

Application: A.22-05-002, et al.

Exhibit No.: _____

Witness: E Bradford Mantz

**SUPPLEMENTAL TESTIMONY OF
E BRADFORD MANTZ – CHAPTER 1B
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY**

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**



March 3, 2023

TABLE OF CONTENTS

I.	INTRODUCTION	1
A.	Background for Demand Response for Today and the Future	1
B.	Portfolio Cost Effectiveness	3
II.	SUPPLY-SIDE DEMAND RESPONSE PROGRAMS.....	6
A.	Base Interruptible Program (BIP).....	7
1.	Background.....	7
2.	BIP Proposal for 2024-2027	8
B.	Capacity Bidding Program (CBP)	15
1.	Background.....	15
2.	CBP Proposal for 2024-2027.....	17
3.	CBP 2024-2027 Budget Proposal.....	19
C.	Capacity Bidding Residential (CBR) Pilot.....	19
1.	Background.....	19
2.	CBP Residential Pilot Proposal	20
D.	AC Saver Program (Smart Energy Program)	20
1.	Background.....	20
2.	Smart Energy Program Proposals for 2024-2027	23
3.	Smart Energy Program 2024 – 2027 Budget Proposal.....	35
E.	Heat Pump Water Heaters	36
III.	LOAD MODIFYING DEMAND RESPONSE PROGRAMS.....	37
A.	Emergency Load Reduction Program (ELRP) Pilot.....	37
1.	Background.....	37
2.	Proposals for ELRP 2024-2027	41
a.	Address Ambiguity and Potential Restrictions on Use of Prohibited Resources	41
3.	ELRP Budget Proposal	44
a.	2024-2025	45
b.	2026 -2027	45
IV.	ENABLING TECHNOLOGY PROGRAMS AND EMERGING TECHNOLOGIES ..	47
A.	Technology Deployment	47
1.	Background.....	47
2.	Proposed TD Program Changes.....	50

B.	Residential Smart Communicating Thermostat Program (SCT)	52
C.	Technology Incentive Program (TI)	53
1.	Background.....	53
2.	Proposed TI Program Changes	60
D.	Emerging Technology Demand Response (ET-DR) Program	60
1.	Background.....	60
2.	ET-DR Proposal for 2024-2027.....	63
3.	ET-DR Proposed 2024-2027 Budget.....	64
V.	PILOTS.....	64
A.	New Pilots - Electric Vehicle Demand Response Pilot (EVDRP)	64
1.	Background.....	64
2.	Need for an EV DR pilot	66
3.	EV DR Pilot Overview	68
4.	Proposal for 2024-2026 Residential EV DR pilot.....	69
a.	Solicit EV control platform vendors.....	69
b.	Marketing.....	69
c.	Summer DR season offering.....	70
d.	Spring DR season offering.....	70
e.	Incentive structure and targeted participants	70
5.	Budget Proposal for EV DR Pilot.....	71
B.	New Pilot – Battery Storage DR Pilot	72
1.	Background.....	72
2.	Storage DR Pilot Overview	74
3.	Battery Storage DR Pilot Objectives	75
4.	Proposed Budget for Battery Storage DR Pilot	77
C.	New Pilot – Direct Dispatch Pilot (DDP).....	77
1.	Background.....	77
2.	DDP Pilot Objectives.....	80
D.	New Pilot – Grid Isolation Controls Pilot (GICP).....	81
1.	Background.....	81
2.	GICP Overview	82
3.	GICP Objectives	82
4.	Implementation	83

5.	GICP Proposed Budget.....	85
VI.	THIRD-PARTY DEMAND RESPONSE: ELECTRIC RULE 32 OPERATIONS AND THE DEMAND RESPONSE AUCTION MECHANISM PILOT (DRAM) FOR 2024 - 2027	85
A.	SDG&E Support for Direct Market Participation through SDG&E’s Electric Rule 32 for 2024 - 2027.....	85
1.	Background.....	85
a.	Current Status	86
b.	Proposal for Operational Support for 2024-2027	86
B.	Demand Response Auction Mechanism Pilot (DRAM) for 2024 - 2027.....	88
1.	Background.....	88
2.	Current Status	88
3.	DRAM Independent Evaluation	88
4.	Customer Information Working Group (CIWG).....	89
VII.	RELATED ACTIVITIES TO SUPPORT DEMAND RESPONSE.....	90
A.	CAISO Market Integration Study Proposal.....	90
1.	Current Status of CAISO-Integrated DR Programs.....	91
2.	It is unclear whether CAISO market integration has delivered on the goals articulated when it was approved by the Commission.....	91
3.	CAISO Market Issues	92
4.	Proposal For A CAISO Market Integration Study	95
B.	Bottoms Up DR Potential Study.....	96
C.	Demand Response Regulatory Policy, Financial Services and General Support Activities	98
VIII.	MID-CYCLE REVIEW.....	99
IX.	ZIGBEE TECHNOLOGY UPDATE	100
A.	Background.....	100
B.	SDG&E’s Proposal to Discontinue ZigBee Support.....	101
X.	NEW SCOPING ISSUES PRESENTED IN AMENDED SCOPING MEMO	103
A.	Scoping Issue 2c - To improve program cost-effectiveness, usefulness, and system reliability, should the Commission consider design changes to RA-eligible emergency DR programs, such as (but not limited to) dispatch conditions and requirements, compensation & penalties, and performance measurement techniques?	103
B.	Scoping Issue 2d - Should the temporary increase in the DR reliability cap to 3 percent be extended?	104

C.	Scoping Issue 7 – Do the demand response programs proposed by PG&E, SCE, and SDG&E adequately take into consideration the Commission’s Environmental and Social Justice Action Plan? How should the programs be modified to better meet the needs of environmental justice communities?.....	105
D.	Scoping Issue 8 – Should the Commission continue the exemption of energy storage resources not coupled with fossil-fueled generation from the Demand Response Prohibited Resources (PR) Policy (as established in D.18-06-012)?	106
E.	Scoping Issue 9 – Should dual participation rules be modified or clarified?	107
F.	Scoping Issue 10 – Should ratepayers provide funding in 2024-2027 for continued modeling of DR potential and related research overseen by Energy Division?.....	108
XI.	CONCLUSION.....	108
XII.	WITNESS QUALIFICATIONS.....	109

APPENDIX A - SDG&E Program Implementation Plans Demand Response 2024-2027

APPENDIX B - SDG&E Tariffs, Contracts, Applications, and Change Forms 2024-2027

APPENDIX C - Retail Baseline Working Group Report

1
2
3
4
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8
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**SUPPLEMENTAL TESTIMONY OF
E BRADFORD MANTZ
CHAPTER 1B**

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I. INTRODUCTION

My supplemental testimony gives an overview of San Diego Gas & Electric Company’s (SDG&E) Demand Response (DR) programs for program years 2024 through 2027 that are the subject of this application, requests program changes, proposes new pilots, studies and provides other updates as necessary or appropriate to be included.¹ Additionally, my supplemental testimony provides a budget request in the total amount of \$135,435,636 to cover the costs for the activities described herein for the period 2024-2027. Finally, section X below addresses some of the new Phase II scoping issues set forth in the *Assigned Commissioner’s Amended Scoping Memo and Ruling and Assigned Administrative Law Judge’s Ruling on Two Motions* dated December 19, 2022 (“Amended Scoping Memo”).

A. Background for Demand Response for Today and the Future

SDG&E continues to provide its customers with innovative DR programs that offer customers options that fit their lifestyles, homes and businesses. Since SDG&E serves all of San Diego County and a portion of southern Orange County, SDG&E is in a unique position to provide these innovative offerings that work toward the State’s climate goals as well as our focus on a stronger more integrated more reliable grid of the future.

This testimony addresses SDG&E’s budget request for the period 2024-2027. As SDG&E transitions DR into a new vision for the future, our proposals focus on building on

¹ For convenience and clarity, my supplemental testimony is intended to replace and supersede my opening testimony regarding Program Years 2024-2027 (dated May 2, 2022). Where appropriate, my supplemental testimony updates information from my prior testimony that has become either moot or outdated due to the passage of time.

1 an established foundation of the past. SDG&E proposes to sunset several programs that are
2 outdated or no longer cost effective and do not fit our customer base, as well as to propose
3 new programs, pilots and studies.

4 Accordingly, my testimony will not discuss the DR Auction Mechanism (DRAM) or
5 the DRAM evaluation report since the report has been delayed and we do not believe the
6 report will be released in time for SDG&E's response to be included into the filing of this
7 DR application. SDG&E reserves the right to address the DRAM at a later date, and
8 possibly through supplemental testimony in this proceeding depending on the timing of the
9 report's release.

10 As further discussed below, SDG&E is requesting modifications to its existing DR
11 programs to be less brand specific by moving to more technology neutral models to allow
12 customers to choose their own technology as outlined in our section on our proposed Smart
13 Energy Program (SEP), which will allow a larger selection of smart devices other than
14 thermostats to participate. SDG&E believes that the move to more technology neutral
15 models will encourage more customers to participate over time. We believe this will be
16 especially attractive for our residential customers as discussed in more detail below.

17 SDG&E also will be requesting Commission approval to retire older programs that
18 have either reached the end of the installed equipment's life cycle or that customers do not
19 see the value nor want to participate in as described below. Additionally, to help move to a
20 more innovative DR of the future concept, SDG&E is proposing new pilots like our Energy
21 Storage, Vehicle Grid Integration (VGI) and Virtual Power Plant (VPP) pilots, which will
22 inform us and help us ultimately design and launch future innovative DR programs that will
23 position DR for the future and allow us to be a better source to grid reliability using new

1 technology. As utilities and grid operators face new flexibility challenges, demand
2 response is more important than ever. Applications for demand-side resources are
3 evolving as a result.²

4 **B. Portfolio Cost Effectiveness**

5 Our portfolio cost effectiveness reflects the fact that DR is in a transition phase,
6 meaning that the DR programs of the past need to be revamped to become more innovative
7 and focus on the utilization of new technologies to help fit into the grid of the future.

8 SDG&E's proposed DR portfolio, as filed in this application, achieves a total resource cost
9 (TRC) cost effectiveness score of 0.2.³ SDG&E acknowledges that this number does not
10 rise to the Commission's and SDG&E's desired level of cost effectiveness that we envision
11 for our programs.

12 Unfortunately, unlike other utilities in the state, SDG&E's DR programs cannot rely
13 on large industrial or manufacturing customers that can shut down or shed load at their
14 commercial or industrial sites. Instead, SDG&E's programs must focus on the predominant
15 customer classes that make up most of our service area, such as small and medium
16 commercial and light industrial customers and our residential customer base.

17 SDG&E's plans continue to capitalize on advancements in technology and
18 information systems to be able to open its programs to more customers, thereby increasing
19 participation to increase cost effectiveness. An example is building and upgrading our

² <https://www.greentechmedia.com/articles/read/how-demand-response-meets-the-grid-edge#:~:text=Demand%20response%20is%20shifting%20away%20from%20systemwide%20implementation,resources%20is%20changing.%20The%20only%20problem%20is%20scale.?msclkid=37134e5ec1b611eca491a2cb0f5ea061>

³ See Supplemental Testimony of Brenda Gettig Chapter 5B for calculation of TRC cost effectiveness score. As Ms. Gettig notes, if SDG&E were to utilize the 2022 updated ACC, SDG&E's portfolio TRC cost effectiveness score increases to 0.7.

1 information technology (IT) systems to be able to signal, manage and settle VPPs, electric
2 vehicles (EVs) and other distributed energy resources (DERs) that are or will be integrated
3 into our distribution system to help support the grid. This capability comes with an increase
4 in IT and other costs, which is discussed in other portions of my testimony or in other
5 chapters.⁴ SDG&E plans on continuing to enhance necessary information technology
6 systems to support our portfolio efforts. These innovations cause higher IT costs now, and
7 SDG&E is spreading these costs across our existing programs, but these costs are crucial to
8 future efforts. SDG&E notes that not all of this potential value is captured and reflected in
9 SDG&E's current cost effectiveness scores. Part of our overall IT upgrades and
10 implementations will allow us to target DR to certain locations and this capability is only
11 going to grow as technology, marketing strategies and adaption of new devices by our
12 customers allows us to get more granular data on distribution operations.

13 A major contributor to the lowering of our cost-effectiveness of our Supply Side DR
14 programs⁵ is the updated avoided capacity benefits in the Avoided Cost Calculator (ACC).⁶
15 The new values are lower than the avoided capacity benefits used in the 2018 through 2022
16 program cycle, and they drop to \$70 and \$54 kW/year in 2026 and 2027, respectively.
17 SDG&E notes that the new values have made DR less valuable and potentially less desirable
18 or competitive.⁷ While it is important not to offer unnecessary demand response programs,

⁴ See Prepared Direct Testimony of Ellen Kutzler Chapter 2B.

⁵ "Supply side" demand response programs are those bid into the California Independent System Operator (CAISO) markets as a "supply" resource.

⁶ See Supplemental Testimony of Brenda Gettig Chapter 5B.

⁷ See Supplemental Testimony of Brenda Gettig Chapter 5B for discussion of impact of 2022 updates to ACC.

1 SDG&E asserts its proposed programs still play a role in providing system reliability for the
2 near future.

3 As mentioned above, SDG&E continues to have challenges related to the customer
4 mix in our service area. For example, fourteen of our large customers who signed up for the
5 Emergency Load Reduction Program (ELRP) Pilot in 2021 have stated that they prefer
6 newer programs that are “pay for performance” with higher incentives and no penalties like
7 the ELRP, as opposed to other DR programs. However, there has been no evaluation,
8 measurement or verification (EM&V) studies performed to see if the ELRP is cost effective
9 and if it would have any impact on our filed cost effectiveness scores. The ELRP has been
10 effective in bringing in incremental MW from customers that normally would not participate
11 in DR programs. Their participation in the ELRP is assumed to have helped the grid.⁸

12 Although SDG&E is not satisfied with its current cost effectiveness scores,⁹ the
13 analysis performed for this application provides a baseline to be used over the application’s
14 timeline to determine whether some programs modifications have worked and if other
15 programs should be terminated. SDG&E believes it is premature to value SDG&E’s cost
16 effectiveness in light of the new ELRP emergency programs.

17 For this application, SDG&E has adjusted its programs budget to allocate funding
18 with an increased focus on recruiting new customers and aggregators to help grow its
19 programs and pilots in an effort to increase our cost effectiveness. SDG&E’s customer base
20 is significantly different than the other IOUs, making it difficult to recruit new customers

⁸ D.21-003-056, p. 5 (ELRP Subgroup A.1).

⁹ Detailed Cost Effectives analysis is provided in the Supplemental Testimony of Brenda Gettig Chapter 5B supporting this application.

1 and make sizable gains in the programs load. Again, SDG&E's current customer mix does
2 not include large commercial or industrial accounts; instead, it is comprised of mostly small
3 to medium commercial accounts and our residential customer base, making it a challenge to
4 find enough participating customers to shift significant load during a DR event.

5 In this application, SDG&E is making a major transition to move DR from older
6 established but non-effective programs to newer programs like our CBP Elect and the Smart
7 Thermostat Program approved in the Summer Reliability OIR Phase II¹⁰ to replace our older
8 CBP options and our TI, TD and AC Saver options. We are also proposing new innovative
9 pilots that are evaluating EVs, batteries, VPPs and other ideas to move us towards our goal
10 of DR programs of the future. SDG&E requests that the Commission consider our cost
11 effectiveness in light of this transition.

12 SDG&E also requests that if the Commission wants SDG&E to continue any of the
13 DR programs it has proposed to retire, the Commission allow SDG&E to submit a
14 subsequent funding request to run these programs as mentioned below in my testimony.
15 SDG&E further requests that if ordered to run any of our proposed retired programs, the
16 Commission also order that they are not to be considered in our cost effectiveness
17 calculations going forward.

18 **II. SUPPLY-SIDE DEMAND RESPONSE PROGRAMS**

19 SDG&E proposes to continue to grow and improve its supply-side portfolio of
20 existing DR programs as resources that help meet grid needs and continue to give our
21 customers options to reduce loads at critical times. SDG&E also proposes to retire some

¹⁰ D.21-12-015, CBP Elect Attachment 1, p. 6 and Smart Thermostat Program pp. 13-14.

1 existing programs due to low or no customer participation. The following section describes
2 our existing supply-side DR Programs and SDG&E’s proposed changes for 2024 -2027.

3 **A. Base Interruptible Program (BIP)**

4 **1. Background**

5 The Base Interruptible Program, or BIP, offers a monthly capacity payment to
6 commercial customers that can commit to curtailing at least 15% of Monthly Average Peak
7 Demand, with a 20-minute notification. It can be available for multiple reliability-only
8 events, including system emergencies (CAISO notices). This program qualifies as a supply
9 resource (as it is bid into the CAISO) and is open to bundled customers as well as Direct
10 Access (DA) customers and CCA customers. This program aims for a DR product¹¹ that
11 enables emergency responsive demand response resources to state and local situations.

12 With its incentive structure, as well as its penalties for non-performance, and a short
13 notification period, this program is most suitable for commercial customers who can shut
14 down production quickly, with certainty, and usually without a significant cost to its
15 business. In SDG&E’s experience, large manufacturing or other large assembly line
16 businesses, or businesses which operate production 24 hours a day, tend to be the best
17 candidates for participation. SDG&E’s effort to grow the program to become suitable for
18 successful market participation has had disappointing results, with no additional customers

¹¹ A DR “Product” is the term for a Demand Response offering that has a specific trigger, hours that it can be called, and a specific notification window. Products may differ by being triggered based off different scenarios, and their notification windows may differ such as the day before an event (aka “Day Ahead”). Alternatively, the scenario may be that circumstances warrant load drop based on a forecast for the same day, *i.e.*, a forecast for grid needs later in the day necessitate load shed the same day; the notification would be sent the same day the load shed is needed (as a “Day Of” product). Each product has specific hours during which events can be triggered. In this way, the customers know exactly during which hours of the day they will be called upon, and if they will be notified the day ahead, or on the same day. Typically, Day Of events pay more to customers for load shed, since there are less hours/days to prepare.

1 joining the program. At the time of this filing, there are no customers currently enrolled in
2 the program. SDG&E's territory is not a good target market for the program because it has
3 a very limited amount of large industrial customers that can shed load quickly from which to
4 draw participants for such an emergency type program. SDG&E has been challenged with
5 growing the program even with increased marketing efforts including direct mail letters,
6 emails, SDG&E's account executive consultations, and direct phone calls. SDG&E also
7 made several modifications to the program's tariffs to make it more attractive for
8 aggregators and opened the program to additional smaller customers that have a demand of
9 less than 100kW.¹² Despite the additional efforts to educate and attract eligible SDG&E
10 customers to join BIP, no customers have expressed an interest in signing up.

11 **2. BIP Proposal for 2024-2027**

12 SDG&E is proposing in this application to retire BIP in 2024. The proposed BIP
13 program end date is December 31, 2023.

14 Year after year, SDG&E has spent money for marketing campaigns in an effort to
15 increase participation and improve cost effectiveness of the BIP program. SDG&E has
16 made significant changes to its tariffs to make the program more attractive to customers and
17 aggregators alike to no avail. The results were disappointing and did not achieve our
18 objective of adding any additional enrolments. SDG&E has not been able to identify any
19 large industrial customers or large manufacturers that can quickly reduce energy within 20
20 minutes of receiving notice who are willing who enroll and participate in a program like
21 BIP.

¹² D.21-03-056, Attachment 1, p. 19.

1 SDG&E’s BIP over the past several years has had minimal enrollments. SDG&E
2 has had less than ten customers in the program over the last nine years. In 2019, the
3 program unenrolled 50% of the customers because the customers were not meeting the
4 minimal requirements as set out in the tariff. In 2019 the number of customers enrolled was
5 a total of two compared to the previous year, which was four.

6 Customers must be able to meet minimal requirements, otherwise they are not good
7 candidates to perform during events and may incur penalties. According to Customer B
8 (customer names are anonymized due to privacy rules) during an interview about overall
9 satisfaction levels with BIP, the customer stated they left the program because “the penalties
10 were too harsh, resulting in them sometimes losing more money than they could have been
11 paid and saved on their energy reductions because they regularly faced challenges executing
12 their load reduction plan for an event.”¹³ This customer also said, “they are no longer
13 enrolled in the program because they were unable to train and keep knowledgeable staff to
14 enact their load reduction plan during events.” Also, as events were being called later in the
15 evening when trained staff were not on site, this caused them to miss their firm service level
16 on multiple occasions. The issue was compounded as the number of events increased in
17 recent years, which eventually lead to their decision to leave the program.”¹⁴ SDG&E
18 regularly communicated with our customers to make sure that they understood the
19 program’s terms and conditions as outlined in the tariff and were aware of the penalties in

¹³ SDG&E hired a consultant in 2021 to conduct interviews with former and current enrolled BIP customers to understand their satisfaction levels with the program. The interviews conducted on unenrolled customer also focused on why the business decided to leave the program.

¹⁴ Nexant Base Interruptible Program Interview Results Draft (submitted to SDG&E on August 20, 2021), at p. 5 of Interview Findings.

1 order to ensure the best customer experience possible. Below is a table that reflects
2 enrollments in BIP from 2012 to 2021 showing total accounts and customers.¹⁵ The
3 reduction from 2018 to 2019 was due to customers no longer meeting their performance
4 requirements.

5 **Table EBM – 1**
6 **Historical BIP Customer Enrollments**

BIP Historical Enrollments	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Accounts	17	7	55	66	76	66	55	44	44	0
Total Customers	13	66	54	45	55	55	24	22	22	0

7
8 Since 2018, SDG&E has continued to increase marketing efforts to target customers
9 and get additional customers to join the program. For example, below are some of the
10 efforts and results from 2020 into 2021:

11 **First Quarter 2020:**

- 12 • SDG&E’s “Save the Day” marketing campaign brought additional
13 awareness to demand response programs, including BIP.
- 14 • One aggregator wanted to enroll a customer with 400kW load shed, however
15 the customer was disqualified due to Rule 41 eligibility rules in 2020, which
16 prohibited customers from dually enrolling in a demand response program if
17 they are enrolled in any other demand response program or rate.¹⁶

¹⁵ A customer can have more than one account enrolled.

¹⁶ SDG&E’s Electric Rule 41, Sheet 1. “Dual participation is suspended for all enrollments on or after October 26, 2018.” https://tariff.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE_41.pdf

1 **Second Quarter 2020:**

- 2 • SDG&E’s marketing campaign launched online advertising (“ads”) on April
3 7, 2020. This campaign included banner advertisements, paid search, paid
4 social and streaming radio ads. “Banner advertisements” are a form of
5 advertising displayed on a website at top of page or side area or social media
6 platform - one example is Facebook, and these are intended to attract
7 consumers to a specific product or brand, increasing awareness and/or driving
8 consumers to the brands website. “Paid searches” are where SDG&E pays for
9 ads to show up in internet search engines such as Google, Yahoo, etc. A paid
10 search ad is generally text, and not images. These ads are displayed when an
11 end user types search terms into a search engine, and they are delivered an ad
12 on that topic. “Paid social ads” run on social media channels. These ads
13 include images and text and are intended to drive users to a website.
14 “Streaming” radio ads are ads which a listener would hear when they are
15 streaming online radio, for example Pandora. In addition, the campaign
16 included a streaming TV ad which launched a 30 second video on June 20,
17 2020.
- 18 • SDG&E received one application from an aggregator wanting to
19 enroll a single customer into BIP. However, the customer was not
20 eligible again due to prohibition of dual participation in more than one
21 DR program as set out in Rule 41. The customer chose to stay in their
22 current program.

1 **Third Quarter 2020:**

- 2 • SDG&E experienced increased traffic to demand response program
- 3 web pages due to the heat and stresses to the California grid during
- 4 the summer¹⁷ in August and September. However, the web traffic of
- 5 people who viewed the web sites did not result in any new
- 6 enrollments. Also, in 2020 SDG&E updated its DR web pages to
- 7 provide a refreshed look to provide more straight forward information
- 8 and encouraging customers to sign up for the program. SDG&E
- 9 performed the refresh to improve the readability and entice customers
- 10 to enroll.
- 11 • An email campaign was created and launched targeting BIP potential
- 12 customers that were identified by researching eligible commercial
- 13 accounts that are not already enrolled in a DR program or rate and
- 14 specifically targeting them because they had a load profile that might
- 15 potentially fit with BIP where participation might have been
- 16 beneficial to the customer. SDG&E would not know their potential
- 17 for sure until it received the results. The data lists of potential BIP
- 18 customers were modified and cleaned up to avoid duplicates before
- 19 SDG&E sent the emails. Over 3,000 tailored communications were
- 20 sent to these potential customers. This included 218 letters sent on

¹⁷ Summer reliability issues in 2020 included rolling blackouts in the state of California due to extreme weather conditions that exceeded the existing electricity resource planning targets as noted in a Press Release from the California Independent System Operator, California Public Utilities Commission and California Energy Commission joint release dated October 6, 2020. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M348/K229/348229612.PDF>

1 July 31, 2020, and 2,790 letters sent on August 14, 2020, which
2 included a hyperlink to learn more about the program, as well as how-
3 to sign up. The click rates, or the number of times customers clicked
4 on the pertinent links for more information, for customers that clicked
5 on the hyperlink were 0% for the letters sent in July. The rate was
6 just 1.6% for August, meaning that both times very few customers
7 clicked on the hyperlink to take them to the BIP landing page to get
8 more information about the program or the call to sign up.¹⁸ During
9 this time frame in 2020, customers were utilizing digital content as
10 their main source of information.

11 **Q4 2020 and into Q1 2021:**

- 12 • SDG&E launched a new tool to help SDG&E account executives
13 further identify and target potential BIP customers. This tool
14 identifies current customers in SDG&E territory and takes into
15 consideration their usage history to perform a propensity sensitivity
16 analysis to see if the customer would benefit (and therefore enroll)
17 based on actual enrolled customers in DR Programs. The tool also
18 looks at their demand and the difference between the peak usage and
19 non-peak usage to determine how much a customer could save if they
20 joined a demand response program such as BIP and Capacity Bidding
21 Program (CBP).

¹⁸ SDG&E uses “click rate” to measure how many people visited the BIP web page based off the email campaign sent in Q3, 2020. Click Rate is defined as the percentage of people visiting a web page who access a hypertext link from an email to a particular advertisement.

- Account executives and business analysts from the SDG&E's Business Services Teams were trained on the tool in early 2021. So far, applying this new tool has not provided any additional customers for BIP enrollment.

Despite all of these additional efforts, SDG&E's BIP has not enrolled any new customers in the last two years and SDG&E unenrolled the last remaining two customers at their request in 2021.¹⁹ The recent customers that were unenrolled from BIP indicated that the reason for unenrollment was because "the incentive payments didn't justify the cost of the lost production."²⁰ If the incentives are increased, the program may attract a few more enrolments, but it also makes the program less cost effective.

Again, SDG&E's territory is different compared to that of Southern California Edison Company (SCE) or Pacific Gas and Electric Company (PG&E), related particularly to the number of eligible customers that would participate in BIP. SDG&E's territory lacks sufficient accounts of large industrial customers and large manufacturers, refineries, agricultural water pumping, and cement plants that all have the ability to reduce energy within 20 minutes, which make them likely candidates for BIP. As of 2021, PG&E and SCE each had hundreds of customers enrolled in BIP.²¹ Furthermore, SDG&E's territory has very few large manufacturers that are members of the California Large Energy Consumers Association (CLECA), further limiting the pool of eligible and willing customers to join BIP.

¹⁹ SDG&E unenrolled a construction materials aggregator that had two accounts enrolled in BIP.

²⁰ K. Olson, Procurement Director.

²¹ Email from PG&E staff dated July 13, 2021, and email from SCE staff dated July 20, 2021. Numbers may not reflect today's enrollments.

1 Currently, the cost effectiveness total resource cost (TRC) for BIP is 0.158. A TRC
2 value of 1.0 is considered ideally cost effective and SDG&E's efforts have not yielded any
3 new participants. SDG&E's BIP has historically not been cost effective, but its ratio is now
4 lower than it has ever been. Thus, continuing to spend ratepayer funds and resources to try
5 to grow program with inherent challenges at such a low starting point within SDG&E's
6 territory is difficult to justify.

7 SDG&E at this time does not see a viable path forward to make BIP cost effective, as
8 it does not see a path to get new customers to participate. For all of these reasons, SDG&E
9 seeks Commission approval to retire BIP on January 1, 2024. SDG&E also does not seek
10 any further budget for BIP in 2024 and beyond.

11 Should the Commission reject SDG&E's proposal to retire BIP, then SDG&E
12 respectfully requests the Commission authorize a regulatory path forward for SDG&E to
13 request the additional budget that would be necessary to continue BIP for 2024 and beyond,
14 if so ordered. SDG&E also requests that the Commission remove the requirement for BIP to
15 be cost effective and for it to be removed from SDG&E's cost effectiveness calculations
16 portfolio wide. SDG&E requests this since SDG&E does not believe that its overall
17 portfolio cost effectiveness for its remaining programs should be negatively impacted by
18 including BIP when it has requested to end the program.

19 SDG&E requests the Commission approve our proposal to retire BIP in 2024.

20 **B. Capacity Bidding Program (CBP)**

21 **1. Background**

22 The Capacity Bidding Program is a voluntary demand response program that offers
23 customers various product options by which they can earn incentive payments in exchange
24 for reducing energy consumption when requested by the utility. This program is available to

1 bundled customers and customers being billed on a utility commercial, industrial or
2 agricultural rate schedule. It is also available to DA and CCA customers. Bundled
3 customers receive capacity and energy payments from SDG&E and DA customers receive
4 capacity payments, with energy-based compensation and savings subject to their contractual
5 relationships with their DA providers.

6 The struggle to attract and retain new customers to CBP continued throughout the
7 program cycle. For example, in 2020 a chain of 23 pharmacy/convenience store accounts
8 joined CBP; however, they all left the program in 2021 and transferred to direct participation
9 in the CAISO market under SDG&E's Electric Rule 32. The aggregator representing the
10 pharmacy chain stated that the reason the customers were moved over to SDG&E's Electric
11 Rule 32 was because the customer did not like the number of events being called. So not
12 only is there a desire to have fewer events, but there are also competing programs for
13 customers that are less restrictive.

14 In 2019, SDG&E called the maximum number of events²² per month in September
15 and October. In 2020, SDG&E called the maximum number of events allowed per month in
16 July, August, September and October. SDG&E filed advice letters 3321-E,²³ 3306-E,²⁴
17 3522²⁵ all with requests to limit events to address the expressed customer fatigue and reduce

²² SDG&E filed in Advice Letter 3321-E which was approved and implemented to limit the CBP consecutive events to three in a row in a given week and allow a maximum of six events per month per product.

