81
	14-Aug	16	21	1.91	2.27	2.17	2.24	0.94	1.13	0.88	0.99
	17-Aug	16	21	4.21	4.48	4.22	4.31	3.94	4.44	4.10	4.29
	1-Oct	16	20	6.92	6.91	6.78	6.87	1.83	1.45	1.29	1.35
	2-Oct	17	20	7.93	8.08	7.84	7.91	2.67	2.57	2.22	2.26
2021	9-Jul	16	21	3.72	3.88	3.96	3.95	-0.81	-1.12	-1.08	-1.14
	27-Aug	19	20	4.24	4.49	4.63	4.55	-5.13	-5.39	-5.28	-5.37
	7-Sep	16	21	4.6	4.55	4.4	4.42	0.44	0.18	-0.03	-0.07
	8-Sep	16	21	2.99	2.84	2.86	2.9	-0.72	-1.01	-1.17	-1.18
	9-Sep	16	21	2.77	2.95	2.77	2.91	0.52	0.84	0.54	0.64

Table 9: Point Estimates of Precision and Bias by SubLAP

SubLAP	Sample Size	Bias (%)		Precision (%)	
		Individual First	Aggregate First	Individual First	Aggregate First
Central	100	7.75	0.10	10.84	7.30
	500	7.64	-0.28	10.27	6.32
	1,000	7.61	-0.36	10.17	6.17
	2,000	7.60	-0.40	10.11	6.08
High Desert	100	18.59	13.76	27.57	24.63
	500	8.23	0.85	13.08	10.11
	1,000	7.29	-0.66	10.75	7.87
	2,000	7.60	-1.26	10.46	7.18
Low Desert	100	27.77	27.77	36.83	36.83
	500	52.19	51.24	61.62	60.63
	1,000	40.03	37.87	49.27	47.34
	2,000	29.13	26.29	35.85	33.39
North	100	7.77	1.46	12.54	9.59
	500	7.03	-0.81	9.92	6.40
	1,000	6.93	-1.15	9.82	6.16
	2,000	6.87	-1.22	9.62	5.92
Northwest	100	21.63	19.90	34.64	33.53
	500	10.84	4.87	18.82	15.43
	1,000	8.38	1.56	14.61	11.00
	2,000	8.00	0.08	12.99	8.89
West	100	9.42	0.30	12.23	7.03
	500	9.16	-0.48	11.39	5.51
	1,000	9.00	-0.80	11.23	5.30
	2,000	8.99	-0.80	11.14	5.16

Appendix B

Retail Baseline Working Group Final Report

March 1, 2021

RETAIL BASELINE WORKING GROUP

FINAL REPORT

March 1, 2021

RETAIL BASELINE WORKING GROUP
FINAL REPORT

Contents

EXECUTIVE SUMMARY

Decision (D.) 17-12-003 adopted demand response (DR) activities and budgets for years 2018 through 2022, but kept open the demand response applications filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the IOUs) (Applications (A.) 17-01-012, 17-01-018, and 17-01-019) in order to consider remaining matters in the consolidated proceeding, including the issue of demand response baselines.[1]

D.17-12-003 clarified that alternative wholesale baselines had been developed through the California Independent System Operator's (CAISO) Energy Storage and Distributed Energy Resources (ESDER) Phase II process.[2] Further, D.17-12-003 concluded that alternative baselines should be addressed in a future decision in that proceeding (outside of the mid-cycle review)[3] and instructed the Utilities to file a copy of the wholesale baselines tariff, following adoption of the tariff by the Federal Energy Regulatory Commission (FERC).[4] On November 8, 2018, in compliance with D.17-12-003, the Utilities filed a copy of the *FERC Tariff Amendment to Implement Energy Storage and Distributed Energy Resource Requirements, i.e., baseline methods*.[5]

The Administrative Law Judge presided over a prehearing conference on January 10, 2019 to establish next steps for addressing baselines. At a workshop held on March 22, 2019, the Utilities presented information on the current Commission-approved retail baselines; the CAISO wholesale Baselines; similarities, differences, and interaction between retail and wholesale baselines; and the costs of and funding options for expanding baseline options. A ruling was issued on April 8, 2019, directing parties to respond to a set of questions regarding baselines.[6] Parties filed responses to the April 8, 2019 ruling questions on April 24, 2019; replies were filed on May 3, 2019.[7]

On July 11, 2019, the Commission issued D.19-07-009 to address the Auction Mechanism, Baselines, and Auto Demand Response for Battery Storage. Ordering Paragraph 19 established the Retail Baseline Working Group (RBWG) to develop proposals to address five baseline issues.[8] The RBWG is required to present its proposals in a report served to all parties no later than April 1, 2021.[9]

---

[1] D.19-07-009 at page 3.

[2] D.17-12-003 at Finding of Fact 149.

[3] *Id*. at Conclusion of Law 74.

[4] *Id*. at page 153.

[5] D.19-07-009, page 4.

[6] See Administrative Law Judge's Ruling Directing Responses to Questions and Filing of Previous Demand Response Baseline Development and Implementation Costs, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M279/K201/279201986.PDF

[7] The following parties filed opening comments: Council, OhmConnect, PG&E, SDG&E, and SCE. The following parties filed reply comments: Council, OhmConnect, PG&E, and SCE.

[8] D.19-07-009, Ordering Paragraph (OP) 19.

[9] *Id*. at 86.

PURPOSE

The purpose of this final report is to describe the activities and proposals of the RBWG pursuant to D. 19-07-009, Ordering Paragraph 19.

As ordered by Ordering Paragraph 19, the RBWG discussed and developed proposals to the following issues:

1. Assess if adjustment cap of + or – 40 percent is still suitable for retail 10-in-10 when the day of adjustment for wholesale is + or – 20 percent.
2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.
3. Consider flexibility in changing retail baselines.
4. Consider whether the wholesale and retail baseline should be aligned, or can they be different.
5. Consider the pros and cons of an aggregate versus individual baseline.

The Capacity Bidding Program (CBP) is the only IOU retail DR program that uses an energy baseline (BL) for settlement.[10] Therefore, the RBWG addressed CBP baseline issues. The Demand Response Auction Mechanism (DRAM) baselines were out of scope for the RBWG.[11]

CHRONOLOGY OF WORK DONE

Participants

RBWG participants have included[12] the Energy Division (ED) Staff of the California Public Utilities Commission (CPUC), SCE, PG&E, SDG&E, Public Advocates Office (PAO), California Energy Storage Alliance (CESA), California Efficiency + Demand Management Council (CEDMC), EnergyHub, OhmConnect, California Energy Commission (CEC), Sunrun, ecobee, NRG, Center for Sustainable Energy, CPower, Enel X, Clean Energy Regulatory Research, and Polaris Energy.

---

[10] The Base Interruptible Program (BIP) uses a Firm Service Level (FSL).
[11] See D.19-07-009, OP 17 ("We adopt, for retail settlement purposes in the Demand Response Auction Mechanism, the four baseline methods approved by the Federal Energy Regulatory Commission: (1) a day matching customer load 10-in-10 baseline with a 20 percent cap; (2) a weather matching baseline with a 40 percent cap; (3) the use of control groups; and (4) a five-in-ten baseline for residential customers, with a 40 percent cap.").
[12] Not all identified parties participated consistently. While the RBWG was originally coordinated by an ED staff member, the IOUs were requested to continue to lead after her departure from the CPUC.

Stakeholder Meetings

Between September 2019 and November 2020, the RBWG held a series of meetings, some held in-person at the CPUC in San Francisco, and some held remotely. In-person meetings were held on September 24, October 22, and November 13, 2019 and conference calls were held on October 7 and 28, 2020 and November 19, 2020.

External Consultant

In order to help inform the five questions tasked by the CPUC to be addressed by the RBWG, external consultant Applied Energy Group (AEG) was engaged to perform an analytical study of the efficacy of the different day-of adjustments caps. The scope of this study was limited to IOU non-residential customers in CBP by analyzing 10 in 10 baselines either at the aggregate or individual customer level with day of adjustments of 20%, 30% and 40%. Subsequent to the completion of the study, AEG prepared a report,[13] which was distributed to the service list on October 8, 2020 (see Appendix B hereto) and thereafter AEG staff presented its findings to interested participants on October 28, 2020 (see Appendix C hereto).

REQUIRED ISSUES

<u>Issue #1</u>: Assess if adjustment cap of + or – 40 percent is still suitable for retail 10-in-10 when the day of adjustment for wholesale is + or – 20 percent.

> **Issue Definition:** The issue presented is whether third-party Aggregators should continue to utilize the current CPUC adopted + or – 40 percent adjustment cap for *retail* (CPUC) use or reduce the adjustment cap to + or – 20 percent.[14] Such an adjustment cap would continue to be optional and left to the discretion of the third-party Aggregator during the monthly CBP nomination process. On the *retail* side, the Day-Of Adjustment is generally calculated using the first three of the four hours prior to the event, divided by the average load for the same hours using the prior 10 weekdays for CBP participants. This Day-Of Adjustment should not exceed plus or minus 40% of the individual calculated baseline.
>
> **How it affects DR:** The use of the adjustment cap facilitates measurement of demand response performance based on actual demand and the weather condition on the event date. The adjustment cap will limit the magnitude of the baseline adjustment and is necessary to reflect a more accurate load condition during the event.

---

[13] See "Baseline Comparative Analysis – 2019 Statewide Load Impact Evaluation of the California Capacity Bidding Programs," dated October 1, 2020.

[14] D. 12-04-045, OP 10, set the "optional" adjustment cap at +/- 40 percent for the 10 in 10 baseline. Previously, D. 09-08-027 (pp. 140-141) established a +/- 20% adjustment cap for the 10 in 10 baseline. (Note: the term "retail" pertains to the baseline methodology utilized for settlement under CPUC rules as compared to wholesale settlement under the CAISO tariff.)

Proposed Solution(s): The RBWG recommends retaining the current + or – 40 percent adjustment cap. The reasons for this are: (1) AEG's study did not find a large difference between the + or - 20 percent and + or - 40 percent caps, (2) parties generally were amenable to the + or – 40 percent cap as it provides greater flexibility, and (3) retaining the current cap eliminates the need for system changes and costs that utilities would face if the cap were lowered to + or – 20 percent.[15]

Issue #2: Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.

Issue Definition: This issue pertains to which entity should determine whether to elect to utilize the adjustment cap (i.e., +/- 20% or +/-40%). As part of the RBWG, this topic was restated to be one that is between either the utility on the one hand or the customer/Aggregator on the other. Because in the CBP the Aggregator owns the relationship with the customer, it would be appropriate for the Aggregator to work with the customer to determine whether to utilize the adjustment cap. As a matter of clarification, the issue at hand is limited to the adjustment cap and does not pertain to the selection of a different baseline option (e.g., going from a 10 in 10 baseline to 5 in 10 baseline), which would require CPUC approval.

How it affects DR: The entity that has the ability to elect to utilize the baseline adjustment cap is in the best position to understand what is most suitable.

Proposed Solution(s): The general consensus is that the current framework where the Aggregator (not the utility) determines whether or not to apply the adjustment cap is adequate. As it relates to the determination between the Aggregator and its customer, this would be between these two parties and would not involve the utilities.

Issue #3: Consider flexibility in changing retail baselines.

Issue Definition: This issue pertains to how frequently a party can modify its adjustment cap (i.e., +/- 20% or +/-40%). Since the current nomination frequency is monthly, parties generally agree that the adjustment cap option can be

[15] The AEG study began well before the summer 2020 heat waves, and the initial draft of the AEG Report was released in July 2020. AEG examined event-days and event-like days from 2018 and 2019, and as such its analysis did not reflect the extreme heat conditions that occurred in 2020. Although this did not necessarily impact AEG's analysis because only a + or – 20 percent or + or – 40 percent day-of adjustment was being considered. However, performing the same analysis under the 1-in-30 weather conditions that prevailed during the August and September 2020 heat events would have been informative.

selected as frequently as monthly. It is not interpreted to be the frequency by which a *retail* baseline methodology can be changed (e.g., going from a 10 in 10 baseline to 5 in 10 baseline) because the 10 in 10 baseline is the only available *retail* baseline option for CBP at this time.[16] If additional baseline options become available, then rules for utilization would need to be developed.

How it affects DR: The frequency by which the baseline adjustment cap is applied can potentially affect performance based on customer operations.

Proposed Solution(s): Keep the monthly adjustment option methodology for that specific month, such that a customer cannot modify the adjustment cap until the next month.

Issue #4: Consider whether the wholesale and retail baseline should be aligned, or can they be different.

Issue Definition: This issue can be interpreted in three ways. The first interpretation is that all elements of a baseline option need to be aligned. This includes the actual baseline option (e.g., 10 in 10), the adjustment cap (e.g., +/- 40%) and the settlement level (individual/customer vs. aggregate/resource). The second interpretation is that while the baseline option (e.g., 10 in 10 baseline) needs to match there can be divergence in the adjustment cap. The third interpretation is that the baseline option and adjustment cap are aligned, but there can be divergence in the settlement level (individual/customer vs. aggregate/resource). The following table illustrates this point through four combinations.

Combination	Baseline Option	Adjustment Cap	Settlement Level
1	10 in 10	+/- 20%	Individual/Customer
2	10 in 10	+/- 40%	Individual/Customer
3	10 in 10	+/- 20%	Aggregate/resource
4	10 in 10	+/- 40%	Aggregate/resource

[16] D.19-07-009, OP 18, ordered the three Utilities to include proposals for implementing the 5 in 10 baseline for residential customers as part of their respective Mid-Cycle Advice Letters, which were due April 1, 2020. At the time of submission of this RBWG Final Report, the CPUC had not acted on these Mid-Cycle Advice Letters.

The RBWG interpreted the question as being limited to the adjustment cap and the settlement levels because the 10 in 10 baseline option is the only one available at the *retail* level at this time.

With respect to the adjustment cap, the *wholesale* (CAISO) baseline rules provide for a +/- 20% adjustment cap under the 10 in 10 baseline option.[17]

As it relates to the settlement level, which is further discussed in Q-5, the CPUC at the *retail* level prescribes the use of an individual (customer) level baseline while the CAISO at the *wholesale* level mandates an aggregate/resource level baseline.

How it affects DR: While lack of alignment may create certain differences for *retail* (CPUC) and *wholesale* (CAISO) settlements, the magnitude of the differences may or may not have material cost implications.

Proposed Solution(s): The general consensus is that *wholesale* and *retail* baselines do not need to be aligned, since AEG did not find any particular baseline combination to clearly outperform others.

<u>Issue #5</u>: Consider the pros and cons of an aggregate versus individual baseline.

Issue Definition: The issue deals with the level at which settlement occurs. An individual baseline means that settlement occurs at the participant (customer) level. An aggregate baseline is at the resource level comprised of multiple participants (customers). Today, the *retail* (CPUC) settlement is at the individual level while the *wholesale* (CAISO) settlement is at the resource level. Please refer to the AEG report, which discusses the pros and cons of aggregate vs. individual baselines (see pp. 6-7 of the study in Appendix B).

How it affects DR: An aggregate baseline may not necessarily be reflective of the performance of individual participants. Therefore, the two baseline calculations may lead to different load reduction estimates for the same participant/resource.

Proposed Solution(s): The RBWG generally agrees that having different settlement levels is acceptable (i.e., individual participant for *retail* (CPUC) and resource for *wholesale* (CAISO)). While the AEG study recommends an aggregate baseline for *retail* (CPUC) settlement (p. 5 of study), which would

[17] CAISO Tariff Section 4 Roles and Responsibilities, Subsection 4.13.4.1c Ten-in-Ten Baseline Methodology. Available at http://www.caiso.com/Documents/Section4-Roles-and-Responsibilities-asof-Jan1-2021.pdf.

seemingly align with the *wholesale* (CAISO) methodology, there are three reasons against doing so. First, the findings of the AEG study were not conclusive in identifying the single best baseline, as the accuracy of a baseline depends on the customer mix. And there was no consensus within the RBWG on the preference for one or the other. Second, moving to an aggregate baseline at the *retail* (CPUC) level would involve system modifications and associated costs for the utilities. Third, currently Aggregators have the greatest visibility into their customers' performance using individual baselines, which would not be as visible under an aggregate/resource baseline.

APPENDIX

Appendix A: Applied Energy Group's Baseline Analysis Final Report

Appendix B: Applied Energy Group's Baseline Analysis Final Presentation

Appendix A:
Applied Energy Group's Baseline Analysis Final Report

AEG

Applied Energy Group

BASELINES COMPARATIVE ANALYSIS

2019 Statewide Load Impact Evaluation of the
California Capacity Bidding Programs

October 1, 2020

BASELINES COMPARATIVE ANALYSIS

Report prepared for:

PACIFIC GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON
SAN DIEGO GAS & ELECTRIC COMPANY

Energy Solutions Delivered.

This work was performed by

Applied Energy Group, Inc.
2300 Clayton Road Suite 1370
Concord, CA 94520

Project Director: K. Marrin

Project Manager: A. Nguyen

Project Team: X. Zhang

in consultation with Pacific Gas & Electric Company, Southern California Edison, San Diego Gas & Electric Company, and the Demand Response Measurement & Evaluation Committee.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

SUMMARY AND KEY FINDINGS

This report documents the comparative analysis performed by Applied Energy Group (AEG) contracted by the PG&E on behalf of the Investor Owned Utilities (IOUs) to fulfill the Demand Response Retail Baseline Working Group (Working Group) requirements.

Research Objectives

Per CPUC Decision 19-07-009[1], the April 8, 2019 Ruling asked parties whether the current retail settlement baseline for the Capacity Bidding Program (CBP) should be revised, what the revisions would entail, and what implementation timeline should be adopted. Discussions during the March 22, 2019 workshop explained that the relationship between the retail and wholesale settlement baselines results in differences in load reduction quantities. Multiple parties agree that the retail settlement baselines should align better with the wholesale settlements. The purpose of this report is to compare how the current retail baselines perform along with identifying better performing baseline options, those that provide the highest accuracy while minimizing bias. In a perfect world, the retail baseline would result in the same load impact calculations as the wholesale baselines. The current retail settlement baseline is an individual 10-in-10 baseline with a maximum 40% adjustment cap. The wholesale settlement baseline is an aggregate[2] 10-in-10 baseline with a maximum 20% adjustment cap.

The D. 19-07-009 established the Working Group to investigate the following issues[3]:

1. Assess if an adjustment cap of ±40% is still suitable for retail settlement baselines when the day-of adjustment for wholesale settlement baselines is ±20%.
2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.
3. Consider flexibility in changing retail baselines.
4. Consider whether the wholesale and retail baseline should be aligned or if they can be different.
5. Consider the pros and cons of an aggregate versus individual baseline.

The goal of this analysis will directly address the 1st and 5th issues and hopefully provide insights into the other 3 issues. This analysis investigated six potential options for retail settlement baselines, including both the aggregate and individual baselines, with three different adjustment caps, 20%, 30%, and 40%. The main goal of this analysis was to identify the most effective baseline to represent the counterfactual, or what would have happened in absence of an event, with respect to accuracy and bias.

Research Methodology

To perform the comparative analysis, AEG calculated hypothetical baselines and compared them to a known counterfactual for each of the six potential baselines for both event days and event-like days in program years 2018 and 2019. Then, AEG summed the baseline estimates to the resource level

[1] CPUC D.19-07-009, p. 83.

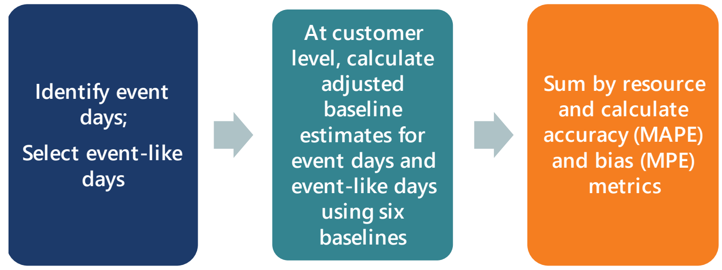
[2] Aggregate baselines are performed at the resource level, which is comparable to Product+Aggregator+Sub-LAP level.

[3] CPUC D.19-07-009, p. 86.

(segmentation of Product, Aggregator, and Sub-LAP) and calculated the accuracy and bias of each of the baselines on both day types in program years 2018 and 2019.

Figure 1-1 outlines the comparative analysis and the key steps are described as follows:

Figure 1-1 Description of Analysis Steps



Identifying event days and selecting event-like days. For this analysis, AEG utilized program years 2018 and 2019, identifying event days for both PY2018 and PY2019. Comparable event-like days were selected as part of the ex-post analysis[4] in both program years. Note that to keep comparisons consistent between the three IOUs, we only use event days and event-like days from months May through October.

Calculating baselines. Using the 10-in-10 day matching baseline specified in the CAISO's Baseline Accuracy Work Group Proposal by Nexant[5], we calculated the adjusted baseline estimates for PY2018 and PY2019 event days and event-like days. Six variations of the 10-in-10 day matching baseline were estimated at the customer level, calculating the adjustment ratio at both aggregate and individual levels and applying 20%, 30%, and 40% adjustment caps. We executed the six baselines on three scenarios: (1) event days, wherein the adjusted baselines were calculated for the window that the actual event was called; (2) event-like days assuming three-hour events called from HE17-HE19 or 4 PM to 7 PM; and (3) event-like days assuming two-hour events being called from HE19-HE20 or 6 PM to 8 PM.

The event-like day scenarios were selected to simulate events typically called by CBP as the program continues to align with the Resource Adequacy (RA) window, HE17-HE21 or 4 PM to 9 PM. Note that both event-like day scenarios use the same data, the differences in the results are driven by two factors: (1) the adjustment window (HE13-HE15 v. HE15-HE17), which determines the adjustment ratio; and (2) the event window (HE17-HE19 v. HE19-HE20), which is used to measure accuracy and bias.