²³ AL 3321-E was approved on 4/4/2019 and effective on 5/1/2019. In this AL SDG&E limited the number of consecutive events to three days and limited the events per month to six.

²⁴ AL 3306-E was approved on 12/7/2018 and effective on 12/15/2018. In this AL SDG&E proposed to increase price triggers to reduce the number of CBP events.

²⁵ AL 3522-E Mid-Cycle Update was approved and effective on August 4, 2022. In this AL SDG&E proposed to update price triggers to reduce the number of CBP events.

1 the number of events being called. These advice letters have been approved by the
2 Commission.

3 **2. CBP Proposal for 2024-2027**

4 For the 2024-2027 program cycle, SDG&E proposes to retire the traditional CBP
5 products²⁶ while retaining and focusing on the new CBP Elect products that are more closely
6 aligned with the CAISO's peak times of 4pm to 9pm.

7 SDG&E is confident after speaking with and receiving feedback from its current
8 CBP aggregators that retiring the existing traditional CBP products is welcomed and will
9 encourage existing customers to transition to the new CBP Day-Ahead and Day-Of 1pm-
10 9pm Elect products. It is encouraging to see a CBP product enhancement that has been so
11 well received by all stakeholders.²⁷

12 SDG&E forecasts that the addition of the CBP Elect option could bring an additional
13 5MWs of new load shed with up to ten new commercial customers.²⁸

14 In order to continue to recruit new customers into CBP, SDG&E proposes to update
15 the non-performance penalty of the CBP tariff. SDG&E's CBP's current program structure
16 penalizes customers who do not perform at least 75% of nominated load reduction. Current
17 structure is shown in Table EBM-2.

²⁶ Traditional CBP Day-Ahead and CBP Day-Of 11am-7pm and 1pm-9pm products.

²⁷ Phone conversation with PG&E's CBP Program Manager on July 13, 2021.

²⁸ 5 MWs of new load shed is based off feedback via email received from aggregators.

1

Table EBM- 2

CBP Current Incentive/Energy Payment and Non-Performance Penalties	
Actual Load Reduction for such product	Adjusted Event Capacity Payment Amount for such product
More than 100 percent of nominated load reduction for such product	Payment equal to 100 percent of unadjusted Event capacity payment account for such product
75-100 percent of nominated load reduction for such product	Payment calculated by prorating between 75 and 100 percent of unadjusted event capacity payment amount for such product
50% -74.99% percent of nominated load reduction for such product	Zero
Less than 50 percent of nominated load reduction for such product	Penalty equal to (0.50 minus actual reduction divided by nominated load reduction) multiplied by the unadjusted event capacity payment amount

2

The proposed changes are in Table EBM-3:

3

4

Table EBM-3

CBP Proposed Incentive/Energy Payment and Non-Performance Penalties	
Actual Load Reduction for such product	Adjusted Event Capacity Payment Amount for such product
More than 100 percent of nominated load reduction for such product	Payment equal to 120 percent of unadjusted Event capacity payment account for such product
30-100 percent of nominated load reduction for such product	Payment calculated by prorating between 30 and 100 percent of unadjusted event capacity payment amount for such product
<30 percent of nominated load reduction for such product	Zero

5

6

The proposed changes to CBP are critical to help retain aggregators and customers

7

while attracting new customers and aggregators to the program. These changes are also vital

8

to increasing cost effectiveness, because when additional customers join the program, kW

9

enrolled increases, thus the cost effectiveness improves.

1 **3. CBP 2024-2027 Budget Proposal**

2 **Table EBM-4**
3 **CBP Budget**

	2024	2025	2026	2027	TOTAL
CBP	\$1,673,919	\$1,734,683	\$1,744,749	\$1,775,705	\$6,929,057

4
5 SDG&E is seeking \$6,929,056 for the CBP for 2024-2027. Should the Commission
6 reject or modify in any way SDG&E’s proposal, then SDG&E respectfully requests the
7 Commission to authorize a regulatory path forward to request the budget necessary to
8 manage CBP in 2024-2027 reflecting any Commission modifications.

9 The proposed program implementation plan and tariff changes are contained in
10 Appendix A.

11 **C. Capacity Bidding Residential (CBR) Pilot**

12 **1. Background**

13 On March 26, 2021, the Commission authorized SDG&E’s CBR Residential Pilot²⁹
14 with an approved budget of \$708,000, including administrative costs and incentives.³⁰
15 D.21.12.015 approved the continuation of the CBP Residential Pilot through 2022.

16 SDG&E launched the pilot as quickly as it could during the summer of 2021.³¹
17 However, because of the late start, the pilot did not have adequate preparation time to
18 implement and recruit aggregators and customers before the 2021 DR season, which started
19 on May 1st. SDG&E’s CBP aggregators are currently not positioned to handle residential

²⁹ D. 21-03-056, Attachment 1, p. 9.

³⁰ D.17-12-003, p. 191, OP 22.

³¹ The CBP Residential Pilot was not approved until March 2021.

1 customers and typically only work with Commercial and Industrial accounts. D.21-12-015
2 approved our request to continue the Pilot in 2022³² and my testimony for 2023 also requests
3 to continue the pilot and its evaluation.³³

4 **2. CBP Residential Pilot Proposal**

5 If the pilot is successful, SDG&E seeks the Commission's approval after the post
6 evaluation and measurement review has been completed in 2024 to propose via a Tier 2
7 Advice Letter that the CBP Residential Pilot be approved as a new product to be added to
8 the Capacity Bidding Program. SDG&E is not requesting additional funds at this time and if
9 SDG&E files an Advice Letter requesting to covert the Pilot to a program and it is approved,
10 SDG&E would cover the incentives and administration from the currently filed and
11 requested CBP budget. SDG&E is not proposing any tariff changes at this time.

12 **D. AC Saver Program (Smart Energy Program)**

13 **1. Background**

14 Currently, SDG&E offers a program named AC Saver. AC Saver is a supply side
15 DR program bid into the CAISO market. AC Saver participants have either a direct load
16 control switch installed on their air-conditioner or a thermostat with settings that can be
17 adjusted by the manufacturer. Events last between two and four hours per day and may be
18 called between April and October. The maximum number of annual events is 20, with 5
19 additional events that may be called during CAISO or SDG&E emergencies only. The
20 program is usually activated when SDG&E bids in and then receives an award from CAISO,

³² D.21-12-015, Attachment 2, p. 6.

³³ Prepared Direct Testimony of E Bradford Mantz Chapter 1A, p. EBM-7, lns. 6-15.

1 but the program may also be called at SDG&E’s discretion in other circumstances, including
2 local emergencies.

3 Participants with direct load control switches installed on their air-conditioner
4 receive an annual capacity payment based on the size of their air-conditioner and the cycling
5 option that they choose. Residential customers can select 100% or 50% cycling and
6 Commercial customers can select 50% or 30% cycling. This incentive is paid in December
7 each year.

8 Participants with thermostats enroll in the program using the following process.
9 Since customers must have a device that controls an air-conditioner to be eligible for AC
10 Saver, customers must first register their thermostat through their thermostat manufacturer’s
11 website or app so that SDG&E knows that the thermostat is installed and online. Enrolling
12 through the manufacturer also allows the manufacturer to adjust the thermostat settings
13 when SDG&E activates the program. SDG&E’s signaling platform then pulls in these
14 pending enrollments from the manufacturer application programming interface (API)³⁴ and
15 verifies customer eligibility. Eligible customers currently receive \$50 from the SDG&E
16 Technology Deployment program (TD) for completing this step. If the customer is already
17 participating in a rate with events or DRAM when they register the thermostat, the customer
18 remains enrolled on that program and receives the \$50 TD payment only.³⁵ If the customer

³⁴ An API is software intermediary that allows two applications to talk to communicate with other. In the case SDG&E signaling portal talks with the manufacturer portal.

³⁵ SDG&E implemented the enrollment process in this way because enrolment in DRAM or a rate with events does not require a thermostat and enrollment in these programs cannot be performed within a SD&8E thermostat portal. Customers must enroll in DRAM through their third party and customers must also change rate within the SDG&E MyAccount portal. AC Saver enrollments on the other hand must be done within the thermostat portal because the thermostat must be verified in order for the customer to be eligible.

1 is not already enrolled in a demand response program when they register the thermostat, the
2 customer is enrolled in the AC Saver thermostat program. In 2020, 92% of customers who
3 received a TD incentive from a thermostat enrolled in the AC Saver program. Thus, the TD
4 and AC Saver programs are closely intertwined.

5 Once the customer is enrolled in the AC Saver program, residential customers
6 receive an annual capacity payment of \$20, provided that the customer remains enrolled in
7 the program through October 31st and the thermostat remains online. Since few commercial
8 customers were eligible for AC Saver in the past, commercial customers currently receive
9 no annual capacity payment, but SDG&E is requesting to change that in this application.

10 In the last DR application, SDG&E expanded the AC Saver program from including
11 only customers with direct load control switches to including both switches and
12 thermostats.³⁶ In this application, SDG&E is requesting to expand the program even further
13 by opening it up to customers with devices that control end uses other than air-conditioners.
14 SDG&E's proposal to expand program eligibility is described in detail in the proposal
15 section below. Since the program name "AC Saver" does not apply to controls of end uses
16 other than air-conditioners, SDG&E proposes to rename this program the "Smart Energy
17 Program."³⁷ This program will therefore be referred to as the Smart Energy Program (SEP)
18 for the remainder of the testimony regardless of the time period being discussed.

³⁶ A.17-01-019, Prepared Direct Testimony of E Bradford Mantz (January 17, 2017), p. EBM-8.

³⁷ The new name would apply to Commission filings and reporting. SDG&E retains the right to brand this and any program other names in its marketing and customer-facing communications.

1 **2. Smart Energy Program Proposals for 2024-2027**

2 SDG&E’s proposals for the Smart Energy Program focus on modernizing the
3 program and increasing participation. In short, SDG&E proposes to:

- 4 1) Retire the switch portion of the program.
- 5 2) Expand the program to customers with devices which control end uses other
6 than air-conditioning.
- 7 3) Modify the annual incentive structure to accommodate the addition of new
8 devices.
- 9 4) Add commercial customer incentives.
- 10 5) Add an enrollment incentive of \$200 per kw to the program.
- 11 6) Consolidate the program into a single day-of product.

12 Each of these proposals are described in further detail below.

13 **Proposal 1: SDG&E proposes to retire the direct load control switch portion**
14 **of the Smart Energy Program**

15 On February 1, 2016, in the SDG&E 2017 Demand Response Program Proposal,
16 SDG&E proposed to allow the existing direct load control switches to continue to be part of
17 the Demand Response portfolio through 2023 and to transition away from the older pager
18 device technology to newer technology as these devices reach their end-of-life cycle.³⁸

³⁸ San Diego Gas & Electric Company (U 902 E) 2017 Demand Response Program Proposals Pursuant to the Assigned Commissioner and Administrative Law Judge’s Ruling Providing Guidance for Submitting Demand Response Programs and Activities Proposal Filings, p. 20.

1 D.16-06-026 approved this proposal.³⁹ In 2018, SDG&E continued with this approach in
2 A.17-01-018.⁴⁰

3 For the reasons described below, both the enrollments and the load reduction per
4 customer from the switches participating in the Smart Energy Program have declined
5 through the years, resulting in low aggregate event performance results. Customers have
6 shown over time a preference for newer technology like smart thermostats and the flexibility
7 they provide over an installed switch. The low aggregate load reduction provided by the
8 switches no longer warrants the administrative and software costs of continuing to
9 administer the switch portion of the program and signal the switches. Increasing the
10 aggregate load reduction from the program would require installing new switches on air-
11 conditioners which is cost prohibitive because SDG&E would have to pay for both the
12 switch itself and the installation. Therefore, for the reasons explained below, SDG&E
13 proposes to retire the switch portion of the Smart Energy Program.

14 The load reduction per customer from the switches has declined over the years for
15 the following reasons:

- 16 1. The summer RA window changed from 1 p.m. to 6 p.m. to 4 p.m. to 9 p.m. in
17 2019. This significantly reduced the load impact per switch, since there is
18 less AC use in the evening to curtail.
- 19 2. TOU pricing plans were implemented during this program cycle, causing
20 customers to conserve energy due to higher prices, with the on-peak period
21 change to 4 p.m. to 9 p.m. This may have impacted the available MW since
22 customers have adjusted to not pay higher prices for electricity.

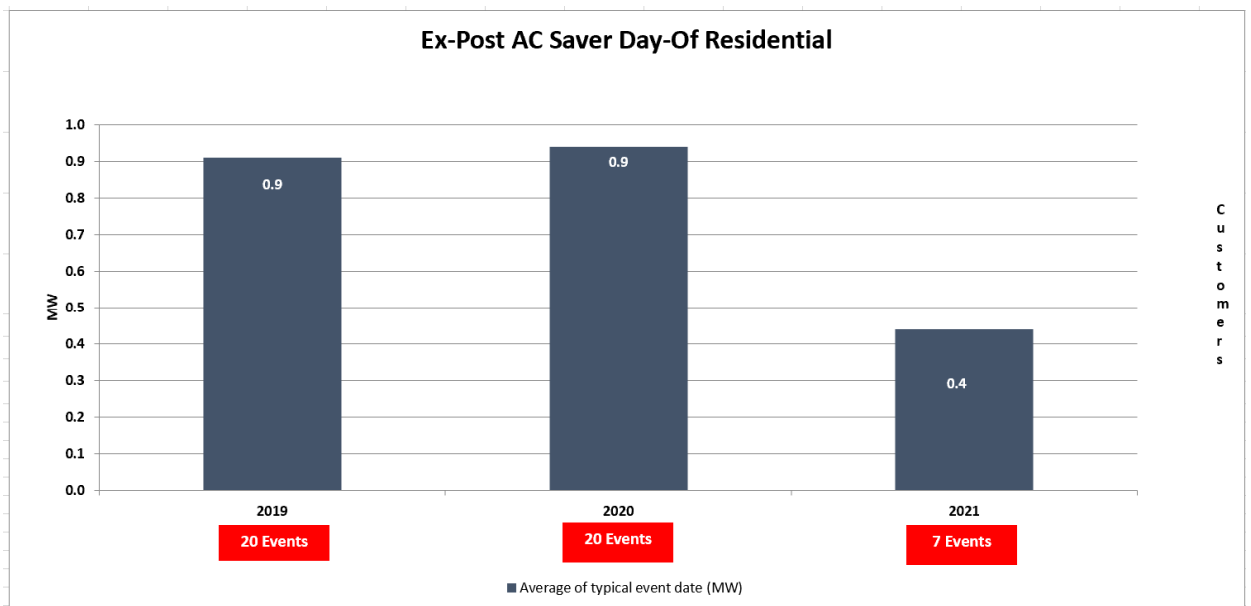
³⁹ Decision Adopting Bridge Funding for 2017 Demand Response Programs and Activities, pp. 1 and 36.

⁴⁰ A.17-01-019, Prepared Direct Testimony of E Bradford Mantz (January 17, 2017), p. EBM-8.

- 1 3. The current direct load control switches have been in field for a long time as
2 most of the existing switches were installed between 2004 and 2010. Due to
3 their age, the switches may fail. The switches are one way communication
4 devices, meaning we can signal them, but we have no way of monitoring
5 them in an automated fashion to determine if they are failing or shutting off
6 the customers' air conditioner. Since we cannot identify the customers with
7 failing switches, we cannot unenroll these customers from the program or
8 replace the switch. The result is that when switches fail, the average load
9 impact per customer from the program goes down.
- 10 4. In addition, the number of customers participating in the program has
11 declined between 2018 and 2022. SDG&E's goal for 2018-2022 was to
12 maintain the existing switches because installing new switches was cost
13 prohibitive. Over time customers move out and opt out of the program so
14 with no new customers coming overall enrollment dropped.

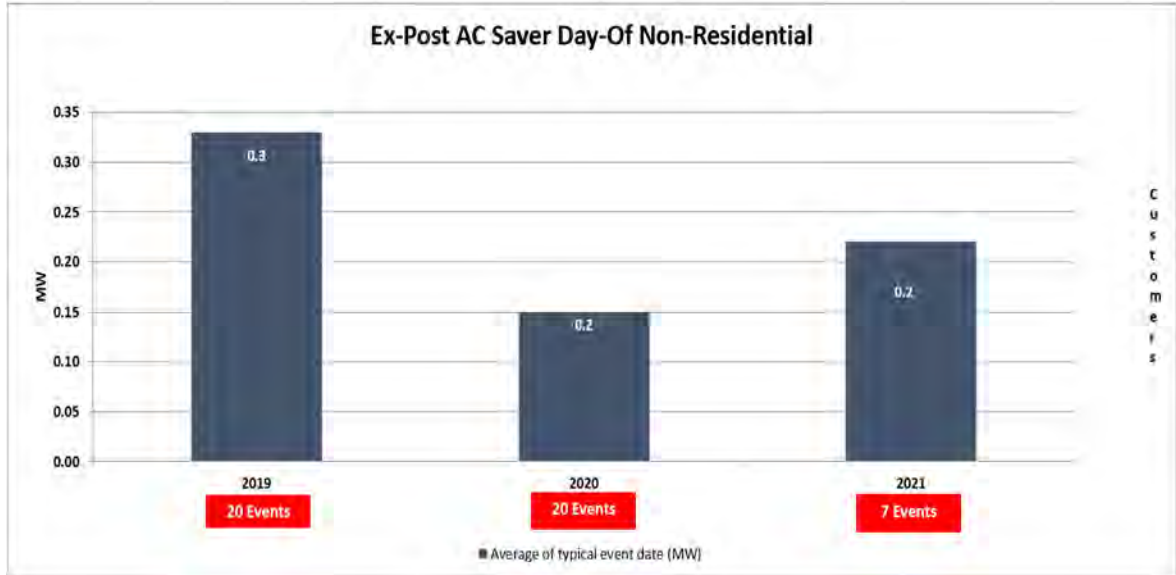
15 The graphs below show how both enrollments and the aggregate load impacts per
16 customer have dropped from year to year for both residential and commercial participants.

17 **Figure EBM-1**



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Figure EBM-2



These reductions in load impacts per device and program enrollment occurred despite SDG&E efforts to reduce program free ridership. SDG&E unenrolled low performing customers in 2017 in order to improve the cost-effectiveness of the program. These low performers were identified using smart meter data. However, events in 2017 typically occurred between 6:00 p.m. and 8:00 p.m. whereas in 2016 events had typically occurred between 2:00 p.m. and 6:00 p.m., because the program switched from a load trigger to price trigger in preparation for bidding into the CAISO market in 2018. This change in the event times offset the gains made by unenrolling low performing customers.

Growing the program again with new technology is not feasible. SDG&E issued a Request for Proposals (RFP) in 2016 for two way communicating direct load control devices. The proposal went out to approximately twelve bidders; the proposals received ranged from low \$4M to very high \$94M, and all were out of the cost-effective range.

Growing the program with new technology is also complex. SDG&E would need to fund the program to install direct load control devices to increase participation to get more

1 load reduction, which will cost approximately \$75 per device and a \$110 installation fee per
 2 device. SDG&E will also need continue to offer field services, which cost approximately
 3 \$133K to \$150K for each year and continue to contract with a third-party vendor to maintain
 4 the devices and the customer facing program administration at a cost of approximately
 5 \$537K to \$604K each year. Upgrading one-way communication devices to 2-way
 6 communication would be very costly. As mentioned above, we issued an RFP in 2016 and
 7 learned then that the costs would be exorbitant, which would presumably be even higher
 8 today.

9 SDG&E is proposing to transition customers currently participating in the direct load
 10 control switch program to thermostat enrollment or other devices. SDG&E wants to
 11 maintain customer participation in DR programs where they are viable through robust
 12 targeted marketing to our current direct load control participants. As Table EBM-5 reflects,
 13 SDG&E’s enrollments indicate that customer interest in smart communicating thermostats
 14 far outweighs the one way communicating direct load control switch.

15 **Table EBM-5**
 16 **Thermostat v. Direct Load Control Switch Enrollments**

Year	New Thermostat Enrollments	New Direct Load Control Switch Enrollments
2018	6,119	40
2019	4,742	25
2020	6,571	12
2021	3,600	22

17
 18 SDG&E plans to communicate to the existing direct load control participants
 19 numerous times in early 2024 through direct mail and email campaigns to encourage
 20 customers to enroll a thermostat or new device in the Smart Energy Program. Customer

1 surveys show that 20% of participants with a direct load control switch already have a smart
2 thermostat.

3 We will continue with a contract with our third party to support field services for
4 those customers who choose for their equipment to be removed and call center support for
5 any questions regarding the transition and operational concerns and scheduling equipment
6 removal to ensure the transition is a positive customer experience.

7 **Proposal 2: Open up the Smart Energy Program to customers with any device**
8 **that can curtail energy use during an event or control energy**
9 **storage.**

10 Currently, only customers with a device that curtails air-conditioning use are eligible
11 for the Smart Energy Program. This is because the primary goal for the program for 2018-
12 2022 was to expand the program to offer both switches and thermostats and to implement a
13 robust bring your own thermostat offer. SDG&E has achieved this goal and has set a new
14 goal for the 2024 – 2027 program cycle of expanding the program to devices that can
15 control behind the meter devices other than air-conditioners. Expanding the Smart Energy
16 Program to additional devices is key to increasing the demand response potential of
17 SDG&E's portfolio because the Smart Energy Program incentive structure and program
18 design is working well for thermostats. The Smart Energy Program is the largest supply
19 side program in SDG&E's portfolio in terms of both customer and load reduction. In
20 addition, allowing more devices to participate in the Smart Energy Program makes
21 operational sense because many signaling platforms now have built in integrations with
22 APIs of manufacturers of devices other than thermostats. Having customers enroll through
23 the same signaling platform, in the same program, with the same general incentive
24 structures, makes for a clean program implementation.

1 The residential smart home device market is also growing, and more smart
2 technologies are ready for participation in utility demand response programs than there were
3 in 2017. Others are not yet ready but may become ready during the next program cycle.
4 Some technologies that SDG&E plans to consider for program include smart plugs, water
5 heating controls, pool pump controls, and whole home devices that can control multiple end
6 uses, such as the Amazon Alexa. Not all devices will qualify for inclusion in the program.
7 Some end uses may have a low average load reduction because few are running between
8 4:00 p.m. and 9:00 p.m. However, SDG&E expects many new devices to become program
9 ready between 2024 and 2027 and is proposing to expand the Smart Energy Program so
10 customers with these devices have a way to participate in demand response.

11 The minimum eligibility requirement for a device to qualify for an enrollment
12 incentive should be that the device can either curtail an end use or control behind the meter
13 energy storage. The device may either be directly controlled by SDG&E or by the device
14 manufacturer so long as the vendor has signed the appropriate contracts with SDG&E. This
15 is in line with the primary goal of SEP which is to compensate customers who already have
16 a smart device for participating in a demand response program. To maximize participation
17 in a bring you own device program, it is important that devices that are commercially
18 available and popular with customers. It is also important not to be too restrictive as to how
19 the event is communicated to the device because new methods of communicating events to
20 customers are emerging. For example, Fort Collins Utility is encouraging customers to use
21 software called IFTTT to program their smart appliances to respond to time of use rates.⁴¹
22 SDG&E is still exploring whether this software can be leveraged for event calling.

⁴¹ https://ifttt.com/fcu_tod

1 However, if a method is found, the program devices' requirements should be flexible enough
2 to incorporate new ideas for communicating events.

3 It will not be feasible to bring every device that meets the minimum requirements
4 onto the program because it will take time for SDG&E to evaluate new technologies, sign
5 new agreements with vendors, and set up enrollment processes for each device type. In
6 addition, some devices that meet this definition may have too small a load reduction to
7 justify the costs of bringing them onto program. SDG&E plans to start out by considering
8 manufacturers that our signaling platform has existing integrations with since those will be
9 the lowest cost to onboard. After that, SDG&E will move on to evaluating a broader group
10 of devices.

11 **Proposal 3: SDG&E proposes to update the annual Smart Energy Program**
12 **residential program incentive structure to accommodate new**
13 **devices.**

14 Residential customers with thermostats in the current program receive \$20 per year
15 from the Smart Energy Program. This structure is working well for SEP customers. The
16 structure is easy to explain and implementing the current incentive did not require expensive
17 change to systems and participation is high in the program. However, \$20 per year may not
18 be the appropriate amount for all devices. Some devices may provide a significantly lower
19 load reduction than a thermostat and others may provide a higher load reduction. SDG&E
20 proposes to use the same strategy for the Smart Energy Program. The current \$20
21 thermostat payment is equal to \$50 multiplied by the average load reduction of a
22 thermostat.⁴² When SDG&E brings on additional devices, the annual incentive will be set at

⁴² The 2020 ex-post load peak day reduction of an online thermostat averages around 0.4 kW. If one multiplies \$50.00 times .40, it calculates as a \$20.00 incentive.

1 up to \$50 times the average load reduction of the devices for that customer. SDG&E may
2 but is not required to use information about the customer (*e.g.*, customer class, climate zone)
3 to determine the average load reduction expected from the device for that customer. This
4 will maintain the current successful straightforward payment structure while ensuring that
5 the incentives are in line with the load reduction potential of the devices.

6 **Proposal 4: Annual Smart Energy Program incentives should be made**
7 **available to commercial customers.**

8 The Smart Energy Program currently does not offer an annual incentive to
9 commercial customers with thermostats due to numerous considerations. First, in 2017
10 when SDG&E proposed to expand the Smart Energy Program to any device that could
11 control an air-conditioner,⁴³ the vast majority of commercial customers were not eligible
12 because rates with events (like Critical Peak Pricing (CPP)) were the standard pricing plan
13 for all commercial customers and customers could not participate in both the Smart Energy
14 Program thermostat and a rate with events.

15 Second, since most commercial customers were not eligible, the commercial portion
16 of the Smart Energy Program was expected to consist mainly of the existing customers with
17 thermostats not enrolled on a rate with events who were migrated to the Smart Energy
18 Program in 2018. These existing customers had received a generous upfront offer of free
19 thermostat and installation and had never received an ongoing incentive, so SDG&E did not
20 believe an ongoing incentive was necessary for these customers.

21 Things have changed. The percentage of commercial customers eligible for the
22 Smart Energy Program increased greatly in 2021. This occurred when the two Community

⁴³ A.17-01-019, Prepared Direct Testimony of E Bradford, Mantz (January 17, 2017), p.EBM-9.

1 Choice Aggregators ⁴⁴(CCAs) in San Diego County initiated their commodity programs
2 (CCA Programs) in which SDG&E commercial customers that were enrolled in a
3 commodity rate with a DR component like Critical Peak Pricing (CPP) were unenrolled
4 from their rate when they transitioned to CCA service, thus increasing the pool of eligible
5 customers for participation in a non-rate IOU DR program. These transitions will be
6 ongoing for the next several years as other communities join one of the CCAs. Customers
7 participating in CCA service are not eligible for SDG&E's commodity rates with events
8 because they purchase their energy from a provider other than SDG&E. Therefore, as of
9 March 2022, only 60% of commercial customers were still enrolled on a rate with events.
10 Since rates with events like CPP are not an option for CCA enrolled customers, the Smart
11 Energy Program provides commercial customers receiving CCA service a way to participate
12 and receive incentives. Another factor expected to further increase the number of
13 commercial customers eligible for SEP over time is that a rate with events will soon no
14 longer be the default rate for new small commercial customers.⁴⁵ Due to both community
15 choice aggregation and the change in the standard pricing plan for new small commercial
16 customers, we expect many more commercial customers to be eligible for SEP commercial
17 between 2023 and 2027 than there were in 2018-2020 and this supports our request to make
18 the above-mentioned program changes.

⁴⁴ The two CCA's active in SDG&E's service area are Clean Energy Alliance and San Diego Community Power.

⁴⁵ D.21-07-010, p. 30.

1 SDG&E proposes that the annual commercial incentives be calculated the same way
2 as the residential annual incentives by multiplying the average load reduction from a
3 thermostat by \$50.

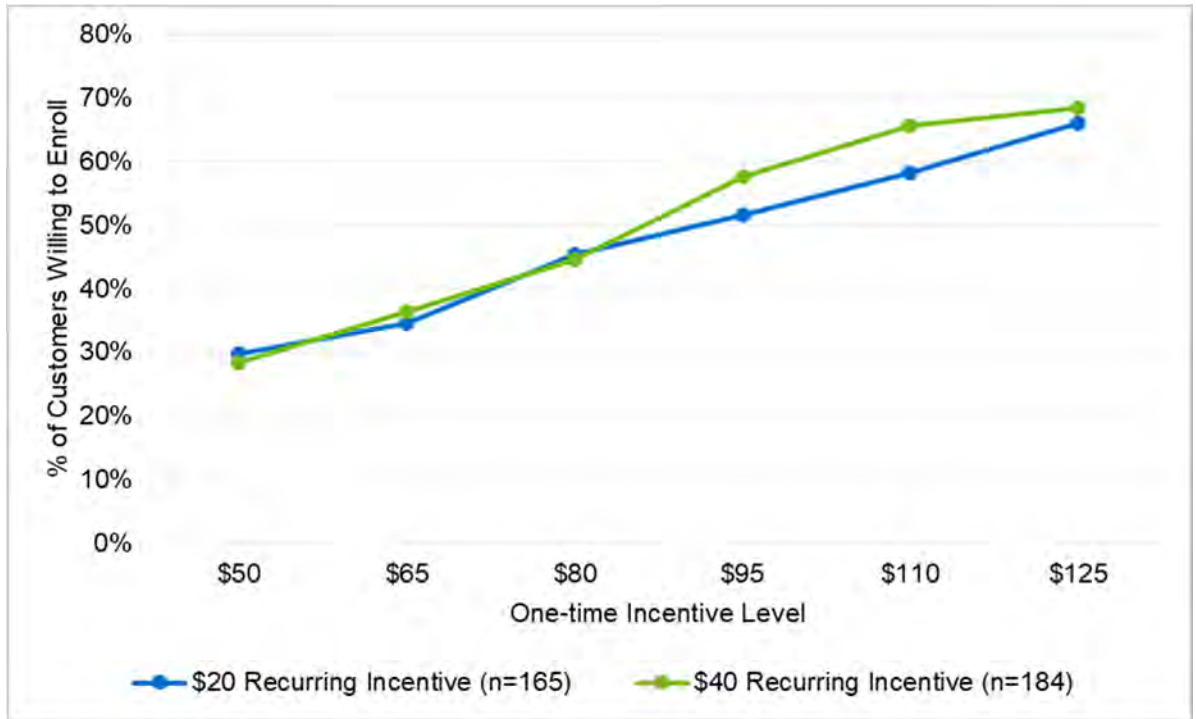
4 **Proposal 5: SDG&E proposes to add an enrollment incentive of \$200 per kW**
5 **to the Smart Energy Program.**

6 Currently, SEP customers receive an incentive payment from the TD program for
7 bringing their own thermostat into SEP and their ongoing annual incentive from the SEP.
8 However, for the reasons described in the TD section below, SDG&E is proposing to
9 eliminate the TD program, which means that SEP customer would no longer receive any
10 upfront incentive for enrolling in the program unless an enrollment payment is added to the
11 SEP program. SDG&E conducted research on customers participating in the SEP program
12 with direct load control switches to find out if these customers would be willing to move to
13 SEP thermostat once the switches were retired. The results showed that only 30% of the
14 surveyed customers stated they would be interested participating in the SEP with a \$50
15 enrollment payment. However, when customers were asked if they were interested in
16 participating in SEP with an \$80 enrollment payment, 45% of the surveyed customers stated
17 they would be interested. These results show the size of the enrollment payment has a
18 significant effect on customer willingness to participate. Raising the annual incentive from
19 \$20 to \$40 did not increase the number of customers who expressed interest in the
20 thermostat program when the enrollment incentive was between \$50 and \$80. Even when a
21 \$40 annual incentive was combined with higher enrollment incentives, the change in the
22 number of customers who said they would be interested was less than ten percent.⁴⁶ Figure

⁴⁶ Changes in the annual incentive were surveyed only among residential customers only.

1 EBM-3 below illustrates these results, indicating enrollment payments are an effective
2 method of encouraging customers to participate. Therefore, it is important to add an
3 enrollment payment to the SEP program once the TD program is retired.

4 **Figure EBM-3**



5
6
7 **Proposal 6: Consolidate the Smart Energy Program into one day-of product**
8 **when the direct load control switches are retired.**

9 Currently, the SEP has two products: (i) a day-of product for the switches (which
10 SDG&E proposes to retire), and (ii) a day-ahead product for the thermostats. Once the
11 switches are retired, SDG&E proposes that the program consist of only a day-of product that
12 will encompass thermostats as well as any new devices that join the program. Keeping only
13 a single product will prevent the program from being fragmented into smaller pieces
14 dispatched at slightly different times. Keeping all of the technologies within the same
15 product will also allow SDG&E to combine different technologies to provide a level load

1 reduction over a full four-hour event if necessary. Accordingly, SDG&E proposes that the
2 SEP consist of a single day-of product. The program should be classified as “day-of”
3 because there is no requirement for customers to be notified of the event a day in advance.

4 **3. Smart Energy Program 2024 – 2027 Budget Proposal**

5 SDG&E requests the following annual budgets for the proposed Smart Energy
6 Program.

7 **Table EBM-6**
8 **Smart Energy Program Budget**

	2024	2025	2026	2027	TOTAL
Smart Energy Program	\$2,394,101	\$2,587,462	\$3,008,520	3,122,893	\$11,112,976

9
10 The proposed budget for the Smart Energy Program includes program administrative
11 and incentives. The proposed budget for 2024 through 2027 of the Smart Energy Program
12 includes the costs of administering the continuing portion of the program and the annual and
13 enrollment incentives. In addition, the 2024 budget includes funding for the transition of
14 direct load control switches to thermostats. These transition costs include program
15 administration to support the transition from Smart Energy Program direct load control
16 switches to thermostats, as well as any costs associated with closing out the switch portion
17 of the program. SDG&E seeks the Commission’s approval to retire the air conditioning
18 switch portion of the program on December 31, 2023. SDG&E does not seek any further
19 budget in 2024 and beyond for AC Switches. Should the Commission reject SDG&E’s
20 proposal to retire the AC Saver direct load control switch program, SDG&E respectfully
21 requests the Commission authorize a regulatory path forward for SDG&E to request the
22 additional budget that would be necessary beyond 2023, if so ordered. Also, if SDG&E is

1 required to offer the switch portion of the program, SDG&E further requests that the
2 Commission remove the requirement for the switch portion of the program to be cost
3 effective and for it to be removed from SDG&E's cost-effective calculations portfolio wide.
4 SDG&E's overall portfolio cost effectiveness for its other DR programs should not be
5 negatively impacted if SDG&E is required to include the switch portion of the program in its
6 portfolio when SDG&E has requested to end that portion of the program.

7 In summary, SDG&E requests the Commission approve SDG&E's proposals for the
8 Smart Energy Program to focus on modernizing the program and increasing participation.

9 To recap, SDG&E proposes to:

- 10 1) Retire the AC switch portion of the program.
- 11 2) Expand the program to customers with devices which control end
12 uses other than air-conditioning.
- 13 3) Modify the annual incentive structure to accommodate the addition of
14 new devices.
- 15 4) Add commercial customer incentives.
- 16 5) Add an enrollment incentive of \$200 per kw to the program.
- 17 6) Consolidate the program into a single day-of product.

18 The Smart Energy Program PIP is located in Appendix A and the tariff changes are
19 located in Appendix B.

20 **E. Heat Pump Water Heaters**

21 SDG&E will enroll customers that have received the Small Generator Incentive
22 Program (SGIP) Heat Pump Water Heater (HPWH) incentive into any of SDG&E's supply

1 side DR programs.⁴⁷ SDG&E is not seeking any additional funding and will fund HPWH
2 out of approved program funding. If additional funding is needed to bring HPWR into DR
3 programs, SDG&E requests Commission approval to seek additional funding via Advice
4 Letter submission.

5 **III. LOAD MODIFYING DEMAND RESPONSE PROGRAMS**

6 **A. Emergency Load Reduction Program (ELRP) Pilot**

7 **1. Background**

8 To comply with D. 21-03-056, Ordering Paragraphs 7 and 8, SDG&E launched the
9 ELRP effective May 1, 2021, in compliance with the guidelines laid out in Attachment 1 of
10 the same decision.⁴⁸ “The purpose of ELRP is to allow the large electric IOUs and CAISO
11 to access additional load reduction during times of high grid stress and emergencies
12 involving inadequate market resources, with the goal of avoiding rotating outages while
13 minimizing costs to ratepayers.”⁴⁹ The objective of the ELRP is to determine if it is a
14 viable pathway to securing emergency resources outside of the existing market framework
15 programs. Pilot eligibility spans a variety of customer groups from large non-residential
16 customers not currently participating in market-based demand response programs,
17 residential and non-residential aggregators for existing participants in other DR programs
18 (BIP, CBP), DR bid into the CAISO, otherwise known as Proxy Demand Response
19 Resources (PDRs) and VPPs, which may include battery storage or electric vehicle fleets.
20 Subsequently, the CPUC issued D.21-12-015 which modified subgroup A.4 VPP, added

⁴⁷ D. 20-04-036, Decision Establishing Heat Pump Water Heater Requirements, COL 27 & 28.

⁴⁸ The Joint IOU’s (SCE, PG&E & SDG&E Jointly filed an AL (SDG&E AL-3750 & AL 3750-E).

⁴⁹ D.21-03-056, Section 5, p. 18.

1 subgroup A.5 which focuses on vehicle to grid integration, and subgroup A.6 which is open
2 to individual residential customers to the ELRP⁵⁰ and increased the incentive to \$2 per
3 kWh.⁵¹

4 The eight eligibility groups, as described in the decision⁵² are:

5 Group A: Select non-residential customers and aggregators that are not participating in
6 DR programs:

- 7 • A.1. Non-Residential, Non-DR Customers
- 8 • A.2. Base Interruptible Program (BIP) Aggregators
- 9 • A.3. Rule 21 Exporting Distributed Energy Resources (DERs)
- 10 • A.4. Virtual Power Plants (VPP)
- 11 • A.5 Vehicle-Grid- Integration (VGI) Aggregators
- 12 • A.6 Residential Customers

13 Group B: Market-integrated proxy demand response (PDR) resources

- 14 • B.1. Third-party DR Providers (DRPs)
- 15 • B.2. IOU Capacity Bidding Programs (CBP)

16 Participants in groups A.1 through A.5 must enroll with SDG&E before events occur
17 and must nominate a reduction for each event. This confirmed nomination forms the basis
18 of the performance element of the participation payments. There is no capacity payment and
19 no penalties for non-performance, only a payment at a rate of \$2 per kWh.

⁵⁰ D.21-12-015, Attachment 2, p. 7.

⁵¹ D.21-12-015, Attachment 2, p. 13.

⁵² D.21-12.015, Attachment 2, p. 2.

1 ELRP group A.6 is open to individual residential customers. In accordance with
2 D.21-12-015, SDG&E will automatically enroll all its CARE/FERA and Peak Day
3 behavioral program customers in the ELRP A6 group on May 1, 2022.⁵³ The A.6 subgroup
4 will also be open on an opt-in basis to other eligible residential customers. Participants will
5 receive a payment of \$2 per kWh for incremental load reduction based on actual
6 performance. The incremental load reduction is determined by subtracting the energy use
7 during the event period to the energy use of the baseline.

8 The DRPs that are in Sub Group B.1 are authorized to invoice SDG&E for their
9 reductions after the fact, two times per year.⁵⁴ ELRP events may be called from May to
10 October when a CAISO Day-Ahead (DA) or a Day-Of (DO) Notice is called.⁵⁵ Events may
11 last from one (1) to five (5) hours, with an annual dispatch limit of sixty (60) hours. Events
12 may be called any day of the week during the hours of 4pm to 9pm.⁵⁶ Courtesy notifications
13 for events will be sent to participants via text, or call.

14 Initial feedback from our customers to SDG&E's Account Executives and other
15 SDG&E ELRP staff note that customers like the ELRP's design and the flexibility to shed
16 load as well as being able to export to the grid. The ELRP also allows a customer the ability
17 to use their Behind the Meter Generation Rule 21 interconnected device as permitted.⁵⁷

⁵³ D.21-12-015, OP 28 and 36.

⁵⁴ D.21-12-015, Attachment 2, p. 19.

⁵⁵ CAISO Operating Procedures, System Emergency, Procedure 4420.

⁵⁶ D.21-12-015, Attachment 2, p. 2.

⁵⁷ D.21-12-015, Attachment 2, p. 5.

1 These same customers appear to have been participating in the ELRP when events are called
2 to the best of their ability.

3 SDG&E started enrolling customers in ELRP A.1 in late June 2021 with favorable
4 responses from our largest customers. At the end of September of 2021, SDG&E had 12
5 customers enrolled in the ELRP with a combined load reduction of 42.5 MW. SDG&E lost
6 one customer who was enrolled in the ELRP in August when they switched their
7 participation from the ELRP to the California State Emergency Program (CSEP) based on
8 the higher incentive payment.

9 For the 2022 ELRP, season SDG&E saw increased enrollments in Subgroup A1
10 which climbed from the 12 enrolled customers in 2021 to 44 enrolled customers with over
11 100 MW of incremental load reduction (ILR). Enrolled meters also jumped from ~29
12 meters to over 500 meters in 2022. Thus, reenforcing customer preference for ELRP
13 participation.

14 Customers have indicated to SDG&E that they like the straightforward proposition
15 of ELRP Group A.1., which includes:

- 16 • \$2 per kWh for verified load drop
- 17 • No penalty for non-performance
- 18 • Allowed to use their Behind the Meter (BTM) devices to either drop
19 load or export load to the grid during times of need.⁵⁸

20 SDG&E has seen its largest customers who historically have not participated in any
21 of SDG&E's existing DR programs sign up and perform in the ELRP. Due to these
22 customers participating, they are providing new incremental kWh's that SDG&E could not

⁵⁸ Export only if the customer has an existing Rule 21 export permit in place.

1 have counted on in the past. During the 2021 events, approximately 186,177 kWh of load
2 shed was achieved to support the grid. There was no participation in ELRP from any of the
3 other Subgroups A or B in 2021 so no data is available on the efficacy of these subgroups in
4 2021. In 2021 and 2022, SDG&E proactively reached out to CBP and Rule 32 DRPs who
5 are contracted to deliver DR from the DRAM to encourage them to enroll in ELRP
6 Subgroups B.1 or B.2. For 2022, we have 2 DRPs participate in Subgroup B.1 and 3
7 Aggregators participate in B.2. Also in 2022, we had participation in Subgroups A.2 – Non
8 Residential Aggregators, A.3 – Rule 21 Exporting Distributes Energy Resources (DERs) and
9 A.5 Vehicle Grid Integration (VGI) Aggregators. We anticipate enrollments in A.4 Virtual
10 Power Plants in 2023.

11 **2. Proposals for ELRP 2024-2027**

12 SDG&E recognizes the Commission’s rationale for extending the pilot though 2025
13 or longer.⁵⁹ The Commission also has ordered that “as experience is gained that the IOU’s
14 may seek to modify various aspects of the ELRP design via IOU specific or joint IOU Tier 2
15 Advice Letters on or before January 15 of each program year.”⁶⁰ SDG&E’s
16 recommendations for the ELRP for 2024 to 2027 are discussed below.

17 **a. Address Ambiguity and Potential Restrictions on Use of** 18 **Prohibited Resources**

19 While D.21-03-056 allows for the use of back up generation (BUGs) in the ELRP,⁶¹
20 this language can be somewhat confusing to participants and/or sends a mixed message as to
21 whether the participants might ultimately be penalized for using BUGs. Indeed, there seems

⁵⁹ D.21-12-015, pp. 130-131.

⁶⁰ D.21-12-015, Attachment 2, p. 20.

⁶¹ D.21-12-015, Attachment 2, p. 1.

1 to be a desire from the Energy Division (ED) following the Decision to substantially limit
2 the use of BUGs by employing reporting requirements and calling for varying dispatch
3 priorities. The reporting requirements set forth in the decision specified the following data
4 to be provided: location, type of fuel used, minimum notification time required to dispatch
5 the generator and the capacity of the generator. However, Energy Division staff asked that
6 minimum notification time and ramp time also be reported and issued a detailed reporting
7 template with additional information, some of which either doesn't exist for all participants
8 (e.g., energy output of unit) or is burdensome for the participants requested additional data
9 be collected and provided outside of the decision's requirements. Collection of this
10 information, and additional supplemental information that IOUs are requested to collect, is
11 not only administratively burdensome but some participants are hesitant to provide all the
12 data. Customers are concerned that the disclosure could open them up to additional
13 inspections, scrutiny or future penalties from the California Energy Commission (CEC),
14 California Public Utilities Commission (CPUC) or California Air Resources Board (CARB,
15 which governs the use of generators).

16 SDG&E notes these restrictions and limitations complicate and/or reduce the
17 effectiveness of the program. For example, notwithstanding the Decision's permitted use of
18 BTM resources in the ELRP, participants are still required to adhere to their current air
19 quality district permit restrictions, which may limit the ability to utilize BUGs and in turn
20 respond to ELRP events unless they receive a waiver of the air permit regulations by the
21 Governor.⁶²

⁶² The work around so far has been through Governor Proclamations, such as those issued in the summer of 2020 in August and September, and more recently on June 17, 2021, which provided

1 Also, the Governor’s “Proclamation of A State of Emergency” issued on July 30,
2 2021, authorized the use of BUGs for both the ELRP and the new California State
3 Emergency Program.⁶³ However, the proclamation only authorized the use of behind the
4 meter resources through October 31, 2021. For 2023 forward, the restrictions are in place
5 that the use of behind the meter resources considered a prohibited resource are not allowed
6 to be used during a ELRP event unless the Governor’s Office provides an emergency
7 waiver.⁶⁴ The State needs to find a better solution for approving the usage of customers
8 behind the meter resources than the current policy of issuing limited, short-term one-off
9 Executive Orders for each called ELRP DR event. Without an expanded waiver, similar to
10 what is in the Governor’s Emergency Proclamation but with a longer duration, it is very
11 likely customers in the ELRP would need to hold off using their prohibited resources as to
12 not exceed CARB’s usage limits or lower their level of participating MWs by excluding
13 their behind the meter resources. SDG&E submits that this is an extra burden that could
14 impact the Commission’s and the State of California’s desire to get every available MW
15 active to help the grid during an emergency. While SDG&E understands that some of these
16 issues may fall outside of the CPUC’s primary area of responsibility, the CPUC can take an
17 instrumental role in trying to get these changes enacted and allow the ELRP to grow and
18 provide the MW that are needed during statewide emergencies.

19 SDG&E has two suggestions for the Commission to consider:

exemptions to air quality restrictions. These proclamations tend to occur near real-time, which can limit awareness and not or allow for sufficient planning by DR participants.

⁶³ Proclamation of a State of Emergency issued by the CA Governor’s Office July 30, 2021, Section 4 (a-g).

⁶⁴ *Id.*

- SDG&E suggests that the Commission make clear whether or not behind the meter resources including prohibited fossil-fueled resources can be utilized. Customers want to avoid the imposition of restrictions or limitations whereby participants are reluctant to use them due to ambiguity, onerous reporting requirements, and/or dispatching cues which are complicated and hard to understand.
- SDG&E also proposes that the CPUC work with other agencies such as CARB and the CEC to implement the following changes: 1) allow an automatic exemption from air quality permit restrictions when an ELRP event is called to reflect the State’s reliance on these resources for grid support; and 2) remove provisions that prioritize certain resources (*e.g.*, non-prohibited resources such as solar and batteries) over other resources (*e.g.*, prohibited resources, such as fossil fueled generators), and 3) require no additional reporting requirements beyond the requirements set forth in the decision.⁶⁵

3. ELRP Budget Proposal

The ELRP was initially approved for the years 2021-2025 with the years 2023-2025 subject to review and revision in this application.⁶⁶ Later, D.21-12-015 updated the annual balancing account caps for ELRP to the amounts shown in the above table with the exception of 2024 and 2025 for ELRP A6 administration.⁶⁷ Although D.21-12-015 stated

⁶⁵ These proposals are also presented in SDG&E’s 2022 ELRP advice letter AL 4142-E.

⁶⁶ D.21-12-015, Attachment 2, p. 1.

⁶⁷ D.21-12-015, OP 21.

1 that subgroup A6 would also be in place for four years (2022-2025)⁶⁸ it only included
 2 administrative funding for 2022 and 2023.⁶⁹ Provided that the ELRP A6 administrative
 3 budget is extended to be available for 2024 and 2025, the balancing account caps included in
 4 D.21-12-015 include sufficient funding for SDG&E to continue the ELRP pilot through the
 5 end of 2025 (*see* Table EBM-7).

6 **Table EBM-7**

ELRP Annual Balancing Account Caps \$ Millions			
	2023	2024	2025
ELRP A6 Admin	\$3.0	\$3.0	\$3.0
ELRP non A6 Admin	\$3.0	\$0	\$0
ELRP Incentives (all)	\$31.1	\$31.1	\$31.1
Total	\$34.1	\$34.1	\$34.1

7
 8 **a. 2024-2025**

9 SDG&E requests the Commission approve an additional allocation of \$3.0 million
 10 dollars per year for 2024 and 2025 for administrative costs to administer the ELRP A.6
 11 Residential program through the end of 2025.⁷⁰

12 **b. 2026 -2027**

13 SDG&E supports the continuation of the ELRP and requests the Commission
 14 continue and extend all of the ELRP Subgroups through the end of 2027 and requests

⁶⁸ D.21-12-015, Attachment 2, p. 1.

⁶⁹ D.21-12-015, OP 21.

⁷⁰ D.21-12-015, Attachment 2, pp. 21 & 22 (only provided for administration for the A.6 residential group through 2023 though the incentive budget was approved through 2025).

1 approval of additional funding to cover the years 2026 & 2027 in the amount of \$71 million
2 as detailed in Table EBM-8 below.

3 **Table EBM-8**
4 **ELRP Funding request for 2026 & 2027**

ELRP 2026-2027 Budgets in \$MM			
Expense	2026	2027	Total
Incentives*	\$ 31.1	\$ 31.1	\$ 62.2
Admin*	\$ 4.9	\$ 4.9	\$ 9.8
Total	\$ 36.0	\$ 36.0	\$ 72.0

*All Subgroups

5
6 SDG&E believes that with the changes occurring in DR program design over the
7 next several years it is prudent to keep all of the eligibility subgroups active. As the
8 technology becomes more adapted and event experience is gained by SDG&E, especially in
9 Subgroups such as A.4 -VPP and Subgroup A.5 -VGI, as well as the others, continuing the
10 ELRP is important.

11 SDG&E's larger commercial customers have shown that they like participating in
12 Subgroup A.1 and bring additional kWh of incremental load shift and drop to the Grid.
13 Also, SDG&E hopes but does not know if there will be adequate electric power supply
14 resources in the event of extreme weather during times of greatest need in the summer 2025
15 through 2027; thus, extending the ELRP is prudent.

16 SDG&E requests that the Commission extend the ELRP until 2027 for SDG&E and
17 approve SDG&E's requested funding requests for A.6 for 2024 & 2025 and all of the ELRP
18 Subgroups for 2026 and 2027.

1 **IV. ENABLING TECHNOLOGY PROGRAMS AND EMERGING TECHNOLOGIES**

2 **A. Technology Deployment**

3 **1. Background**

4 SDG&E’s Technology Deployment (TD) Program provides an upfront incentive for
5 enrolling a device that curtails energy use in an eligible demand response program. Below
6 is a summary of the current program:

- 7 • TD is a “bring your own device” program (sometimes referred to as
8 “BYOD”), which means that the purpose of the upfront payment is to
9 incentivize customers to enroll a device of their choice in a demand
10 response program.
- 11 • TD offers fixed incentives to customers who enroll an eligible device
12 in a qualifying demand response program. The incentive per device is
13 calculated by taking an average load impact per device and
14 multiplying by \$100. Load impacts may come from either
15 measurement and evaluation results or engineering estimates. The
16 average load impact may be calculated either for all customers or by
17 sub-group (*e.g.*, customer class or by climate zone).
- 18 • Customers are required to enroll in either a rate with events, the AC
19 Saver Program, the Capacity Bidding Program (CBP), or a program
20 run by a third-party with a DRAM contract in order to qualify.

21 SDG&E has seen consistent growth from smart communicating thermostats (SCT)
22 via the TD program. Below is a summary of new accounts that have received incentives
23 each year since SDG&E launched the “bring your own thermostat offer” in 2017.

1
2

TABLE EBM-9
Customers Receiving TD Incentive (2017 – 2022)

Year	Number of customers who received a TD incentive
2017	6,082
2018	6,119
2019	4,742
2020	6,571
2021	3,607
2022	11,401

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Three key marketing strategies contributed to the high number of enrollments in the program. First, thermostat manufacturers have contributed to high participation by marketing the program to existing customers with smart thermostats. Second, one manufacturer increased program enrollments from their customers by five times by offering the customer the opportunity to join the program while setting up the thermostat. Third, SDG&E’s marketing team also supported the program through e-mails to customers, online advertising, and social media.

11
12
13
14
15
16

The high enrolments are encouraging because the BYOD model has far lower costs than a direct installation program.⁷¹ The TD thermostat incentive is \$50, whereas the price of a free thermostat with installation would be over \$225. Between 2014 and 2017, SDG&E installed 17,000 new residential thermostats whereas from 2017 through 2020 SDG&E issued 23,000 bring you own thermostat incentives, thus bringing in more customer at a lower cost.

⁷¹ In a direct install program, the utility pays for both the thermostat and the installation of the thermostat.

1 However, the program has experienced challenges as well. A major challenge with
2 the program is that thermostats customers purchase on their own through retail channels
3 cannot be signaled directly by SDG&E as the thermostat settings must be adjusted by the
4 manufacturer. The way enrollment and device signaling work in this situation is as follows.
5 Customers must first register their thermostat through their thermostat manufacturer's
6 website or app so that SDG&E knows that the thermostat is installed and online. SDG&E's
7 signaling platform then pulls in these pending enrollments from the manufacturer
8 application programming interface (API)⁷² and verifies customer eligibility. In order to call
9 an event SDG&E enters the event into our signaling portal which communicates the event to
10 the manufacturer through the API and the manufacturer portal adjusts the thermostat
11 settings. The signaling portal then retrieves data about the event from the manufacturer
12 portal such as how many thermostats were online during the event. This model means that if
13 the manufacturer decides to no longer participate in the program, then SDG&E can no
14 longer adjust the thermostat settings.

15 A second challenge has been explaining the complex program design to customers.
16 Currently, a customer may qualify for the TD program by enrolling in the Smart Energy
17 Program, a rate with events, DRAM, or CBP. Of these, 92% of TD customers enroll in what
18 will be the Smart Energy Program, 4% enroll in a rate with events, 4% enroll in DRAM and
19 none have enrolled in CBP. This program structure is too complex to convey briefly to
20 customers in a thermostat enrollment "app" so the brief description shown describes the
21 combined and SEP incentives. To explain the more complex program design more fully,

⁷² An API is software intermediary that allows two applications to talk to communicate with other. In the case SDG&E signaling portal talks with the manufacturer portal.

1 SDG&E includes full detail of all the options on its program website, and when customers
2 enroll in TD a program-specific welcome e-mail is sent out with the information applicable
3 to the program the customer chose to enroll in. However, the inherent complexity of the
4 program design is still a constant challenge.

5 **2. Proposed TD Program Changes**

6 SDG&E proposes to retire the TD Program in 2024. Although in theory the TD
7 program is a separate technology program, in reality it is functioning as an enrollment
8 payment for the SEP program. Eliminating TD and adding an enrollment payment to the
9 SEP program is conceptually appropriate, protects ratepayers from paying for devices that
10 cannot be signaled, and greatly simplifies the program design which will improve the
11 customer experience.

12 The TD program is not a true technology program. The purpose of a TD incentive is
13 to encourage customers who already have devices to enroll in a DR program rather than to
14 encourage customers to purchase a new device. In addition, all of thermostats currently
15 participating in the TD program must be controlled by the thermostat manufacturer, they
16 cannot be controlled directly by SDG&E. These features are out of line with a traditional
17 technology program which incentivizes customers to install new technology that can be
18 directly signaled by the utility. However, these features make sense for an enrollment
19 payment to the SEP program.

20 The current program design in which TD customer can participate in either SEP, a
21 rate with events, CBP, or pilots not subject to cost effectiveness (*e.g.*, DRAM) is also too
22 complicated and causes issues. Given that the device settings can only be adjusted by the
23 manufacturer allowing customers to meet the eligibility requirement for a TD incentive by
24 participating in third-party programs (as contracted DRAM resources), it is not a good use of

1 ratepayer funds and creates a confusing customer experience. If the aggregator or third
2 party does not have a contract in place with the manufacturer, then they will be unable to
3 adjust the device settings in which case the customer will not be participating in a demand
4 response program using their technology. If the third party has an agreement with the
5 manufacturer, then different issues arise. The thermostat manufacturers have stated that
6 their automated platforms do not allow the same thermostat to be enrolled simultaneously in
7 two conflicting demand response programs in order to prevent two different companies from
8 sending conflicting commands to the same thermostat.⁷³ So, if the customer enrolls through
9 the third-party thermostat portal the customer cannot then enroll in SDG&E's thermostat
10 portal so that SDG&E can verify that the thermostat exists and is online. From a customer
11 perspective, having to apply with both the third party and SDG&E to get the full incentive
12 available is cumbersome and confusing. In addition, third parties receive a capacity
13 payment from SDG&E with the understanding that they are responsible for any incentives to
14 the customer. When SDG&E pays a full incentive to the third party and an incentive to the
15 customer, that results in an overpayment. Customers deserve a simple, straightforward
16 program enrolling structure in which they enroll either or SDG&E or a third party but not
17 both.

18 As SDG&E expands this program to additional devices, it is possible that some
19 controls eligible for the program will be able to communicate through an open standard. In
20 this case some of the problems with allowing customers participating in CBP or DRAM to
21 receive a TD incentive listed above would not apply. However, offering customers the
22 opportunity to participate in numerous program options still makes the program difficult to

⁷³ OEM Terms and Conditions of Service.

1 explain to customers. Many customers now enroll in the program through a device app.
2 There is not a lot of space on a smart phone to explain a complicated program design. In
3 one case, a manufacturer built the program enrollment process into their product initial set
4 up process, which increased program participation tremendously. However, although a link
5 to the SDG&E program website with full program information is made available, the
6 messaging within the app focuses solely on the combined TD/SEP incentive as anything else
7 would be too complex to explain. In order to maximize program participation SDG&E must
8 offer straightforward program designs that are in line with modern program enrollment
9 methods. Therefore SDG&E proposes to eliminate TD as a separate program and to add an
10 enrollment payment to the SEP program.

11 **B. Residential Smart Communicating Thermostat Program (SCT)**

12 D.21-12-015 directed all three IOUs to offer a new Smart Communicating
13 Thermostat (SCT) program.⁷⁴ The decision included the following description of the
14 program:

15 The decision authorizes a budget of up to \$22.5 million in technology incentives
16 (\$75 per measure) to develop a limited, two-year Residential (SCT) program for 2022-23 to
17 incentivize the installation of up to 300,000 SCT in hot climate zones (Climate Zones 9, 10,
18 11, 12, 13, 14, and 15). This program will be run statewide within each IOU's service
19 territory, and the IOUs may request up to an additional 10% of each IOU's proportional
20 share of the technology incentive budget for administrative costs. Fifty percent of the
21 technology incentive budget, or up to \$11.25 million, will be available to third-party DRPs
22 to provide rebates through third-party demand response programs. Third-party DRPs should

⁷⁴ D.21-12-015, OP 42.

1 have competitively equal access to the rebates as the IOUs. This program will require
2 customer pre-enrollment in a market integrated supply-side Demand Response program.
3 Eligible market integrated programs are Demand Response Auction Mechanism, Smart
4 Energy Program, Capacity Bidding Program-Residential, and AC Saver. The technology
5 incentive amount will be up to \$75, limited to the full cost of the SCT. Prior to incentive
6 payment, the IOUs must verify installation of an eligible thermostat and enrollment in an
7 eligible IOU or third-party program.⁷⁵

8 This program has not yet launched so no data is available to evaluate the efficacy of
9 the program. SDG&E does not recommend continuing the SCT program beyond 2023 for
10 Smart Energy Program customers since it would be duplicative of the SEP enrollment
11 incentive. There is not enough information from the CBP residential plot yet to determine
12 whether or not open up the CBP program to residential customers so it is premature to
13 determine whether or not SCT should be made available to residential CBP participants.

14 SDG&E has not included any budget request for SCT for 2024 to 2027 since its
15 request is to not offer the program, nor does it offer any program modifications. If the
16 Commission denies SDG&E's request to retire SCT as proposed, then SDG&E requests that
17 the Commission provide a regulatory path for SDG&E to seek cost recovery for additional
18 funding that would be needed to continue the program past 2023.

19 **C. Technology Incentive Program (TI)**

20 **1. Background**

21 SDG&E's Technology Incentives (TI) Program offers incentives for the purchase
22 and installation of qualified demand response measures that provide verified, dispatchable,

⁷⁵ D.21-12-015, Attachment 1, p. 13.