Comparing accuracy and bias. AEG summed the baseline estimates by resource and utilized two metrics: (1) the mean absolute percent error (MAPE) for accuracy, and (2) the mean percent error (MPE) for bias. For both metrics, the goal is to be low or very close to zero to ensure more accurate and less biased estimates. In calculating these metrics, the actual load for event-like days is simply the actual load of each day since no event was called on those days. For event days, we defined the actual load as the estimated reference load in the ex-post analysis since we do not know the true value of the load in the absence of an event.

The approach used to do the comparisons was formulated with careful consideration of how the Capacity Bidding Program is implemented. Recall that retail settlement payments for each event day are done at the aggregator level. Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement. Because of the resource nomination component of the CBP tariff, AEG and the IOUs agree that the measure of accuracy and bias should be performed at the resource level, acknowledging that the resource is nominated and dispatched as a unit. The MAPE and MPE metrics presented for each IOU and program tell us, on average, for each resource, how accurate and biased the baseline estimates are

[4] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs, p. B-1.

[5] https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf

compared to the true value for that resource. Simple numerical examples of the comparison approach are shown in Section 2 (Example Calculation).

Key Findings

We summarize the findings of the comparative analysis at the state level, a total of five[6] programs from all three IOUs. Looking at the results at the state level can simplify the decision-making process in determining the most effective and appropriate baseline for retail settlement. The program-level comparisons are presented in Section 3 and show how both the participant population and the timing of event window can drive the effectiveness of the six baselines.

Table 1-1 shows the most effective baseline from all five programs.[7] This summary accounts for each program's two top (or most effective) ranking baselines for both accuracy and bias and shows the strength of their score in parenthesis. For example, looking at all programs and all event-like day scenarios, aggregate baseline with 20% adjustment cap ranked 1st or 2nd in accuracy in 3 out of 5 programs (shown in red text). Similarly, looking at all programs and all scenarios, aggregate baselines (regardless of the adjustment cap) ranked 1st or 2nd in bias in 3.5 out of 5 programs (shown in blue text). Five is the highest possible score, where all five programs favored a specific baseline. One is the lowest score, which indicates that each of the five programs favored different baselines.

Table 1-1 Accuracy and Bias – All Programs

	Best Accuracy			Least Bias		
Scenario	**Overall**	**Ind v. Agg**	**Adj Cap**	**Overall**	**Ind v. Agg**	**Adj Cap**
All Event-like days	**Agg 20% (3)**	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	**Agg (3.5)**	30% (2.2)

Red text and **blue text** used to highlight the example used in the text above.

Looking at Table 1-1, we can conclude the following:

- Aggregate baselines consistently give the least bias, considering all five programs and all scenarios used in this analysis. The 30% adjustment cap also shows the least bias in 2.2 out of 5 programs, considering all scenarios.
- Event-like day scenarios (HE17-HE19 and HE19-HE20 event windows) show better accuracy using aggregate baselines, while the event day scenarios show better accuracy using the individual baselines. All scenarios show better accuracy using a lower adjustment cap (20%).

[6] (1) PG&E Day Ahead; (2) SCE Day Ahead; (3) SCE Day Of; (4) SDG&E Day Ahead; and (5) SDG&E Day Of.

[7] Each program within each IOU bear equal weight in Table 1-1Table 3-1, i.e., SDG&E DA and DO programs both contribute equally in each category.

Note that the event-like day scenarios are highly valuable since the MAPE and MPE, i.e., accuracy and bias, were calculated using actual load data[8].

Because aggregate baselines resulted in the better accuracy and bias overall, we wanted to further explore differences in adjustment caps for only aggregate baselines. Table 1-2 shows the average loss in accuracy and increase in bias when selecting an aggregate baseline for each of the three adjustment caps. For example, looking at event-like day scenarios, if the aggregate baseline with 30% adjustment cap is selected, we see a 0.49% decrease in accuracy and 0.33% increase in bias, on average (shown in red text). Looking at Table 1-2, we see decreases in effectiveness that are all under 2.3%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap. Furthermore, looking at event day scenarios, which show better accuracy using individual baselines, we see that selecting an aggregate baseline approach will result in relatively small "losses", showing 1.47% to 2.28% decreases in accuracy.

Table 1-2 Average Decrease in Effectiveness – Aggregate Baselines

	Lost Accuracy			Increased Bias		
Scenario	**Agg 20%**	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
All Event-like days	0.26%	**0.49%**	0.76%	0.68%	**0.33%**	0.28%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

Red text used to highlight the example used in the text above.

Recommendation and Rationale

As mentioned in the research objectives, the overall goal of this analysis is to determine the most appropriate baseline for retail settlement. The comparative analysis focused on measuring the effectiveness (best accuracy and least bias) of each baseline with careful consideration of how CBP is implemented.

In these recommendations, it is important to keep in mind the following key points:

- Retail settlement payments for each event day are made at the aggregator level.
- Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement.
- A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

Recommendation

AEG recommends selecting the aggregated baseline with a 20% adjustment cap. The aggregate baseline is the most accurate overall, across all scenarios, and is also the most appropriate to the tariff and program implementation. Furthermore, the aggregate baseline with a 20% cap also has the advantage of being the same as the wholesale baseline settlement, which alleviates concerns around mismatches in the retail and wholesale settlement baseline results.

In Table 1-3 below, we present a comparison of both the recommended retail baseline (aggregate with 20% cap) and the current retail baseline (individual with 40% cap). The values shown in the table indicate

[8] The comparisons derived from the event day scenarios are also theoretically valid but come with constraints due to modeling errors in the ex-post analysis.

a ranking out of 6, with 1 ranking the highest (most accurate or least biased) and 6 ranking the lowest. The current baseline ranks 4.4-4.7 out of 6 in accuracy and 3.2-3.6 out of 6 in bias across all programs while the recommended baseline ranks 2.3-3.0 out of 6 in accuracy and 3.6 out of 6 in bias. This indicates that the recommended baseline is more accurate, and similar in bias to the existing baseline.

Table 1-3 Comparison of Recommended vs. Current Retail Baselne – Average Ranking

	Aggregate with 20% Cap		Individual with 40% Cap	
Scenario	**Accuracy Ranking**	**Bias Ranking**	**Accuracy Ranking**	**Bias Ranking**
All Event-like Days	2.3	3.6	4.7	3.6
Event Days	3.0	3.6	4.4	3.2
All Scenarios	2.5	3.6	4.6	3.5

Rationale

In this section we provide more context around our recommendation with respect to the two key aspects for the baseline: (1) individual vs. aggregate; and (2) the adjustment cap.

Comparing Effectiveness Across Baselines

It is important to note that this analysis greatly emphasized how much the participant population and the timing of the event window can influence the effectiveness of the six baselines. The program-level results presented in Section 3 demonstrate how accuracy and bias can swing from year-to-year, depending on these two factors (participant population and event timing).[9]

Fortunately, between the 6 baseline options, both accuracy and bias are not highly sensitive within a single population and program year. In other words, in any given year, the loss of accuracy or bias between individual versus aggregate or between 20%, 30%, and 40% adjustment caps is minimal. This lack of sensitivity is consistent in all program-level program year comparisons (graphs shown in Appendix). Therefore, we believe that additional focus should be placed on the appropriateness of the selected baseline including its alignment with CBP program implementation and coordination with the wholesale baseline.

Individual vs. Aggregate Baselines?

AEG recommends that the Aggregate Baseline be used for retail settlement with the following reasons:

- Aggregate baselines, regardless of the adjustment cap, consistently minimizes the bias. Across all scenarios, all five programs and two program years, aggregate baselines show less biased adjusted baseline estimates.
- Looking only at the event-like day scenarios, aggregate baseline, regardless of the adjustment cap, give the best accuracy across all five programs and two programs years. The event-like day scenarios also hold more weight since the accuracy and bias are measured relative to actual load data.

[9] The most illustrative example from this analysis is shown in Figure A-17 and Figure A-18, which show SDG&E's PY2018 Day Of Program. Looking at the event-like day scenarios, notice how the MAPE and MPE are extremely high when the event is called from HE17-HE19 compared to when the event is called from HE19-HE20. Note that these two scenarios use the exact same participants and data, i.e., the event-like days and the 10 baseline days are the same in both scenarios.

- The aggregate baseline treats the resource as a unit, instead of looking at customers individually, by determining the adjustment ratio at the resource level. The resource, as discussed above, is a key factor in how CBP is implemented.
  - It is important to note that customer-level calculations are important to aggregators and can still be provided when the aggregate baseline is implemented.

	Pros	Cons
Individual Baselines	• Provides more accurate estimates for individual customers.	• Provides less accurate estimates at the resource level. • Is not in alignment with the wholesale settlement baseline.
Aggregate Baselines	• Provides more accurate estimates at the resource level. • Aligns with the wholesale settlement baseline.	• Provides less accurate estimates for individual customers.

Which adjustment cap is the most appropriate?

State-level results show that the 20% adjustment cap gives adjusted baseline estimates with the best accuracy, while the 30% adjustment cap gives the least bias. However, both accuracy and bias are not highly sensitive to the adjustment cap. We see such small differences in accuracy and bias between the 20%, 30%, and 40% caps that selecting one over the other does not mean a significant loss in effectiveness. Given that the wholesale baseline already uses a 20% adjustment cap, the advantages of aligning the two caps far outweigh the very small increase in bias.

2

STUDY METHODS

This section presents the methods employed in this study. In the first section, we describe the prescribed approach used to calculate the six variations of the 10-in-10 day matching baseline. In the second section, we describe the comparative analysis that was used to compare the six baselines.

The main goal of this analysis was to identify the most effective baseline to represent the counterfactual, or what would have happened in absence of an event, with respect to accuracy and bias.

Calculating the 10-in-10 Day Matching Baseline

The 10-in-10 day matching baseline calculation was estimated according to the CAISO's Baseline Accuracy Work Group Proposal by Nexant using each of the six variations below:[10]

- Aggregate 10-in-10 day matching with maximum 20% day-of adjustment,
- Aggregate 10-in-10 day matching with maximum 30% day-of adjustment,
- Aggregate 10-in-10 day matching with maximum 40% day-of adjustment,
- Individual 10-in-10 day matching with maximum 20% day-of adjustment,
- Individual 10-in-10 day matching with maximum 30% day-of adjustment,
- Individual 10-in-10 day matching with maximum 40% day-of adjustment.

Note that in this analysis, the aggregate level is defined as the combined segmentation of Product, Aggregator, and Sub-LAP. This is to create a comparable simulation to the wholesale settlement baseline, which defines the aggregate level at the resource level.

The calculation was completed by following the steps outlined below. Note that steps 2 through 5 are italicized. They are included in the official definition of the day matching baseline, but since all 10 of 10 eligible days are selected for the baseline calculation, the ranking and selection (covered in steps 2 through 5) are unnecessary. Furthermore, step 10 was not completed as part of this analysis since the comparisons were done on the adjusted baseline estimates, which is calculated in step 9.

1. Identify the 10 eligible baseline days that occurred prior to an event, excluding weekends, other event days, ISO holidays, award dates, outages, etc.
2. *Calculate the hourly participant load for the event day and for each eligible baseline day.*
3. *Calculate total MWh during the event period for each eligible baseline day.*
4. *Rank the baseline days from largest to smallest based on MWh consumed over the event period.*
5. *Select the top ten baseline days out of the pool of eligible days.*
6. Average hourly customer loads across the ten baseline days to generate the unadjusted baseline.
7. Calculate the day-of adjustment ratio (at aggregate or individual level) based on the adjustment window: three hours immediately prior to the event with a one-hour buffer.

[10] https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf

$$Adjustment\ ratio = \frac{Total\ kWh\ during\ adjustment\ hours}{Unadjusted\ baseline\ kWh\ over\ adjustment\ hours}$$

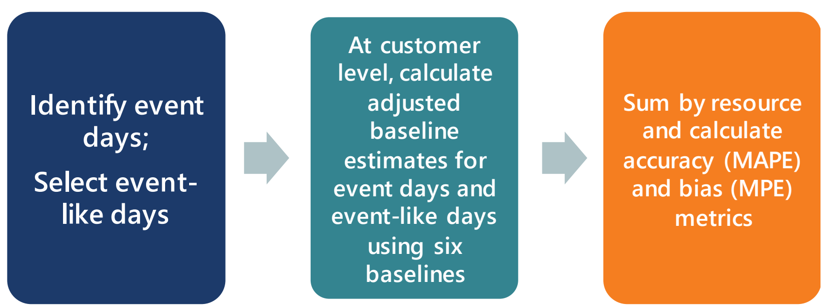
8. If the day-of adjustment ratio exceeds adjustment cap, limit the adjustment ratio to the cap, where X can be 20%, 30%, 40%. The adjustment cap is up =1+X and down =1-X.
9. Apply the day-of adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline estimate.
10. Calculate the Actual Load Reduction as the difference between the adjusted baseline and actual electricity use for each event hour.

Note that a key distinction between the baselines occurs in step 7. The day-of adjustment ratio for an individual baseline is calculated at the customer level, i.e., for each customer and event day. However, for an aggregate baseline, the day-of adjustment ratio is calculated at the aggregate level, i.e., for each resource and event day.

Comparative Analysis

Figure 2-1, to the right, outlines the comparative analysis that was performed to identify the most effective baseline. We discuss each step in detail in the following subsections. Note that the selection of event-like days was completed as part of the ex-post impact analyses in PY2018 and PY2019. [11]

Figure 2-1 Description of Analysis Steps



In this hypothetical comparative analysis, AEG calculated adjusted baseline estimates for each of the six baselines described above on both event days and event-like days at the customer level. Then, AEG summed the adjusted baseline estimates to the resource level (segmentation of Product, Aggregator, and Sub-LAP) and calculated the accuracy and bias of each of the baselines on both day types in program years 2018 and 2019 as follows:

- On event-like days we measure the effectiveness of each baseline (using accuracy and bias) by comparing the adjusted baseline estimate to the actual event-like day load where both represent a counterfactual, or what would have happened on an event-day in absence of an event.
- We conducted a similar comparison on event days; however, we used the reference load from the ex-post analysis as the reference point to measure accuracy and bias. The reference load is used in this comparison since it is the counterfactual produced by the ex-post models.[12]

Selecting Event-Like Days

To select the event-like days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. To determine how close event day temperature is to a potential event-like day, we calculated a Euclidean distance metric defined as the square root of

[11] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs, p. B-1.
[12] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs, p. 8.

the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance; in PY2018 and PY2019, we used three different Euclidean distance metrics to select similar non-event days: (1) daily maximum temperature; (2) average daily and daily maximum temperatures; (3) average daily temperature. The Euclidean distance metrics used can be calculated by Equations 1 through 3 below.

$$ED_1 = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2} \quad (1)$$

$$ED_2 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2 + (MaxTemp_{event} - MaxTemp_{non-event})^2} \quad (2)$$

$$ED_3 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2} \quad (3)$$

Since all three IOUs called several different event windows, we placed the focus on the entire day instead of a specific event window. Because we limited the pool to within-year non-event days, we selected less non-event days for each program year analysis to accommodate both the non-event day pool and the available customer data. To ensure that we selected an adequate group of event-like days, we do a final check and compare the distributions of weather and day types. For example, if there are more event days in August and more event days on a Tuesday, we try to account for that in the selected event-like days.

In the figures below, we show comparisons of the distributions of average daily temperature of event days and event-like days. We show one comparison for each utility by program year, because the selection was done at the utility level instead of the program or product level. We use this approach to accommodate customer moves between products or programs and the automation process of running individual customer regression models.

Figure 2-2 PG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019

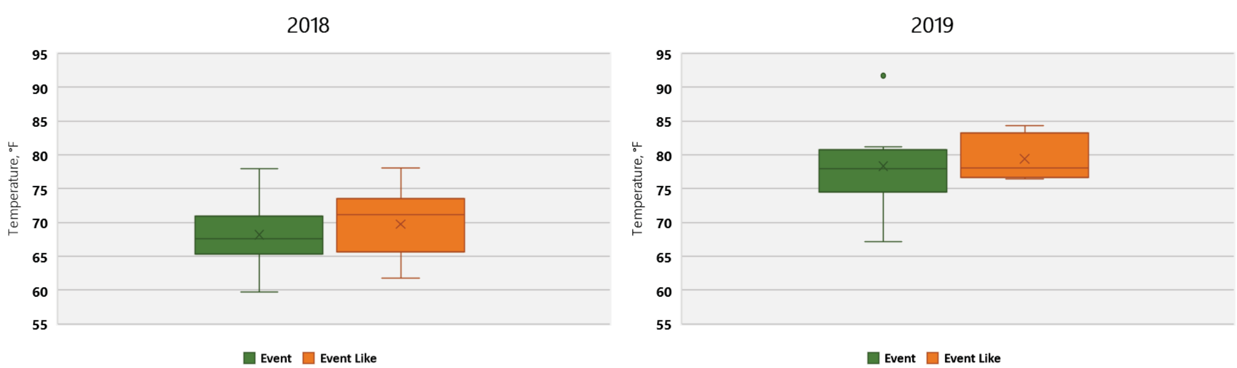


Figure 2-3 SCE Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019

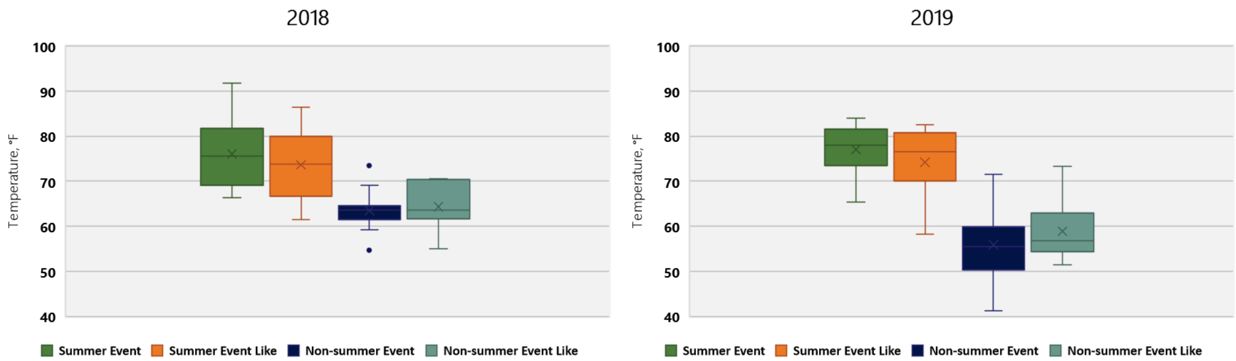
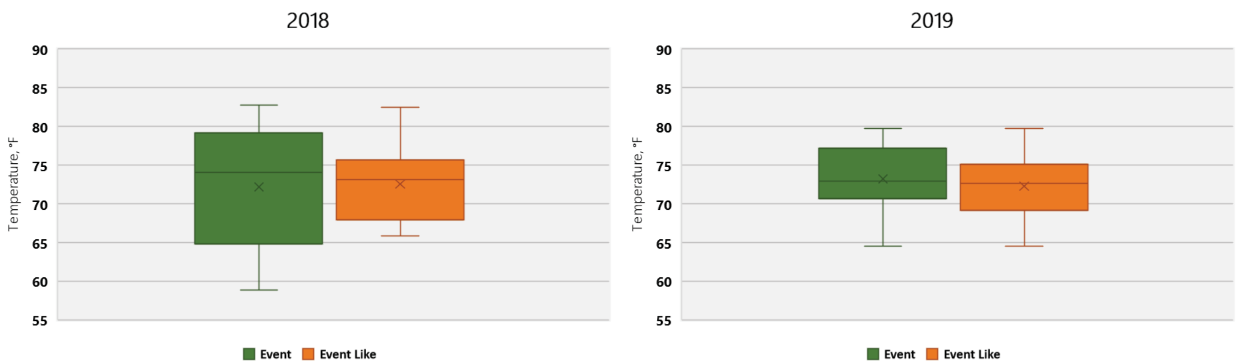


Figure 2-4 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019



Calculating the Baselines

Using the 10-in-10 day matching baseline methodology discussed above, we calculated the six baselines[13] for three scenarios resulting in 18 individual calculations:

- Event days in PY2018 and PY2019 over the actual event window.
- Event-like days in PY2018 and PY2019 assuming three-hour events were called from HE17-HE19 or 4 PM to 7 PM.
- Event like days in PY2018 and PY2019 assuming two-hour events were called from HE19-HE20 or 6 PM to 8 PM.

The event-like day scenarios were selected to simulate events typically called by CBP as the program continues to align with the Resource Adequacy (RA) window, HE17-HE21 or 4 PM to 9 PM. Note that both event-like day scenarios use the same data, the differences in the results are driven by two factors: (1) the adjustment window (HE13-HE15 v. HE15-HE17), which determines the adjustment ratio; and (2) the event window (HE17-HE19 v. HE19-HE20), which is used to measure accuracy and bias.

[13] We estimated the baselines for six variations, calculating the adjustment ratio at both aggregate and individual levels, applying 20%, 30%, and 40% adjustment caps.

Calculating Accuracy and Bias

Once we calculated the six baselines for each of the three scenarios, we compared the various estimates using measures of accuracy and bias. The mean absolute percent error (MAPE) measures accuracy, which is the measure of how close the estimate is to the known value. The mean percent error (MPE) measures bias, which is when estimates are always higher or lower than the known value. Equations (4) and (5) show the MAPE and MPE, respectively.

$$MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right| \tag{4}$$

$$MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h} \tag{5}$$

For both metrics, the goal is be low or very close to zero to ensure high accuracy or low bias estimates.

The actual load for event-like days ($Actual_h$ in Equations 4 and 5) is simply the load on each day since no event was called on those days. For event days, we defined the actual load as the estimated reference load in the ex-post analysis since we do not know the true value of the load in the absence of an event.

To compare the six baselines, AEG calculated the MAPE and MPE at the simulated resource level, which is the combination of product, aggregator, and sub-LAP. In doing so, we are establishing an apples-to-apples comparison between the six baselines for each scenario, where in the MAPE and MPE point estimates tell us, on average, for a resource, how close is the estimated baseline to the true value for that group. In the next section, we will also discuss further the rationale behind the comparison approach.

Example Calculation

An important distinction in the analysis is the difference between the individual baseline and the aggregate baseline. Below, Table 2-1 provides a simple numerical example of how the MAPE and MPE are calculated for an individual baseline estimate vs. an aggregate baseline estimate for a single ratio cap value. The example includes two resources, Resource 1 with three customers, and Resource 2 with only a single customer. The adjustment ratios for customers in Resource 1 (shown in red text) illustrate the differences between the individual and aggregate baselines. The method score (highlighted in blue) compares the effectiveness of the two baselines.

Table 2-1 Resource-level Comparison: Calculation Example

	Individual Baseline				Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.14	155.51				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.26	178.44				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.30	184.61	508.56	518.56	2.0%	-2.0%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.4%*	*2.4%*

	Aggregate Baseline				Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.23	167.41				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.23	174.67				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.23	174.67	508.56	516.75	1.6%	-1.6%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.2%*	*2.6%*

A few key notes on the example above:

- The MAPE and MPE are calculated for each resource and event day. The average MAPE and MPE for each IOU and program (Day Ahead or Day Of) is calculated to achieve the accuracy and bias score for each of the six baselines. In this approach, each resource and event day is given equal weight in each IOU and program.
- Resource 1 demonstrates the difference between an individual adjustment versus an aggregate adjustment (shown in red text). In the individual baseline method, the adjustment ratio is determined at the customer level, while in the aggregate baseline method, the adjustment ratio is determined at the aggregate level.
- Resource 2 contains a single customer, thus the estimates in the individual and aggregate baselines are the same.

Exclusions

During review of results and discussions with the IOUs, AEG excluded the data points that met the following criteria:

- Negative MAPE – this occurs only in the event day scenarios and is caused by negative values in the ex-post estimated reference load. This indicates significant modeling errors in the ex-post regression models.
- Missing MAPE or MPE – this is caused by missing hourly usage data.
- Outlier MAPE – outliers were determined by looking at the distribution of the MAPE at the customer level by IOU and program, identifying customers and events with highly erratic loads. This criterion excluded four customers from all three IOUs and around 1% of total data.

3

RESULTS AND COMPARISONS

The comparisons presented in this section were derived using the approach described in Section 2,Calculating Accuracy and Bias. The approach used to do the comparisons in this analysis was formulated with careful consideration of how the Capacity Bidding Program is implemented.

Recall that retail settlement payments for each event day are done at the aggregator level. Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement. So, in theory, aggregators can collectively nominate 10 customers as a resource for 2 MW curtailment, but on any given event, only dispatch 3 out of the 10 customers to deliver the 2 MW curtailment.

Because of the resource nomination component of the CBP tariff, AEG and the IOUs agree that the measure of accuracy and bias should be performed at the resource level, acknowledging that the resource is nominated and dispatched as a unit.

Summary of Findings

The following section discusses the results at the State level, i.e., for all IOUs and programs, five[14] programs altogether.

Event-like Day Results

In this subsection, we discuss the “winning” baseline, looking only at the event-like day scenarios. We find the results from these scenarios highly valuable since the MAPE and MPE, i.e., accuracy and bias, were calculated using actual load data[15]. In these simulations, we are testing how effectively the six variations of the 10-in-10 day matching baselines estimate the actual load of the event window.

Table 3-1 shows the most effective baseline from the five programs.[16] This summary accounts for each program’s two top (or most effective) ranking baselines for both accuracy and bias and shows the strength of their score in parenthesis. For example, looking at all programs and all event-like day scenarios, aggregate baseline with 20% adjustment cap ranked 1st or 2nd in accuracy in 3 out of 5 programs (shown in red text). Similarly, looking at all programs and event-like day HE17-HE19 scenarios, aggregate baseline (regardless of the adjustment cap) ranked 1st or 2nd in bias in 3 out of 5 programs (shown in blue text). Five is the highest possible score, where all five programs favored a specific baseline. One is the lowest score, which indicates that each of the five programs favored different baselines.

Looking at Table 3-1, we can conclude the following:

- Aggregate baselines, regardless of the adjustment cap, give estimates with better accuracy and less bias.
- The lower adjustment cap (20%) gives estimates with the better accuracy, however the higher adjustment caps (30% and 40%) minimize the bias.

[14] (1) PG&E Day Ahead; (2) SCE Day Ahead; (3) SCE Day Of; (4) SDG&E Day Ahead; and (5) SDG&E Day Of.

[15] The comparisons derived from the event day scenarios are also theoretically valid but come with constraints due to modeling errors in the ex-post analysis.

[16] Each program within each IOU bear equal weight in Table 3-1, i.e., SDG&E DA and DO programs both contribute equally in each category.

Because aggregate baselines resulted in the better accuracy and bias overall, we wanted to further explore differences in adjustment caps for only aggregate baselines. Table 3-2 shows the average loss in accuracy and increase in bias when selecting an adjustment cap for the aggregate baseline. For example, if the 30% adjustment cap is selected, we see a 0.49% decrease in accuracy and 0.33% increase in bias, for both HE17-HE19 and HE19-HE20 event windows, on average (shown in red text). Looking at Table 3-2, we see decreases in effectiveness that are all under 1%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap.

Table 3-1 Accuracy and Bias – Event-like Day Scenarios

Event-like Day Scenario	Best Accuracy			Least Bias		
	Overall*	**Ind v. Agg***	**Adj Cap**	**Overall***	**Ind v. Agg**	**Adj Cap**
Event-like Days (HE17-HE19)	Agg 20% Agg 30% (3)	Agg (4)	20% (2.5)	Agg 30% Agg 40% (3)	**Agg** **(3)**	40% (2.5)
Event-like Days (HE19-HE20)	Agg 20% Ind 20% (3)	Ind, Agg (2.5)	20% (3)	Agg 30% (5)	Agg (4.5)	30% (3)
All Event-like days	**Agg 20%** **(3)**	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)

Red text and **blue text** used to highlight the example used in the text above.

Table 3-2 Average Decrease in Effectiveness – Event-like Days – Aggregate Baselines

Event-like Day Scenario	Lost Accuracy			Increased Bias		
	Agg 20%	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
Event-like Days (HE17-HE19)	0.24%	0.49%	0.78%	0.76%	0.46%	0.38%
Event-like Days (HE19-HE20)	0.27%	0.48%	0.75%	0.59%	0.21%	0.18%
All Event-like days	0.26%	**0.49%**	0.76%	0.68%	**0.33%**	0.28%

Red text used to highlight the example used in the text above.

Results for All Scenarios

Similar to the previous subsection, Table 3-3 shows the most effective baseline from all three IOUs and programs, looking at only event days and all three scenarios overall, and Table 3-4 shows the average loss in accuracy and increase in bias when selecting an adjustment cap for the aggregate baseline.

Comparisons on the event day scenarios shift the results to show better accuracy using the individual baselines. However, the aggregate baselines still show the least bias, consistent with the event-like day scenarios. The event day scenarios also show higher decreases in effectiveness when selecting the aggregate baseline, on average, but they are still relatively small with all decreases under 3%.

When looking at all scenarios, the aggregate baseline methodology, regardless of the adjustment cap, still gives estimates with better accuracy and less bias, showing very low decreases in effectiveness, all under 1.3%, on average.

Table 3-3 Accuracy and Bias – Event Days and Overall

Scenario	Best Accuracy: Overall	Best Accuracy: Ind v. Agg	Best Accuracy: Adj Cap	Least Bias: Overall	Least Bias: Ind v. Agg	Least Bias: Adj Cap
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	Agg (3.5)	30% (2.2)

Table 3-4 Average Decrease in Effectiveness – Event Days and Overall – Aggregate Baselines

Scenario	Lost Accuracy: Agg 20%	Lost Accuracy: Agg 30%	Lost Accuracy: Agg 40%	Increased Bias: Agg 20%	Increased Bias: Agg 30%	Increased Bias: Agg 40%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

As mentioned in the Section 1 (Research Objectives), one of the issues for investigation in this analysis is to consider whether the wholesale and retail baselines should be aligned or if they can be different. In Table 3-5 below we present a comparison of both the current wholesale baseline (aggregate with 20% cap) and the current retail baseline (individual with 40% cap). The values shown in the table indicate a ranking out of 6, with 1 ranking the highest (most accurate or least biased) and 6 ranking the lowest. The current retail baseline ranks 4.4-4.7 out of 6 in accuracy and 3.2-3.6 out of 6 in bias across all programs while the current wholesale baseline ranks 2.3-3.0 out of 6 in accuracy and 3.6 out of 6 in bias. This indicates that aligning the wholesale and retail baselines to both be aggregate baselines with 20% cap would result in more accurate estimates and similar bias, at the resource level.

Table 3-5 Comparison of Current Wholesale Baseline vs. Current Retail Baselne – Average Ranking

Scenario	Aggregate with 20% Cap: Accuracy Ranking	Aggregate with 20% Cap: Bias Ranking	Individual with 40% Cap: Accuracy Ranking	Individual with 40% Cap: Bias Ranking
All Event-like Days	2.3	3.6	4.7	3.6
Event Days	3.0	3.6	4.4	3.2
All Scenarios	2.5	3.6	4.6	3.5

Program-level Comparisons

In this subsection, we present the comparisons by program for all three IOUs. Each program will have two graphs, all following a uniformed color scheme: blue for accuracy and orange for bias. In addition, each graph will have the following components:

- A separate block, indicating each of the three event scenarios: (1) Event days; (2) Event-like days assuming HE17-HE19 event window; and (3) Event-like days assuming HE19-HE20 event window.
- The best score for each scenario shown in red text and red box.
- The current retail settlement baseline (Individual Baselines with 40% adjustment cap) shown in a striped pattern fill.

The program-level comparisons show how both the participant population and the timing of event window can drive the effectiveness of the six baselines.

PG&E Results

Starting in PY2018, PG&E only offers Day Ahead product offerings.

Day Ahead Program

The DA program results cover 55 event days and 29 event-like days across PY2018 and PY2019. Across both program years, the DA program includes 12 unique resources and 948 unique customers. Figure 3-1 and Figure 3-2 show the accuracy and bias comparison for all three scenarios, respectively.

For PG&E DA, we can conclude the following:

- The event-like day scenarios show consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline has low sensitivity to the timing of the event window (HE17-HE19 v. HE19-HE20).
  - The two event-like day scenarios have very consistent bias comparisons, showing less bias using the aggregate baseline (dark orange bars are consistently lower), with the 40% adjustment cap showing the least bias in both individual and aggregate baselines. The event-like days also show all positive MPE estimates, indicating that the estimates are lower, on average, than the actual event-like day loads.
  - Looking at accuracy, the HE17-HE19 event window show results consistent to bias, showing the best accuracy using the aggregate baseline with 40% adjustment cap.
  - The HE19-HE20 event window simulation shows slightly different accuracy results, with the individual baselines showing better accuracy. Also note that the aggregate baseline with 40% adjustment cap shows the lowest accuracy. This is due to the results from PY2018 event-like days (see Figure A-1 and Figure A-3), which is an indicator that the customer mix, i.e., population distribution, can largely influence the effectiveness of the baseline.
- The event days show results comparable to the HE19-HE20 event-like day scenarios, despite the differences in magnitude, showing better accuracy using the individual baselines. This is due to PG&E DA calling 30 out of 55 events that start on HE19. It is also interesting to note that the event days show the 20% adjustment cap to perform the highest effectiveness.

Figure 3-1 PG&E Day Ahead Program: Accuracy Comparison – Resource-level

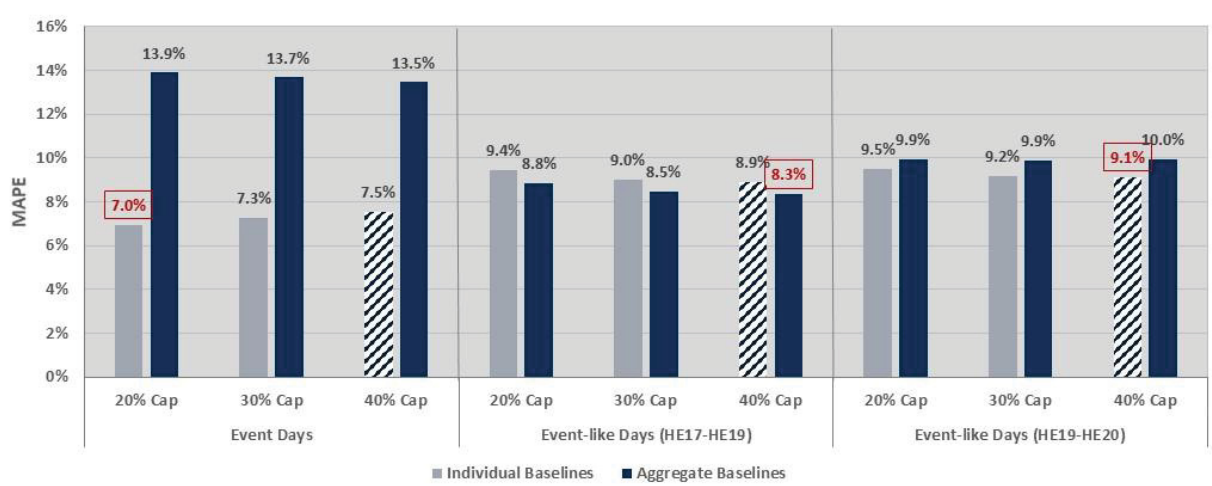
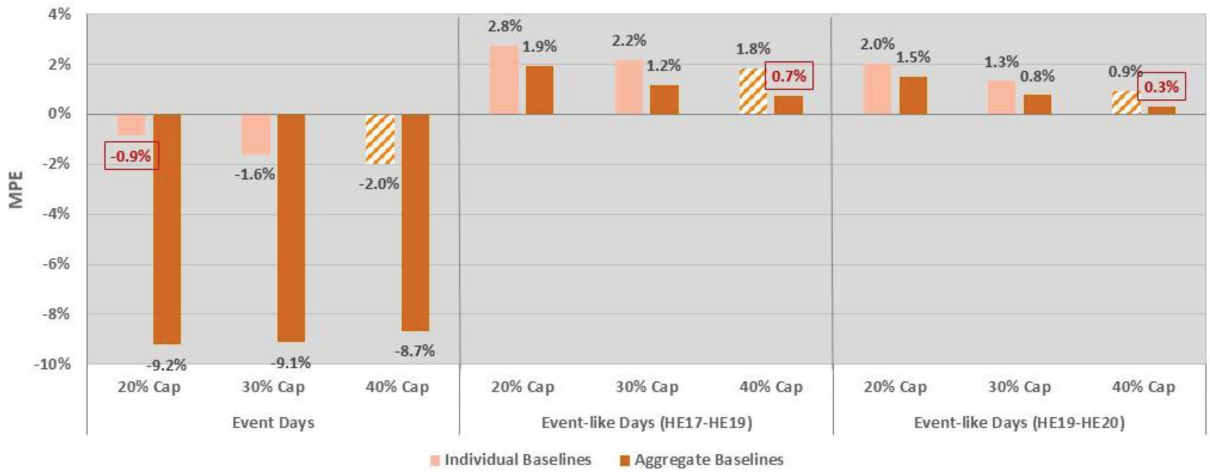


Figure 3-2 PG&E Day Ahead Program: Bias Comparison – Resource-level



SCE Results

Day Ahead Program

The DA program results cover 44 event days and 42 event-like days across PY2018 and PY2019. Across both program years, the DA program includes five unique resources and 385 unique customers. Figure 3-3 and Figure 3-4 show the accuracy and bias comparison for all three scenarios, respectively.

For SCE DA, we can conclude the following:

- The event-like day scenarios show very consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20).
  - The two event-like day scenarios have very consistent accuracy and bias comparisons, showing better effectiveness using the aggregate baseline (dark blue and dark orange bars are consistently lower), with the 40% adjustment cap showing the best accuracy and least bias in both individual and aggregate baselines.
  - The event-like days also show all positive MPE estimates, indicating that the estimates are consistently lower, on average, than the actual event-like day loads.
- The event days show conflicting results, and this is largely driven by the PY2018 results (shown in Figure A-5), which show the best effectiveness using the individual baselines with 20% adjustment cap. The PY2019 event day comparisons, however, show results more consistent with the event-like days, showing the best accuracy using the aggregate baseline with 40% adjustment cap. It is also interesting to note that the PY2019 event days show the 20% adjustment cap to give the least bias.

Figure 3-3 SCE Day Ahead Program: Accuracy Comparison – Resource-level

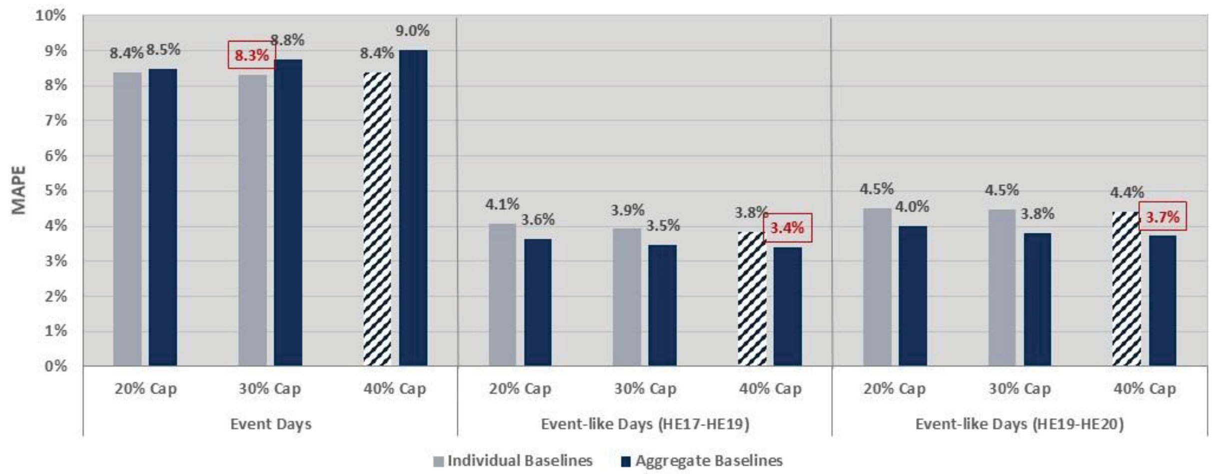
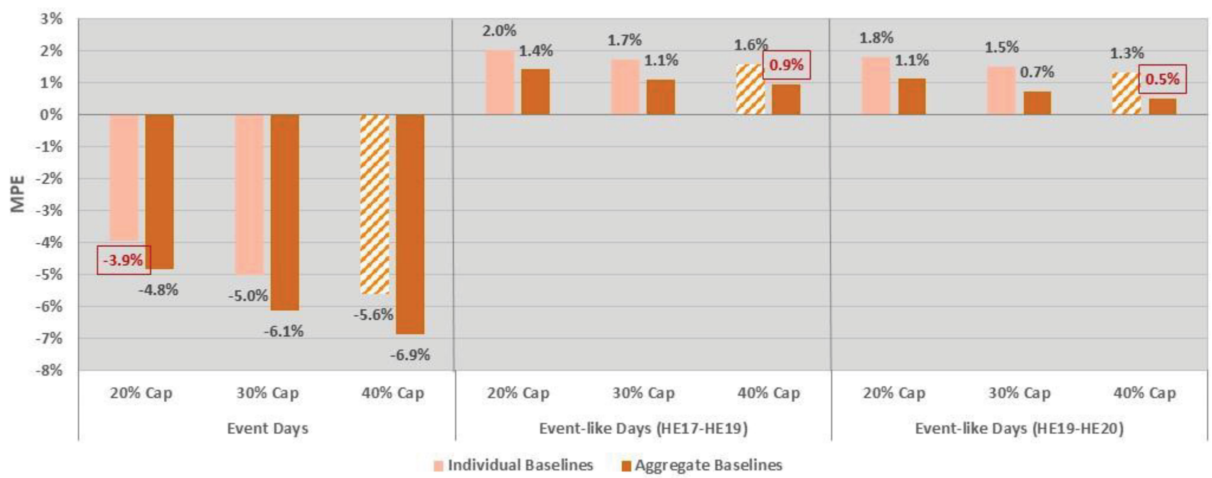


Figure 3-4 SCE Day Ahead Program: Bias Comparison – Resource-level



Day Of Program

The DO program results cover 49 event days and 42 event-like days across PY2018 and PY2019. Across both program years, the DA program includes 6 unique resources and 368 unique customers. Figure 3-5 and Figure 3-6 show the accuracy and bias comparison for all three scenarios, respectively.

For SCE DO, we can conclude the following:

- The event-like day scenarios show very consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20).
    - Like SCE DA, the two event-like day scenarios have very consistent accuracy and bias comparisons, showing better effectiveness using the aggregate baseline (dark blue and dark orange bars are consistently lower). However, the 20% adjustment cap shows the best accuracy, while the higher adjustment caps (30% and 40%) show less bias in both individual and aggregate baselines.

- The event-like days also show all positive MPE estimates, indicating that the estimates are consistently lower, on average, than the actual event-like day loads.

- Similar to PG&E DA, the event days show results comparable to the HE19-HE20 event-like day scenario, showing better accuracy using the individual baselines. This is due to SCE DO calling 38 out of 49 events that start on HE19. Also comparable to the HE19-HE20 event-like day scenario, individual baseline with 20% adjustment cap gives the most bias.