1 on-peak load reduction at customer-owned facilities. Eligible customers can receive up to
2 \$200 per kilowatt (kW) of verified, dispatchable, fully automated on-peak load reduction.

3 The total of the earned incentive is limited to 75% of the total project cost.

4 The TI program has been in existence since 2006 and is often called “Auto DR”
5 across the other IOUs’ portfolios. Several changes to the program design have been
6 implemented over the years to spur contractor and customer participation with little to no
7 effect. These changes have made the program relatively unattractive to contractors and
8 customers despite aggressive marketing campaigns and messaging over the years. As a
9 result, SDG&E plans to sunset its TI program on December 31, 2023. It is worth noting that
10 if the TI program were subject to cost effectiveness tests it would have been found to be not
11 cost-effective.

12 During the 2015-16 program cycle, 99% of incentive payments were assigned to
13 third-party contractors⁷⁶ and in 2017, the program began making the first of the 40%
14 performance payments⁷⁷ resulting from 2015-2016 projects. During this time, it was
15 discovered by SDG&E program staff administering the program that the majority of
16 customers were either underperforming⁷⁸ or not performing at all and therefore were not
17 eligible for their final 40% performance payments.

⁷⁶ Customers had the option to assign their incentive checks directly to the contractor that supplied and installed the equipment.

⁷⁷ At the end of the first year of program performance customers are eligible to receive the remaining incentive payment (40%) based upon their verified first year event performance.

⁷⁸ Customer incentive payments are based upon their verified and approved load shed test. It is expected that they perform at the same level during the first year’s performance or risk losing their second payment and if they grossly underperform, risk having their initial (60%) payment clawed back as well.

1 Contractors stated that program was no longer profitable to their companies and as a
2 result became disengaged and the program suffered greatly. Customers on the other hand,
3 were used to getting their EMS systems at low or no cost through the program.

4 Contributing factors that led to contractors leaving the program.

- 5 • Contractors did not want to be responsible for the customers' event
6 performance.
- 7 • Lowered incentive amount from \$300/kW to \$200/kW was not
8 attractive.
- 9 • Claw back risk and penalties for non-performance by customer.
- 10 • Some contractors waited for over 2 years for their final payments and
11 then were still not paid for balance of job because of non-performance
12 by the customer.

13 The following provides a summary of some of the changes to the TI program
14 instituted since 2017 and results.

15 **2017 (Bridge Year):**

16 The IOUs request to reinstate the 100% one-time payment with approved load shed
17 test was denied by the Commission. Instead, the Commission ordered (D.16-06-029) the
18 IOUs to lower incentive to \$200/kW, pay up to 75% of Total Project and continue to utilize
19 the 60%/40% incentive payment structure that pays 60% when the load shed test is
20 completed and the remaining 40% incentive upon completion on first year performance.
21 Incentives were payable only to the customer (no third-party payments are allowed) and
22 despite heavy SDG&E marketing/promotion of the program, no new projects were received
23 in 2017.

1 **2018-22:**

2 The 2018-2022 TI program design was the same as 2017, however in 2018, the
3 market began transitioning towards cloud-based systems that are less expensive, nimbler and
4 more responsive to building conditions than traditional EMS systems.

5 2018 saw no new applications for TI. However, later in the year SDG&E began
6 working with one contractor targeting Small and Medium Business (SMBs) customers
7 (typically national chain accounts) with their cloud-based system and although the projects
8 were relatively small in size (kW) compared to the sizes typically seen with previous TI
9 applications, the contractor noted that any incentive (even small ones) were well received by
10 the customer. To this day they continue to be the main contractor participating in the TI
11 program and have since become an aggregator in the Capacity Bidding Program (CBP) as a
12 result.

13 **Customer/Contractor Feedback:**

14 In 2019 SDG&E contracted with Travis Research to conduct an independent
15 research study on the TI Program titled “Demand Response Technology Incentives (TI)
16 Program Qualitative Study.” The study provided a summary of recommendations for
17 consideration by program management for future program changes.

18 Cold calls made to unassigned accounts by SDG&E’s Business Contact Center
19 (BCC) representatives received the following comments from small and medium business
20 customers:

- 21 • Not interested, I have too many other things going on now.
- 22 • How does it reduce my energy bill each Month?
- 23 • Are you really SDG&E or a sales agent?

1 Furthermore, SDG&E Account Executive meetings with customers received the
2 following feedback:

- 3 • Do not want to participate in a DR program that has penalties. They
4 will curtail voluntarily if able during a DR event.
- 5 • Hotels comment that a DR program would not work for them as the
6 customer experience is their priority.

7 The following list of marketing tactics has been implemented over the years in an
8 effort to increase program participation.

9 **2017 (Bridge Year):**

- 10 • Reviewed SDG&E CAP audits for potential opportunities.
- 11 • Cold calls to over 500 small and medium unassigned commercial
12 customers.
- 13 • Account Executive face to face meetings with large, assigned
14 accounts
- 15 • Refresh of Trade Pros fact sheet and article
- 16 • Trade Pros Publications – TI Article

17 **2018:**

- 18 • Monthly Trade Pros training seminars at SDG&E's Energy
19 Innovation Center
- 20 • Produced Technology Incentives video
- 21 • Content packages for the local municipalities and trade publications
- 22 • Account Executive face to face meetings with large, assigned
23 accounts

1 **2019:**

- 2 • Monthly Trade Pros training seminars at SDG&E’s Energy
- 3 Innovation Center
- 4 • Linked in email campaign
- 5 • E-Newsletter email blast campaign
- 6 • Demand Response Technology Incentives (TI) Program Qualitative
- 7 Study (Travis Research)
- 8 • Technology Incentives web page redesign
- 9 • Demand Response “Save the Day” campaign.
- 10 • Account Executive face to face meetings with large, assigned
- 11 accounts

12 **2020-21:**

- 13 • Digital Marketing Tactics with emphasis on TI.
- 14 • Global Coronavirus Pandemic severely hampered outreach efforts.

15 Since 2019, SDG&E has only had one contractor submitting the majority of

16 applications. The resulting projects (typically chain accounts) barely meet the minimum

17 requirements for program participation and contribute little energy savings. Relying on one

18 vendor to drive the program is not prudent.

19 In 2020, during the COVID-19 pandemic, the program received several application

20 cancellations due to business closures. These projects were part of the restaurant and

21 hospitality sectors that were hit hard by the pandemic and the restrictions placed on

1 businesses by state and local authorities due to COVID-19⁷⁹ mandates and restrictions.
 2 However, the applications received through the end of 2022 have been cancelled at the
 3 customer/Aggregators request.

4 In Q3 2021, SDG&E saw the majority of the COVID-19 restrictions lifted, allowing
 5 businesses to reopen and contractors to get back to work. However, it has not translated into
 6 an influx of new projects. The 67 applications received in 2021 were from an energy
 7 consultant looking to leverage project dollars (incentives) in their quest to secure projects
 8 from customers that have yet to be realized. SDG&E has received zero new projects to date
 9 in 2023.

10 **Table EBM-10**
 11 **Technology Incentives Applications received vs. Projects Completed**

	2017	2018	2019	2020	2021
Application received (Including rollover from previous year)	0	0	48	45	67
Projects completed	0	0	7	0	0

12
 13 **Successes and Challenges:**

- 14 1. Sporadic program participation by contractors and customers over the years.
 15 a) With a limited number of projects completed, there is little
 16 contribution to other DR programs.
 17 2. Poor customer performance.
 18 a) Average customer first year performance is less than 50% of original
 19 committed load shed test results.
 20 b) Since 2017, TI projects have contributed less than 75kW to the DR
 21 portfolio.

⁷⁹ Coronavirus disease (COVID-19) is an infectious disease caused by the SARS-CoV-2 virus It is often referred to as COVID-19. See https://www.who.int/health-topics/coronavirus#tab=tab_1

1 3. No customer retention in demand response programs after the 3-year program
2 participation requirement is met.

3 4. Budget spend: (2017 – July 2021).

4 a) Incentives paid: \$6,300.00

5 b) Administrative spend: \$1.3M

6 **2. Proposed TI Program Changes**

7 SDG&E is requesting to retire the Technology Incentive Program for the above-
8 mentioned reasons. The decline of contractor participation over the years and inconsistent
9 customer event performance are key indicators of a mature program that is ready to be
10 retired. Should the Commission reject or modify in any way SDG&E’s proposal above to
11 retire the TI program, then SDG&E respectfully requests the Commission to authorize a
12 regulatory path forward for SDG&E to request the additional budget that would be
13 necessary to manage and promote the TI program in 2024 through 2027 since SDG&E is not
14 seeking any budget for TI in this application.

15 **D. Emerging Technology Demand Response (ET-DR) Program**

16 **1. Background**

17 The Emerging Technology Demand Response (ET-DR) Program focuses on the
18 identifying and evaluating emerging innovative technologies and strategies, a challenging
19 and increasingly important area of demand response. The ET-DR Program focuses on
20 demand response of the future for the San Diego region while also helping the State address
21 challenging grid conditions. Given in today’s evolving environmental conditions and during
22 critical supply challenges, the opportunity for developing creative, innovative, flexible and
23 cost-effective demand response solutions has never been greater. The ET-DR Program staff
24 are energized and will continue to research companies and more complex technologies that
25 promise significant demand reduction potential in the short or mid-term time horizon.

1 Beyond the addition of smart devices and systems that provide the foundation a network of
2 flexible BTM resources to support DR of the future, the ET-DR Program will also seek to
3 identify technologies that complement the changes throughout our core Demand Response
4 Program portfolio such as Auto Demand Response, Integrated Distributed Energy Resources
5 (IDER) proceeding, Microgrids and Virtual Power Plants. The Portfolio is centered on
6 whole facility smart technologies that enhance ratepayers' ability to respond to changes in
7 demand conditions that will help address supply challenges. The ET-DR program will
8 explore and investigate how dynamic price signals combined with smart technologies and
9 communication networks can be used in concert with dynamic price signals to enable and
10 motivate bundled customers to provide grid-benefits when needed. At a minimum, each
11 evaluation project will address the following:

- 12 • The technology's or strategy's overall merits.
- 13 • Applicability to existing SDG&E customer programs.
- 14 • Benefits to both demand reduction and energy efficiency were applicable.
- 15 • Possible adoption barriers.
- 16 • Cost-effectiveness.
- 17 • Risks.
- 18 • Collaboration with the other California IOUs; and
- 19 • Recommendations for on the utilities' support and future involvement
20 in and in support for demand response technologies and strategies.

21 The ET-DR 2018-2022 program cycle was very successful in the types of projects
22 that were able to be initiated and completed during the program budgeted period. Some of
23 the technologies researched throughout the 2018-2022 program cycle included: Smart Voice

1 Assistant device, a time of use (TOU) messaging app and device, a Distributed Energy
2 Resources (DER) Data Analytics tool to identify customers for Demand Response
3 participation, an Electric Vehicle Charging impact study, a Thermal Storage for
4 Refrigeration project and a Whole Home DR study.

5 The DER Data Analytics tool has helped identify non-residential customers who are
6 most likely to benefit from participating in DR programs as well as by leveraging distributed
7 energy resources such as solar and battery. The tool will help the DR team target market
8 customers to encourage more participation in DR programs.

9 SDG&E recently initiated an exciting new Virtual Power Plant project that was
10 completed and active in 2022. SDG&E plans to build on the lessons learned and do
11 additional related research on Virtual Power Plants in 2023-2027. The ET-DR team
12 continues to work with vendors to expand our existing Virtual Power Plant that will include
13 a variety of devices across several customers. Also, SDG&E is focused on expanding our
14 VPPs to other parts of our service area and conduct additional testing. A Virtual Power
15 Plant has the potential to grow into a vast collection of devices that could potentially be
16 spread out across the SDG&E service area and serve as a grid resource for DR events as
17 well as other grid needs. This type of project requires significantly more funding to not only
18 install the various devices installed at customers' premises but also to ensure the devices can
19 be signaled on a third party developed platform and controlled by SDG&E. This is an
20 example of a more complex and technical project that requires additional funding due to the
21 extensive coordination with external stakeholders and focus on multiple types of devices
22 installed at customers' premises. The menu of devices offered will vary by customer based
23 on their potential to participate in the Virtual Power Plant and could include Smart

1 Thermostats, Water Heating Controllers, Electric Vehicle Charging Controllers and battery
2 storage.

3 For more detailed information on these projects, please see the Demand Response
4 Emerging Technology SDG&E Semi-Annual Reports, submitted to the Commission, dated
5 March 31 and September 30 of each year within the program cycle.⁸⁰

6 **2. ET-DR Proposal for 2024-2027**

7 The ET-DR proposal for 2024-2027 is a 77% budget increase from the 2019-2022
8 years approved in the 2018-2022 filing. Additional funding is needed to transition from the
9 2018-2022 program cycle where most evaluations have been focused on single devices to
10 the 2024-2027 program cycle where SDG&E desires to study more complex and technical
11 technologies that support DR of the future. SDG&E plans to identify and evaluate more
12 innovative and flexible demand response solutions that may include but not be limited to
13 IDER, Microgrids, Virtual Power Plants and whole home/facility controls that could
14 potentially be integrated with dynamic or real-time pricing. The ET-DR Program believes
15 the additional funding will help ensure the ability to evaluate more innovative and technical
16 solutions that stand to provide greater grid benefits and are aligned with the Demand
17 Response Portfolio per the CPUC's guidance. The expected outcome for this approach is
18 the execution of up to 4 to 6 projects per year based on the 2018-2022 project history.

⁸⁰ See A.11-03-001. These reports are submitted as compliance filings pursuant to D.12-04-045, pp. 145-146 and 225, OP 59.

1 **3. ET-DR Proposed 2024-2027 Budget**

2 **Table EBM-11**
3 **ET-DR Budget**

	2024	2025	2026	2027	TOTAL
ET-DR	\$1,250,000	\$1,250,000	\$1,250,000	\$1,250,000	\$5,000,000

4
5 This increased budget will allow the ET-DR Program to function as stated above,
6 while keeping the minimum necessary staff to procure and execute DR projects that are
7 aligned with the DR portfolio objectives and the State’s increased focus on more significant
8 demand reduction tactics and strategies.

9 The updated Pilot Implementation Plan (PIP) for ET-DR is included in Appendix A
10 of this testimony.

11 **V. PILOTS**

12 **A. New Pilots - Electric Vehicle Demand Response Pilot (EVDRP)**

13 **1. Background**

14 As of 2020, San Diego County has ~2,477,631 vehicles. Of that number, 51,616 are
15 electrified with 32,057 battery electric vehicles (BEV), and 19,559 Plug-in Hybrid Electric
16 Vehicles (PHEV).⁸¹

17 In California’s effort to fight against climate change, all new car and passenger
18 trucks sold in California will be required to be zero-emission vehicles by 2035. Not
19 surprisingly, the number of electric vehicles in California and in San Diego is expected to
20 grow substantially.

⁸¹ California Energy Commission Zero Emission Vehicle and Infrastructure Statistics Veloz’s sales dashboard, as viewed on 6.30.2021 at the website of the California Department of Motor Vehicles (Zero Emission Vehicle and Infrastructure Statistics (ca.gov)).

1 Most electric vehicles are charged at home. When plugged in, Level 2 chargers draw
2 roughly 6 kW and Level 1 chargers draw between 1.5-2.0 kW of electricity over multiple
3 hours. However, electric vehicle loads are flexible and can be scheduled to charge during
4 off-peak hours.

5 SDG&E's main strategy for managing electric vehicle loads to date has been to
6 encourage electric vehicle owners to sign-up for time of use rates (TOU) designed for
7 electric vehicles. With electric vehicle TOU rates, SDG&E does not directly manage
8 vehicle charging. Instead, the TOU rates encourage customers to shift load from higher
9 priced peak hours to lower priced off-peak and super off-peak hours. A TOU rate is
10 considered "passive" demand response, leaving the control completely to the customers to
11 take actions. Moreover, the TOU rates generally do not isolate the EV loads but apply to the
12 whole home.

13 As of Q3 2021, SDG&E estimated there are 48,446 residential light duty EV⁸² in
14 SDG&E's service territory. There are approximately 24,445 residential customer accounts
15 enrolled on TOU rates designed for electric vehicles.⁸³ However, about 50% of the
16 registered residential EVs in SDG&E's service area are not currently participating on an EV
17 TOU rate.

18 Although SDG&E has implemented default TOU rates for residential customers,
19 there are multiple advantages to having EVs directly respond to prices and active DR control
20 signals rather than the passive response to TOU rates. An example is the shifting of

⁸² SDG&E internal Clean Transportation Q3, 2021 data.

⁸³ *Id.*

1 charging times to the lower priced Super Off-Peak hours from the On Peak hours of 4 p.m. -
2 9 p.m.

3 **2. Need for an EV DR pilot**

4 An EV DR pilot can explore the demand response potential benefits that EV TOU
5 rates do not deliver on their own. In specifics:

- 6 • It enables SDG&E to manage charging times for EVs that have not
7 signed up for EV TOU rates and to test acceptance.
- 8 • Testing to see if we can further automate and deliver more flexible,
9 reliable, and predictable load reductions from customers who elect to
10 sign up for EV TOU rates.
- 11 • It provides SDG&E the ability to test the ability to test a staggering
12 EV charging strategy to minimize the effect and stress on the grid
13 from all of EV loads coming onto the grid at once during off peak
14 hours.
- 15 • It enables SDG&E to build the control strategy to adjust EV charging
16 in response to CAISO day-ahead market prices.
- 17 • It also provides the option to inform customers to use EVs to absorb
18 and store excess solar energy.
- 19 • The load management technology also enables better feedback to
20 customers about their EV charging patterns and the energy and
21 emissions savings from using electricity as a fuel source instead of
22 fossil-based fuels.

1 There is limited data to understand charging behavior for customers who are not on
2 an EV TOU rate (*i.e.*, homes on a default TOU rates or tiered rates). It is important to assess
3 and analyze EV charging pattern data to determine the best way to utilize EVs for grid
4 services while maintaining a positive customer experience.

5 As part of the pilot, SDG&E will test the use of direct communication with vehicle
6 on-board computers, known as telematics, for gathering information on the electric vehicle
7 charging, vehicle miles driven, location of charge (home, work, public charging), speed of
8 charge, timing of charging, and other details. The data will be used to produce EV load
9 profiles and analyze charging patterns with and without load management. The EV DR pilot
10 will encourage customer enrollments and allow SDG&E to study charging patterns in order
11 to design optimization strategies that are best suited to different customer behaviors and
12 inform future program design.

13 There are three main approaches utilizing EV to respond to demand response events
14 were identified for EV customers in the market:

- 15 1. Use TOU rates to incentivize customers to shift charging to off-peak
16 periods.⁸⁴⁸⁵
- 17 2. Work with charging manufacturers to recruit existing sites and manage
18 charging by adjusting or reducing energy use during demand response
19 events.⁸⁶ and

⁸⁴ SDG&E's EV TOU rates: <https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans>

⁸⁵ Green Mountain Power Rate 72: <https://greenmountainpower.com/wp-content/uploads/2020/09/Rate-72-EV-Off-Peak-Charging.pdf>

- 1 3. Use automaker original equipment manufacturer (OEM) telematics to
2 directly communicate with vehicles, access charging data,⁸⁷ and actively
3 manage charging during demand response events.⁸⁸

4 **3. EV DR Pilot Overview**

5 With the explosive growth of EVs and the increased amount of charging stations
6 installed at residential homes,⁸⁹ SDG&E proposes an EV focused demand response pilot that
7 offers customers the options to optimize charging, receive incentives to offset their energy
8 bill and to participate in demand response events that provide benefits to the grid.

9 The pilot will last for 3 years (2024-2026) with the following main objectives:

- 10 1. Demonstrate the ability of residential EVs to be a reliable Demand Response
11 resource.
- 12 2. Demonstrate the ability of EVs to increase load between 10am-2pm in Spring
13 season to absorb excess solar generation.
- 14 3. Determine whether charge start times can be staggered to manage loads and
15 avoid all vehicles coming online at the same time.
- 16 4. Validate the program design, incentive structure and cost effectiveness

⁸⁶ Eversource Energy <https://www.eversource.com/content/ema-c/residential/save-money-energy/clean-energy-options/electric-vehicles/ev-charger-demand-response#:~:text=EV%20Home%20Charger%20Demand%20Response%20You%20can%20earn,of%20peak%20demand%2C%20when%20others%20are%20using%20more.>

⁸⁷ BGE EV Pulse: <https://landing.bge.ev-pulse.com/>

⁸⁸ National Grid: <https://www.nationalgridus.com/MA-Home/Connected-Solutions/EV-and-PHEV-Program>

⁸⁹ Governor Newsom's Zero-Emissions by 2035 Executive Order N-79-20, California Air Resources Board <https://ww2.arb.ca.gov/resources/fact-sheets/governor-newsoms-zero-emission-2035-executive-order-n-79-20>

1 SDG&E’s EV DR pilot is designed to offer more options to the customers and gather
2 best practices to design a program with the highest chance of success.

3 **4. Proposal for 2024-2026 Residential EV DR pilot**

4 **a. Solicit EV control platform vendors**

5 SDG&E plans to offer customers the option to manage vehicle charging by either
6 communicating directly with the vehicle on-board computer or by controlling the vehicle
7 charger. SDG&E will issue a request for proposal (RFP) for one or two Original Equipment
8 Manufacturer (OEM) aggregators to handle customer enrollment, signaling DR events,
9 monitor and optimize charging during DR seasons, provide required data for EM&V and
10 meet all of SDG&E’s IT system and cyber security requirements.

11 The selected vendor will be responsible for dispatching participating electric vehicles
12 per SDG&E’s instruction, and therefore will need to be able to communicate with the
13 participating chargers and vehicles. As a result, only customers with compatible technology
14 for the selected vendor(s) will be eligible to participate in the pilot. To ensure that the pilot
15 can reach as many EV owners as possible, SDG&E intends to take into consideration in the
16 RFP process the total number of potentially controllable vehicles that each vendor can reach.

17 To ensure premium experience, SDG&E will request vendors to provide options for
18 customers to opt out of the event at any time. The pilot will request the vendor to allow
19 customer to set up minimum battery threshold to make sure when customers are
20 participating in DR events, their battery capacity will be above the threshold that customer
21 set based upon their own comfortable level.

22 **b. Marketing**

23 SDG&E will design marketing strategies to engage local EV customers and
24 communities. SDG&E will utilize the digital and traditional marketing strategies and host

1 customer education events where applicable. SDG&E will design a new website landing
2 page for EV customers to enroll in the pilot directly.

3 **c. Summer DR season offering**

4 Summer DR season lasts from May 1 to October 31. Between 30-60 events per
5 season can be called with each event typically lasting 2-3 hours for non-holiday weekdays
6 and weekends, between 4 p.m.- 9 p.m. If needed, however, events could be up to five hours
7 in duration. When an event is called, the customer's charging will be paused or slowed
8 down for the event. Customers will be provided options to opt out of an event at any time.

9 **d. Spring DR season offering**

10 SDG&E proposes adding a Spring DR season which would encompass March and
11 April to this pilot to align with SDG&E's existing EV TOU rates for the winter super offer
12 peak period to incentivize EVs to charge from 10 a.m. to 2 p.m. when there is excess solar
13 energy on the grid. The customer will need to give SDG&E permission to receive
14 notifications to maximize the charging from 10 a.m. to 2 p.m. SDG&E will send day ahead
15 notification to the customers to opt in an event. The customer will also receive an alert 30
16 minutes before the event starts and they can opt out of the event at any time.

17 **e. Incentive structure and targeted participants**

18 SDG&E proposes to target 1,000 EVs for this 3-year pilot. To test out the incentives
19 structure to maximize customer enrollment, the pilot will offer three (3) incentive options:

- 20 • Option 1. \$16 monthly incentive
- 21 • Option 2. \$100 enrollment and \$100 annual incentive
- 22 • Option 3. \$200 enrollment and \$100 annual incentive with 2-year
23 commitment if they remain enrolled and participate in the Pilot.

1 If the customer does not respond to event signals, then the customer would forfeit the
2 \$100 annual incentive that they would have earned.

3 The plan is to test three incentives options for the customers. If an option doesn't
4 have enough participation for evaluation purposes, SDG&E will consider recruiting
5 customers for the specific option in order to gather enough participation data. The pilot will
6 also target EV customers that are on different rates including EV TOU rates, default TOU
7 customers and tiered rate customers to evaluate the load reduction potential.

8 Below is a matrix to measure the success of each incentive model:

- 9 1. Average time needed to sign up a customer
- 10 2. Customer participation
- 11 3. Customer drop-off rate

12 The incentive will be paid as a bill credit or incentive rebate. There will be no
13 penalty for customers who opt out of DR events, other than forfeiting the annual incentive.

14 **5. Budget Proposal for EV DR Pilot**

15 SDG&E requests a budget of \$3.3 million over the three years for the residential EV
16 DR pilot. The table below includes the requested pilot budget for administration and
17 incentives. SDG&E will administer a robust E&MV evaluation to evaluate the pilot for
18 possible enhancements and proposals to become a program in the 2028-2032 Funding
19 Cycle.⁹⁰

⁹⁰ Prepared Direct Testimony of Lizzette Garcia -Rodriquez, Chapter 4B.

1
2

**Table EBM-12
EV DR Pilot Proposed Budget:**

	2024	2025	2026	2027	TOTAL
Electric Vehicle Demand Response Pilot	\$933,366	\$1,070,432	\$1,329,372	n/a	\$3,333,171

3
4

B. New Pilot – Battery Storage DR Pilot

5

1. Background

6 Battery storage in SDG&E’s territory has grown substantially in recent years, with
7 the current number of residential interconnections surpassing 62MW of installed capacity at
8 over 9,100 premises.⁹¹ The growth of residential battery installations has grown at an
9 annual rate of 150%.⁹² The vast majority – approximately 97% - of these installations have
10 occurred at sites that also have solar installed on the premise.⁹³ Further, approximately 5.5%
11 of all new residential solar installations are concurrently installed with battery storage.⁹⁴

12 With the high penetration of solar installations at residential sites in SDG&E’s territory,
13 there is substantial room for future growth in battery storage for this customer segment.

14 Residential battery installations are an attractive end-use for demand response;
15 however, SDG&E currently does not have a residential or commercial DR program that is
16 explicitly designed to target this technology. With the substantial growth in installations and

⁹¹ Active residential battery installations per SDG&E Interconnection Database, as of July 2021.

⁹² *Id.*

⁹³ SGIP Database for Residential storage in SDG&E’s territory, through September 2021.
<https://www.selfgenca.com/report/public/>

⁹⁴ 2020 and 2021 residential solar and battery installations, per SDG&E’s Interconnection Database, as of July 2021.

1 customer interest in battery storage, there is a clear opportunity to develop and test a pilot
2 demand response program that relies on this technology.

3 Preliminary evidence⁹⁵ suggests that residential battery storage can produce 5.5kW
4 of load reduction per device when dispatched for 2-hour events. The limiting factors of load
5 reduction are the length of the event, the amount of solar power available during the event,
6 and the size of the batteries. The average size for residential battery installations in
7 SDG&E's territory is approximately 5.7kW,⁹⁶ which is comparable to the average
8 installation size used for the impact evaluation at National Grid (average size, 6.5kW,
9 N=50). Given the number of installed residential batteries in SDG&E's territory, this study
10 indicates that there is approximately 52MW of dispatchable and curtailable load currently
11 available among residential customers. According to SDG&E's 2020 Behind the Meter
12 Battery Market Study,⁹⁷ there is expected to be approximately 150MW of residential behind
13 the meter battery capacity installed in SDG&E's territory by 2027 and up to 280MW by
14 2030.⁹⁸

⁹⁵ https://ma-eeac.org/wp-content/uploads/MA19DR02-E-Storage_Res-Storage-Summer-Eval_wInfographic_2020-02-10-final.pdf

https://ma-eeac.org/wp-content/uploads/MA19DR02-E-Storage_Res-Storage-Winter-Eval_wInfographic_2020-09-23.pdf

⁹⁶ SDG&E Emerging Tech Report, Behind—the-meter Battery Market Study DR19SDG0002, Figure 5.

⁹⁷ Emerging Technology Report, Behind the Meter Battery Market Study DR19SDG0002.

⁹⁸ *Id.*

1 **2. Storage DR Pilot Overview**

2 Battery storage as a demand response resource has many characteristics that make it
3 a valuable technology to deliver grid services. Because storage requires both charging and
4 discharging, batteries can draw power during opportune times and discharge to premises
5 during periods of peak demand. This technology is especially valuable in California
6 because it can absorb excess solar production, reduce ramping needs, and lower peak
7 demand. Batteries can also respond to economic signals, reducing consumption according
8 to day-ahead market prices or fixed TOU schedules. Finally, having battery storage at a
9 premise can produce reliability benefits as customers can continue to use power during
10 Public Safety Power Shutoff (PSPS) events or in case of system outages. From the
11 customer’s perspective, batteries allow them to take better advantage of on-site solar,
12 manage their bills, or provide backup power for reliability.

13 While individual customers are using their batteries for various reasons such as peak
14 shaving during on Peak hours, there is limited participation in the current DR programs or
15 pilots. At the same time, visibility into customer BTM battery usage patterns is poor. This
16 leads to a disconnect in quantifying the precise value of demand response, as customers may
17 not be operating their battery in a way that is beneficial to the grid. There is a clear
18 opportunity to learn more about how customers use their battery systems and determine how
19 much demand response potential exists in this fast-growing resource.

20 The Battery Storage DR Pilot seeks to answer questions about how residential and
21 small commercial customers with existing batteries currently use them, whether the existing
22 storage systems can be successfully dispatched for demand response events or to respond to
23 day-ahead market prices. In addition, the pilot will test how incentive levels and structures
24 influence customer participation and identify the optimal incentive levels and structure.

1 Finally, the pilot will study how settlement baselines should be modified to accurately
2 capture the value of battery resources through a baseline accuracy simulation.

3 **3. Battery Storage DR Pilot Objectives**

4 SDG&E's Battery Storage DR Pilot will be available to residential and small
5 commercial customers (with maximum monthly demand less than 20kW) and will enable
6 them to use their existing battery technology to participate in DR events and respond to
7 CAISO day-ahead prices as a VPP. As part of the pilot, SDG&E will undertake several
8 research objectives to understand how customers use their batteries in the absence of any
9 utility intervention, what program design elements will maximize net program benefits, what
10 types of demand response impacts are feasible from controlling the batteries, and what kinds
11 of settlement baselines accurately capture these impacts for settlement in the CAISO market.

12 Eligible customers in both residential and commercial sectors will already have a
13 battery installed on-site and agree to allow SDG&E and/or other approved third parties to
14 control their battery and access the battery data. Incentive levels to participate in this pilot
15 will be specifically tested in two ways. First, the levels will be tested through a research
16 survey that will assess the effect of different incentive structures and levels on residential
17 and commercial customers' choices. Second, incentive levels will be tested through offering
18 different incentive levels upon customer recruitment.