Figure 3-5 SCE Day Of Program: Accuracy Comparison – Resource-level

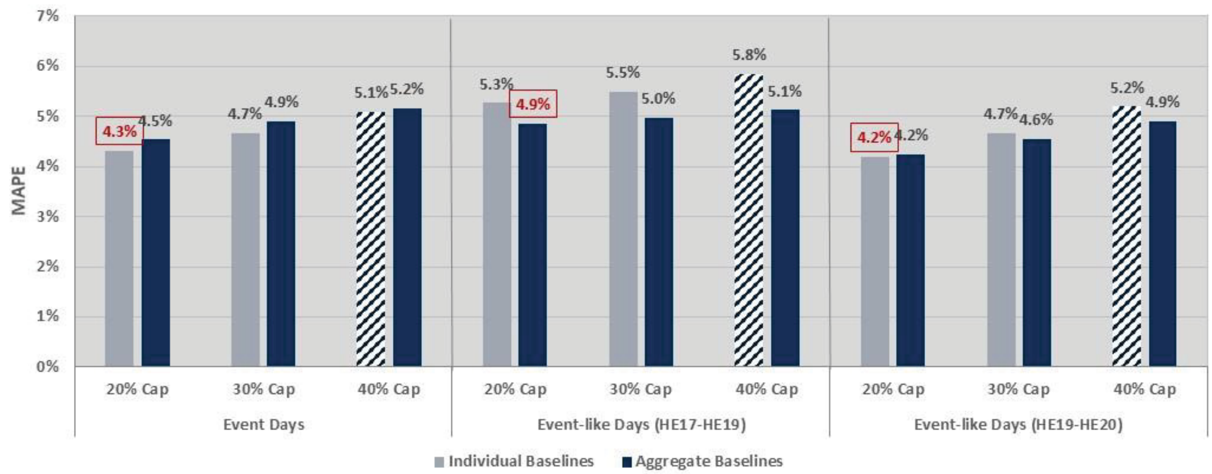
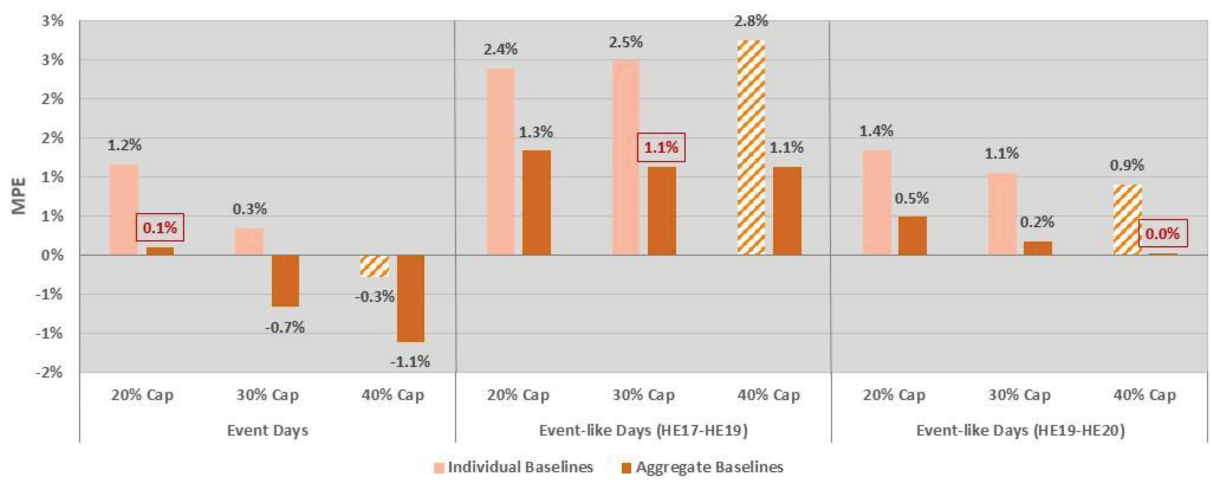


Figure 3-6 SCE Day Of Program: Bias Comparison – Resource-level



SDG&E Results

Day Ahead Program

The DA program results cover 48 event days and 36 event-like days across PY2018 and PY2019. Across both program years, the DA program includes seven unique resources and 75 unique customers. Figure 3-7 and Figure 3-8 the accuracy and bias comparison for all three scenarios, respectively.

For SDG&E DA, PY2018 and PY2019 have some conflicting results, and these are apparent in the overall comparisons. Recall that SDG&E DA experienced large customer unenrollment in the middle of PY2018.

All PY2018 participants are included in the event-like day scenarios regardless of mid-year unenrollment, thus the drastic change in the participant population between PY2018 and PY2019 ultimately drives the differences in the results. Referring to the program year graphs will be helpful in the discussion of the results. The graphs are in the Appendix, Figure A-13 through Figure A-16.

- All scenarios show consistent accuracy results but conflicting bias results. This is largely driven by conflicting bias results from the two program years.
- For event-like days, this indicates that the accuracy of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20). On the other hand, bias comparisons show some sensitivity to the timing of the event window.
    - The two event-like day scenarios have very consistent accuracy comparisons, showing better accuracy using the individual baseline (light blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines.
    - Looking at bias, the event-like day scenarios show very conflicting results. In this case, it may be helpful to only look at PY2019 results (shown in Figure A-16), since it is more representative of the participant population in future years. PY2019 bias comparisons for SDG&E DA also show less bias using the individual baseline (light orange bars are consistently lower). However, the effect of the adjustment cap is different in the two event window simulations, showing least bias at 40% adjustment cap for HE17-HE19 events and least bias at 20% adjustment cap for HE19-HE20 events.
- Similar to the event-like day scenarios, the event days show better accuracy using the 20% adjustment cap, but instead showing better accuracy using the aggregate baseline (dark blue bars are consistently lower). Again, we see conflicting bias results for the event days. Thus looking only at PY2019 results (shown in Figure A-16), we see less bias using the aggregate baseline (dark orange bars are lower) and the least bias using the 20% adjustment cap.

Figure 3-7 SDG&E Day Ahead Program: Accuracy Comparison – Resource-level

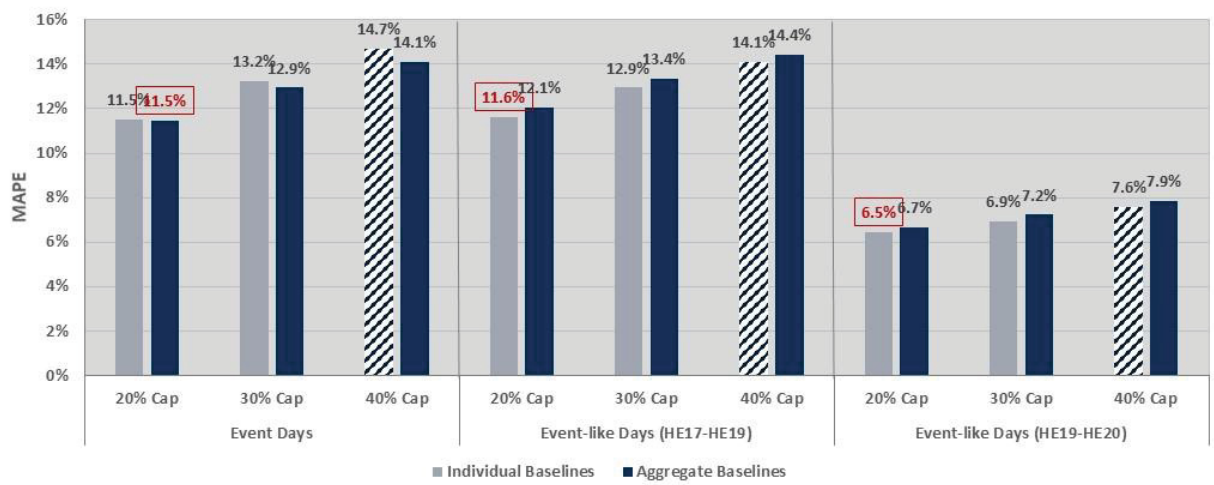
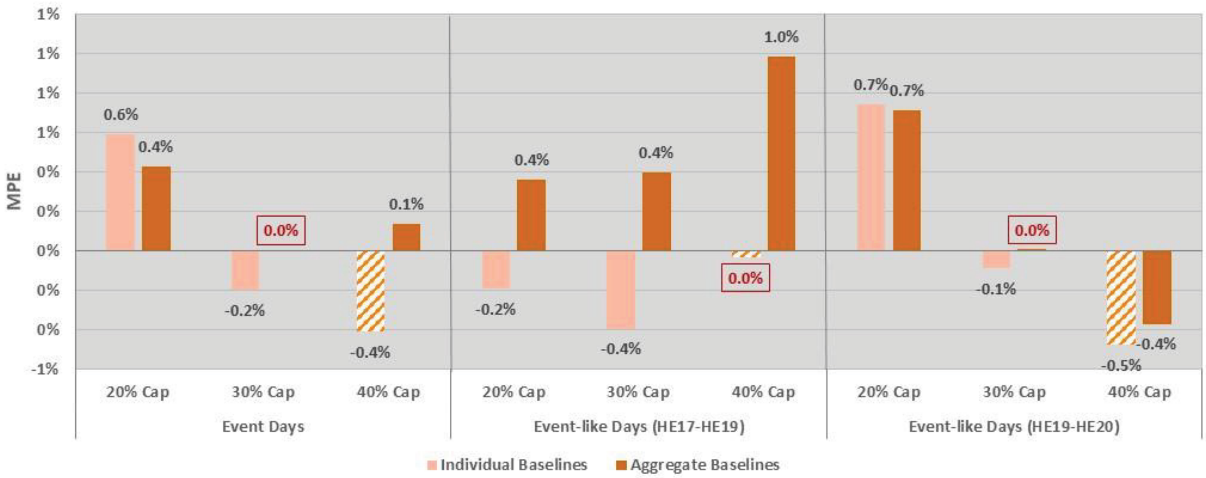


Figure 3-8 SDG&E Day Ahead Program: Bias Comparison – Resource-level



Day Of Program

The DO program results cover 19 event days and 36 event-like days across PY2018 and PY2019. Across both program years, the DO program includes seven unique resources and 201 unique customers. Figure 3-9 and Figure 3-10 show the accuracy and bias comparison for all three scenarios, respectively.

SDG&E DO did not experience a drastic participant turnover in PY2018 and PY2019, thus we do not see the same results like in SDG&E DA. However, looking at the event-like day comparisons, the overall results for both program years seem to indicate the sensitivity to the timing of the event window. This is also driven by conflicting results from PY2018 and PY2019 and referring to the program year graphs will also be helpful in the discussion of the results. The graphs are in the Appendix, Figure A-17 through Figure A-16.

- The event-like day comparisons for PY2018 and PY2019 show different results:
  - PY2018 comparisons (shown in Figure A-17 and Figure A-18) indicate that both accuracy and bias of the baselines are sensitive to the timing of the event window. However, recall that SDG&E DO only called 3 events in PY2018, all starting on HE18 and that event-like days were selected to be the most comparable to events. It is possible that PY2018 participants have highly variable loads during HE17-HE19 even on non-event days, making it difficult to effectively estimate the event window load through the 10-in-10 day matching baseline.
  - PY2019 comparisons (shown in Figure A-19 and Figure A-20), on the other hand, show very consistent results between the two event-like day scenarios. Both event window scenarios show better accuracy using the aggregate baseline (dark blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Bias comparisons also show preference to the 20% adjustment cap.
- The event day comparisons for PY2018 and PY2019 also show different results:
  - PY2018 comparisons (shown in Figure A-17 and Figure A-18) have results consistent with PY2018 event-like days with HE19-HE20 event windows, showing better accuracy using the individual baseline (light blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Again, likely driven by the combination of events called in PY2018 and typical participant loads during HE18-HE21.

- PY2019 comparisons (shown in Figure A-19 and Figure A-20), on the other hand, show very consistent results with the two event-like day scenarios. In PY2019, SDG&E DO called a comparable number of events starting on HE17 and HE18. PY2019 events show better accuracy using the aggregate baseline (dark blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Bias comparisons also show preference to the 20% adjustment cap.

Figure 3-9 SDG&E Day Of Program: Accuracy Comparison – Resource-level

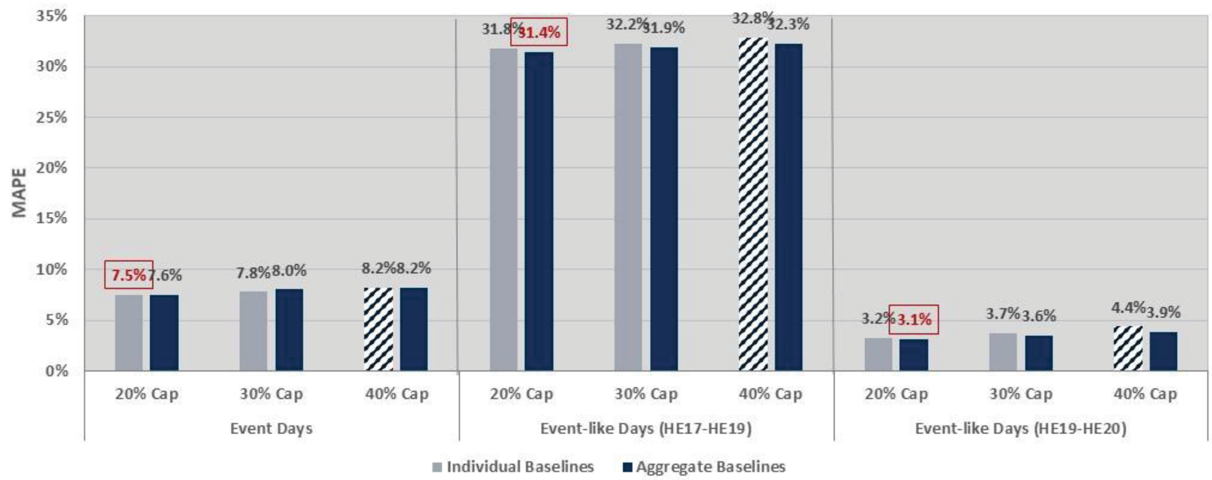
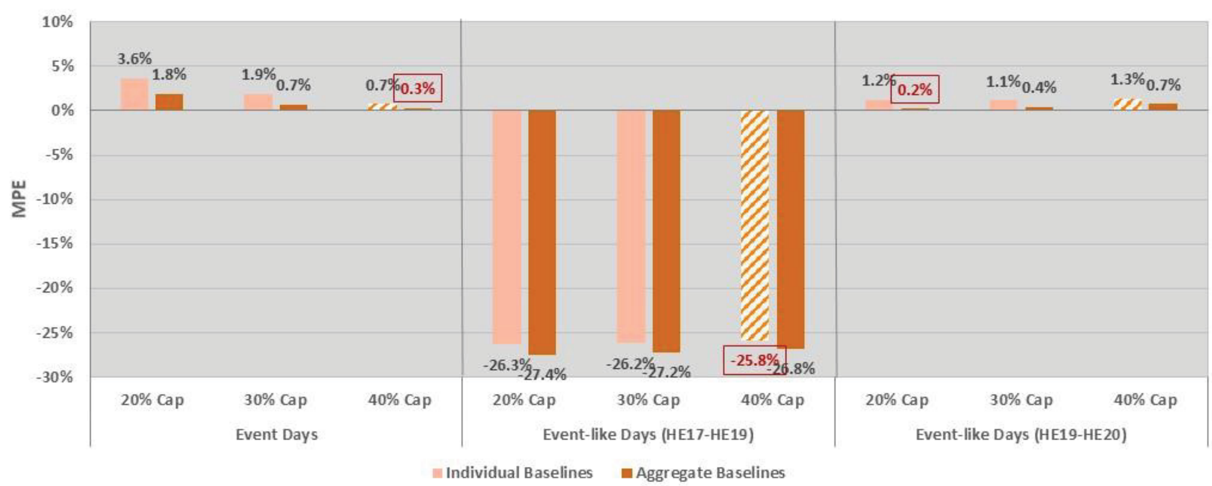


Figure 3-10 SDG&E Day Of Program: Bias Comparison – Resource-level



A

ADDITIONAL TABLES AND GRAPHS

PG&E Results by Program Year

Day Ahead Program

The PG&E DA program PY2018 results cover 46 event days and 23 event-like days and include 11 unique resources and 561 unique customers.

Figure A-1 PG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

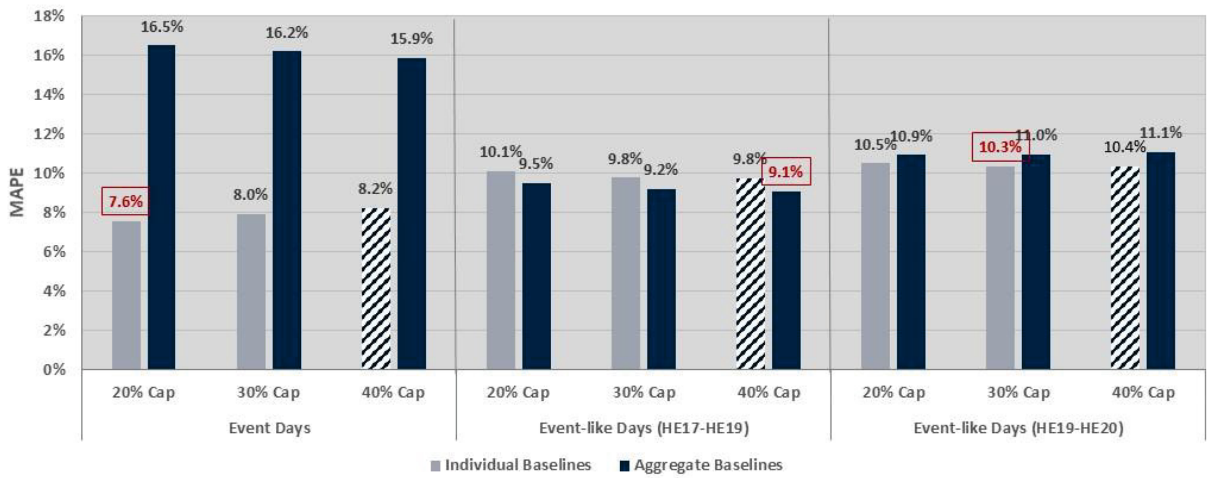
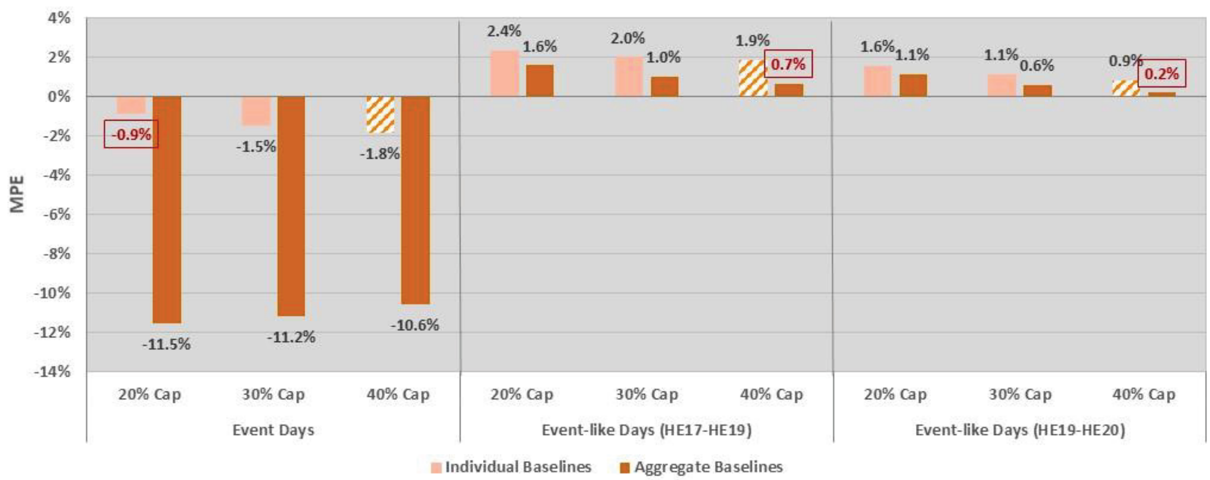


Figure A-2 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The PG&E DA program PY2019 results cover 9 event days and 6 event-like days and include 10 unique resources and 793 unique customers.

Figure A-3 PG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

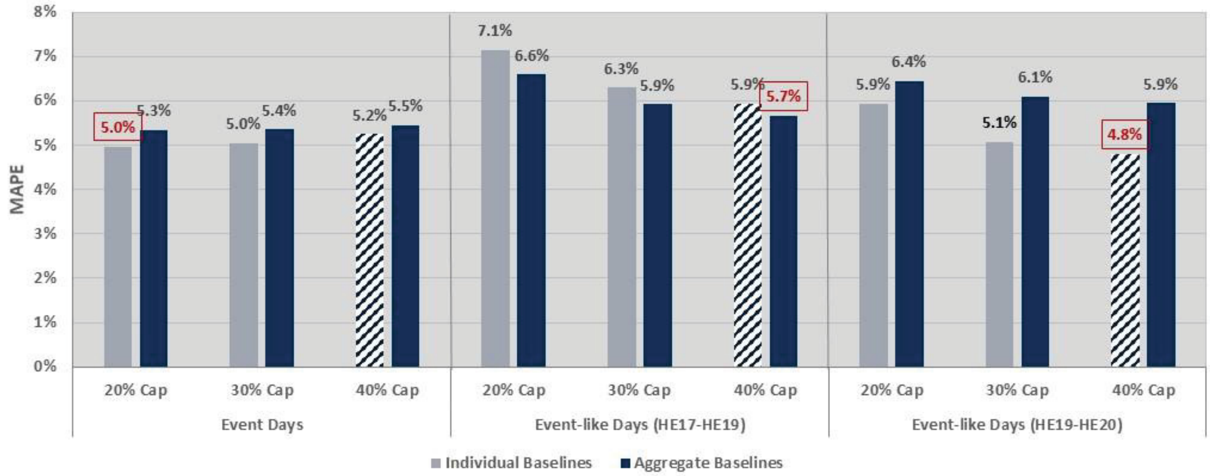
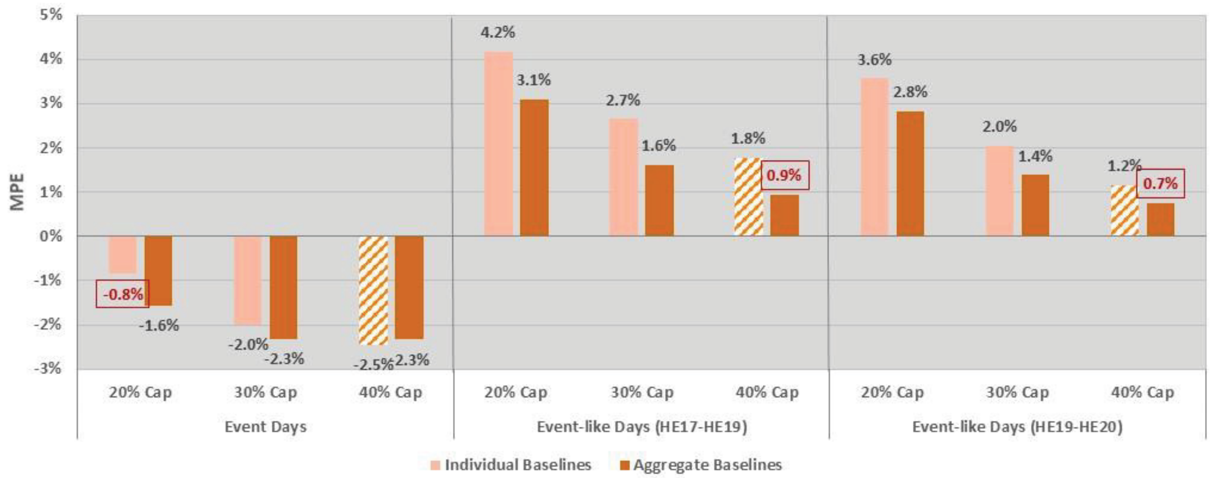


Figure A-4 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



SCE Results by Program Year

Day Ahead Program

The SCE DA program PY2018 results cover 23 event days and 29 event-like days and include 3 unique resources and 74 unique customers.

Figure A-5 SCE Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

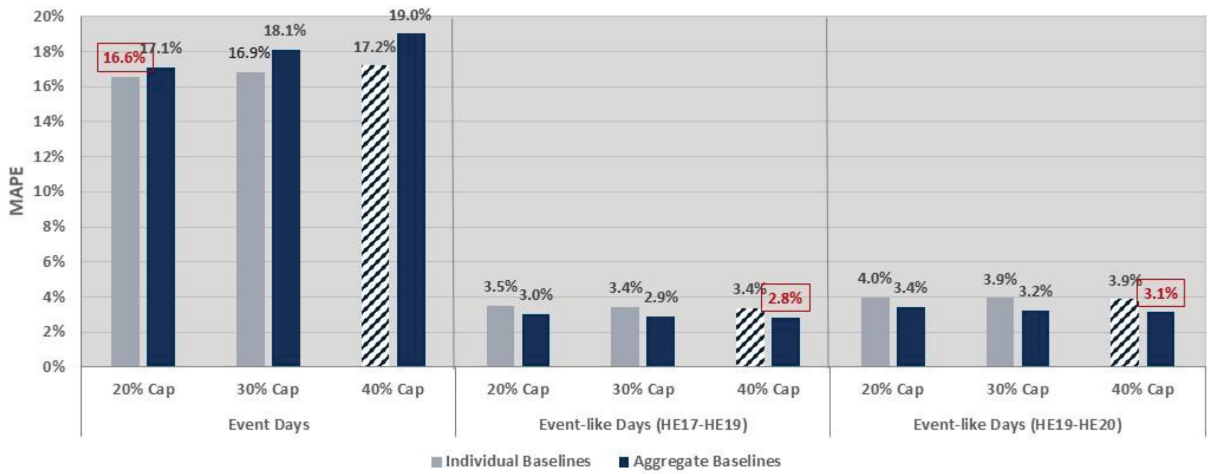
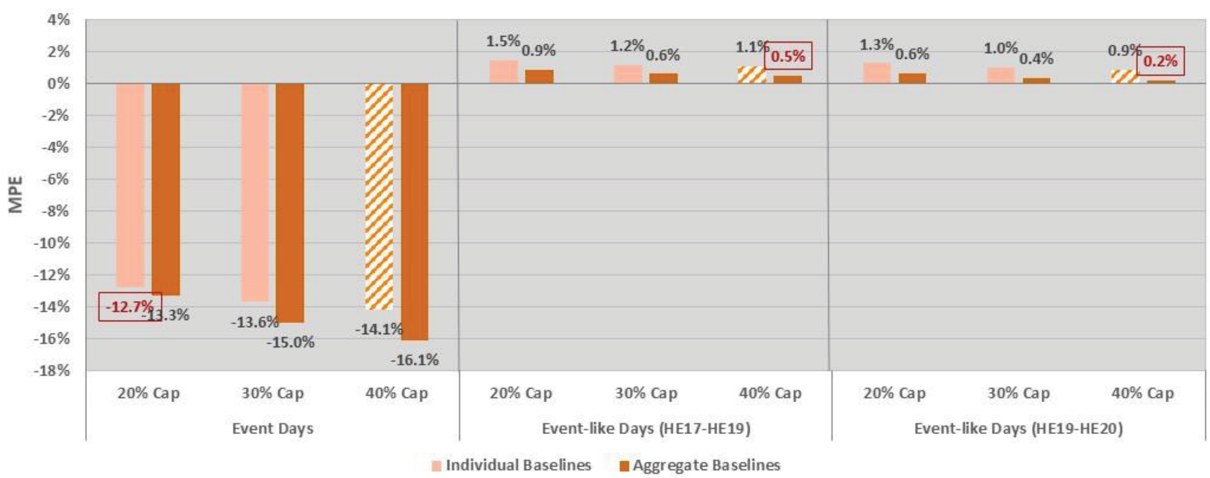


Figure A-6 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The SCE DA program PY2019 results cover 21 event days and 13 event-like days and include 4 unique resources and 399 unique customers.

Figure A-7 SCE Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

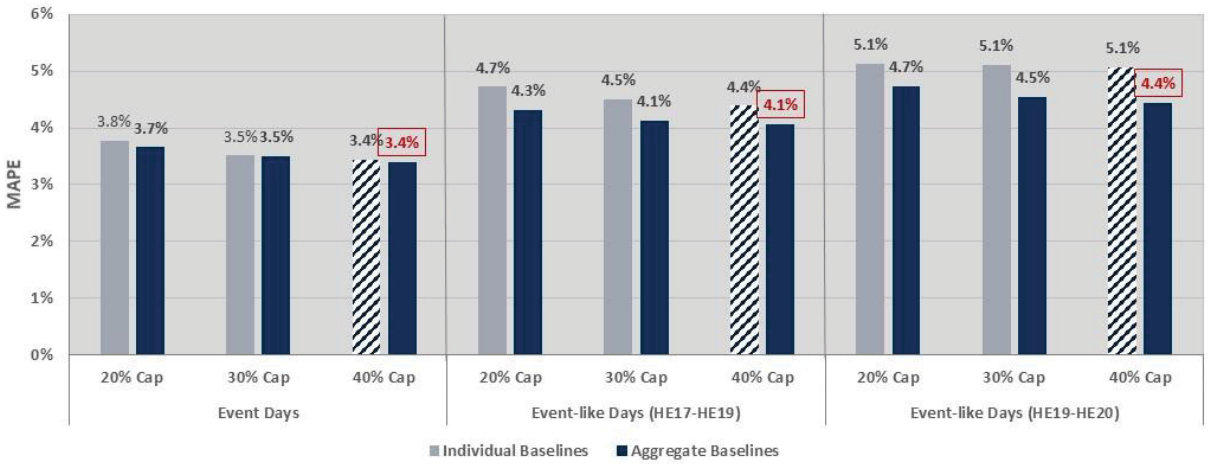
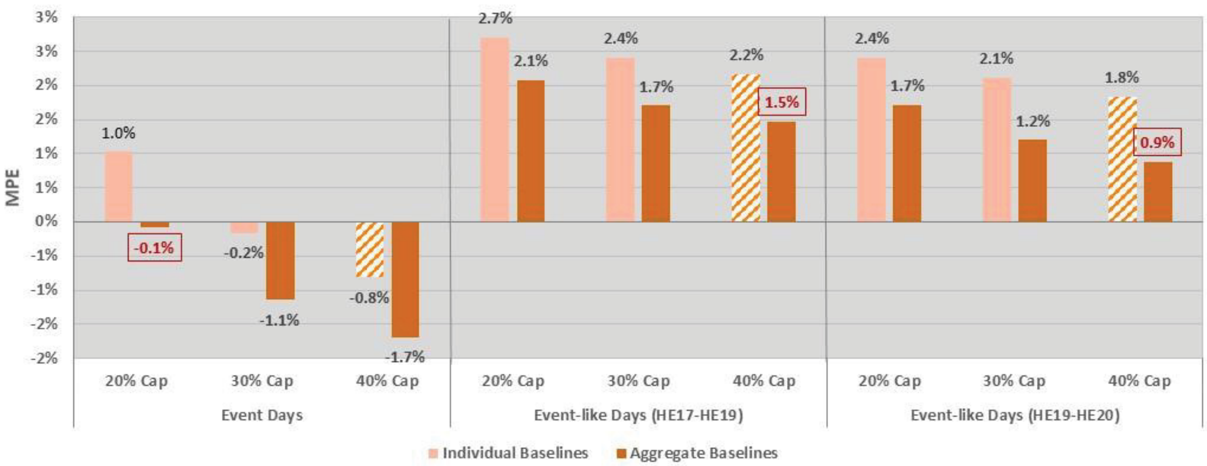


Figure A-8 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



Day Of Program

The SCE DO program PY2018 results cover 25 event days and 29 event-like days and include 5 unique resources and 308 unique customers.

Figure A-9 SCE Day Of Program: Accuracy Comparison – Resource-level (PY 2018)

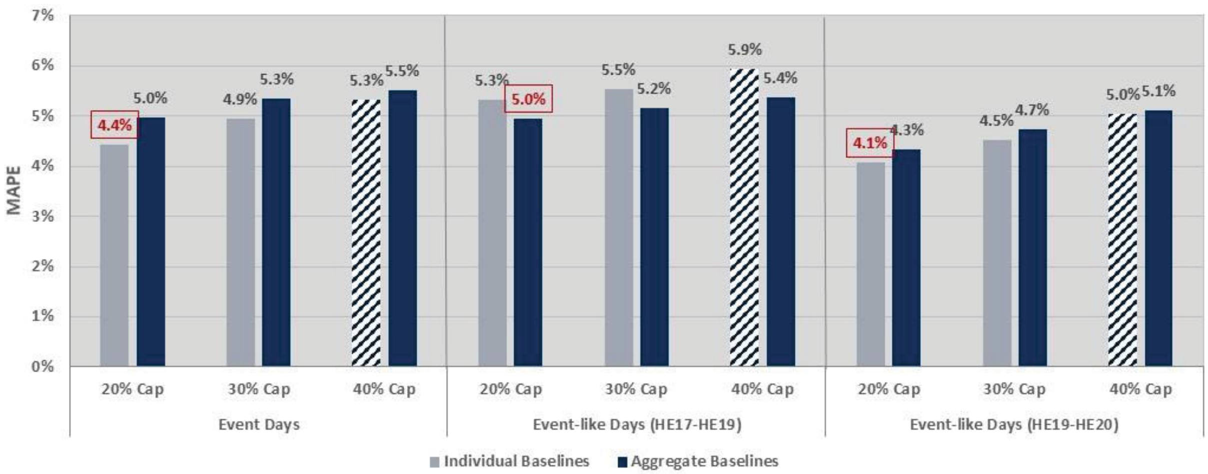
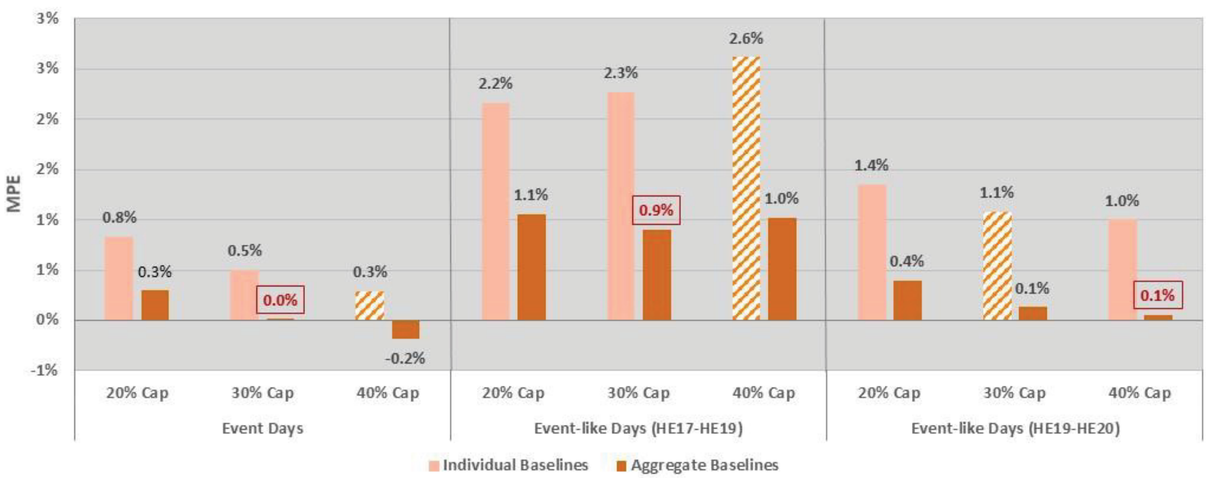


Figure A-10 SCE Day Of Program: Bias Comparison – Resource -level (PY 2018)



The SCE DO program PY2019 results cover 24 event days and 13 event-like days and include 5 unique resources and 203 unique customers.

Figure A-11 SCE Day Of Program: Accuracy Comparison – Resource -level (PY 2019)

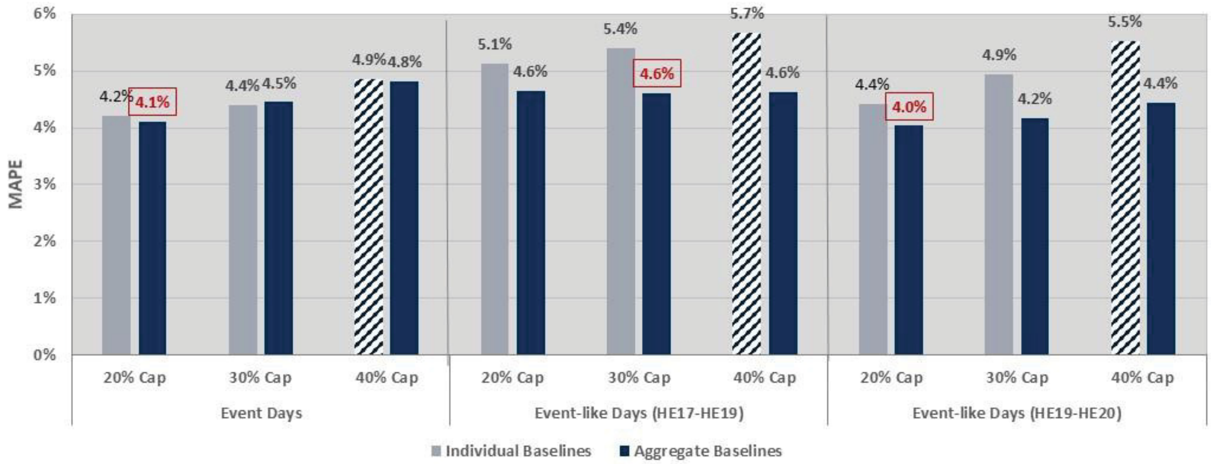
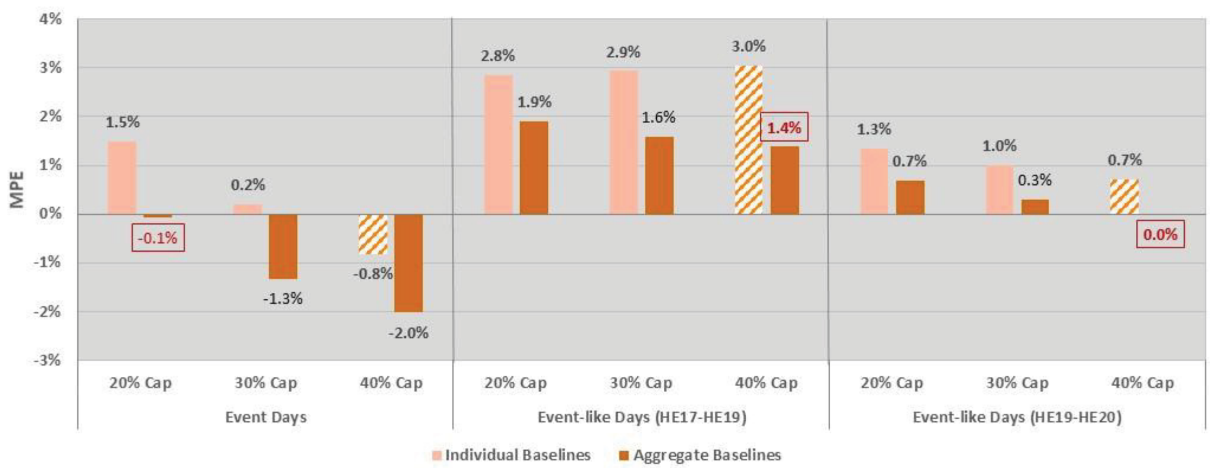


Figure A-12 SCE Day Of Program: Bias Comparison – Resource -level (PY 2019)



SDG&E Results by Program Year

Day Ahead Program

The SDG&E DA program PY2018 results cover 26 event days and 23 event-like days and include 4 unique resources and 68 unique customers.

Figure A-13 SDG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

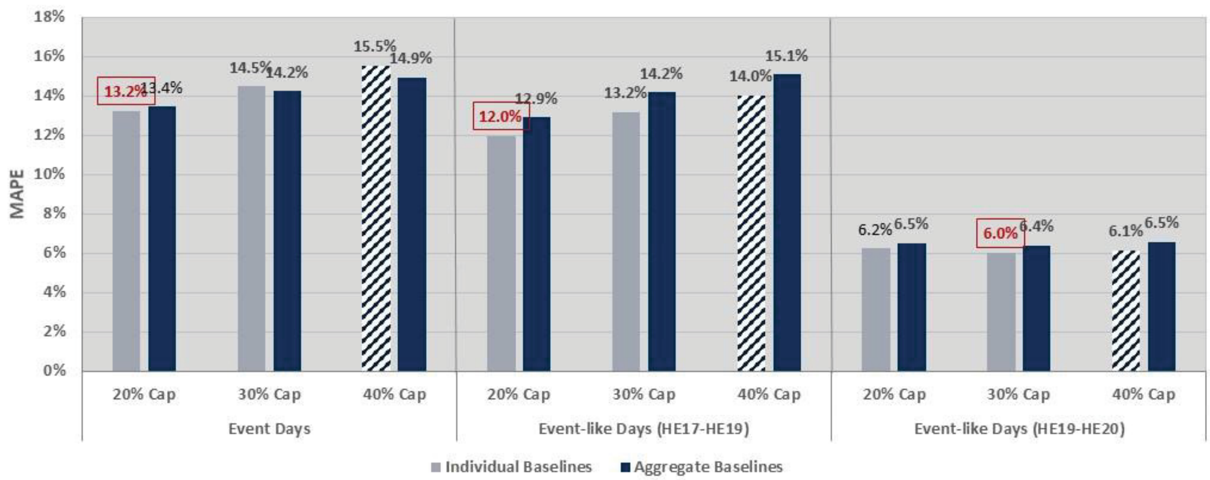
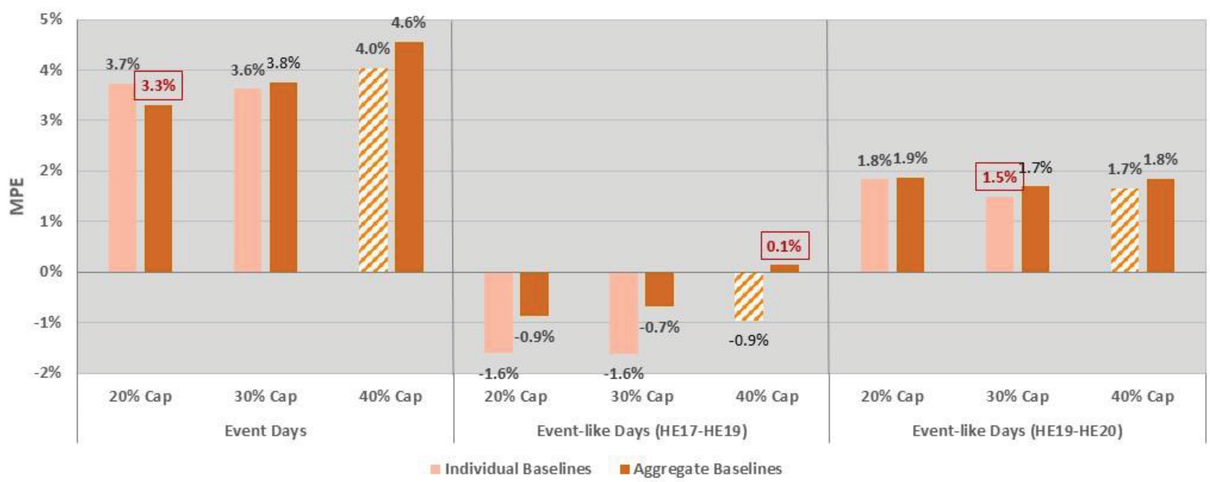


Figure A-14 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The SDG&E DA program PY2019 results cover 22 event days and 13 event-like days and include 6 unique resources and 11 unique customers.