19 The mechanism for demand response will be the charge and discharge of the
20 participant's battery during demand response events, which can range from two (2) to six (6)
21 hours in duration. These events may be called at any time from June to October. SDG&E
22 will also test the ability to control the battery in response to CAISO day-ahead market
23 prices.

24 The storage DR pilot has five specific evaluation objectives:

- 1 1. How are battery storage customers using their storage on their own?
- 2 2. What is the dispatchable load reduction potential during the Resource
- 3 Adequacy timeframe window (4pm-9pm)?
- 4 3. What is the optimal incentive structure and amount?
- 5 4. Can SDG&E use battery storage to respond to Day-Ahead market prices?
- 6 5. What baseline/settlement methods work best for battery storage in the
- 7 CAISO market?

8 The pilot will be conducted in four distinct phases. Note that there is staggered
9 timing of the pilot for residential and then commercial participants, with some phases that
10 will overlap in timing:

- 11 1. Planning: Contract with battery/inverter vendors, IT systems build, develop
12 and deploy research survey
- 13 2. Learning: Recruit residential participants, gather baseline battery
14 consumption data, finalize the first-year pilot design, and field enrollment
15 survey.
- 16 3. Implementation: Run the pilot for residential customers and commercial
17 customers.
- 18 4. To evaluate the success of the pilot, a separate load impact analysis will be
19 conducted at the end of the pilot in 2027 as described in the Load Impact
20 Evaluation Plan that can be found in the Prepared Direct Testimony of
21 Lizzette Garcia-Rodriguez (Chapter 4B) ⁹⁹

⁹⁹ Prepared Direct Testimony of Lizzette Garcia -Rodriquez, Chapter 4B.

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4. Proposed Budget for Battery Storage DR Pilot

Table EBM-13

	2024	2025	2026	2027	TOTAL
Battery Storage DR Pilot	\$1,498,699	\$1,526,411	\$1,524,716	-	\$4,549,826

The PIP for this Pilot can be located in Appendix A.

C. New Pilot – Direct Dispatch Pilot (DDP)

1. Background

Since 2019, SDG&E has seen a shift in the market on the types of Automated Energy Management Systems being purchased and installed. Cloud-based energy management systems (EMS) are a proven technology for many utilities nationwide providing both on-going energy load reduction through advanced controls and software and providing significant on-demand flexible capacity for small and medium commercial end users. These systems are more affordable to business customers and are being implemented without the restrictions placed upon them by utility program requirements. Additional obstacles include too low an incentive for customers to be inconvenienced by allowing utilities or third parties to control their behind the meter energy systems and loads.

In addition, customer acceptance of and installations of batteries for storage is on the rise, yet there is currently no opportunity for battery storage systems to effectively participate in utility sponsored demand response programs.

Another viable technology that is now in the marketplace is DERs. DERs are energy assets that can be any size and provides various levels of (kWh) and some can be flexible in

1 their ability to meet customer, utility, and grid needs while others are not.¹⁰⁰ DERs can also
2 encompass the best of auto DR (ADR) technologies and expand beyond simple heating,
3 ventilation and air conditioning (HVAC) and smart communicating thermostats to include
4 solar, storage, energy efficiency, and demand management energy resources that are
5 creating new opportunities for commercial and residential customers.

6 Many facilities in SDG&E service territory have existing ADR capabilities that do
7 not currently participate in DR programs. SDG&E is technology agnostic and looks
8 forward to including technologies and devices, regardless of their manufacturer, that are
9 currently active in the marketplace and meet the pilot's requirements for participation.

10 With the key lesson learned so far from the ELRP, the pay for performance model
11 with no penalties for non-performance is preferred. Large commercial customers in
12 SDG&E'S service territory appreciate the flexibility and more control when participating in
13 demand response programs and SDG&E expects that small and medium commercial and
14 industrial customers would appreciate the flexibility as well.

15 SDG&E is proposing a three (3) year pilot for commercial and industrial customers
16 that already own qualifying ADR enabled equipment (excluding smart communicating
17 thermostats) that have controls and can directly curtail their energy usage when signaled and
18 dispatched directly by the utility for demand response events.

19 The pilot as proposed would pay \$1/kWh¹⁰¹ for Day-Ahead or Day-Of participation
20 of verified load shed per event with no penalties for non-performance and would be

¹⁰⁰ See R.21-06-017 Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future (June 24, 2021), pp. 7-9.

¹⁰¹ Initial conversations with contractors indicated that this was an attractive price point for participation in the pilot.

1 dispatched by the utility. SDG&E would trigger events on any day of the week, year-round
2 including holidays. Direct Dispatch events shall be effective from 4:00 p.m. – 9:00 p.m. A
3 DDP event may be triggered for local system need, in response to high forecasted
4 temperatures, extreme conditions, emergencies or whenever the CAISO has issued an alert
5 or warning notice. The CAISO shall also be entitled to request that the utility, at its
6 discretion, call a program event. Events may also be triggered for testing/evaluation
7 purposes. The load shed will not be bid into the CAISO market, however.

8 This pilot is targeted at commercial and industrial customers that already own
9 qualifying ADR technology enabled equipment including energy management systems,
10 energy storage and “future” technologies located at commercial properties with monthly
11 max demands greater than 20kW that can curtail their energy usage when receiving an ADR
12 signal directly to their devices of an event initiated by SDG&E for demand response or grid
13 emergencies.

14 SDG&E will contract with a third-party for customer enrollments in the pilot but will
15 be responsible for calling of events and providing customer settlements.

16 The goal of this pilot is to:

- 17 • Test if a pure “pay for performance” pilot with no penalties that
18 utilize various types of open ADR enabled energy management
19 systems dispatched by the utility will provide incremental load drop.
- 20 • Test marketing strategies to entice this existing customer base to
21 participate in the pilot or a DR program in the future.
- 22 • Test higher incentive structure than current DR programs to determine
23 the role incentives play in event participation.

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2. DDP Pilot Objectives

SDG&E plans to target customers that already own qualifying ADR-enabled equipment (excluding smart communicating thermostats) including energy management systems, energy storage and “future” technologies located at commercial properties (with monthly max demands greater than 20kW) that can curtail their energy usage when dispatched by the utility for demand response events.

- 1. Traditional Energy Management Systems (excluding Smart Communicating Thermostats).
- 2. Energy Storage (Commercial and Industrial).
- 3. “Future” Devices.

The goal of this pilot is to test if a pure “pay for performance” pilot with no penalties for various types of open ADR enabled energy management systems dispatched by the utility and provides a slightly higher incentive than current DR programs will motivate commercial and industrial customers to participate in demand response events.

SDG&E will issue a request for proposal (RFP) for the customer outreach, recruitment, and retention of participants for the pilot which will include all activities required to solicit and retain participants by a third-party implementer. SDG&E will retain dispatching of events and customer settlements for the pilot and will have final approval of all marketing and recruitment activities related to the pilot.

SDG&E seeks the Commission’s approval to come back to the Commission via advice letter to update and finalize the pilot after three years or advise of next steps after an evaluation and measurement review has been conducted to determine if the pilot should be converted into a full program. If the pilot cannot be viable as a program, SDG&E will seek the Commission’s permission to terminate the pilot.

1 In this application, SDG&E is requesting a budget of \$4,796,591.00 for the pilot
 2 years 2024-2026 and for \$2,702,582.00 for 2027 if converted to a program.

3 To evaluate the success of the pilot a separate load impact analysis will be conducted
 4 at the end of the pilot as described in the Load Impact Evaluation Plan that can be found in
 5 the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4B).

6 **Table EBM -14**
 7 **DDP Proposed Budget:**

	2024	2025	2026	2027	TOTAL
Direct Dispatch Pilot	\$1,948,082	\$1,415,095	\$1,433,414	n/a	\$4,796,591

	2024	2025	2026	2027	TOTAL
Direct Dispatch Program	n/a	n/a	n/a	\$2,702,582	\$2,702,582

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 9
 10 The PIP for this Pilot is located in Appendix A.

11 **D. New Pilot – Grid Isolation Controls Pilot (GICP)**

12 **1. Background**

13 Over the past 2 years, SDG&E residential and commercial customers have added
 14 over 150 MW of solar capacity and over 20 MW of battery storage. At the same time,
 15 technology solution providers have been working to develop BTM solutions that can
 16 provide California’s solar-equipped homes and small businesses with automated grid
 17 islanding capability (with or without energy storage), which allow for solar self-
 18 consumption and demand management.

1 These new islanding controls technologies will be able to effectively isolate BTM
2 generation from the grid while allowing homes and businesses to remain energized – even
3 during a grid outage or PSPS event.

4 **2. GICP Overview**

5 Individual grid isolation technology is part of a new and growing sector that will
6 allow customers to safely “isolate” from the grid in response to a PSPS event, outage,
7 demand response event or CAISO or SDG&E declared emergency and can be signaled by
8 SDG&E.

9 On-demand load reduction capability. During blue sky conditions grid isolation
10 technologies can be used to drop loads or island the location the grid due to economic needs
11 or in response to CAISO alerts, warnings, emergencies. During island operation, microgrid
12 isolation technologies can be used to manage customer loads thereby extending the amount
13 of time that the customer’s BTM resources can keep the customer energized. When
14 operating in island mode as part of a multi-customer microgrid these devices have the ability
15 to deliver locational load reductions thereby protecting the circuit and preventing customer
16 BTM damage while providing increased service reliability by allowing customers to use
17 their BTM devices to remain energized during outages or PSPS events.

18 Once proven and UL¹⁰² certified, we believe the technology should be able to deliver
19 local and grid related benefits.

20 **3. GICP Objectives**

21 The objective of the pilot will be to test new isolation technologies and assess if the
22 technology works as designed and whether it can effectively and safely isolate homes or

¹⁰² UL stands for “Underwriters Laboratories.”

1 businesses with solar and/or battery storage or other devices from the grid. In addition, the
2 pilot seeks to test and verify load reduction strategies while quantifying the magnitude of the
3 load shed under different event scenarios such as the time of day, event duration and
4 locational dispatch. The pilot will also test customer acceptance of the technology.

5 Device manufacturers are working on solutions compliant with all commercially
6 viable ADR protocols.

7 **4. Implementation**

8 SDG&E will issue a request for proposal (RFP) seeking a third-party implementer
9 that can provide and install the approved grid isolation technology and they will also include
10 all activities required to solicit and retain participants. SDG&E will retain dispatching of
11 events and customer settlements for the pilot and will have final approval of all marketing
12 and recruitment activities related to the pilot.

13 The GICP will pay for the purchase and installation costs for the new UL Certified
14 innovative technologies that enable the safe isolation of locations from the grid and for
15 participation in DR programs during blue sky and island modes. Participants must agree to
16 participate for the duration of the pilot in order to receive ownership of the technology.
17 Failure to do so risks the removal of the equipment.

18 The grid isolation technology is required to have an embedded public safety
19 interlock that conforms to national electric code requirements, has Underwriter Laboratories
20 (UL) certification, and prevents behind the meter generation from back-feeding to the grid.
21 The device must also be able to receive a signal to be switched back to grid synchronized
22 mode when the grid is energized.

23 GICP events can be called at any time of the year, including weekends and holidays,
24 for local system need, in response to CAISO emergencies, PSPS events, or for testing

1 purposes. Events will typically last from one (1) to two (2) hours with a maximum event
2 duration of four (4) hours. Day Ahead and Day Of advance notice of events will be
3 provided to customers via text message and/or email.

4 The pilot has the following objectives:

- 5 1. Can participants effectively and safely isolate themselves from the grid in
6 response to a signal from the utility?
 - 7 a. What amount of load impact can be provided to the grid as a result
8 and for how long?
 - 9 b. Can isolation help to mitigate system under generation periods as well
10 as local system peak loads? How and to what effect.
- 11 2. Can the technology be locationally dispatched by utility circuit ID or zip
12 code?
- 13 3. What is the customer experience during isolation events?
- 14 4. Does the technology provide similar or additional benefits when installed
15 within Disadvantaged Communities (DACs)?

16 This pilot seeks to enroll between 50-100 locations for participation. As part of the
17 pilot, SDG&E will first attempt to recruit participants in low income or disadvantaged
18 communities. Ideal participants would have either solar, battery storage installed, or an
19 electric vehicle (such as the Ford™ F150 Lightning)¹⁰³ in order to be eligible for the pilot.

20 SDG&E seeks the Commission’s approval to submit a Tier 2 advice letter to either 1)
21 update and finalize the pilot after three years, or 2) advise of next steps after an evaluation and

¹⁰³ Electric vehicle manufactures such as Ford are promoting that their EVs will have electric vehicle to building (EVB) and electric vehicle to grid (EVG) functionality at some point in the future (when the technology becomes available). <https://www.ford.com/trucks/f150/f150-lightning/2022/features/intelligent-backup-power/>

1 measurement review has been conducted to determine if the pilot should be converted into a full
2 program.

3 To evaluate the success of the pilot a separate load impact analysis will be conducted
4 at the end of the pilot in 2027 as described in the Load Impact Evaluation Plan that can be
5 found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4B).

6 **5. GICP Proposed Budget**

7 SDG&E is requesting a budget of \$3,100,912 for 2024 - 2026 for the pilot.

8 **Table EBM-15**
9 **Proposed Budget Figure**

	2024	2025	2026	TOTAL
Grid Isolation Controls Pilot (GICP)	\$1,030,088	\$1,033,549	\$1,037,275	\$3,100,912

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11 **VI. THIRD-PARTY DEMAND RESPONSE: ELECTRIC RULE 32**
12 **OPERATIONS AND THE DEMAND RESPONSE AUCTION MECHANISM**
13 **PILOT (DRAM) FOR 2024 - 2027**

14 **A. SDG&E Support for Direct Market Participation through SDG&E's**
15 **Electric Rule 32 for 2024 - 2027**

16 **1. Background**

17 SDG&E's Electric Rule 32 (Rule 32) governs how SDG&E interacts with third-party
18 Demand Response Providers (DRPs). The Commission, in D.15-03-042, and later in D.16-
19 18-06-008, authorized SDG&E to put into place certain processes and systems to facilitate
20 third-party DRPs' ability to bid demand response resources into the CAISO wholesale
21 market as Proxy Demand Resources (PDRs) and/or Reliability Demand Response Resources
22 (RDRRs).

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a. Current Status

As of March 31, 2022, SDG&E had approximately 57,000 customers with active Customer Information Service Request for Demand Response Providers (CISR-DRP) on file, authorizing to share their personal energy-related data with DRPs under Rule 32. As of March 31, 2022, SDG&E had approximately 65,500 active and inactive Rule 32 customers in SDG&E’s systems including 38,100 customers actively registered in the CAISO Demand Response Registration System (DRRS) with DRPs under Rule 32.

SDG&E filed AL 3746-E on May 12, 2021, to increase customer registrations by 200,000 for a total of 260,000. This advice letter was approved on October 12, 2021.

Current enrollment forecasts and growth rates provided by DRPs estimate a total of approximately 120,000 enrollments at the end of 2024. Based on current enrollment forecasts and growth rates provided by DRPs, SDG&E is using a growth rate of approximately 50,000 enrollments per year for 2024 – 2027 to allow for adequate funding to support these forecasted enrollments.

**Table EBM–16
Rule 32 Enrollment Forecasts 2024-2027**

	2024	2025	2026	2027
Estimated Cumulative Yearend Enrollments	120,000	170,000	220,000	270,000

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b. Proposal for Operational Support for 2024-2027

SDG&E is requesting funding to provide operational and production support for third-party market participants, and Rule 32 information technology related processes. The

operational costs consist of program management, administrative support, systems support and licensing fees. The annual distribution of these costs is outlined below.¹⁰⁴

Table EBM –17
Rule 32 Budget Proposal 2024-2027

	2024	2025	2026	2027	TOTAL
Rule 32	\$663,536	\$681,386	\$700,468	\$720,385	\$2,765,775

SDG&E notes that these costs are associated with SDG&E’s support for direct market participation by third parties and therefore are tracked separately from SDG&E’s DR portfolio. Furthermore, because these costs are for third-party support, they are not included in SDG&E’s cost-effectiveness analysis of its own DR programs. The Commission should consider these costs as part of cost-effectiveness of third-party market participation in the future.

SDG&E’s budget request and staffing plan reflects SDG&E’s DR budget practice that provides for a “best case” scenario where SDG&E supports a robust program and a large number of third-party market participants without risking being underfunded. Upon approval, SDG&E will use its prudence and only staff as necessary to support this process. It is important to note that SDG&E only recovers actual costs spent which means SDG&E will only recover actual expenditures relating to the approved funding request.¹⁰⁵

¹⁰⁴ These costs do not include IT or Measurement and Evaluation support. IT staffing costs associated with Rule 32 support are included in the Prepared Direct Testimony of Ellen Kutzler – Chapter 2B, Table EK-1: Information Technology Budget Proposal 2024-2027. Measurement and Evaluation staffing costs associated with Rule 32 support are included in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez – Chapter 4B, Table LG-10: 2024-2027 Measurement and Evaluation Budget for R32.

¹⁰⁵ SDG&E does not collect in rates its approved budget or refund unspent funds in rates. Please see the Prepared Direct Testimony of Kenneth Pitsko Chapter 6A for more detail on the cost recovery mechanism.

1 **B. Demand Response Auction Mechanism Pilot (DRAM) for 2024 - 2027**

2 **1. Background**

3 D.14-12-024 approved SDG&E and the other IOUs to offer a two-year DRAM pilot
4 for 2016 and 2017 to the third-party DRPs to participate directly in the CAISO market.
5 Later, the Commission issued D.16-06-029 and D.17-10-017 to extend the DRAM pilot into
6 2018 and 2019. The Commission then issued decision D.19-07-009 to extend the DRAM
7 pilot through 2023 and D.19-12-040 to further refine the DRAM.

8 **2. Current Status**

9 The DRAM Pilot is currently in its seventh implementation in 2022. The 2023
10 DRAM Request for Offers (RFO) was launched on February 1, 2022, and selected contracts
11 are scheduled to be executed on April 29, 2022. The administration budget for the year
12 2023 was authorized in D.19-07-009, OP 2 at page 107.

13 SDG&E has seen a steady decline in the number of DRPs submitting bids in the
14 DRAM RFOs and the number of DRPs awarded contracts. In the 2017 DRAM RFO,
15 SDG&E had a high of eleven DRPs bid into the RFO and awarded contracts to five DRPs.
16 In the 2022 DRAM RFO, SDG&E had only three DRPs bid into the RFO and awarded
17 contracts to only two DRPs. SDG&E has had no new market entrants in the auctions since
18 the 2020 DRAM RFO which took place in 2019 for 2020 delivery.

19 **3. DRAM Independent Evaluation**

20 D.19-07-009 authorized the IOUs to contract with a consultant to evaluate the
21 continuation of the DRAM and assist the Commission’s Energy Division in monitoring the
22 Auction Mechanism.¹⁰⁶ The evaluation includes performance of delivery years 2018

¹⁰⁶ D.19-07-009, p. 112, OP 16.

1 through 2021, and the solicitation process for years 2019, 2020 and 2021. The final
2 evaluation report was originally scheduled to be made available to all parties no later than
3 December 1, 2021. However, due to the delay in receiving the final evaluation data, a
4 decision by the Commission's Energy Division to include the entirety of the 2021 Auction
5 Mechanism delivery period, as well as an ongoing delay in the receipt of outstanding data
6 requests, the CPUC granted an extension for the final report to be provided to Energy
7 Division by May 23, 2022.

8 The final evaluation of DRAM will not be issued before this application is filed;
9 therefore, SDG&E reserves the right to advise the Commission on SDG&E's position on the
10 future of DRAM after it has had ample time to review and digest the results of the
11 evaluation. SDG&E thus does not include any costs for DRAM in this application prior to
12 the final evaluation report being issued.

13 **4. Customer Information Working Group (CIWG)**

14 Resolution E-5110 issued on December 18, 2020, authorized the Energy Division to
15 initiate a Customer Information WG no later than 60 days after the adoption of the
16 Resolution. The WG is tasked to study The California Efficiency + Demand Management
17 Council's proposal from the DRAM WG and produce a report by June 1, 2021.¹⁰⁷ The
18 Resolution also ordered the IOUs to include the Customer Information Working Group
19 report in their 2023-2027 DR Portfolio Applications.¹⁰⁸ The Customer Information WG was
20 never initiated, therefore there is no report to include in this application.

¹⁰⁷ Resolution E-5110, p. 49, OP 5.

¹⁰⁸ Resolution E-5110, p. 50, OP 6.

1 **VII. RELATED ACTIVITIES TO SUPPORT DEMAND RESPONSE**

2 **A. CAISO Market Integration Study Proposal**

3 In D.14-03-026, the Commission bifurcated DR resources into supply-side DR
4 resources (*i.e.*, resources bid into the CAISO wholesale energy market) and load-modifying
5 DR resources (*i.e.*, resources reshape or reduce the net load curve).¹⁰⁹ Several months later,
6 the Commission issued D.14-12-024 which required full implementation of bifurcated DR to
7 begin January 1, 2018 (*i.e.*, IOUs must integrate supply-side DR programs into the CAISO
8 market by January 2018).¹¹⁰

9 Ahead of the schedule and timeline set forth by the Commission, SDG&E began
10 integrating its supply-side programs into the CAISO market and fully integrated all of its
11 supply-side DR programs in 2015.¹¹¹ SDG&E recognizes that Commission policy over the
12 past decade has been focused on DR market integration into the CAISO market and has led
13 the way in implementing this policy, being the first California utility to integrate its
14 programs. However, as SDG&E gained experience with integrating and operating DR
15 programs in the CAISO wholesale energy market, several significant issues with this
16 approach have become clear. At its root, the main problem with integrating DR into the
17 CAISO markets is that the rules of market integration were designed for traditional “perfect”
18 generation resources, not for customer-backed resources. Although CAISO and the
19 Commission have done an admirable job of creating initiatives and modifying certain
20 policies and rules to better support DR market integration, there are still gaps and more

¹⁰⁹ D.14-03-026, OP 1.

¹¹⁰ D.14-12-024, OP 4.

¹¹¹ SDG&E’s CAISO market-integrated programs include Capacity Bidding Program (CBP), Base Interruptible Program (BIP), and our AC Saver Program.

1 improvements that can be made if it remains appropriate for DR to be integrated into the
2 CAISO market. To this point, no in-depth analysis of the successes and failures of DR
3 market integration has been undertaken in California. As this policy has now been in
4 existence for close to a decade, it is an appropriate time to reflect on and analyze this
5 paradigm.

6 SDG&E advocates rethinking or significantly improving the market integration
7 paradigm for DR and to achieve the goals set forth in the DR OIR. As such, SDG&E
8 recommends that the Commission initiate a large-scale study to determine whether DR
9 market integration is the best mechanism to support the State’s clean energy policy, whether
10 the Commission’s goals for DR market integration have been achieved, and what changes to
11 policies, rules, or processes should occur to make DR a more useful resource.

12 **1. Current Status of CAISO-Integrated DR Programs**

13 SDG&E currently has approximately 15 MW of supply-side DR capacity, all of
14 which is integrated into the CAISO market. SDG&E has integrated its core DR programs¹¹²
15 since 2015, with full integration under CAISO rules being achieved in 2017.

16 **2. It is unclear whether CAISO market integration has delivered on**
17 **the goals articulated when it was approved by the Commission.**

18 In 2013, the Commission initiated Rulemaking (R.)13-09-011 to determine whether
19 and how to bifurcate DR into load-modifying and supply-side resources, “with the intent of
20 prioritizing demand response as a utility-procured resource, competitively bid into the

¹¹² SDG&E’s core DR programs include the Base Interruptible Program (BIP), AC Saver and the Capacity Bidding Program (CBP).

1 California Independent System Operator wholesale electricity market.”¹¹³ The Commission
2 identified the ultimate goal of this process as being “to enhance the role of demand response
3 programs in meeting the state’s long-term clean energy goals while maintaining system and
4 local reliability.”¹¹⁴ Similarly, the Commission stated in a decision in that proceeding that
5 the goals of bifurcation “are to improve the efficiency of demand response and increase the
6 use of all demand response programs...”¹¹⁵

7 It is unclear at this point, almost a decade later, whether these goals have in fact been
8 achieved by the integration of DR into the CAISO market, or, if they have been achieved,
9 whether the costs of doing so have been reasonable. By all accounts, the role of DR in
10 meeting the state’s long-term clean energy goals has been enhanced and the use of DR
11 programs has been increased, as described in the goals. In addition, DR has played a vital
12 role in supporting distribution system and local reliability in recent years. However, given
13 the issues with market integration experienced by SCE and the other IOUs, it is debatable
14 that the efficiency of DR has been increased, or that the achievements have come at a
15 reasonable cost that should continue to be paid.

16 3. CAISO Market Issues

17 In the operation of its market-integrated DR programs, SDG&E has identified the
18 following problems with DR integration into the CAISO market.

¹¹³ R.13-09-011, Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State’s Resource Planning Needs and Operational Requirements, issued September 25, 2013, p. 2.

¹¹⁴ *Id.*

¹¹⁵ D.14-03-026, p. 7.

1 **Issue 1: DR Should Not be Compared to “Perfect” Conventional Generation**
2 **Resources**

3 Since market integration in 2015, SDG&E has seen its DR portfolio decrease from a
4 peak of approximately 30MW to just under 12 MW in its core programs (BIP, AC Saver,
5 and CBP) due to customer attrition as a result of over utilization of the programs leading to
6 customer fatigue and dissatisfaction. Over-utilization of DR programs and the degradation
7 of SDG&E’s DR portfolio can largely be attributed to market bidding requirements and
8 integration rules that cause multi-hour consecutive-day dispatches which ultimately results
9 in over-utilization of the programs/customer fatigue/unenrollment. For instance, under the
10 CAISO Must Offer Obligation (MOO), a perfect resource would be bid for all hours (*e.g.*,
11 24/7/365) with no minimum load/minimum cost (\$0) and no dispatch restrictions (*e.g.*, can
12 be dispatched multiple times in a single day, no hourly or consecutive dispatch limitations).
13 Also, DR in the San Diego area is very weather sensitive, and this affects MW results.
14 Since DR is a use-limited resource, only allowing one dispatch a day the CAISO is trying to
15 reduce the capacity value of DR due to its use-limited nature, which has a cascading impact
16 on the resource (*e.g.*, if the resource gets a lower value, then this makes the resource less
17 cost-effective and could cause incentive reductions, thereby reducing enrollment and
18 participation).

19 **Issue 2: One Program Per Service Account**

20 As described above, SDG&E’s vision for DR is to emphasize DR focused on
21 residential and small business customers. These types of customers often have more than
22 one DR-supporting end-use in the home or business. For example, a home may contain a
23 smart thermostat (SCT), clothes washer, clothes dryer, dishwasher, electric vehicle, water
24 heater, pool pump, solar, and battery energy storage. As technology improves and prices

1 decrease, SDG&E expects more homes to invest in these types of appliances. Currently,
2 SDG&E's DR programs are constrained by the CAISO rule that requires one customer
3 meter to participate in a DR program with one and only one DR device.¹¹⁶ Although it is
4 possible for multiple devices to be aggregated by responding to DR with smart plugs or
5 devices from other OEM manufacturers, such operation is unwieldy and does not allow for
6 the type of DR participation that SDG&E envisions in the future.

7 Rather, SDG&E supports a flexible, technology agnostic approach to DR. Given the
8 hypothetical customer described above, this customer could provide load for economic
9 reasons by turning down, but not completely turning off, their thermostat and could also
10 allow SDG&E to completely shut off their air conditioner compressor during times of grid
11 stress. At the same time, the customer could decide to allow dispatch of their EV's load if
12 they do not have to drive anywhere in the near term or override its dispatch if they have to
13 go somewhere. While these grid services are provided by three different types of end-use
14 devices or providers, market integration rules only allow the customer to participate in one
15 DR program with one device, which more times than not, this leaves DR kW on the table
16 and un-utilized.

17 **Issue 3: "All-or-Nothing" Use of DR Resources**

18 It would be cost-prohibitive to operate a DR program in the most efficient manner
19 under current CAISO operations. DR resources are typically comprised of many customers
20 providing load reduction and partially dispatching a DR resource, even if it wins a CAISO
21 award for partial dispatch, would require a huge investment in systems and technology to
22 allow SDG&E to revise the number of dispatched customers in each resource. For this

¹¹⁶ CAISO Business Practice Manual (BPM) for Demand Response.

1 reason, SDG&E bids its DR resources into the market during the RA window as “all or
2 nothing” (known as “discrete dispatch”). This means that, when awarded, SDG&E will
3 dispatch a DR program in its entirety. However, such bidding and use limitation can result
4 in DR resources being dispatched and customers asked to curtail when the entire quantity of
5 MW may not be needed.

6 **4. Proposal For A CAISO Market Integration Study**

7 For the foregoing reasons, SDG&E proposes the Commission initiate a large-scale
8 study to answer the following basic questions:

- 9 1. Has DR market integration met the Commission’s reasons for adopting this
10 policy? If not, why not? If so, to what degree?
- 11 2. Should supply-side DR continue to be integrated into the CAISO market as a
12 matter of policy?
- 13 3. If continued market integration is appropriate for supply-side DR, what rules,
14 policies, and processes should change to better enable this integration?

15 SDG&E anticipates that this study would be modeled on the recent large-scale
16 Demand Response Potential Study that was initiated in 2014. The three IOUs would co-
17 fund the study and a consultant or consultants would be engaged to design and manage the
18 study, compile data, interview stakeholders as necessary, and prepare recommendations. An
19 advisory committee made up of representatives from the IOUs, the Commission’s Energy
20 Division, CAISO, and other stakeholders as appropriate would provide input on the study’s
21 direction and serve as contacts for the consultants to request data. SDG&E in consultation
22 with PG&E and SCE, expect the study would likely cost approximately \$3 million and
23 divided 40/40/20 between the IOUs with SDG&E’s share to be 20%. Because the study

1 should inform the IOUs' next DR applications for the 2028-2032 cycle, the study should
2 conclude no later than mid-2026.

3 Therefore, SDG&E requests the CPUC approve the proposed study and the initial
4 budget for the study and allow the IOUs to recover the costs through each IOU's balancing
5 accounts.¹¹⁷

6 **B. Bottoms Up DR Potential Study**

7 SDG&E in collaboration with PG&E and SCE proposes a Bottoms Up DR Potential
8 Study. This study is different than the existing CPUC led DR Potential Study which
9 provides an informative range of possibilities, but only represents theoretical "potentials"
10 that were not be easily supportable with the current DR framework that historically has been
11 predicated on load shedding as the primary focus. As a follow-up to the CPUC lead DR
12 Potential Study, SDG&E believes that a new "bottoms-up" DR disaggregation study should
13 be conducted over the 2024-2027 period. The main purpose of this study is to identify and
14 disaggregate end-use loads that are sizeable and flexible enough to help address operational
15 and planning needs, and to determine if these loads can be managed through existing
16 programs or, if not, through new or modified programs. Specifically, this study seeks to
17 accomplish the following:

- 18 • Understand SDG&E customer elasticity by end-use, by comparing
19 disaggregated load data relative to changes in price, as a function of
20 customer sector, hour of day/day of week, use of

¹¹⁷ Prepared Direct Testimony of Lizzette Garcia-Rodriguez Chapter 4B, Table LG-8 includes the budgets for this study.

1 automation/technology, historical EE upgrades, temperature, trailing
2 consumption, historical demand, and other exogenous variables.

- 3 • Identify usage patterns of specific BTM devices that can help improve
4 customer load elasticity.
- 5 • Determine how the load-reduction potential of these devices could be
6 optimally leveraged via the strategic deployment of enabling
7 technology.
- 8 • Develop a supply curve of end-use loads that can be leveraged at each
9 hour of the peak.
- 10 • Convert learning into actionable program design and/or operational
11 insights.

12 Such study will require a broad data set that SDG&E will develop through its pilots
13 described within this testimony and other SDG&E programs. The proposed study would
14 also require transparency with customers and/or aggregators engaging in active decision-
15 making relative to prices. It also requires a substantial sample group to draw conclusions
16 from and sufficient price volatility to identify a response to a signal, as well as an
17 understanding that participants in these pilots may be self-selected as having more elastic
18 loads than the population of SDG&E customers.

19 Given the large volume of data and complex analysis required to complete this study,
20 SDG&E proposes that this study be conducted in conjunction with California's other IOUs
21 and proposes a budget of \$3 MM split between the 3 IOUs as follows: PG&E 40%, SCE
22 40% and SDG&E 20%.

1 Therefore, SDG&E requests the CPUC agree to and approve the study and approve
 2 the initial budget for it and allow SDG&E to recover costs. SDG&E would not attempt the
 3 study unless it is approved for all the IOUs and appropriately co-funded.¹¹⁸

4 **C. Demand Response Regulatory Policy, Financial Services and General**
 5 **Support Activities**

6 There are a number of activities that support the DR programs with costs which are
 7 not related specifically to singular programs. They are general administration and support
 8 areas that support the entire portfolio. These activities include regulatory policy support,
 9 financial analysis, budget management, reporting support, and systems support of SDG&E’s
 10 business systems which directly serve DR programs. SDG&E requests funding at the
 11 following levels for each of the years in the cycle as follows:

12 **Table EBM-18**
 13 **Regulatory Policy Financial services and Support Activities Budget**

		2024	2025	2026	2027
Policy and Financial Support		\$551,399	\$617,109	\$633,986	\$651,644
System Support and Maintenance		\$2,298,637	\$2,729,380	\$2,699,544	\$2,963,047

14 Policy and Financial Support includes the discreet costs related to regulatory policy
 15 staff who oversee and respond to DR data requests, compile DR filings and Commission
 16 reports, participate in Commission-created or required working groups and work with the
 17 DR team to ensure compliance. It also includes costs related to the financial staff who track
 18

¹¹⁸ Prepared Direct Testimony of Lizzette Garcia-Rodriguez, Chapter 4B, Table LG-8 includes the budgets for this study

1 DR budgets and track actual expenses, oversee the financial reporting of the DR portfolio
2 and advise the DR team on financial matters. System Support and Maintenance expenses
3 include the costs directly related and limited to supporting the systems that serve SDG&E's
4 DR team and its DR customers. The proposed budget is based on the anticipated scope and
5 capabilities required to effectively and centrally integrate, manage, and operate SDG&E's
6 portfolio of DR programs. These costs take into consideration some fundamental and high-
7 level assumptions, based on the DR program proposals.

8 **VIII. MID-CYCLE REVIEW**

9 D.16-09-056 ordered the first mid-cycle review advice letter from the IOUs to update
10 the Commission on their portfolios during 5-year cycles. The decision also stated that the
11 utilization of such mid-cycle advice letters themselves should be reviewed in this instant
12 application.¹¹⁹ SDG&E filed its mid-cycle review (AL 3522-E) as required in March of
13 2020, to inform the Commission of its progress and to propose modest program changes
14 midway through the 5-year DR cycle 2018 to 2022. However, that AL has not yet been
15 approved by the Commission at the time of this filing. Thus, the mid-cycle review of
16 SDG&E's programs has not proven to be an effective use of either the IOUs' or the Energy
17 Division's time and resources. SDG&E therefore proposes that no mid-cycle review be
18 required in 2023-2027. SDG&E notes that program changes can already be proposed via
19 advice letter and that avenue remains open to the IOUs. Further, the IOUs all report their
20 monthly activity and spending in their required reporting to the Commission. As such, there
21 are other mechanism by which the IOUs can update the Commission or propose program

¹¹⁹ D.16-09-056, p. 59, OP 9.

1 changes without the need for submitting formal mid-cycle reviews which are time-
2 consuming to prepare and review.

3 **IX. ZIGBEE TECHNOLOGY UPDATE**

4 The purpose of this section of my testimony is to notify the Commission on
5 SDG&E's intent to discontinue its support of demand response and/or other devices that
6 connect to SDG&E's Smart Meters via ZigBee technology.

7 **A. Background**

8 ZigBee technology was a common, if not the premier, meter communication
9 functionality offered in the initial roll outs of smart meters, such as SDG&E's.¹²⁰ It was the
10 communications technology that was contained in SDG&E's meters that were initially
11 installed between 2009 and 2011. All of SDG&E's approximately 1.4 million meters today
12 use ZigBee. This technology also was originally utilized by SDG&E in its retail
13 enablement¹²¹ of the Home Area Network (HAN) devices and early programmable
14 controllable thermostats (SCTs) that were paired with a customer's meter in order to share
15 data. First generation HAN devices were connected to meters directly by the IOU, after
16 testing by the IOU and approved to link with SDG&E's smart meter network. The devices
17 provide near real time usage data to devices in the home. SDG&E also used ZigBee to
18 communicate other data to the HAN in early pilots; most often pricing or bill total estimates
19 when paired with device algorithms that calculated usage and multiplied it by per kW rate,

¹²⁰ ZigBee meters were adopted by all three of the large investor-owned utilities in California: SDG&E, SCE and PG&E.

¹²¹ On September 27, 2012, the CPUC approved Energy Division's resolution E-4527 directing the Utilities, via Ordering Paragraph 1, to submit filings that incorporate specific implementation requirements to enable the retail purchase of devices by customers and for those devices to be tested and paired on SDG&E's meters via ZigBee (detailed in the ordering paragraph). SDG&E filed 2307-E-A with its HAN plan (AL 2307-E-A) which was adopted.

1 etc. This was done to display a proxy for billing information to test customer awareness of
2 energy usage, enable greater understanding of energy usage and its relation to price, and to
3 test behavior.¹²²

4 From the beginning, SDG&E has employed various means to pair devices to meters,
5 and today it uses a third party-run portal and pairing system. Starting in 2014 and through
6 2016, SDG&E provided to customers free of charge and installed ecobee thermostats
7 equipped with ZigBee communicating chips. Currently 7,500 devices (+/- 6,500 ecobee,
8 about 1K other, including HANs that display usage) have been paired at some time with
9 SDG&E's smart meters. However, the technology is limited, and it is not possible to
10 determine exactly how many of those customers continue to utilize the ZigBee feature to
11 view meter data. Since the thermostats normally stay with the home when it is sold,
12 SDG&E would surmise that many customers do not even know about the feature in an older
13 SCT.

14 Today, ZigBee technology is no longer the favored path for meter technology. Wi-Fi
15 is the preferred technology for residential. Today, all communication for DR events with
16 smart communicating thermostats now occur via a Wi-Fi signal. For example, neither Nest
17 nor ecobee currently offer a product with a ZigBee chip, as was so prevalent a decade ago.

18 **B. SDG&E's Proposal to Discontinue ZigBee Support**

19 SDG&E's initial smart meter roll out is nearing the end of its life. Installations of
20 SDG&E's first smart meters will be almost 20 years old by the time this instant DR cycle

¹²² The devices displayed estimated energy costs, which are not accurate reflections of SDG&E billing, but rather are intended to provide a general idea of approximate energy costs to help customers take action. The displayed energy costs are intended for guidance and estimation purposes only. The manufacturers use various methods to calculate the numbers and the estimated cost will be different than actual billing information.

1 ends in 2027. SDG&E has issued a Request for Proposals (RFP) for new smart meters with
2 the view to have new meters to be available in 2023 and beyond in the event older meters
3 start to fail. In its own research, SDG&E has learned that none of the major smart meter
4 vendors today utilize ZigBee technology as they once did, including SDG&E's current
5 meter vendor, Itron.¹²³

6 Given that both the markets for meters and devices, such as communicating
7 thermostats, have moved away from relying on ZigBee, starting in 2023 SDG&E will no
8 longer support new ZigBee device pairing. There has not been demand for new device
9 pairing, and devices that are connected via ZigBee will still remain connected until the
10 customers' future new meters are replaced with a new meter not carrying ZigBee. When
11 new smart meters begin to be installed, sometime after 2023, SDG&E will begin
12 communicating with customers who have ZigBee devices paired with SDG&E's meters that
13 that functionality will no longer work in the new meters. SDG&E will convey educational
14 information about how to obtain energy information through MyAccount, how customers
15 can manage their energy usage through current technology such as through wi-fi digital
16 "assistants," wi-fi smart thermostats or other wi-fi appliance controls. SDG&E will also
17 utilize the opportunity to market its DR programs and incentives.

18 SDG&E's proposal to discontinue support for ZigBee devices is driven mostly by
19 the meter market. SDG&E's decision to not support ZigBee is not an indication that
20 SDG&E does not support energy usage data being shared, or customers having access to that
21 data. It is an indication that the technology landscape has merely changed since smart

¹²³ SDG&E's current meter vendor, Itron, was originally used also by SCE. Itron has merged with Silver Spring which was PG&E's provider, which also does not offer ZigBee in its new meters.

1 meters were first deployed and paired with devices using Zigbee. The technology has
2 moved away from ZigBee.

3 SDG&E's decision to end ZigBee support is included in its DR application herewith
4 since the costs for the vendor' pairing portal has been funded, in part, by a very nominal
5 amount in the DR budget, of approximately \$60,000 per year, which SDG&E is seeking for
6 2023 only. SDG&E seeks no further budget for the portal for 2024 through 2027.

7 **X. NEW SCOPING ISSUES PRESENTED IN AMENDED SCOPING MEMO**

8 On December 19, 2022, an Amended Scoping Memo was issued which presented
9 new scoping issues for Phase II relating to areas that were not addressed in my initial
10 testimony and/or SDG&E's initial application.¹²⁴ Below, I set forth SDG&E's position and
11 views on several of the new scoping issues. For ease of reference, I present my testimony
12 according to the specific scoping issue being addressed.

13 **A. Scoping Issue 2c - To improve program cost-effectiveness, usefulness,**
14 **and system reliability, should the Commission consider design changes to**
15 **RA-eligible emergency DR programs, such as (but not limited to)**
16 **dispatch conditions and requirements, compensation & penalties, and**
17 **performance measurement techniques?**

18 SDG&E does not have any customers in its regular portfolio emergency program, the
19 Base Interruptible Program (BIP). SDG&E has not had any enrolled customers in its BIP
20 since 2021. By this application, SDG&E has requested to close the BIP program, which
21 does not appeal to customers in SDG&E's territory due to the short notification time and the
22 firm service level aspect. BIP typically best suits large manufacturing or other large
23 industrial processing, where processes can be curtailed quickly for certain significant load
24 drop. SDG&E does not have any significant large manufacturing in its territory. Thus,

¹²⁴ Amended Scoping Memo, Section 3.2

1 while this program is largely subscribed in the other IOUs’ territories (up to the 3% cap),
2 SDG&E has not had a similar experience. Given that the ELRP is still a pilot, SDG&E
3 would suggest that the Commission consider testing various aspects of customer
4 participation and performance in the ELRP to determine what customers may utilize most or
5 perform best in for emergency programs that would help inform any changes in the future.

6 **B. Scoping Issue 2d - Should the temporary increase in the DR reliability**
7 **cap to 3 percent be extended?**

8 SDG&E has not come close to hitting the 3% reliability cap (or the previous caps)
9 with its regular portfolio of emergency programs such as BIP for the reasons discussed
10 above. Historically, this issue has been more of a concern for the other IOUs.

11 Going back to 2009 and as the Commission discussed in D.10-06-034, “D.09-08-027
12 reasoned that in recognition of the ongoing examination of the appropriate size and role of
13 emergency programs in R.07-01-041 Phase 3, we [the Commission] decline to expand
14 existing emergency-triggered programs or adopt new emergency programs with similarly
15 limited triggers.”¹²⁵ At that time, the cap was 3.5% of system peak statewide. D.10-06-
16 034, a year later, adopted a settlement that capped the amount of DR capacity at 2% of
17 system peak that was not price-triggered, and used for reliability purposes.¹²⁶ The cap was
18 intended to limit how much DR was relied upon in emergencies and to encourage portfolio
19 diversification. Interestingly, the 2009 decision discusses that the early cap was
20 experimentally put in place to test the “size and role” of emergency DR. Yet, SDG&E
21 would argue that what is being tested in the ERLP is still the size and the role, based on the

¹²⁵ D.10-06-034, p. 5.

¹²⁶ *Id.* at p.10.

1 performance of the various groups which are enrolled. Since SDG&E does not have
2 portfolio emergency DR and cannot attract the customers into its existing BIP, SDG&E is
3 hopeful about the role of ELRP in continuing to test and inform the Commission on what
4 such a cap could or should be. SDG&E suggests that, while the ELRP is a pilot, the
5 temporary increase should be continued so that the Commission can grow the ELRP and test
6 the pilot further, including whether it is reliable over many events and days, at which
7 incentive levels, and with which participating classes of customers and groups of
8 participants (with IOU enrollment or third-party enrollment and so forth).

9 From a policy perspective, SDG&E would submit that the Commission needs to
10 consider this issue in greater detail as part of the discussion if and when it develops a
11 regulatory record to decide if the ELRP should become a permanent program, what role it is
12 to play and at what cost in comparison to other resources (including other distributed energy
13 resources, other DR, and also procurement) in supporting grid reliability during
14 emergencies. Specifically, SDG&E suggests this since, with the proposed retirement of
15 BIP, the ELRP is SDG&E's only emergency DR option. Therefore, SDG&E is interested to
16 see the record in this proceeding developed on this issue by the other parties' testimony and
17 it may respond further if needed.

18 **C. Scoping Issue 7 – Do the demand response programs proposed by**
19 **PG&E, SCE, and SDG&E adequately take into consideration the**
20 **Commission's Environmental and Social Justice Action Plan? How**
21 **should the programs be modified to better meet the needs of**
22 **environmental justice communities?**

23 All of SDG&E's residential programs are open to low-income and customers in
24 environmental justice communities as defined in the ESJA Plan. SDG&E has the ability to
25 target messaging in our marketing in an effort to attract such targeted customers to the
26 programs. The Prepared Direct Testimony of April Bernhardt describes that targeted

1 marketing, education and outreach (MEO) tactics may include updates to the website,
2 collateral, radio, social media, videos, digital advertising, out of home and direct marketing
3 efforts such as email and/or direct mail campaigns as well as messaging through Community
4 Based Organizations (CBOs). These types of efforts can be tailored to certain areas, such as
5 zip codes. SDG&E regularly targets marketing towards residential customers in both
6 English and Spanish where appropriate. SDG&E also included in its MEO testimony of Ms.
7 Bernhardt the request for funding for additional customer research to better understand its
8 customers. All of these efforts continue to strengthen SDG&E's understanding of
9 environmental justice communities and how to reach them for programs that may benefit
10 them.

11 **D. Scoping Issue 8 – Should the Commission continue the exemption of**
12 **energy storage resources not coupled with fossil-fueled generation from**
13 **the Demand Response Prohibited Resources (PR) Policy (as established**
14 **in D.18-06-012)?**

15 SDG&E's position is, overall, the California Air Resources Board (CARB) sets rules
16 around generators and CARB should drive PR policy. However, the use of prohibited
17 resources, or back up generation, that is fossil-fueled and used to charge energy storage
18 resources, should continue to be exempt from the Demand Response Prohibited Resources
19 policy for use in the ELRP. SDG&E recommends that a comprehensive, consistent
20 statewide PR policy be adopted by CARB, including the use of PRs during DR events,
21 including grid emergencies. The goal of such a policy would be to eliminate confusion
22 between programs as to when and when not a PR can be used without relying on executive
23 orders or other actions during emergencies.

24 This aligns with past Commission policy largely as it has developed. D.18-06-012
25 stated: "Storage coupled with fossil-fueled resources should not be permitted to receive

1 incentives for load reduction during a demand response event¹²⁷ and as found in Ordering
2 Paragraphs 2 & 3¹²⁸ of the same decision. Later, Decision 16-09-056, Conclusion of Law 10
3 modified the policy as follows: “The Commission should exempt energy storage, not
4 coupled with fossil-fueled generation, from the list of prohibited resources.” Decision 16-
5 09-056, Ordering Paragraph 3, further expounded and modified the policy as follows:

6 Beginning on January 1, 2018, the following list of resources are prohibited
7 to be used for load reduction during demand response events: distributed
8 generation technologies using diesel, natural gas, gasoline, propane, or
9 liquefied petroleum gas, in topping cycle Combined Heat and Power (CHP)
10 or non-CHP configuration. The following resources are exempt from the list
11 of prohibited resources: pressure reduction turbines and waste-heat-to-power
12 bottoming cycle CHP, as well as energy storage resources not coupled with
13 fossil-fueled generation....

14 SDG&E hopes that the Commission will keep things consistent as much as possible
15 in light of the need of a comprehensive PR policy during emergencies.

16 **E. Scoping Issue 9 – Should dual participation rules be modified or**
17 **clarified?**

18 SDG&E supports the allowance of customers dually participating in a DR program
19 and the ELRP as long as adequate protections and safeguards are incorporated in the ELRP
20 Terms and Conditions to make sure the ratepayer is protected and that double payments to a
21 customer or aggregator for the same load shed during event hours are eliminated with
22 certainty. SDG&E believes that allowing a customer to participate in ELRP and get an
23 incentive payment for any ILR that is in excess or over and above the existing DR
24 programs’ load shed commitment should be allowed and encouraged with verification.

¹²⁷ D.18-06-012 FOF 10, p. 14.

¹²⁸ *Id.* at OP 2 & 3, p. 16.

1 **F. Scoping Issue 10 – Should ratepayers provide funding in 2024-2027 for**
2 **continued modeling of DR potential and related research overseen by**
3 **Energy Division?**

4 Yes, ratepayers should provide funding to continued or new research overseen by the
5 Energy Division, but SDG&E specifies that it has already included such funding in its
6 budget request in its current application in the Direct Prepared Testimony of Lizette Garcia-
7 Rodriguez as a line item for “CPUC Research.” SDG&E’s portion of its contribution to
8 such costs should not exceed what SDG&E has sought approval for within this instant
9 application.

10 **XI. CONCLUSION**

11 SDG&E is pleased to make these Demand Response program, pilots and studies
12 proposals, which support both the goals of California as well as SDG&E to create a cleaner
13 environment and transition DR for the future. SDG&E looks forward to the Commission’s
14 review and collaboration in moving DR forward in the future; to reduce GHG, to meet grid
15 and reliability needs in the most cost-effective manner, and to give customers greater choice.

16 This concludes my prepared direct testimony.

1 **XII. WITNESS QUALIFICATIONS**

2 My name is E Bradford Mantz. My business address is 8335 Century Park Court,
3 San Diego, California 92123. I am employed by SDG&E as the Demand Response and
4 Segmentation Manager for Customer Programs. My responsibilities include the design,
5 implementation and management of demand response programs for SDG&E. I have been
6 employed by SDG&E since 2010.

7 I graduated from The University of Texas, Austin with a Bachelor of Arts in
8 Business Administration with emphasis in Marketing and Petroleum Land Management and
9 a minor in Geology.

10 I have testified previously before the California Public Utilities Commission.

APPENDIX A

SDG&E Program Implementation Plans

Demand Response

2024-2027

**Proposed Plan to Terminate Demand Response
AC Saver (direct load control switches), subset of Smart Energy Program
Program Implementation Plan (PIP)
2024 Transition Year**

Program Name

AC Saver (direct load control switches), subset of Smart Energy Program

Projected Program Budget

Program Name	2024 Budget	Total 2024 Budget
AC Saver (direct load control switches)	\$705,991	\$705,991

Projected Load Impacts by Year

Program Name	2024 Load Impact
AC Saver (direct load control switches)	N/A

Projected Cost Effectiveness for 2024

Program Name	2024 Cost Effectiveness
AC Saver (direct load control switches)	N/A

Program Descriptors

- **Market Sector:**
 - Residential & Commercial
- **Program Statement:**
 - AC Saver is a supply side demand response program. AC Saver participants have a direct load control switch installed on their air-conditioner that can be cycled at 50% or 100% for Residential customers and 30% or 50% for Commercial customers. Events last between two and four hours per day and may be called between April and October. The maximum number of annual events is 20 with 5 additional events that may be called during CAISO or SDG&E emergencies only.
 - The direct load control switches are aging and 90% of the switches currently installed for our participating customers are approaching their end of life cycle.
 - We are proposing to terminate AC Saver direct load control switches and transition customers to Smart Energy thermostats or other approved technology.
 - Data shows that customer interest in thermostats far outweighs direct load control switches

**Proposed Plan to Terminate Demand Response
AC Saver (direct load control switches), subset of Smart Energy Program
Program Implementation Plan (PIP)
2024 Transition Year**

- **Program Transition Plan**

- Direct Load Control switches will be deactivated at the end of the 2023 Demand Response event season on October 31, 2023
- In an effort to maintain customer participation in Demand Response programs, all active participants will be communicated to encouraging them to continue to participate in Demand Response Programs.
- Outreach efforts to participants will be targeted and frequent with messaging to encourage joining the Smart Energy thermostat program.
- Customers will continue to receive an annual bill credit on their SDG&E bill in December, with a fixed \$50 credit for their enrollment in the program.
- Customers will continue to be required to stay enrolled in the program through October 31 to earn the annual bill credit.
- The operational program support will continue with a dedicated Advisor and specialist from SDG&E to help support the transition. The budget also includes a contract with a third party for a period of six to twelve months to assist with the transition of customers. The contractor will provide field services for those customers requesting to have their equipment removed and call center support to ensure on going availability for customer calls to provide a good customer experience during the transition period.

Program Termination Rationale and Expected Outcomes

- **Old Technology/Aging Switches**

- One way direct load control switch is one-way communication, we have no insight of knowing if customer receives signal or if they are using their air conditioner when an event is called.
- 90% of the customers currently enrolled in the program with direct load control switches are approaching their end of life cycle. Equipment was installed between 2005 and 2009.
- Data shows that interest in thermostats far outweighs direct load control switches.

Incentives

- Customers will also receive an annual program incentive. The annual incentive will be applied as a bill credit on the customer bill in December.

- **Planned Communication**

- SDG&E plans to roll out a targeted marketing campaign to customers enrolled in the AC Saver program with direct load control switches.
- The marketing campaign will consist of direct mail and email.
- This effort is designed to keep customers enrolled in our Demand Response programs.

**Proposed Plan to Terminate Demand Response
AC Saver (direct load control switches), subset of Smart Energy Program
Program Implementation Plan (PIP)
2024 Transition Year**

- **Program Transition Objectives**
 - Transition as many customers as possible over to the Smart Energy Program with smart thermostat technology as it will enable participants to automate load reduction strategies minimizing the need for the customer to take actions to initiate load reduction strategies during an event.

 - The key program transition goals are to:
 - Optimize and maximize DR program participation and awareness
 - Achieve predictable load reduction

- **Program cycle:**
 - 2024-2027
 - 2024 transition year only

Program Transition Strategy

- **Target Audience**

Customers who are enrolled on AC Saver with direct load control switches

- **Marketing, Education & Outreach**
 - The AC Saver direct load control program marketing effort will focus on transitioning customers to Smart Energy Program with thermostats.

- **Customer Research & Feedback**
 - SDG&E worked with a third party to determine the uptake in thermostat enrollments.
 - Residential and Commercial Participant Surveys were completed and customers expressed interest in continuing on a Demand Response program.

- **Program Transition Delivery**
 - Efforts are targeted to be completed between June and December 2024

Pilot Implementation Plan

Pilot Name

Battery Storage Pilot

Projected Pilot Budget

	2024	2025	2026	2027	TOTAL
Battery Storage DR Pilot	\$1,498,699	\$1,526,411	\$1,524,716	-	\$4,549,826

Pilot Descriptors

Market Sectors

- Residential
- Small Commercial

Pilot Classification

- Pilot

Pilot Term: 3 Years

- 2024: IT systems built, 3rd Party contract awards/customer enrollment
- 2025-26: Pilot Period – Residential & Commercial customers
- 2027: Pilot Period – EM&V Report

Pilot Design

The Battery Storage DR Pilot seeks to answer questions about how residential and small commercial customers with existing batteries currently use them and whether existing storage systems can be successfully dispatched for demand response events or to respond to day-ahead market prices.

SDG&E's battery storage pilot will be available to residential and small commercial customers (with maximum monthly demand less than 20kw) and has existing battery technology installed to participate in demand response (DR) events called by the CAISO or for M&E purposes and respond to CAISO day-ahead prices as a Virtual Power Plant (VPP).

Eligible customers in both residential and commercial sectors will already have a battery installed on-site and agree to allow SDG&E and/or other approved third parties to control their battery and access the battery data. Incentive levels to participate in this pilot will be specifically tested in two ways. First, the levels will be tested through a research survey that will assess the effect of different incentive structures and levels on residential and commercial customers' choices. Second, incentive levels will be tested through offering different incentive levels upon customer recruitment.

SDG&E wants to understand how customers utilize their Storage systems (Batteries) in the absence of any utility intervention, what program design elements will maximize net program benefits, what types of demand response impacts are feasible from controlling the batteries.

The pilot has four specific objectives to be evaluated.

Objective 1: How are battery storage customers using their storage on their own?

Objective 2: What is the dispatchable load reduction potential during the RA window (4pm-9pm)?

Objective 3: What is the optimal incentive structure and amount?

Objective 4: Can SDG&E use battery storage to respond to Day-Ahead market prices?

Objective 5: What baseline/settlement methods work best for battery storage in the CAISO market?

Implementation

Eligible customers must have an existing battery system or/or solar and be enrolled with one of the approved vendors for this pilot. Residential and commercial customers in SDG&E's territory are eligible to apply to participate in this program.

The total annual incentive for any single participant is limited to \$50,000 per year, unless approval is granted by the CPUC. Both Direct Access (DA) and Community Choice Aggregation (CCA) customers are eligible to participate in this pilot, however customers with Backup Generators are not eligible. Customers may de-enroll from the pilot at any point.

Events & Triggers

Two event triggers will be tested as part of the pilot: response to Local utility system need and Day-ahead CAISO market price.

Local System Need:

- An event can be dispatched from June-October, 24 hours a day, including weekends and holidays
- Event duration may range from two (2) hour to six (6) hours
- Up to 60 events per year
- Events may be triggered for testing/evaluation purposes.

Day-Ahead Triggers:

- An event can occur year-round, 24 hours a day, including weekends and holidays
- The CAISO day-ahead price profile will be sent to each device in advance of the event
- Up to 36 events may be called per year, Events may be triggered for economic dispatch or for testing/evaluation purposes.

This test will depend on system integration and capability, thus might not be applicable to all the participants and can be limited by the cost and budget.

Multiple Program Participation

Under no circumstance will a participant taking service under this schedule receive more than one incentive payment for the same interrupted/curtailed load. Eligibility for Multiple Program Participation is defined in Rule 41

Appropriate Electric Metering

All participants must be located in SDG&E's service territory and must have an SDG&E-installed and approved interval data recording meter that provides at least hourly interval data with related

telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems is required for participation.

Battery vendors choosing to participate in this pilot will be required to provide individual participant end use charge and discharge profiles on a regular (e.g. monthly) basis to SDG&E, as well as individual battery settings and status.

Notification Equipment

Only customers with eligible battery technology will be able to participate in this pilot. The required technology includes, but is not limited to, systems that are able to be controlled remotely by SDG&E and/or approved third-party providers. Note that customers without battery storage are not precluded from procuring and installing, at no expense to SDG&E, a battery from an approved vendor in order to participate in the study.

Incentives and Settlement

As part of this pilot, SDG&E will test different incentive levels, informed by the outcome of a conjoint survey that seeks to understand what incentive structures are most attractive to prospective participants. Parameters to be tested may include varying the percent of incentives delivered up-front, incentives per-event or per-kW reduction.

Evaluation Measurement & Verification

To evaluate the success of the pilot a separate load impact analysis will be conducted at the end of the pilot as described in the Load Impact Evaluation Plan that can be found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4B – Appendix A).

Marketing, Education & Outreach

The Marketing, Education and Outreach plan can be found in the Prepared Direct Testimony of April Bernhardt (Chapter 3B).

Program Implementation Plan (PIP)

Program Name

Capacity Bidding Program (CBP) Elect Option

Program Budget

The budget dollars listed below reflect the administrative, capacity and energy incentive costs.

Program Name	2024	2025	2026	2027	Total
Capacity Bidding Program	\$1,673,919	\$1,734,683	\$1,744,749	\$1,775,705	\$6,929,057

Program Descriptors:

Market Sector:

- Residential

Program Classification:

- Program

Program Design:

The Capacity Bidding Program offers customers and aggregators various product options by which participants can earn incentives when they reserve power reduction capacity with the availability and capability to meet requested load reductions during an emergency or abnormally high demands for power. This program is available to commercial/industrial customers receiving bundled service, Direct Access service or Community Choice Aggregation (CCA) service, and being billed on a commercial, industrial or agricultural rate schedule. Participation in this program must be taken in combination with the customer's otherwise applicable rate schedule. This program is also available to "Demand Response Providers," a third-party entity that combines the loads or one or more customers for the purpose of participating in this program.

For multiple program participation, see Electric Rule 41.

The Demand Response Providers recruit participants, help them develop demand reduction strategies, handle notifications of load shedding events, and distribute payments. Demand Response Providers have the flexibility to customize their offering to individual customers and to diversify the portfolio sufficiently to hedge the risk. Customer contracts with Demand Response Providers can include various elements such as a reservation payment, an energy payment, a penalty, or response requirements, among other things, that provide a different reward/risk proposition than SDG&E may be able to offer.