Figure A-15 SDG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

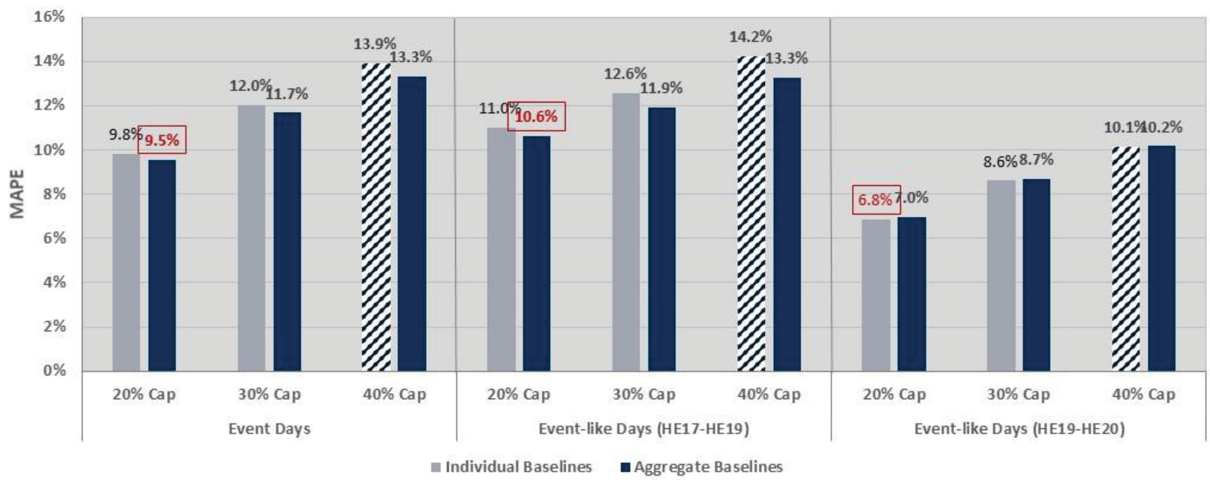
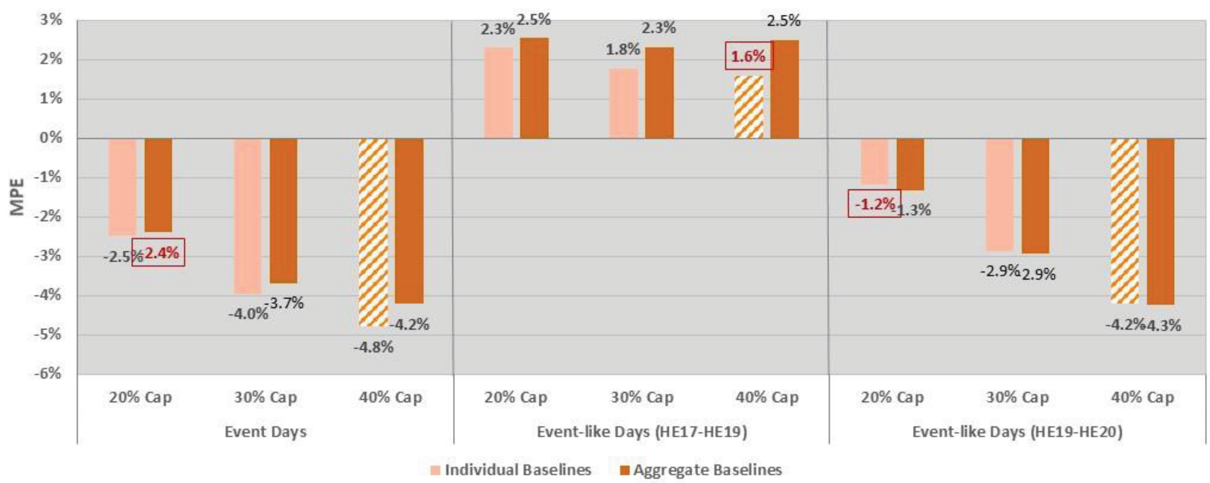


Figure A-16 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



Day Of Program

The SDG&E DO program PY2018 results cover 3 event days and 23 event-like days and include 5 unique resources and 186 unique customers.

Figure A-17 SDG&E Day Of Program: Accuracy Comparison – Resource-level (PY 2018)

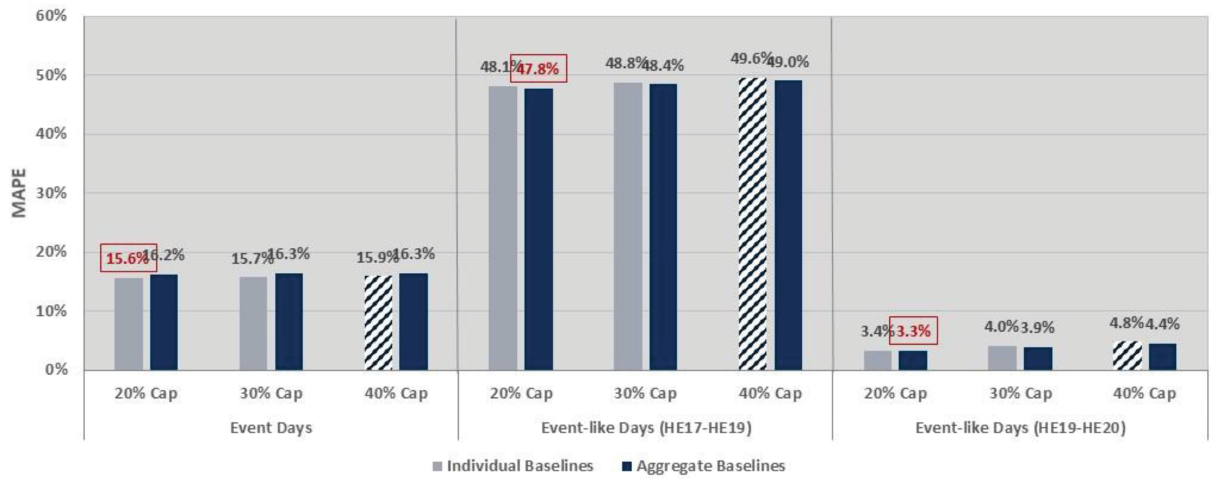
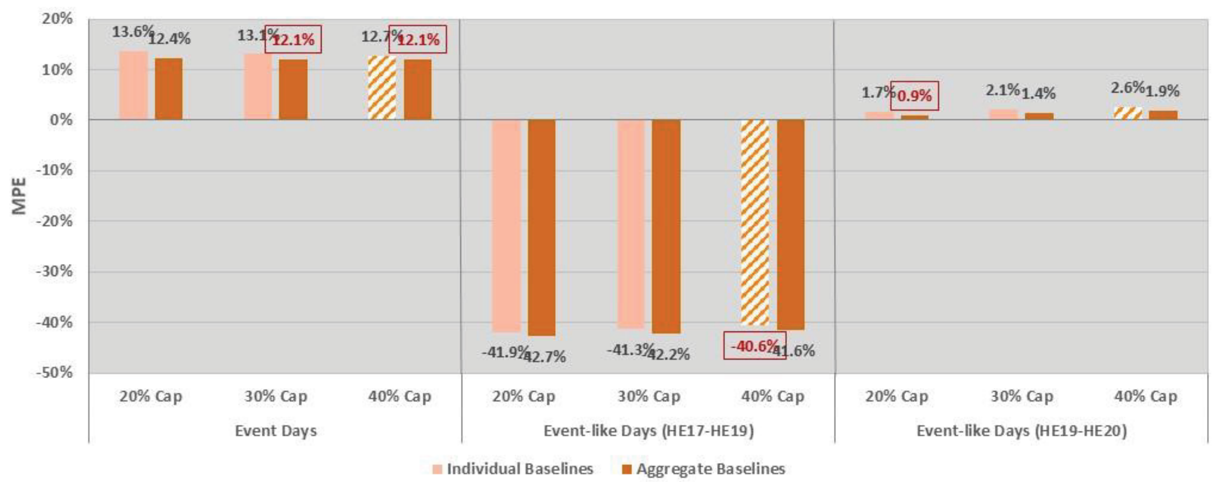


Figure A-18 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2018)



The SDG&E DO program PY2019 results cover 16 event days and 13 event-like days and include 6 unique resources and 193 unique customers.

Figure A-19 SDG&E Day Of Program: Accuracy Comparison – Resource -level (PY 2019)

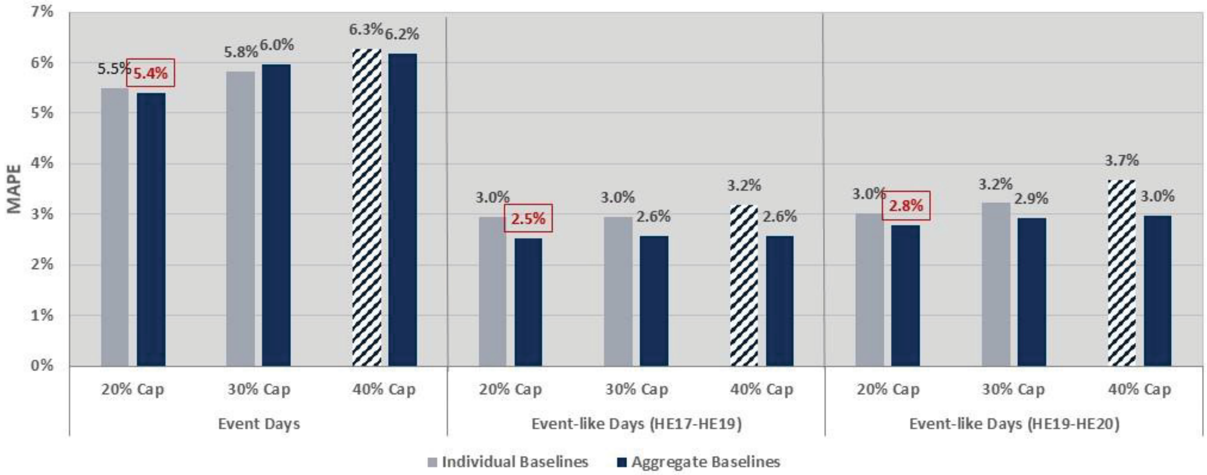
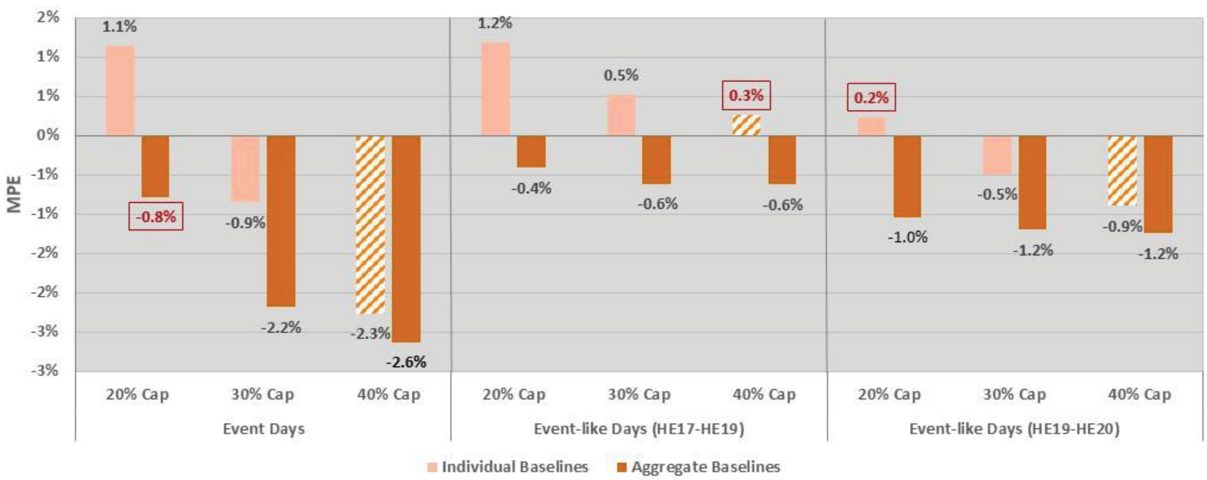


Figure A-20 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2019)



Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 250
Walnut Creek, CA 94596

P: 510.982.3525

Appendix B:
Applied Energy Group's Baseline Analysis Final Presentation

AEG
Applied Energy Group

CAPACITY BIDDING PROGRAM: BASELINE COMPARATIVE ANALYSIS

Abigail Nguyen, Project Manager

Energy solutions. Delivered.

AGENDA

- Analysis Objectives
- Comparative Analysis
- Results by Program
- Key Findings & Recommendations

AEG
Applied Energy Group

Analysis Objectives

ANALYSIS OBJECTIVES

Applied Energy Group

D. 19-07-009 Issues to Investigate

1. Assess if an adjustment cap of ±40% is still suitable for retail settlement baselines when the day-of adjustment for wholesale settlement baselines is ±20%.
2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each.
3. Consider flexibility in changing retail baselines.
4. Consider whether the wholesale and retail baseline should be aligned or if they can be different.
5. Consider the pros and cons of an aggregate versus individual baseline.

Issues Addressed by this Analysis

Directly addresses #1 and #5 by performing comparative analysis

10/10 DAY MATCHING BASELINE

AEG Applied Energy Group

Identify **10** eligible **Baseline Days**

Excluding weekends, other event days, ISO holidays, award dates, outages, etc.

Unadjusted Baseline
average hourly customer loads across 10 baseline days

Same-day Adjustment Ratio
Event day : Unadjusted baseline
using total kWh during adjustment period

Adjustment period: 3 hours prior to event with 1 hour buffer.

*Calculated at __**Aggregate or Individual**__ level, depending on preferred baseline.*

Apply **Adjustment Cap**
Adj Ratio = (1+**X**) if Adj Ratio > (1+**X**) or
Adj Ratio = (1-**X**) if Adj Ratio < (1-**X**)

*Where X is __**20%, 30%, or 40%**__, depending on preferred baseline*

Adjusted Baseline
apply same-day adjustment ratio to each event hour in unadjusted baseline

Actual Load Reduction
= (Adj Baseline – Actual Usage) for each event hour

This step was not performed as part of this comparative analysis

AEG
Applied Energy Group

Comparative Analysis

OVERVIEW OF COMPARATIVE ANALYSIS

1

Establish scenarios for comparison: identify event days, select event-like days

2

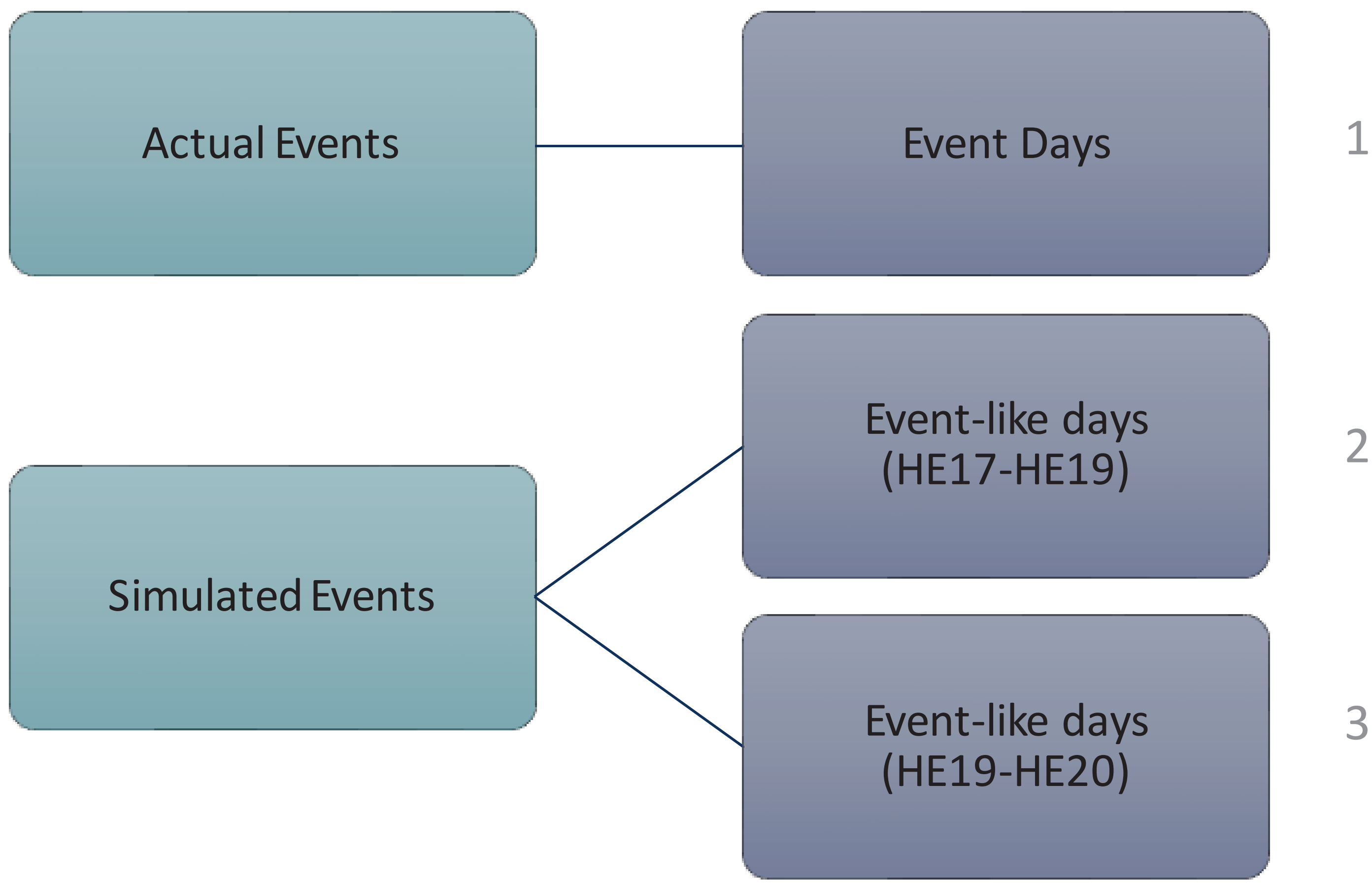
At customer level, **calculate adjusted baseline estimates** for event days and event-like days using *six baselines*

3

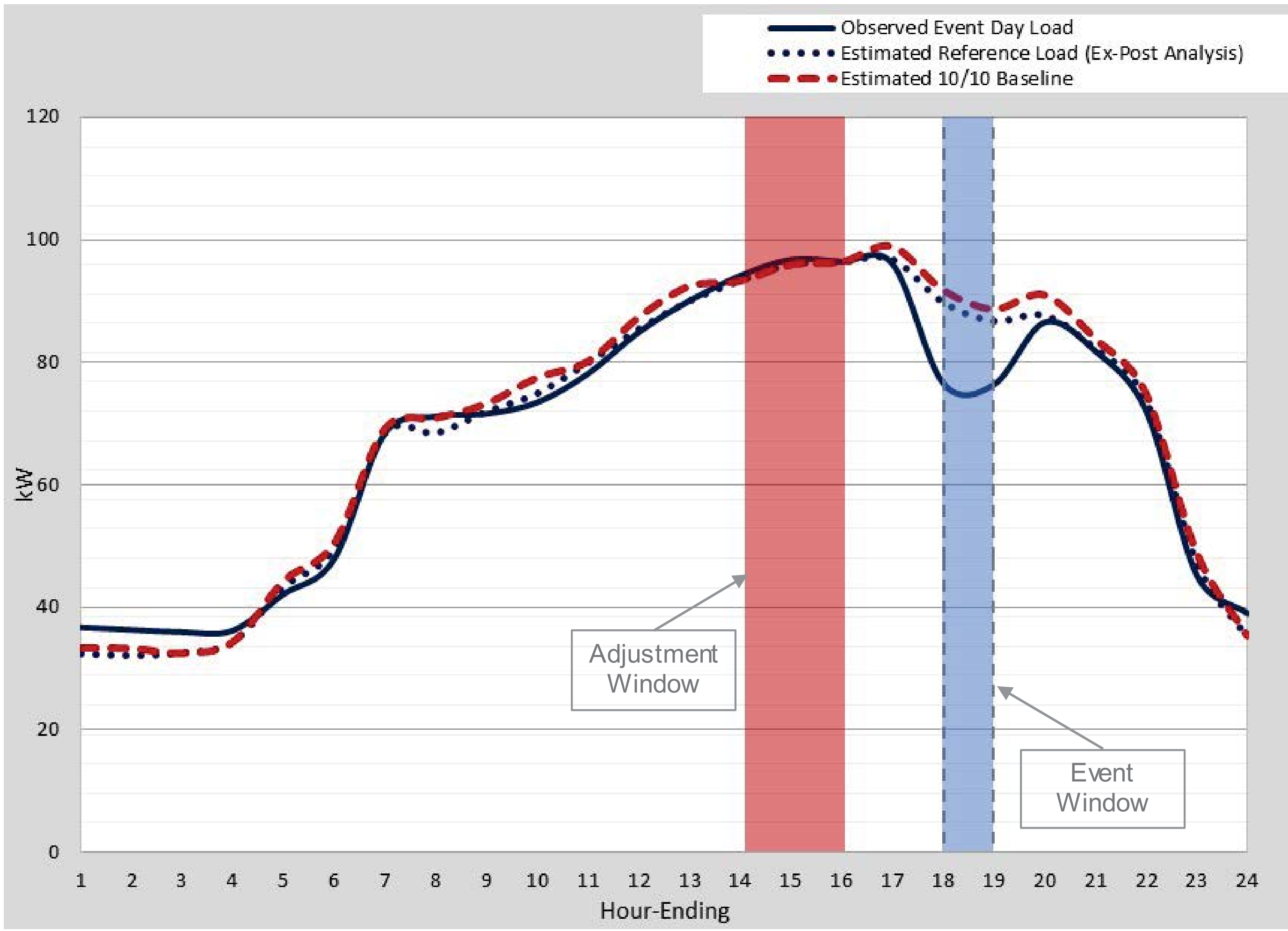
Sum by resource and **calculate metrics**: accuracy (MAPE) and bias (MPE)