Program Objectives:

- Provide an option by which customers can contribute toward reducing peak energy consumption on the utility grid, while at the same time managing and controlling their individual energy consumption and costs.
- Reduce energy costs through customer participation which helps the state as well as the SDG&E community by the reduction of peak energy demands, as well as reducing the likelihood of rolling blackouts and rotating outages.
- Provide customers with tools to better manage their consumption and demand, maximize potential energy savings and participation in demand response programs.
- Target customers with maximum load reduction potential.

Implementation:

1. Eligibility

The CBP is open to any commercial, industrial or agricultural customer with an interval meter. Working directly through SDG&E or through an Aggregator, customers choose the event product that best fits with their operational needs.

Enrolled participants are expected to remain in the program for a minimum of 12 calendar months and must have the required metering and operable communication equipment while participating in the program. Participants may opt out of the program any time after their 12-month term.

2. Operating Months

The program operates May through October (6 months). Weekends and holidays are excluded. Except for the emergency-only events, which may be called on the weekends.

3. Events

There will be one curtailment window for an event on weekdays between the hours of 1:00 p.m. to 9:00 p.m. There is a limit of one event per day, six events per month and a maximum of 24 hours per month. In addition to the six events per month, in the event of an emergency SDG&E may call up to three additional emergency-only events in a given month, only after the six regular events are exhausted. There is a limit of three consecutive events per week.

Emergency events are defined as CAISO declared emergencies or for a local utility system emergency.

4. Event Triggers

Events may be called if the following event triggers are met at the utilities' discretion:

- a) **Elect Day-Ahead Event:** Price trigger is \$200, \$400 or \$600 MWh for the Day-Ahead or as utility system conditions warrant. Day-Ahead market price is defined as CAISO Default Load Aggregation Point (DLAP) or applicable pnode SDGE-APND Day-Ahead market locational marginal price (DAM LMP) Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent

System Operator shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule. The utility may call two test events per year at its discretion.

- b) **Elect Day-Of Event:** Price trigger is \$200, \$400 or \$600 MWh for the Day-Of or as Utility system conditions warrant. Real time price is defined as the CAISO DLAP or applicable pnode SDGE-APND average hourly real time market locational marginal price (LMP). Whenever the CAISO has issued an alert or warning notice, the CAISO shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule. The utility may call two test events per year at its discretion.

5. **Notification Times**

- a) **Day-Ahead Event:** Customers will be notified of an event no later than 5:00 p.m. the day before.
- b) **Day-Of Event 40 Minute:** Customers will be notified of an event no later than 40 minutes before event.

6. **Incentives**

Aggregators will receive capacity and energy payments per the terms of the CBP Tariff¹ in return for their participation in the program.

7. **Marketing, Education & Outreach**

Internal groups will be educated about the CBP program details and customers' eligibility. The CBP Program will work internally to develop cross-program marketing collateral to educate and recruit customers. Communication to aggregators will become a primary focus to improve participation.

This program will primarily be marketed to commercial/industrial customers, receiving bundled service, Direct Access service or Community Choice Aggregation service, and being billed on a commercial, industrial or agricultural rate schedule. Program participation criteria will include the following:

- a) Non-Residential Customers
- b) A fifteen-minute interval data recording meter with related telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems.

8. **EM&V**

EM&V and load impact evaluation will be performed per approved protocols at the end of the program year.

¹ https://tariff.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_CBP.pdf

Pilot Implementation Plan

Program Name

Direct Dispatch Pilot

Projected Program Budget

	2024	2025	2026	TOTAL
Direct Dispatch Pilot	\$1,948,082.00	\$1,415,095.00	\$1,433,414.00	\$4,796,591.00

	2027	TOTAL
Direct Dispatch Program	\$2,702,582.00	\$2,702,582.00

SDG&E is requesting funding to run this pilot for 2024-26. SDG&E will examine the success of the pilot and if the pilot has met its objectives and the design provides benefit to the portfolio then SDGE will request that it be converted to a program in 2027.

Pilot Descriptors

Market Sector

- Commercial & Industrial

Pilot Classification

- Pilot

Pilot Term

- 2024: Pilot preparation, IT systems built, 3rd Party contract awards, recruit participants.
- 2025-2026: Pilot Period
- 2027: EM&V Report

Pilot Design

Many facilities in SDG&E service territory have existing ADR capabilities that do not currently participate in DR programs.

SDG&E is proposing a three (3) year pilot for commercial and industrial customers that already own qualifying ADR enabled equipment (excluding Smart Thermostats) that include Energy Management Systems, Energy Storage and “future” technologies that can curtail their energy usage when dispatched by the utility for demand response events.

SDG&E is technology agnostic and therefore sees this pilot as a new way to engage all commercially viable ADR communication protocols to participate in the pilot.

Pilot Objectives

The goal of this pilot is to test if a pure “pay for performance” pilot with no penalties for various types of open ADR enabled energy management systems dispatched by the utility and provides a slightly higher incentive than current DR programs will motivate commercial and industrial customers to participate in demand response events.

Implementation

SDG&E will issue a request for proposal (RFP) for the customer outreach, recruitment, and retention of participants for the pilot which will include all activities required to solicit and retain participants by a third-party implementer. SDG&E will retain dispatching of events and customer settlements for the pilot and will have final approval of all marketing and recruitment activities related to the pilot.

Eligible participants are commercial and industrial customers with monthly maximum demand greater than 20kW with an existing ADR technology installed on site.

SDG&E will contract with a third-party for customer enrollments but will be responsible for calling of events and providing customer settlements.

Incentives & Settlement

The pilot would pay \$1/kWh for day ahead or day-of participation of verified, dispatchable, fully automated load shed per event with no penalties for non-performance and would be dispatched by the utility.

Events & Triggers

Events for the Direct Dispatch Pilot:

- Can be dispatched 365 days a year, any day of the week (Sunday – Saturday) including holidays during the hours of 4:00 p.m. to 9:00 p.m.
- DDP event durations shall be as follows:
 - minimum two (2) hours and a maximum of four (4) hours.
- DDP has no annual dispatch limit.
- A DDP event may be triggered for local system need, in response to high forecasted temperatures, extreme conditions, emergencies or whenever the CAISO has issued an alert or warning notice.
- Events may be triggered for testing/evaluation purposes.
- Customers or participants must be registered with SDG&E’s Demand Response Automation Server (DRAS) in order to be signaled for event participation.

Multiple Program Participation

Under no circumstance will a participant taking service under this schedule receive more than one incentive payment for the same interrupted/curtailed load. Eligibility for Multiple Program Participation is defined in Rule 41

Appropriate Electric Metering

All customers must be located in SDG&E’s service territory and must have an SDG&E installed and approved interval data recording meter that provides fifteen-minute interval data with related

telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems.

Event Notification/Communication

The Direct Dispatch Pilot participants may choose from two event notification strategies. For day-ahead notification, participants will be notified no later than 5 p.m. the day before a DDP (day-ahead) event will be in effect. Participants in the day-of notification strategy will be notified up to 30 minutes prior to the start of the event.

Customers may elect to be notified of a DDP event by email message or text message. Notice will also be posted on the Utility's website. Customers shall be responsible for ensuring the receipt of any notifications sent by the Utility. Utility does not guarantee the reliability of the e-mail system or Internet site by which the customer has elected to receive notification. A Customer must inform the Utility of its preferred notification method and to provide the Utility with a valid and accurate email address or cell number for a text message, as applicable. The customer shall be responsible for notifying the Utility of any changes to the contact information.

Once a DDP event has been declared, there are no conditions that would warrant the DDP event to be cancelled.

Notification Equipment

The technology required to participate in this program must be able to receive and execute curtailment signals directly from SDG&E or approved third-party vendors. Participants are expected to have an existing battery, energy management system, or other energy management technology in place prior to pilot participation.

Evaluation Measurement & Verification

To evaluate the success of the pilot a separate load impact analysis will be conducted at the end of the pilot as described in the Load Impact Evaluation Plan that can be found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4B – Appendix A).

Marketing, Education & Outreach

SDG&E will issue a request for proposal (RFP) for the customer outreach, recruitment, and retention of participants for the pilot which will include all activities required to solicit and retain participants by a third-party implementer. SDG&E will have final approval of all marketing and recruitment activities related to the pilot.

Pilot Implementation Plan

Program Name

Residential Electric Vehicle Demand Response Pilot

Projected Program Budget

	2024	2025	2026	TOTAL
Electric Vehicle Demand Response Pilot	\$933,366	\$1,070,432	\$1,329,372	\$3,333,171.

Pilot Descriptors

Market Sector

- Residential

Pilot Classification

- Pilot

Pilot Term

- 2024: Pilot preparation, IT systems built, 3rd Party contract awards, participant recruitment.
- 2024-2026: Pilot Period
- 2027: EM&V Report

Pilot Design

SDG&E proposes an EV-focused demand response pilot that offers customers the options to optimize charging and receive incentives in exchange for participating in demand response events that provide benefits to the grid.

The pilot will last for three (3) years (2024-2026) and enable SDG&E to:

1. Demonstrate the ability of residential EVs to be a reliable Demand Response resource.
2. Demonstrate the ability of EVs to increase load between 10am–2 pm during the Spring DR season (Feb to April) to absorb excess solar generation
3. Test staggering the "start and stop" EV charging times during the super off-peak period to avoid secondary EV peak when at scale.
4. Validate the program design, incentive structure, and cost-effectiveness

The pilot will also target all EV customers, including those who have not signed up for EV TOU rates. Incentives will be offered as a bill credit. SDG&E will offer three incentive structures to customers and allow them to select the option they prefer:

- Option 1. \$16 monthly incentive
- Option 2. \$100 enrollment and \$100 annual incentive
- Option 3. \$200 enrollment and \$100 annual incentive with 2-year commitment

SDG&E plans to offer customers the option of managed charging via communications with the vehicle computer or via controlling the electric vehicle charger.

When SDG&E calls an event, the customer's charging will be paused or slowed down for the duration of the event. The pilot will allow customers to set battery charge level and time targets to reflect their preferences. Customers will have the ability to opt-out of an event at any time without penalties.

Pilot Objectives

The pilot objectives are to:

1. Demonstrate the ability of residential EVs to be a reliable Demand Response resource during RA window (4pm-9pm).
2. Demonstrate the ability of EVs to increase load between 10am–2 pm in Spring season (Feb to April) to reduce excess solar curtailment
3. Test the theory to "start and stop" EV charging during super off-peak period to avoid secondary EV peak when at scale
4. Validate the program design, incentive structure, and cost-effectiveness

Implementation

Application Process

Eligible customers must be SDG&E residential customers and have an existing battery electric vehicle or plug-in hybrid electric vehicle. Customers who opt for electric charger load control must use approved Electric Vehicle Supply Equipment (EVSE) providers and install the vehicle charger. Customers who opt for managed charging via telematics must sign a contract authorizing SDG&E and its vendor permission to manage charging via telematics.

Customers may unenroll from the pilot at any time. Customers must agree to allow SDG&E and contracted vendors to manage their electric vehicle charging, including setting charge and discharge profiles on a daily or per-event basis. Customers will be able to specify the target level of charge and time by when that level of charge must be reached.

Events & Triggers

- Events will be dispatched during DR season from May 1st to October 31st any day of the week (Sunday – Saturday) during the hours of 3:00 pm to 10:00 pm.
- Load building events can be dispatched during the Spring DR season from February 1st to April 30th, in which case SDG&E will instruct EVs to charge from 10 am to 2 pm when there is excess solar energy on the grid.
- Events will typically last 2-3 hours,
- The EV pilot will have a maximum dispatch limit of 60 events per season
- SDG&E may also trigger events for testing/evaluation purposes.

Multiple Program Participation

Under no circumstance will a participant taking service under this schedule receive more than one incentive payment for the same interrupted/curtailed load. Eligibility for Multiple Program Participation is defined in Rule 41

Appropriate Electric Metering

All customers must be located in SDG&E's service territory and must have an SDG&E installed and approved interval data recording meter that provides hourly interval data with related telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems.

As part of the solicitation, SDG&E will ask vendors if they can supply end-use vehicle charge data, vehicle miles driven, level of charging, and location (home / away) of charging. Vendors who can supply vehicle end-use data will be preferred in the bidding process.

Event Notification/Communication

Customers may elect to be notified of EV load reduction or load building events by e-mail message or text message. SDG&E's will also post notice of events on its website. A customer must register with SDG&E's Demand Response Automation Server (DRAS), inform SD&GE of their preferred notification method.

SDG&E will send day-ahead notifications to the customers and send an alert 30 minutes before the event starts. Customers can opt-out of the event at any time.

Notification Equipment

The technology required to participate in this program must be able to receive and execute curtailment signals directly from SDG&E or applicable third-party vendors. Participants are expected to have an existing electric vehicle in place prior to pilot participation.

Incentives

SDG&E will offer three (3) incentives options to pilot participants and allow them to pick the one they like. The three (3) incentive options are:

- Option 1. \$16 monthly incentive
- Option 2. \$100 enrollment and \$100 annual incentive
- Option 3. \$200 enrollment and \$100 annual incentive with 2-year commitment

The incentives will be paid to customers as bill credits or incentive rebate

Evaluation Measurement & Verification

To evaluate the success of the pilot a separate load impact analysis will be conducted at the end of the pilot as described in the Load Impact Evaluation Plan that can be found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4A – Appendix A).

Pilot Implementation Plan

Program Name

Residential Electric Vehicle Demand Response Pilot

Projected Program Budget

	2024	2025	2026	TOTAL
Electric Vehicle Demand Response Pilot	\$933,366	\$1,070,432	\$1,329,372	\$3,333,171.

Pilot Descriptors

Market Sector

- Residential

Pilot Classification

- Pilot

Pilot Term

- 2024: Pilot preparation, IT systems built, 3rd Party contract awards, participant recruitment.
- 2024-2026: Pilot Period
- 2027: EM&V Report

Pilot Design

SDG&E proposes an EV-focused demand response pilot that offers customers the options to optimize charging and receive incentives in exchange for participating in demand response events that provide benefits to the grid.

The pilot will last for three (3) years (2024-2026) and enable SDG&E to:

1. Demonstrate the ability of residential EVs to be a reliable Demand Response resource.
2. Demonstrate the ability of EVs to increase load between 10am–2 pm during the Spring DR season (Feb to April) to absorb excess solar generation
3. Test staggering the "start and stop" EV charging times during the super off-peak period to avoid secondary EV peak when at scale.
4. Validate the program design, incentive structure, and cost-effectiveness

The pilot will also target all EV customers, including those who have not signed up for EV TOU rates. Incentives will be offered as a bill credit. SDG&E will offer three incentive structures to customers and allow them to select the option they prefer:

- Option 1. \$16 monthly incentive
- Option 2. \$100 enrollment and \$100 annual incentive
- Option 3. \$200 enrollment and \$100 annual incentive with 2-year commitment

SDG&E plans to offer customers the option of managed charging via communications with the vehicle computer or via controlling the electric vehicle charger.

When SDG&E calls an event, the customer's charging will be paused or slowed down for the duration of the event. The pilot will allow customers to set battery charge level and time targets to reflect their preferences. Customers will have the ability to opt-out of an event at any time without penalties.

Pilot Objectives

The pilot objectives are to:

1. Demonstrate the ability of residential EVs to be a reliable Demand Response resource during RA window (4pm-9pm).
2. Demonstrate the ability of EVs to increase load between 10am–2 pm in Spring season (Feb to April) to reduce excess solar curtailment
3. Test the theory to "start and stop" EV charging during super off-peak period to avoid secondary EV peak when at scale
4. Validate the program design, incentive structure, and cost-effectiveness

Implementation

Application Process

Eligible customers must be SDG&E residential customers and have an existing battery electric vehicle or plug-in hybrid electric vehicle. Customers who opt for electric charger load control must use approved Electric Vehicle Supply Equipment (EVSE) providers and install the vehicle charger. Customers who opt for managed charging via telematics must sign a contract authorizing SDG&E and its vendor permission to manage charging via telematics.

Customers may unenroll from the pilot at any time. Customers must agree to allow SDG&E and contracted vendors to manage their electric vehicle charging, including setting charge and discharge profiles on a daily or per-event basis. Customers will be able to specify the target level of charge and time by when that level of charge must be reached.

Events & Triggers

- Events will be dispatched during DR season from May 1st to October 31st any day of the week (Sunday – Saturday) during the hours of 3:00 pm to 10:00 pm.
- Load building events can be dispatched during the Spring DR season from February 1st to April 30th, in which case SDG&E will instruct EVs to charge from 10 am to 2 pm when there is excess solar energy on the grid.
- Events will typically last 2-3 hours,
- The EV pilot will have a maximum dispatch limit of 60 events per season
- SDG&E may also trigger events for testing/evaluation purposes.

Multiple Program Participation

Under no circumstance will a participant taking service under this schedule receive more than one incentive payment for the same interrupted/curtailed load. Eligibility for Multiple Program Participation is defined in Rule 41

Appropriate Electric Metering

All customers must be located in SDG&E's service territory and must have an SDG&E installed and approved interval data recording meter that provides hourly interval data with related telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems.

As part of the solicitation, SDG&E will ask vendors if they can supply end-use vehicle charge data, vehicle miles driven, level of charging, and location (home / away) of charging. Vendors who can supply vehicle end-use data will be preferred in the bidding process.

Event Notification/Communication

Customers may elect to be notified of EV load reduction or load building events by e-mail message or text message. SDG&E's will also post notice of events on its website. A customer must register with SDG&E's Demand Response Automation Server (DRAS), inform SD&GE of their preferred notification method.

SDG&E will send day-ahead notifications to the customers and send an alert 30 minutes before the event starts. Customers can opt-out of the event at any time.

Notification Equipment

The technology required to participate in this program must be able to receive and execute curtailment signals directly from SDG&E or applicable third-party vendors. Participants are expected to have an existing electric vehicle in place prior to pilot participation.

Incentives

SDG&E will offer three (3) incentives options to pilot participants and allow them to pick the one they like. The three (3) incentive options are:

- Option 1. \$16 monthly incentive
- Option 2. \$100 enrollment and \$100 annual incentive
- Option 3. \$200 enrollment and \$100 annual incentive with 2-year commitment

The incentives will be paid to customers as bill credits or incentive rebate

Evaluation Measurement & Verification

To evaluate the success of the pilot a separate load impact analysis will be conducted at the end of the pilot as described in the Load Impact Evaluation Plan that can be found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4A – Appendix A).

Pilot Implementation Plan (PIP)

Program Name

Grid Isolation Controls Pilot (GICP)

Projected Program Budget

	2024	2025	2026	TOTAL
Grid Isolation Controls Pilot	\$1,026,644.00	\$1,030,443.00	\$1,034,356.00	\$2,882,526.00

SDG&E requested funding to run this pilot for 2024-26. SDG&E will examine the success of the pilot and if the pilot has met its objectives and the design provides benefit to the portfolio then SDGE will request that it be converted to a program.

Market Sector

- Residential

Pilot Classification

- Pilot

Pilot Term: 3 years

- 2024: Pilot preparation, IT systems built, 3rd Party contract awards.
- 2025-2026: Pilot Period
- 2027: EM&V Final Report

Pilot Design

The pilot seeks to pioneer the adoption of technologies that allow customers to safely “isolate” from the grid on demand from the utility during PSPS events, local outages, or CAISO declared emergencies.

The technology must have imbedded a public safety interlock that conforms to national electric code requirements, has UL approval and prevents back feeding a de-energized grid during a Public Safety Power Shutoff (PSPS) event or in the event the grid is down for other causes. It must also be able to be switched to grid synchronized mode when the grid is energized.

The Grid Isolation Controls Pilot (GICP) will pay for the purchase and installation costs for new and innovative technologies that enable the safe isolation of homes from the grid for participation in Demand Response programs.

Pilot Objectives

The pilot will test the ability of residential customers to safely isolate from the grid when dispatched by a utility signal in response to a PSPS or demand response event.

The pilot has the following objectives to be evaluated. Specifically:

1. Can participants effectively and safely isolate from the grid in response to a signal from the utility?
 - a. What amount of load impact can be provided to the grid as a result and for how long?

- b. Can isolation help to mitigate the duck curve and local system peak loads? How and to what effect?
2. Can the technology be locationally dispatched by utility circuit ID or zip code?
3. What is the customer experience during isolation events?
4. Does this technology provide similar or additional benefits when installed within Disadvantaged Communities (DACs)?

Implementation

This pilot seeks to enroll between 50-100 residential premises for participation. As part of the pilot, SDG&E will attempt to recruit participants in low income or other disadvantaged communities. All participants should have either existing solar, battery storage, or an electric vehicle installed in order to be eligible.

SDG&E will issue a request for proposal (RFP) seeking a third-party implementer that can provide and install the specified grid isolation technology and will include all activities required to solicit and retain participants. SDG&E will retain dispatching of events and customer settlements for the pilot and will have final approval of all marketing and recruitment activities related to the pilot.

SDG&E will provide at no cost to the participants the islanding technology necessary for evaluation in the pilot. Participants must participate for the duration of the pilot in order to retain ownership of the technology. Failure to do so risks the removal of the equipment and claw back of any received incentives.

GICP events can be dispatched 365 days a year, any day of the week (Sunday-Saturday), including weekends and holidays, in response to CAISO emergencies, PSPS events, or for testing purposes. Events will typically last from two (2) to four (4) hours with a maximum event duration of four (4) hours. Advance notice of events will be provided to customers via text message and email. There is no annual dispatch limit.

Direct Access (DA) or Community Choice Aggregation (CCA) customers are eligible to participate in the pilot. Customers with backup generators (BUG) may not participate in this pilot unless, as part of their application agreement they agree to not use the BUG to self-supply electricity during events.

Multiple Program Participation

Under no circumstance will a participant taking service under this schedule receive more than one incentive payment for the same interrupted/curtailed load. Eligibility for Multiple Program Participation is defined in Rule 41.

Appropriate Electric Metering

All participants must be located in SDG&E's service territory and must have an SDG&E installed and approved interval data recording meter that provides fifteen-minute interval data with related telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems is required for participation.

Event Notification/Communication

Participants may elect to be notified of a GICP event by email message or text message. Notice will also be posted on the Utility's website. Participants shall be responsible for ensuring the receipt of any notifications sent by the Utility. Utility does not guarantee the reliability of the e-mail system or Internet site by which the participant has elected to receive notification. A Participant must inform the Utility of its preferred notification method and to provide the Utility with a valid and accurate email address or

cell number for a text message, as applicable. The participant shall be responsible for notifying the Utility of any changes to the contact information.

GICP event notifications using e-mail must, at its own expense, have access to the internet. Once a GICP event has been declared, there are no conditions that would warrant the GICP event to be cancelled.

The islanding technology used in the pilot must be capable of being signaled by SDG&E's Demand Response Automation Server (DRAS).

Incentives and Settlement

Participants will have the full cost of the islanding technology, including installation, paid for by SDG&E in return, participants must participate for the duration of the pilot in order to receive ownership of the technology. SDG&E will retain dispatching of events and customer settlements for the pilot.

Evaluation Measurement & Verification

To evaluate the success of the pilot a separate load impact analysis will be conducted at the end of the pilot as described in the Load Impact Evaluation Plan that can be found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4B – Appendix A).

Marketing, Education & Outreach

SDG&E will have final approval of all marketing and recruitment activities related to the pilot as proposed by the 3rd party implementer.

Program Implementation Plan (PIP)

Program Name

Smart Energy Program

Program Budget

The budget dollars listed below reflect the administrative, capacity and energy incentive cost.

Program Name	2024	2025	2026	2027
Smart Energy Program	\$2,394,101	\$2,587,462	\$3,008,520	\$3,122,893

Projected Load Impacts by Year

Program Name	2024	2025	2026	2027
Smart Energy Program	7	8	9	10

Projected Cost Effectiveness by Year

Program Name	2024-2027 Cost Effectiveness
Smart Energy Program	TRC 0.4

Program Descriptors

Market Sector

Open to Residential and Non-residential

Program Classification

Supply Resource

Program Statement

Smart Energy Program (SEP) is a program that allows residential and non-residential customers to participate with a customer provided device. The device must be able to curtail energy use or control energy storage; it must be able to receive a communication directly from the utility or the manufacturer must be able to respond to a communication from the utility demand response management system. Customers will receive an incentive for initially joining the program and an annual payment at the end of the year for continued participation.

1. Eligibility

The Smart Energy Program allows individual customers with an approved device that can control a customer's end use to participate in the program. Devices that control energy storage are eligible as well. This is open to residential and non-residential customers, receiving bundled electric service, Direct Access electric service or Community Choice Aggregation electric service, and being billed on a commercial, industrial or agricultural rate schedule. Program participation criteria will include the following:

1. An interval data recording meter with related telecommunications capability, compatible with the Utility's meter reading, time-of-use billing, and telecommunications systems.
2. If a customer is also participating in another demand response program the customer may not enroll in SEP unless permitted by Electric Rule 41.
3. Customer must have electric service (e.g., not gas only).
4. Customers must have an approved device that can curtail energy use or dispatch energy storage during event hours when directed to so do by SD&E. In order for the device to qualify either the device must be able to receive a communication directly from the utility or the manufacturer must be able to respond to a communication from the utility demand response management system.

2. Operating Months

The program will operate 7 days a week, during the months of April through October (7 months)

3. Curtailement Window

There will be one curtailment window for an event between the hours of 12:00 p.m. to 9:00 p.m. There is a limit of one event per day and 24 event hours per month. There is a maximum of three consecutive events. There is also a maximum of 20 events per year, although up to 5 additional events may be called in emergency only. Emergency events are defined as CAISO declared emergencies or for a utility system emergency.

4. Event Triggers

Smart Energy Program Trigger Heat Rates (Btu/kwh)							
	April	May	June	July	August	September	October
Day-Ahead Market	35,000	35,000	35,000	25,000	25,000	25,000	35,000
Real Time Market	130,000	130,000	130,000	35,000	35,000	35,000	130,000

5. **Notification Time**

There is no requirement to notify customers of events. However, all participants are typically notified of events the day ahead.

Program Rationale

The SEP allows participation by individual customers. Marketing efforts should educate customers on participation benefits:

- Receive an upfront and ongoing incentives for saving energy during temporary critical times.
- Help the environment by conserving energy when conservation is needed most.

Objectives

- Provide an option by which customers can contribute toward reducing peak energy consumption on the utility grid, while also managing and controlling their individual energy consumption and costs.
- Reduce energy costs through customer participation, which helps the State and San Diego County by the reduction of peak energy demands, as well as reducing the likelihood of rolling blackouts and rotating outages.
- Provide customers with tools to better manage their consumption and demand, maximize potential energy savings and participation in demand response programs.

Implementation Design

Incentives (program benefits)

- Participants will receive an enrollment incentive when they join the program. This enrollment incentive will be calculated for each device by taking the average load reduction of the device (kW) and multiplying by \$200.
- Customers will also receive an annual program incentive. The annual incentive will be calculated by taking \$50 and multiplying the average load reduction of the device

Program cycle

2024-2027

Program budget

Total Administrative Cost

- Managerial and Clerical Labor, Human Resource Support and Development, Travel and Conference Fees, and General and Administrative Overhead (labor and materials).

Total Direct Implementation Cost

- Includes all financial incentives used to promote participation in a program and the cost of all direct labor, installation and service labor, hardware and materials, and rebate processing and inspection used to promote participation in a program.

Total Marketing & Outreach

- Includes all media buy costs and labor associated with marketing production.

Integrated Budget Allocated to Other Programs

- Includes budget utilized to coordinate with other DR programs.

Program Strategy

Target audience

Residential and Non-Residential

Marketing, Education & Outreach

Marketing will be performed by SDG&E using e-mail, social media, and web advertisements. When using e-mail SDG&E will target customers with higher energy use and those who are more likely to join the program (e.g., customers who recently moved in) In addition, SDG&E will encourage or require manufacturers to market the program to their existing customers as well.

Internal Training Efforts and Activities

Program Delivery

Customer Research & Feedback

The SEP Program will utilize the following tools for research and feedback:

- Smart Meter Data
- DR Participation Data
- Impact evaluations
 - Measure event and non-event changes in energy use due to the program
 - Provide estimates of gross and net energy and demand saving
- Process evaluations
 - Provide recommendations to improve program effectiveness
 - Document program procedures and activities
 - Measure customer satisfaction

Key stakeholders

Program issues and risks

- Event fatigue
- DRAM and CBP residential as a competing program for the same customer base
- Necessity to sign agreements with manufacturers

Statewide coordination

Statewide coordination will occur with the other IOU when feasible.

Program Attributes

Program Design Barriers to Overcome

Innovation

Allowing automated DR lessens the need for customer action to respond to DR events.
Allowing customer choice and preferences ensures that customer satisfaction remains high.
Allowing more types of devices to participate in the program will increase the load reduction from the program and the opportunities customers have to participate.

EM&V

EM&V will be performed and reported per usual protocols including load impacts.

APPENDIX B

**SDG&E Tariffs, Contracts,
Applications, and Change Forms
2024-2027**



**SCHEDULE ~~AC-SMART ENERGY~~
PROGRAMSAVER(SEP)
~~AIR CONDITIONER (AC) SAVER~~**

Sheet 1

APPLICABILITY

~~The Smart Energy Program (SEP) AC-Saver~~ is a voluntary demand response program available to all customers with ~~air conditioner (AC) units installed at their premise with~~ SDG&E approved technology capable of curtailing the customers' ~~energy use AC unit~~. Customers with Net Energy Metering are eligible for this schedule. This schedule is available to customers receiving Bundled Utility Service and billed by the Utility. It is also available to Direct Access (DA) and Community Choice Aggregation (CCA) customers. If the DA or CCA provider offers a demand response program deemed similar by the California Public Utilities Commission (CPUC) per Decision (D.) 17-10-017 Ordering Paragraph 2, then this schedule will be closed to those customers within 30 days. Such DA or CCA customers will be disenrolled from this schedule within 1 year. Service on this schedule must be taken in combination with the customer's otherwise applicable rate schedule.

Electric Rule 41 will apply to this tariff.

TERRITORY

Within the entire territory served by the Utility.

RATES

All charges and provisions of a participating customer's otherwise applicable rate schedule shall apply. The tables below set forth the rates that will be paid to Participants under this schedule for each Product Special Condition 8. for a further description of the calculation of the incentive payment.

Annual Capacity Incentive Day-Of-Product

Residential Day-Of	Per Ton	Non-Residential Day-Of	Per Ton
100% cycling	\$27.00	50% Cycling	\$ 7.50
50% cycling	\$10.35	30% Cycling	\$ 4.50

Annual Capacity Incentive Day-Ahead-Product

	Annual Capacity Payment
Residential Day-Ahead	\$20.00
Non-Residential Day-Ahead	\$0

The annual capacity incentive will be equal to \$50 multiplied by the forecasted load reduction (kW) expected from the device.