ESTABLISH THREE SCENARIOS

PY2018 and PY2019

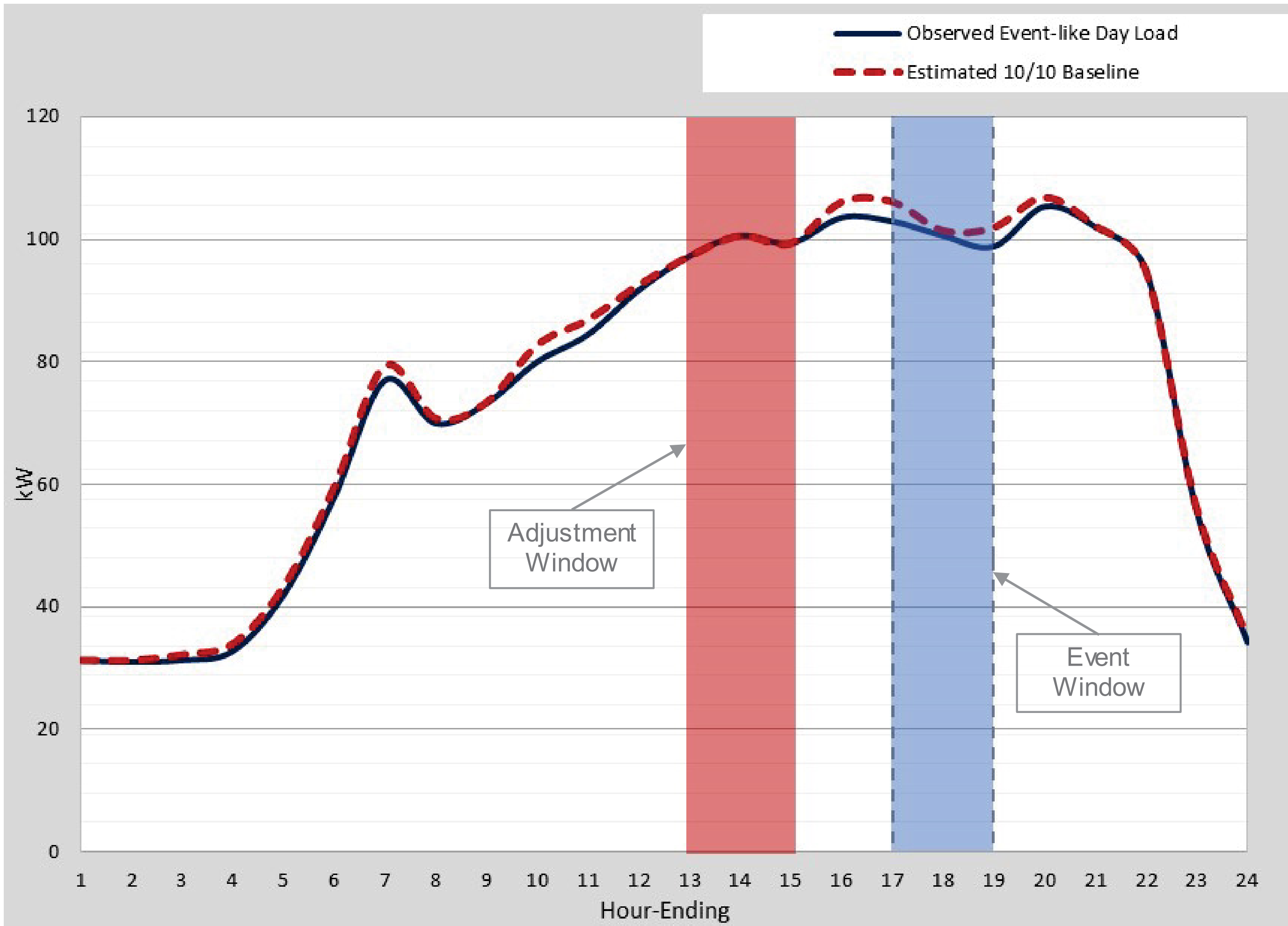


EVENT DAY SCENARIO

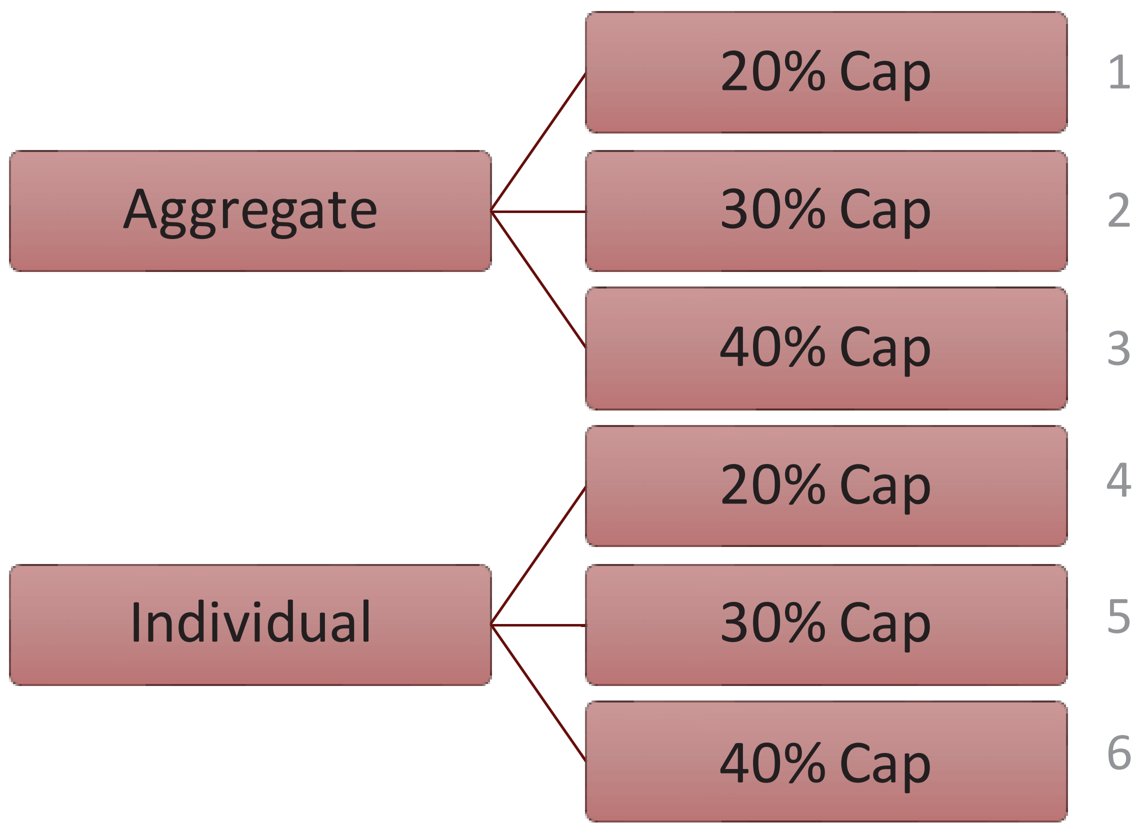


EVENT-LIKE DAY SCENARIO

HE17-HE19



SIX BASELINES



COMPARISON METRICS

Applied Energy Group

ACCURACY

- Mean Absolute Percent Error

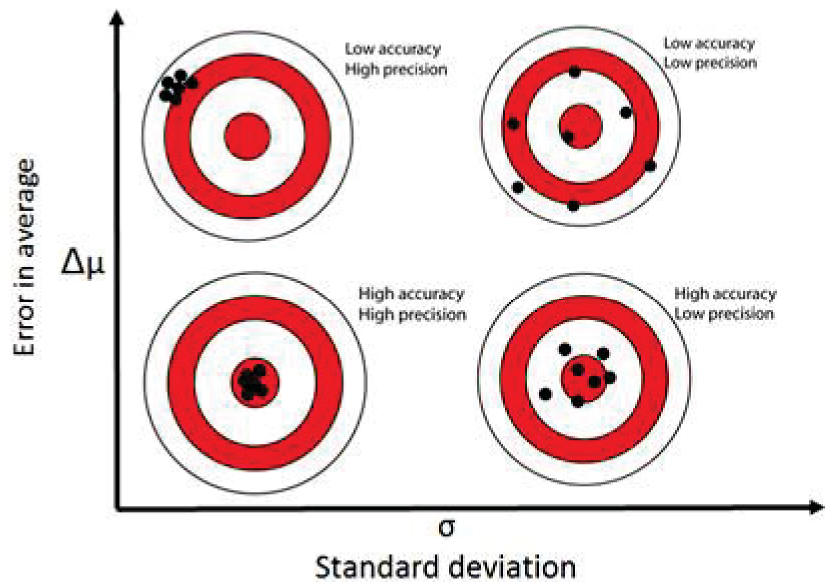
$$MAPE = \frac{100\%}{n} \sum_{h=1}^{n} \left| \frac{Actual_h - Estimate_h}{Actual_h} \right|$$

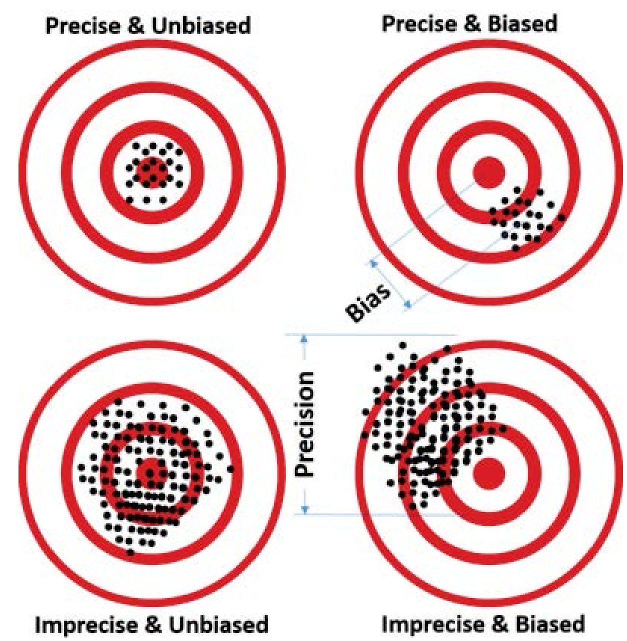
BIAS

- Mean Percent Error

$$MPE = \frac{100\%}{n} \sum_{h=1}^{n} \frac{Actual_h - Estimate_h}{Actual_h}$$

ACCURACY, PRECISION, BIAS





Accuracy - how close the estimate is to the known value

Precision - how close the two or more estimates are to each other

Bias - if estimates tend to be higher or lower than the known value

EXAMPLE CALCULATION

Individual Baseline					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.14	155.51				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.26	178.44				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.30	184.61	508.56	518.56	2.0%	-2.0%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.4%*	*2.4%*

Aggregate Baseline					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.23	167.41				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.23	174.67				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.23	174.67	508.56	516.75	1.6%	-1.6%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.2%*	*2.6%*

A few key notes on the example above:

- This is a simple example showing an individual baseline versus an aggregate baseline using the same adjustment cap.
- Resource 1 demonstrates the difference between an individual adjustment versus an aggregate adjustment (shown in red text).
- Resource 2 contains a single customer, thus the estimates in the individual and aggregate baselines are the same.
- The APE and PE are calculated for each resource and event day.
- The Method Score is the MAPE and MPE for each IOU and program. The simple example assumes that these four observations make up one program.

KEY POINTS ON METRIC DEVT & OVERALL ANALYSIS APPROACH

Retail settlement payments for each event day are made at the aggregator level.

Under the CBP tariff, aggregators are responsible for:
(1) customer recruitment and contracting,
(2) resource MW nominations,
(3) resource MW curtailment, and
(4) customer payment disbursement.

A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

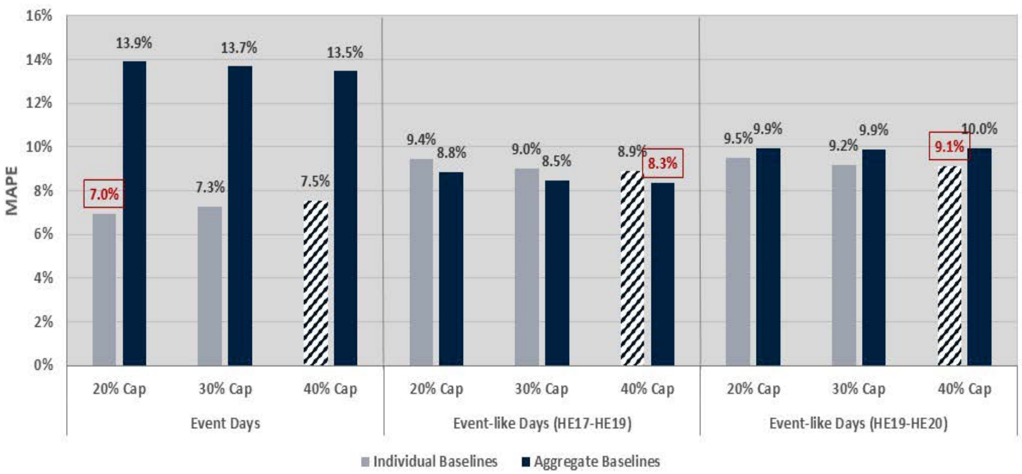
AEG
Applied Energy Group

Results by Program

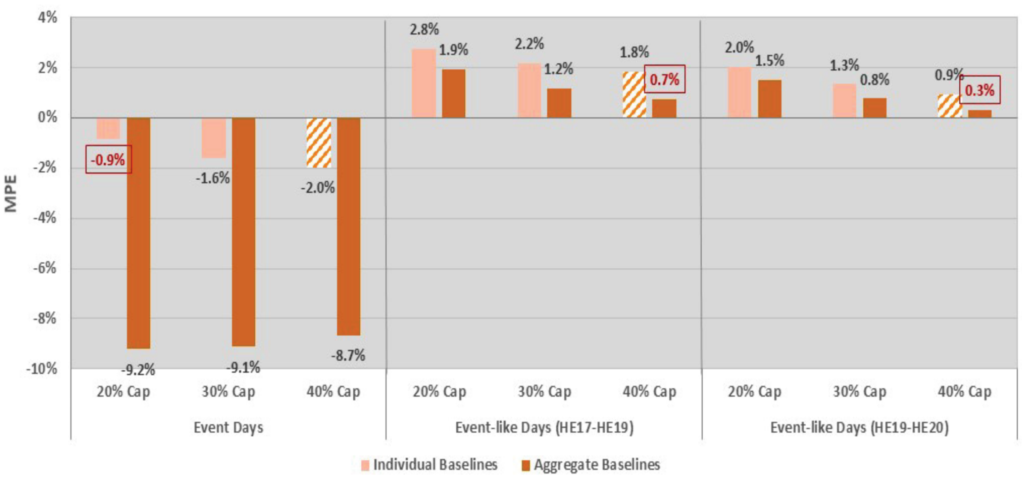
PG&E DAY AHEAD

PY2018 & PY2019

Accuracy Comparison



Bias Comparison



- Covers 55 events & 29 event-like days; 12 resources; 948 customers.
- Event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20).
- Event days and event-like days with HE19-20 simulation show similar results (better accuracy using individual baselines) – this is because PG&E DA called 30 events that start on HE19. Both scenarios use the same adjustment windows.

SCE PROGRAMS

Day Of

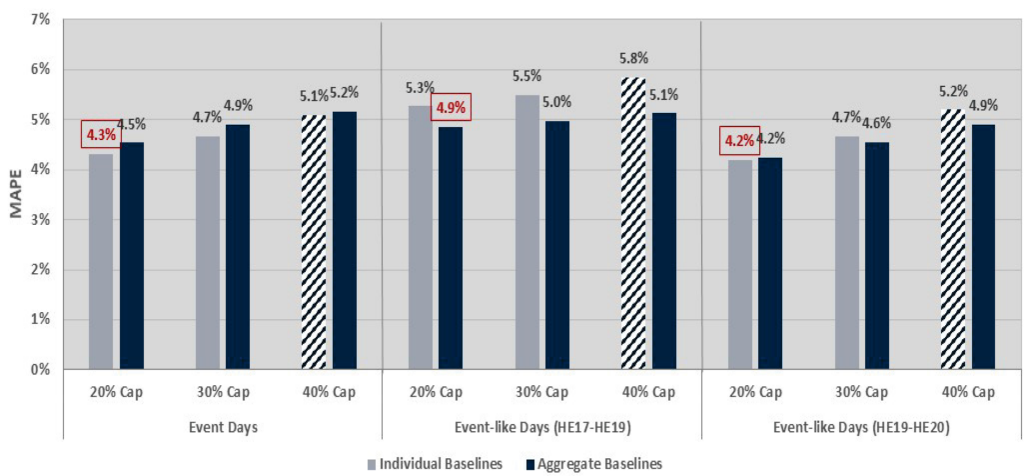
- Like PG&E DA, shows consistent results between PY2018 and PY2019.
- However, results are not consistent with PG&E—top baselines are not the same.

Day Ahead

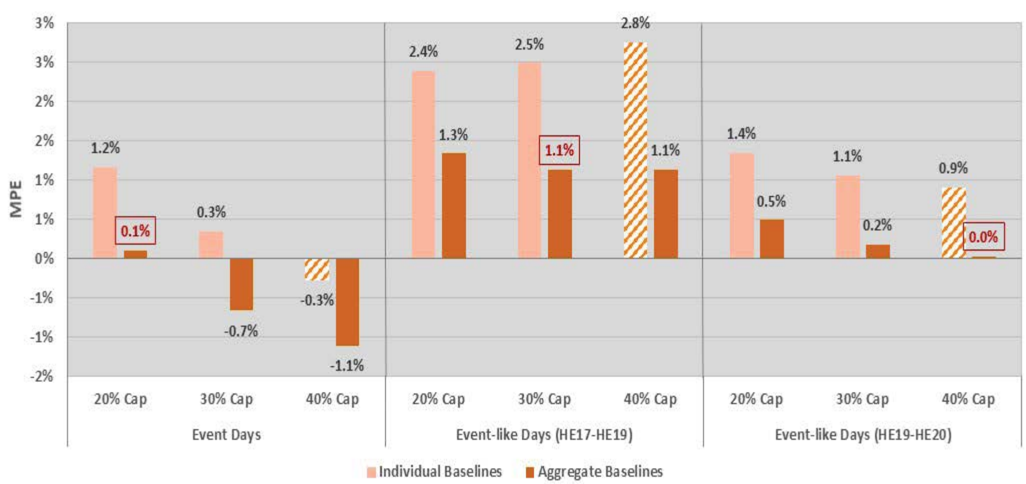
- Year-to-year results demonstrate how baseline effectiveness can be driven by the participant population.

SCE DAY OF
PY2018 & PY2019

Accuracy Comparison



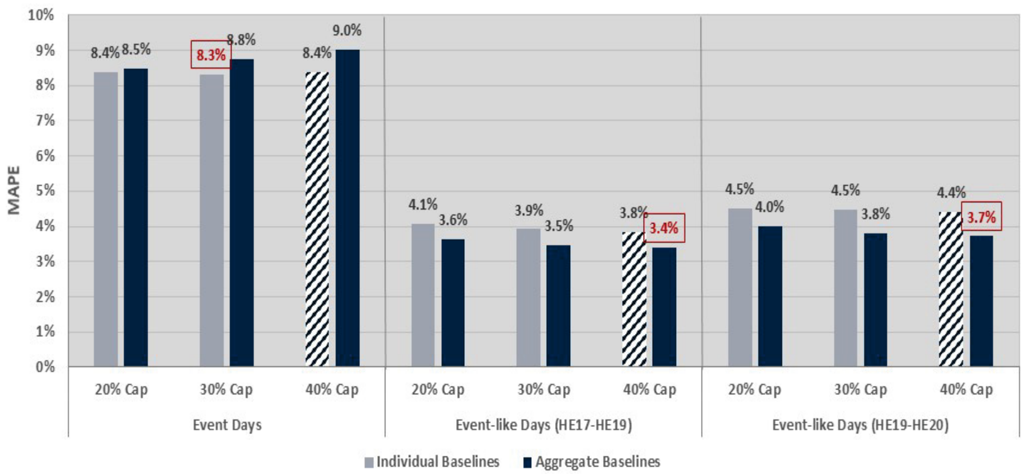
Bias Comparison

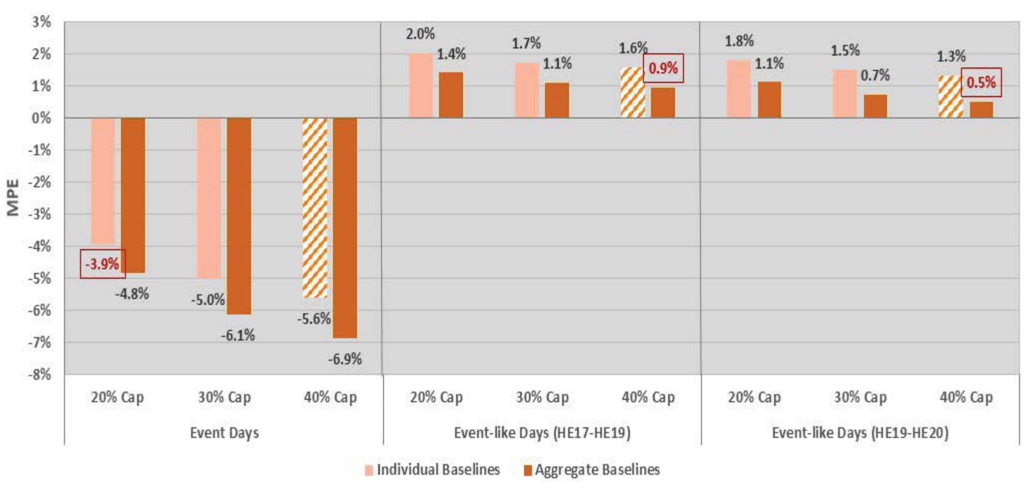


- Covers 49 events & 42 event-like days; 6 resources; 368 customers.
- Again, event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20). Both show Aggregate with 40% cap as most accurate and least bias.
- Like PG&E DA, event days and event-like days with HE19-20 simulation show similar results (best accuracy using individual with 20%) – this is because SCE DO called 38 events that start on HE19.

SCE DAY AHEAD

PY2018 & PY2019



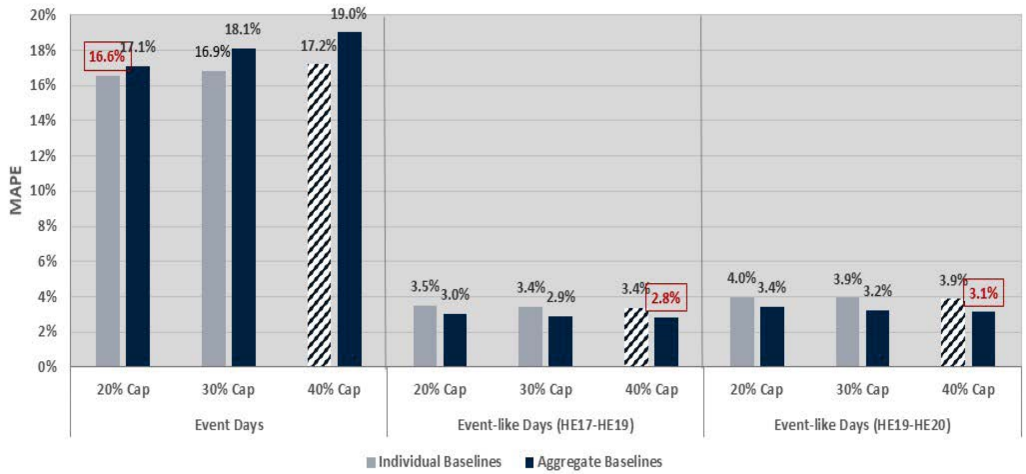


- Covers 44 events & 42 event-like days; 5 resources; 385 customers.
- Again, event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20). Both show Aggregate with 40% cap as most accurate and least bias.
- Event days show conflicting results, mainly driven by PY2018 event day data.

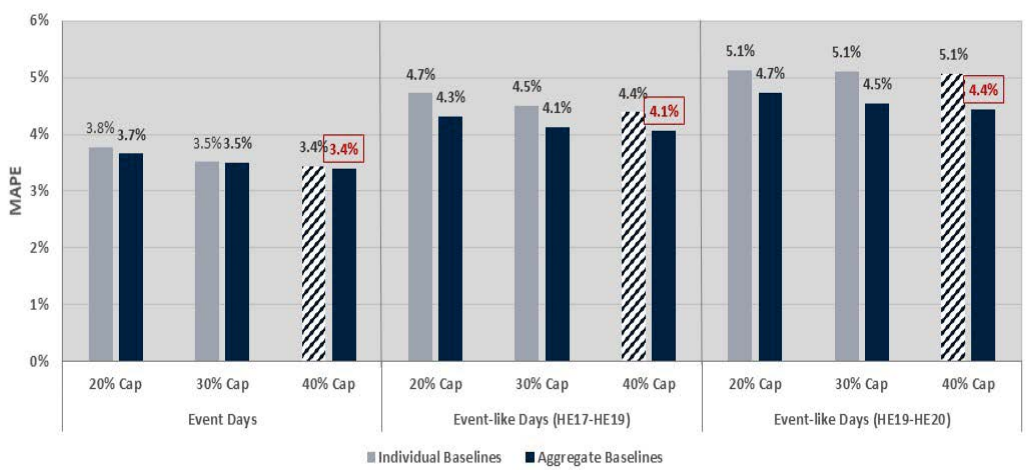
SCE DAY AHEAD

PY2018 versus PY2019

PY2018 Accuracy Comparison



PY2019 Accuracy Comparison



- PY2018 shows event days with very low accuracy and conflicting results (best accuracy using Individual with 20% cap).
- PY2019 shows all three scenarios with very consistent results.

SDG&E PROGRAMS

Day Ahead

- Another example of year-to-year results demonstrating how baseline effectiveness can be driven by the participant population.

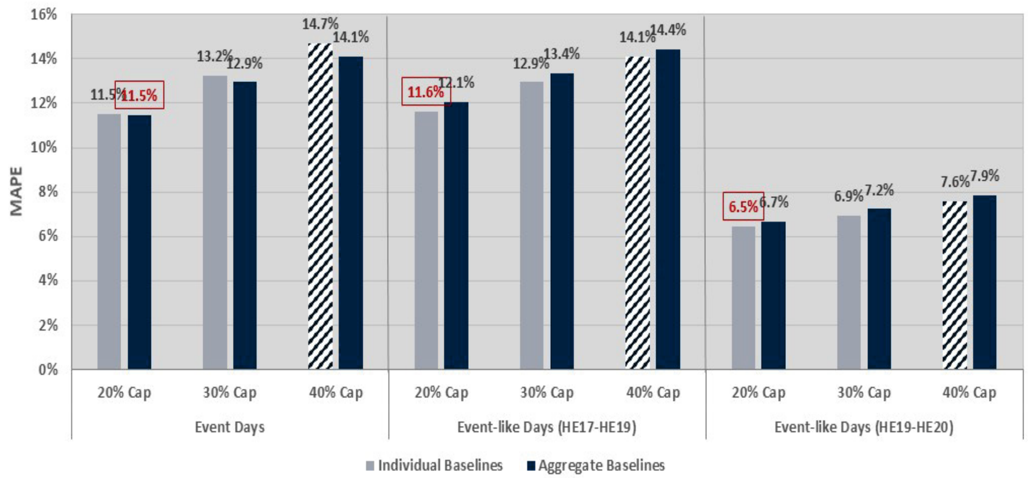
Day Of

- Year-to-year results demonstrate how sensitivity to the timing of the event can be driven by the participant population.

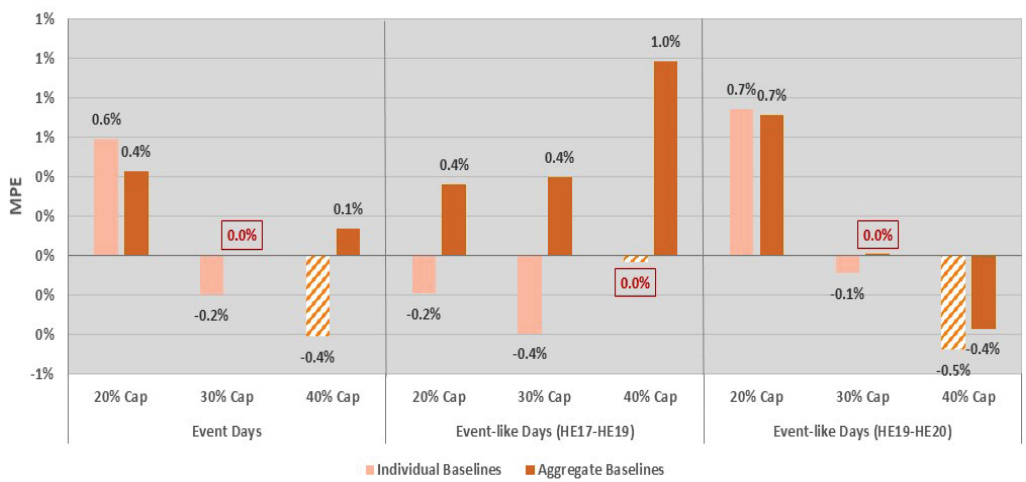
SDG&E DAY AHEAD

PY2018 & PY2019

Accuracy Comparison



Bias Comparison

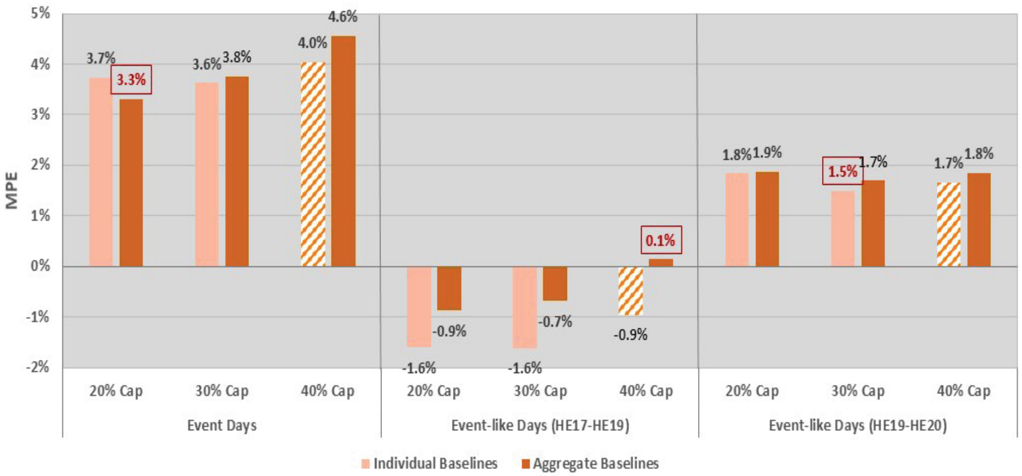


- Covers 48 events & 36 event-like days; 7 resources; 75 customers.
- Consistent accuracy results, but conflicting bias results – largely driven by the differences in participant populations between PY2018 and PY2019.

SDG&E DAY AHEAD

PY2018 versus PY2019

PY2018 Bias Comparison

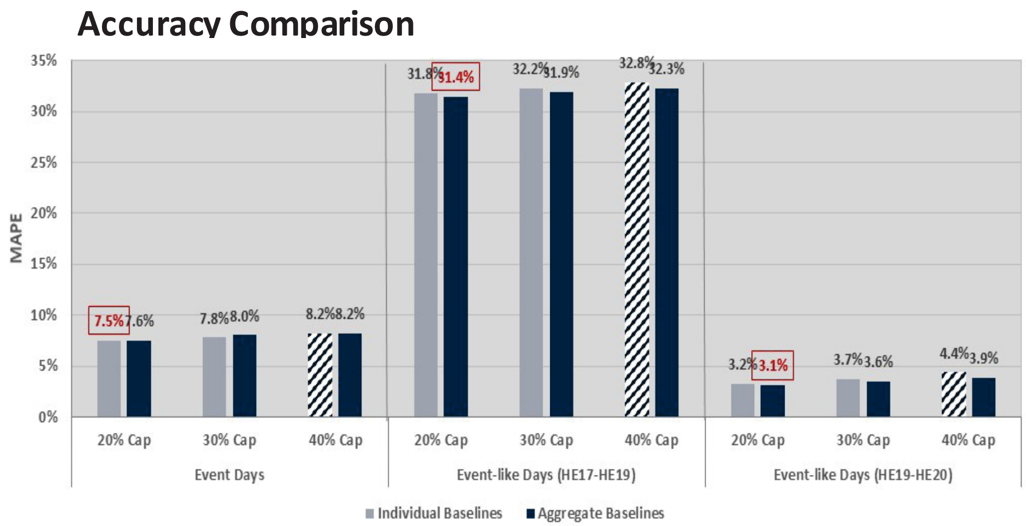


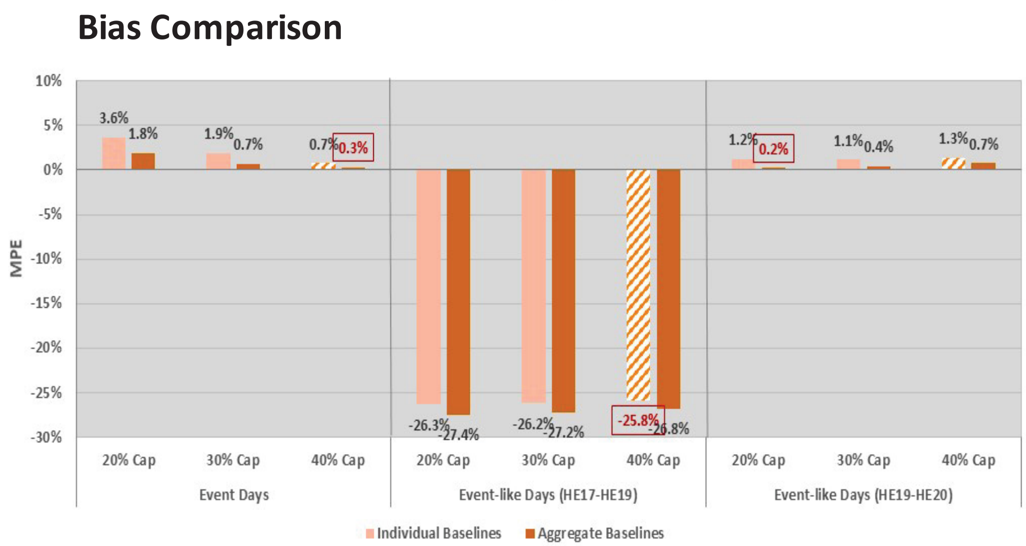
PY2019 Bias Comparison

- PY2018 and PY2019 results show how directional bias and magnitude can be driven by the participant population.
- These two participant populations also show bias sensitivity to event window placement.

SDG&E DAY OF

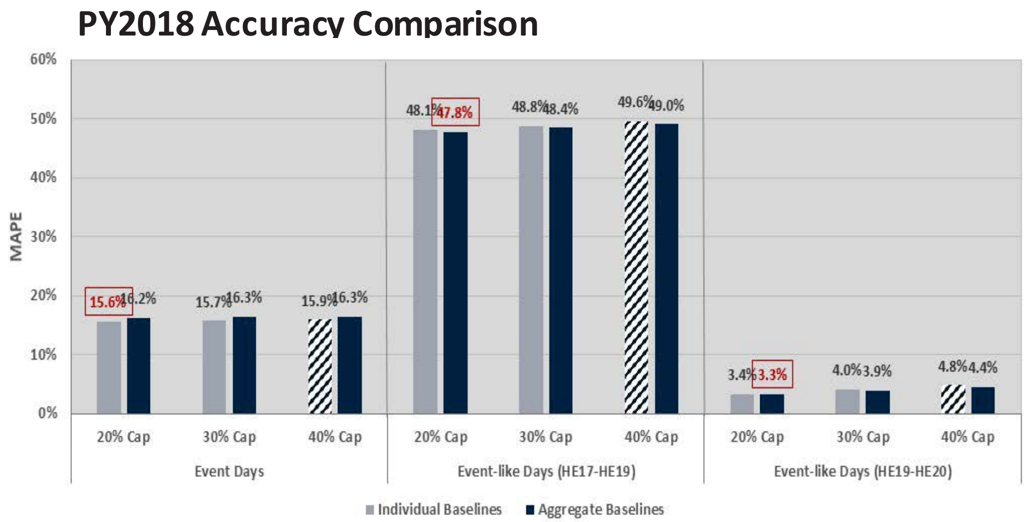
PY2018 & PY2019

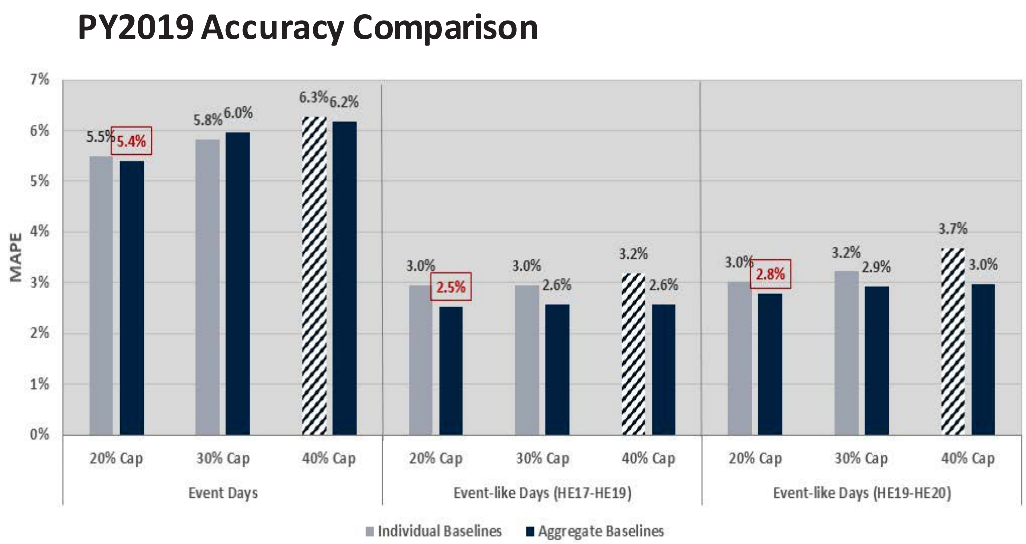




- Covers 19 events & 36 event-like days; 7 resources; 201 customers.
- Event-like day scenarios show conflicting results, indicating that baselines have high sensitivity to the timing of the event, but this also is driven by conflicting PY2018 and PY2019 results.

SDG&E DAY OF
PY2018 versus PY2019





- PY2018 shows event-like days with very high sensitivity to the timing of the event.
- PY2019 shows all three scenarios with very consistent results.

AEG
Applied Energy Group

Key Findings and Recommendations

BEST ACCURACY & LEAST BIAS

Applied Energy Group

Scenario	Best Accuracy Overall	Best Accuracy Ind v. Agg	Best Accuracy Adj Cap	Least Bias Overall	Least Bias Ind v. Agg	Least Bias Adj Cap
All Event-like days	Agg 20% (3)	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	Agg (3.5)	30% (2.2)

Score in parenthesis indicates a ranking out of 5, where 5 is the highest possible score and 1 is the lowest score.

5 = all five programs favored the same baseline
1 = each of the five programs favored different baselines

- BIAS – Aggregate baselines consistently give the least bias; 30% adjustment cap shows the least bias in 2.2 out of 5 programs, considering all scenarios.
- ACCURACY – event-like days scenarios show better accuracy using aggregate baselines, while event day scenarios show better accuracy using individual baselines. All show better accuracy using the 20% adjustment cap.

AVG DECREASE IN EFFECTIVENESS

Aggregate Baselines

	Lost Accuracy			Increased Bias		
Scenario	**Agg 20%**	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
All Event-like days	0.26%	0.49%	0.76%	0.68%	0.33%	0.28%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

Shows the average loss in accuracy and increase in bias when selecting an aggregate baseline in lieu of the top effective baseline for each program and scenario.

- Decreases in effectiveness are all under 2.3%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap.
- Event day scenarios (which shows better accuracy using individual baselines) show relatively small "losses" in accuracy, showing 1% to 2.5% decreases in accuracy.

RECALL KEY POINTS ON ANALYSIS APPROACH

Applied Energy Group

Retail settlement payments for each event day are made at the aggregator level.

Under the CBP tariff, aggregators are responsible for:
(1) customer recruitment and contracting,
(2) resource MW nominations,
(3) resource MW curtailment, and
(4) customer payment disbursement.

A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

RECOMMENDATION

Applied Energy Group

AEG recommends selecting the

Aggregate Baseline with 20% Adjustment cap.

Rationale

- Aggregate baseline is most effective overall, across all scenarios.
- Aggregate baseline is the most appropriate to tariff and program implementation
- Using the 20% cap aligns the retail and wholesale baseline settlements.

AEG Applied Energy Group

RECOMMENDATION

Individual v. Aggregate Baselines?

AEG recommends using the **Aggregate Baseline**.

	Pros	Cons
Individual Baselines	• Provides more accurate estimates for individual customers.	• Provides less accurate estimates at the resource level. • Is not in alignment with the wholesale settlement baseline.
Aggregate Baselines	• Provides more accurate estimates at the resource level. • Aligns with the wholesale settlement baseline.	• Provides less accurate estimates for individual customers.

RECOMMENDATION
Which Adjustment Cap?

20% Cap	• best accuracy
30% Cap	• least bias

AEG recommends using the **20% Adjustment Cap**.

- Both accuracy and bias are not highly sensitive to the adjustment cap – differences in effectiveness, on average, is so small between the three adjustment caps.
- Wholesale settlement already uses the 20% cap – the advantages of aligning the two settlement baselines outweigh the small decrease in effectiveness.

AEG Applied Energy Group

CONTACT INFORMATION

Company	Name	Title/Role	Email	Phone
PG&E	Gil Wong	Project Manager	Gil.Wong@PGE.COM	415-973-2748
AEG	Kelly Marrin	Project Director	kmarrin@appliedenergygroup.com	909-730-7425
	Abigail Nguyen	Project Manager	anguyen@appliedenergygroup.com	916-230-7705
	Xijun Zhang	Senior Analyst	xzhang@appliedenergygroup.com	510-982-3535