Enrollment Incentive

The enrollment incentive will be equal to \$200 multiplied by the forecasted load reduction (kW) expected from the device.

SPECIAL CONDITIONS

- Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1, Definitions.

(Continued)



San Diego Gas & Electric Company
San Diego, California

Revised Cal. P.U.C. Sheet No. 34939-E

Canceling Revised Cal. P.U.C. Sheet No. 31672-E

SCHEDULE ~~AC-SMART ENERGY~~
~~PROGRAMSAVER(SEP)~~
~~AIR CONDITIONER (AC) SAVER~~

Sheet 1

- 2. Qualifying Customer: Service under this schedule is available to all customers receiving bundled Utility service or Direct Access (DA) services, and being billed by the Utility. It is also available to Direct Access (DA) and Community Choice Aggregation (CCA) customers. Customers electing to participate in the Program must meet and comply with all of the requirements for such participation as set forth in this Schedule. Service under this schedule is available to NEM customers. Customers must have a smart meter to be eligible for this program.

(Continued)

1C0

Advice Ltr. No. 3750-E-A

Decision No. _____

Issued by
Dan Skopec
Vice President
Regulatory Affairs

EBM - B-2

Submitted May 28, 2021

Effective May 28, 2021

Resolution No. _____



SCHEDULE SMART ENERGY
PROGRAM(SEP)SCHEDULE AC SAVER
AIR CONDITIONER (AC) SAVER

SPECIAL CONDITIONS (Continued)

3. Program Operation:

- a. The Program's operational season is from April 1 through October 31.
- b. Each operational month of the Program begins and ends at the beginning and ending of such calendar month.
- c. The Program's operational days are Monday through Sunday during the Program's operational season.
- d. The Program's operational hours are from noon to 9:00 p.m. during each of the Program's operational days.
- e. The maximum number of event hours that can be called per year is 80.
- f. The maximum number of consecutive days that events can be called is three.
- g. The maximum number of event hours that can be called per month is 24.
- h. The maximum number of events per day is one.
- i. The maximum number of events per year is 20. Once 20 events have been called additional five may only be called if the trigger "b" or trigger "c" from special condition 6 are met.

N
N

4. Interruptible Period: Each interruptible period ("Event") shall be the period of time during which the Utility has activated the program and will last a ~~sent a signal to the devices for cycling the AC unit for~~ a minimum of two (2) hours and a maximum of four hours (4). Customers ~~on the day-ahead product~~ will have the option to override the event.

5. Interruptible Period Termination: An Event will terminate at the end of the scheduled load reduction period not to exceed four (4) hours unless canceled sooner by SDG&E.

6. Program Trigger:

The trigger for the ~~AC Saver program~~ SEP is as follows:

- a. The utility may call an Event whenever the Utility's electric system supply portfolio reaches a resource dispatch equivalent to the heat rates Btu/kWh listed in the table below.
- b. Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent System Operator shall be entitled to request that the Utility, at its discretion, call a program event pursuant to this Schedule.
- c. SDG&E may call events for imminent local emergencies or local system needs.
- d. SDG&E may call two test events per year.
- e. SDG&E may trigger all or only part of the program, as warranted.

(Continued)



SCHEDULE SMART ENERGY
PROGRAM(SEP)SCHEDULE AC SAVER
AIR CONDITIONER (AC) SAVER

SPECIAL CONDITIONS (Continued)

6. Program Trigger: (Continued)

AC Saver SEP Trigger Heat Rates (Btu/kwh)							
	April	May	June	July	August	September	October
Day-Ahead Market	35,000	35,000	35,000	25,000	25,000	25,000	35,000
Real Time Market	130,000	130,000	130,000	35,000	35,000	35,000	130,000

7. Program Availability: An Event may be called during the Program's operational season, operational days and operational hours as defined above.

8. Incentive Payments:

a. ~~AC Saver Day Of Product~~ Annual Capacity Incentive

~~An annual bill credit will be paid based on the AC unit's tonnage and the customer elected cycling option as set forth in the annual capacity incentive day-of-product table above. If the tonnage is unknown SDG&E will calculate an estimated tonnage. The customers must be enrolled on the program through October 31st and for at least 45 days in order to receive a bill credit. In addition, the customer's device must be active and capable of receiving a signal (e.g. online or meter connected) in order to qualify for the annual bill credit. Validation that the device is active may not be available for all technologies, in these cases customers will receive the bill credit as long as they meet the enrollment requirement.~~

b. ~~AC Saver Day Ahead Product~~

~~An annual bill credit payment will be paid based on predicted load reduction of the device (kW) multiplied by \$50. When determining the predicted load reduction of the device for a specific customer, SDG&E may, but is not required to take into account characteristics such as customer class, customer location, the device settings, the load reduction capacity of the device, and other characteristics predicted to affect the load impact of the device as set forth in the annual capacity incentive day-ahead product table above. The customer must be enrolled in the program through October 31st and for at least 45 days in order to receive a the annual payment for specific calendar year. bill credit. In addition, the customer's device must be active and capable of receiving a signal (e.g. online or meter connected) in order to qualify for the annual bill credit. Validation that the device is active may not be available for all technologies, in these cases customers will receive the annual payment bill credit as long as they meet the enrollment requirement.~~

b. Customers will receive an enrollment payment after SDG&E approves the customers program application and the device is ready to receive a signal from SDG&E. The enrollment payment amount will be determined by multiplying the predicted load reduction of

T, C
T, C



**SCHEDULE SMART ENERGY
PROGRAM(SEP)SCHEDULE AC SAVER
AIR CONDITIONER (AC) SAVER**

the device (kW) by \$50. When determining the predicted load reduction of the device for a specific customer SDG&E may but is not required to take into account characteristics such as customer class, customer location, the device settings, the load reduction capability of the device, and other characteristics predicted to affect the load impact of the device. A customer may only receive one enrollment payment for the same predicted load reduction once every 7 years regardless of participation status.

- 9. Event Notification: ~~SDG&E may notify customers of events via the device display, device mobile app, email, and by other channels as warranted. AC Saver Day-Of participants are encouraged to sign up for a courtesy event notification voice message through SDG&E's website at www.summersaverprogram.com. AC Saver Day-Ahead participants are notified of events via thermostat display, customer portal and/or mobile app and other channels, as warranted.~~
- 10. Emergency Generation Limitations: Participating customers are prohibited from achieving energy reduction by operating backup or onsite standby generation.
- 11. Dispute Resolution: Any dispute arising from the provision of service under this schedule or other aspects of the Program will be handled as provided for in the Utility's Rule 10, Disputes.

APPENDIX C

Retail Baseline Working Group Report



RETAIL BASELINE WORKING GROUP

FINAL REPORT

March 1, 2021

**RETAIL BASELINE WORKING GROUP
FINAL REPORT**

Contents

EXECUTIVE SUMMARY..... 2

PURPOSE 3

CHRONOLOGY OF WORK DONE..... 3

REQUIRED ISSUES 4

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..... 4

2. Consider whether the customer or the Utility/Aggregator should select the retail baseline and determine the pros and cons of each..... 5

3. Consider flexibility in changing retail baselines..... 5

4. Consider whether the wholesale and retail baseline should be aligned, or can they be different..... 6

5. Consider the pros and cons of an aggregate versus individual baseline..... 7

APPENDIX..... 9

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 included¹² 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

Issue #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.

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.

Issue #5: 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.aiso.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



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

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CONTENTS

1	SUMMARY AND KEY FINDINGS	1
	Research Objectives	1
	Research Methodology	1
	Key Findings.....	3
	Recommendation and Rationale	4
	Recommendation.....	4
	Rationale	5
2	STUDY METHODS	7
	Calculating the 10-in-10 Day Matching Baseline.....	7
	Comparative Analysis.....	8
	Selecting Event-Like Days.....	8
	Calculating the Baselines	10
	Calculating Accuracy and Bias	11
3	RESULTS AND COMPARISONS	13
	Summary of Findings.....	13
	Event-like Day Results.....	13
	Results for All Scenarios	14
	Program-level Comparisons	15
	PG&E Results.....	16
	SCE Results	17
	SDG&E Results.....	19
A	ADDITIONAL TABLES AND GRAPHS	A-1
	PG&E Results by Program Year.....	A-1
	Day Ahead Program	A-1
	SCE Results by Program Year.....	A-3
	Day Ahead Program	A-3
	Day Of Program.....	A-5
	SDG&E Results by Program Year	A-7
	Day Ahead Program	A-7
	Day Of Program.....	A-9

LIST OF FIGURES

Figure 1-1	Description of Analysis Steps.....	2
Figure 2-1	Description of Analysis Steps.....	8
Figure 2-2	PG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019.....	9
Figure 2-3	SCE Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019.....	10
Figure 2-4	SDG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019.....	10
Figure 3-1	PG&E Day Ahead Program: Accuracy Comparison – Resource-level.....	16
Figure 3-2	PG&E Day Ahead Program: Bias Comparison – Resource-level.....	17
Figure 3-3	SCE Day Ahead Program: Accuracy Comparison – Resource-level	18
Figure 3-4	SCE Day Ahead Program: Bias Comparison – Resource-level	18
Figure 3-5	SCE Day Of Program: Accuracy Comparison – Resource-level.....	19
Figure 3-6	SCE Day Of Program: Bias Comparison – Resource-level.....	19
Figure 3-7	SDG&E Day Ahead Program: Accuracy Comparison – Resource-level.....	20
Figure 3-8	SDG&E Day Ahead Program: Bias Comparison – Resource-level.....	21
Figure 3-9	SDG&E Day Of Program: Accuracy Comparison – Resource-level	22
Figure 3-10	SDG&E Day Of Program: Bias Comparison – Resource-level	22
Figure A-1	PG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018) A-1	
Figure A-2	PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)	A-1
Figure A-3	PG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019) A-2	
Figure A-4	PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)	A-2
Figure A-5	SCE Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)...	A-3
Figure A-6	SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2018).....	A-3
Figure A-7	SCE Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019) ..	A-4
Figure A-8	SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2019).....	A-4
Figure A-9	SCE Day Of Program: Accuracy Comparison – Resource-level (PY 2018)	A-5
Figure A-10	SCE Day Of Program: Bias Comparison – Resource -level (PY 2018)	A-5
Figure A-11	SCE Day Of Program: Accuracy Comparison – Resource -level (PY 2019).....	A-6
Figure A-12	SCE Day Of Program: Bias Comparison – Resource -level (PY 2019)	A-6
Figure A-13	SDG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)	A-7
Figure A-14	SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)	A-7
Figure A-15	SDG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)	A-8
Figure A-16	SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)	A-8
Figure A-17	SDG&E Day Of Program: Accuracy Comparison – Resource-level (PY 2018).....	A-9
Figure A-18	SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2018).....	A-9
Figure A-19	SDG&E Day Of Program: Accuracy Comparison – Resource -level (PY 2019)...	A-10
Figure A-20	SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2019).....	A-10

LIST OF TABLES

Table 1-1	Accuracy and Bias – All Programs.....	3
Table 1-2	Average Decrease in Effectiveness – Aggregate Baselines.....	4
Table 1-3	Comparison of Recommended vs. Current Retail Baseline – Average Ranking.....	5
Table 2-1	Resource-level Comparison: Calculation Example.....	11
Table 3-1	Accuracy and Bias – Event-like Day Scenarios.....	14
Table 3-2	Average Decrease in Effectiveness – Event-like Days – Aggregate Baselines.....	14
Table 3-3	Accuracy and Bias – Event Days and Overall.....	15
Table 3-4	Average Decrease in Effectiveness – Event Days and Overall – Aggregate Baselines.....	15
Table 3-5	Comparison of Current Wholesale Baseline vs. Current Retail Baseline – Average Ranking.....	15

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 19-07-009¹, 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 aggregate² 10-in-10 baseline with a maximum 20% adjustment cap.

The D. 19-07-009 established the Working Group to investigate the following issues³:

1. Assess if an adjustment cap of $\pm 40\%$ is still suitable for retail settlement baselines when the day-of adjustment for wholesale settlement baselines is $\pm 20\%$.
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.

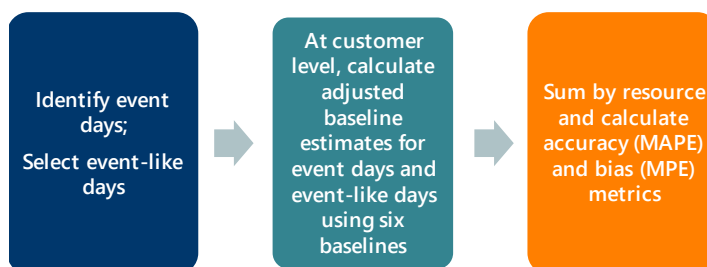
² Aggregate baselines are performed at the resource level, which is comparable to Product+Aggregator+Sub-LAP level.

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 analysis⁴

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 Nexant⁵, 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.ca-iso.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 five⁶ 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

Scenario	Best Accuracy			Least Bias		
	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 1-1, 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 data⁸.

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

Scenario	Lost Accuracy			Increased Bias		
	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 Baseline – Average Ranking

Scenario	Aggregate with 20% Cap		Individual with 40% Cap	
	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	<ul style="list-style-type: none"> • Provides more accurate estimates for individual customers. 	<ul style="list-style-type: none"> • Provides less accurate estimates at the resource level. • Is not in alignment with the wholesale settlement baseline.
Aggregate Baselines	<ul style="list-style-type: none"> • Provides more accurate estimates at the resource level. • Aligns with the wholesale settlement baseline. 	<ul style="list-style-type: none"> • 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.ca.iso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf>

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

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.

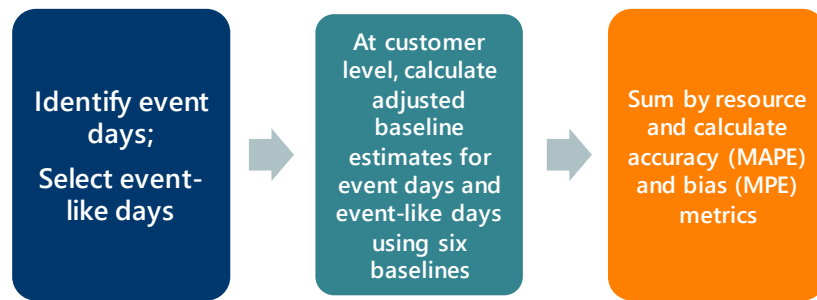
Note that a key distinction between the baselines occurs in step 7. The day-of adjustment ratio for an individual baseline is calculated at the customer level, i.e., for each customer and event day. However, for an aggregate baseline, the day-of adjustment ratio is calculated at the aggregate level,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

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:

Figure 2-1 Description of Analysis Steps



- 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.

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

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

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

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

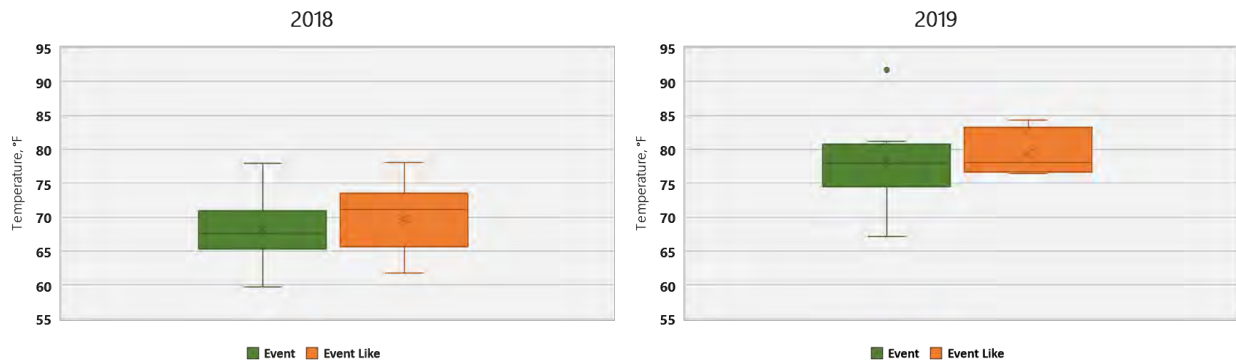


Figure 2-3 SCE Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019

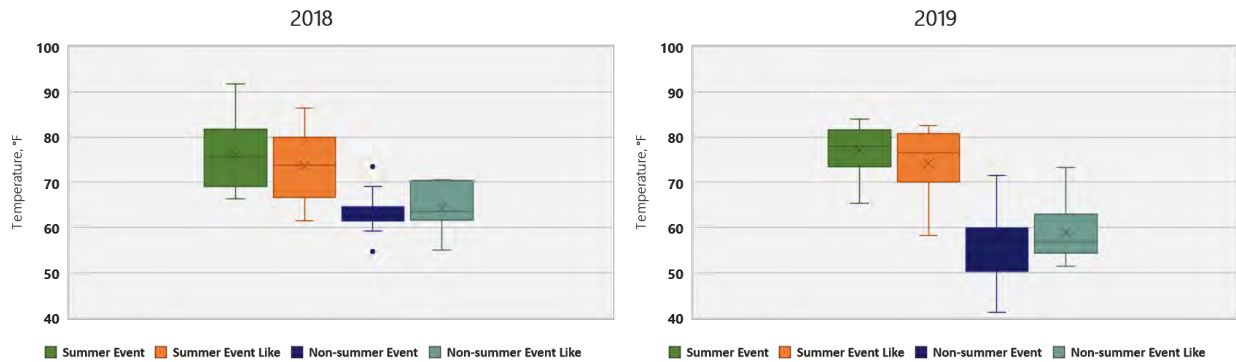
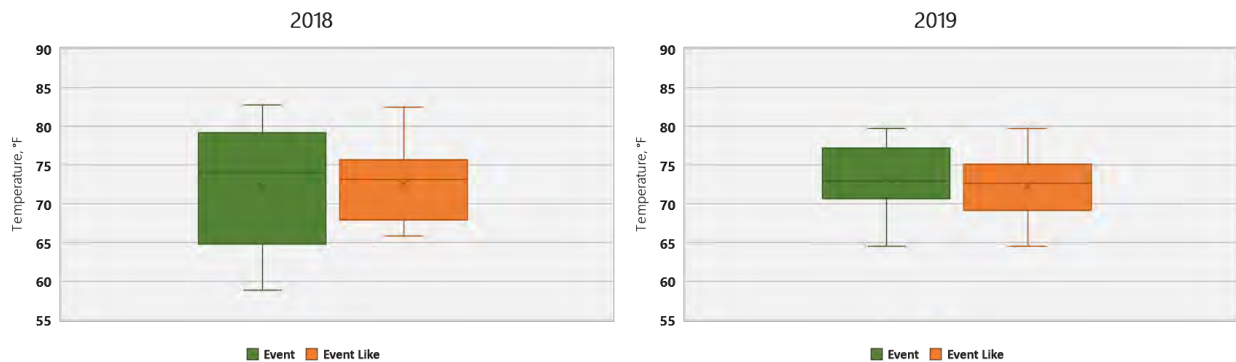


Figure 2-4 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019



Calculating the Baselines

Using the 10-in-10 day matching baseline methodology discussed above, we calculated the six baselines¹³ 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

<u>Individual Baseline</u>					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%
<u>Aggregate Baseline</u>					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, five¹⁴ 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 data¹⁵. 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			Least Bias		
	Overall	Ind v. Agg	Adj Cap	Overall	Ind v. Agg	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			Increased Bias		
	Agg 20%	Agg 30%	Agg 40%	Agg 20%	Agg 30%	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 Baseline – Average Ranking

Scenario	Aggregate with 20% Cap		Individual with 40% Cap	
	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

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

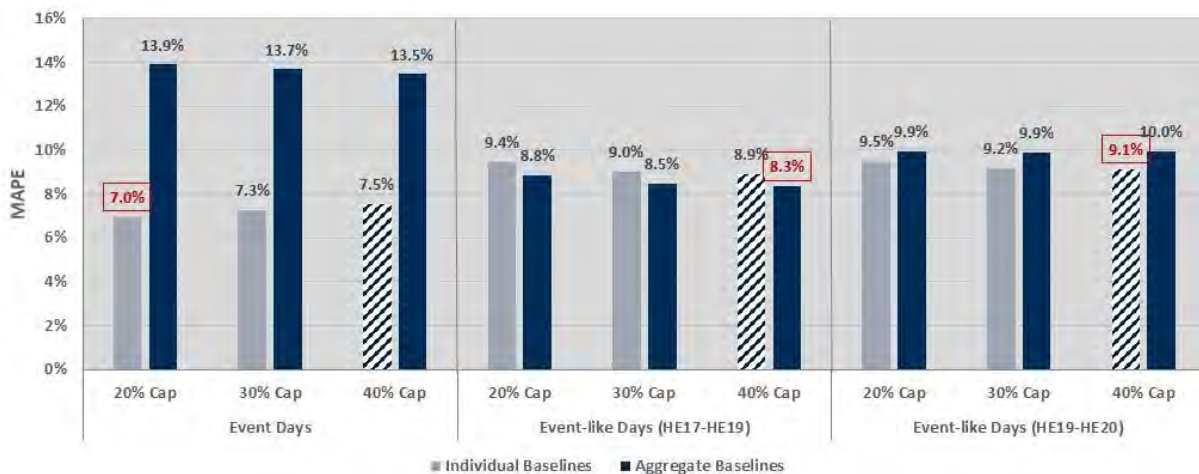
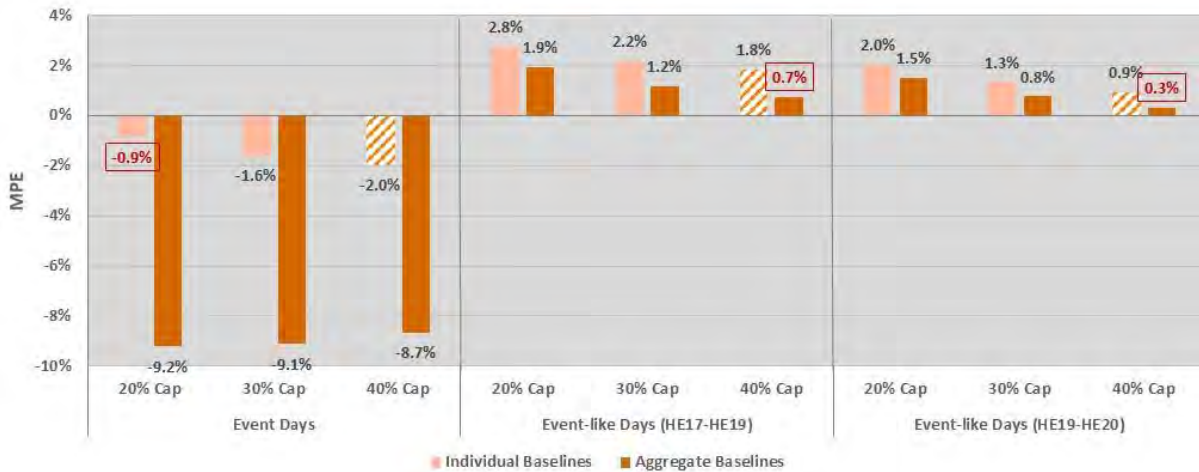


Figure 3-2 PG&E Day Ahead Program: Bias Comparison – Resource-level



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.

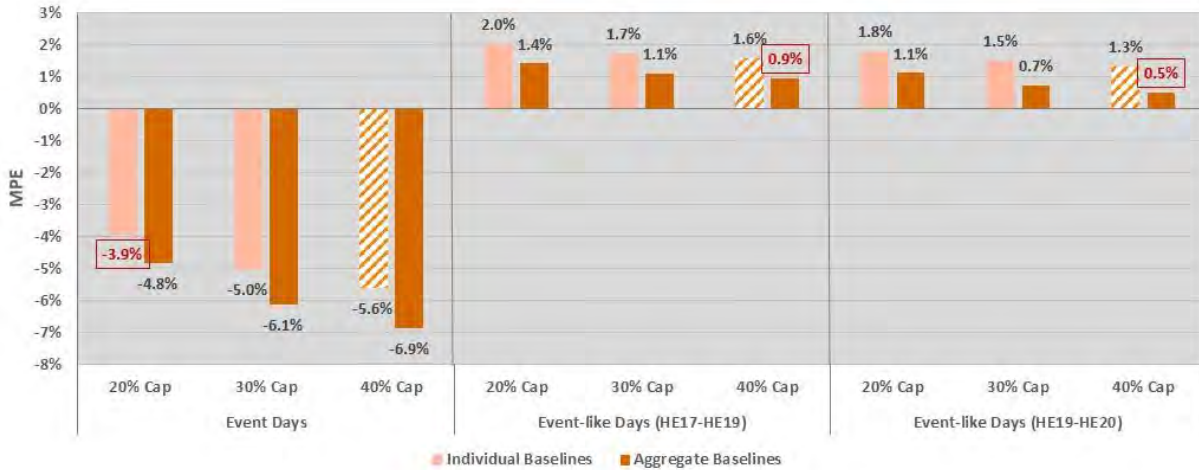
For SCE DA, we can conclude the following:

- 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

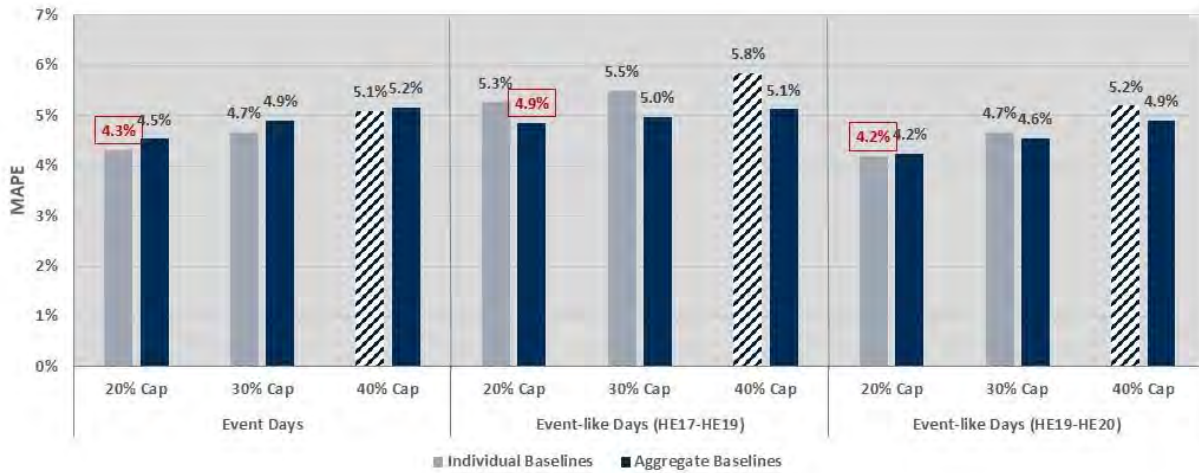
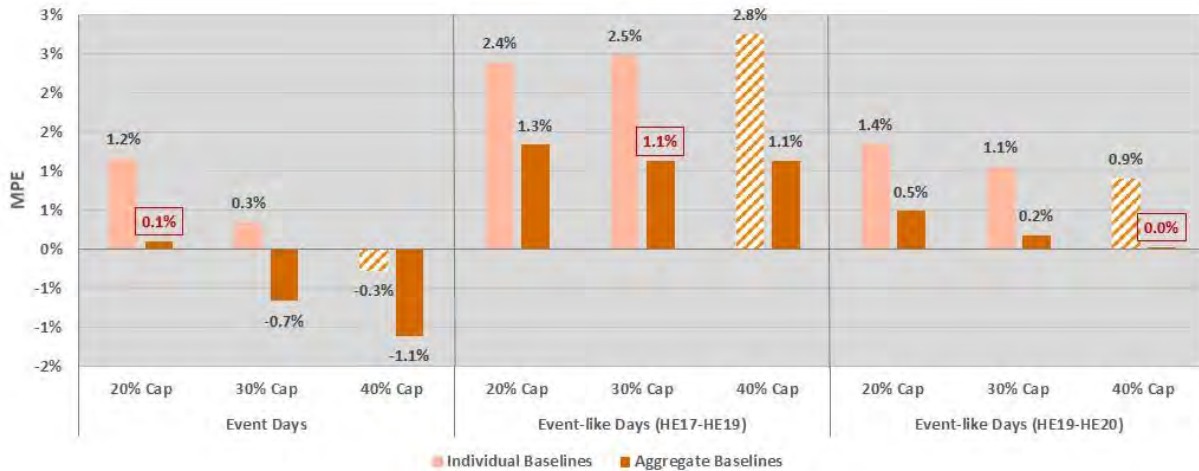


Figure 3-6 SCE Day Of Program: Bias Comparison – Resource-level



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

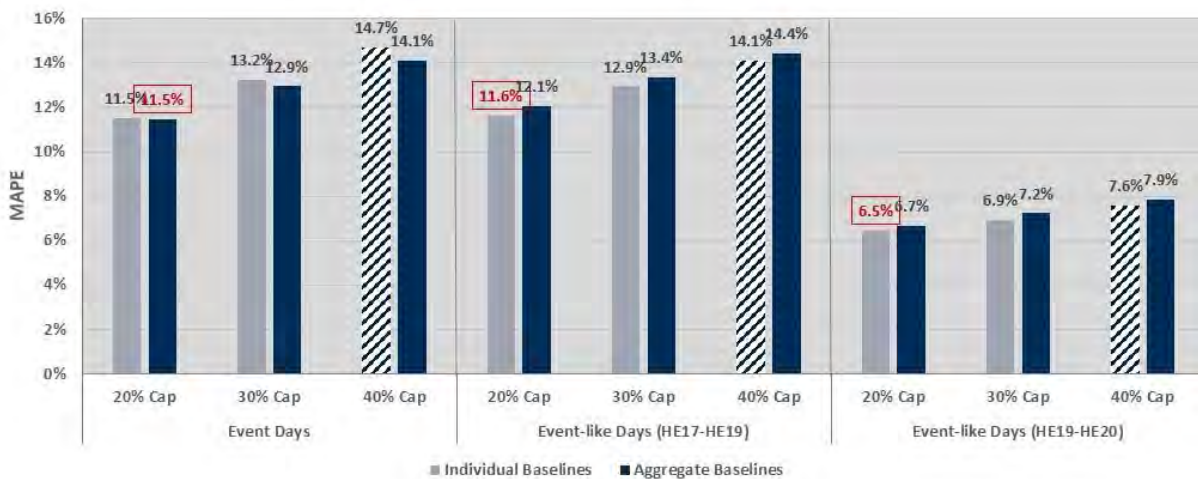


Figure 3-8 SDG&E Day Ahead Program: Bias Comparison – Resource-level



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

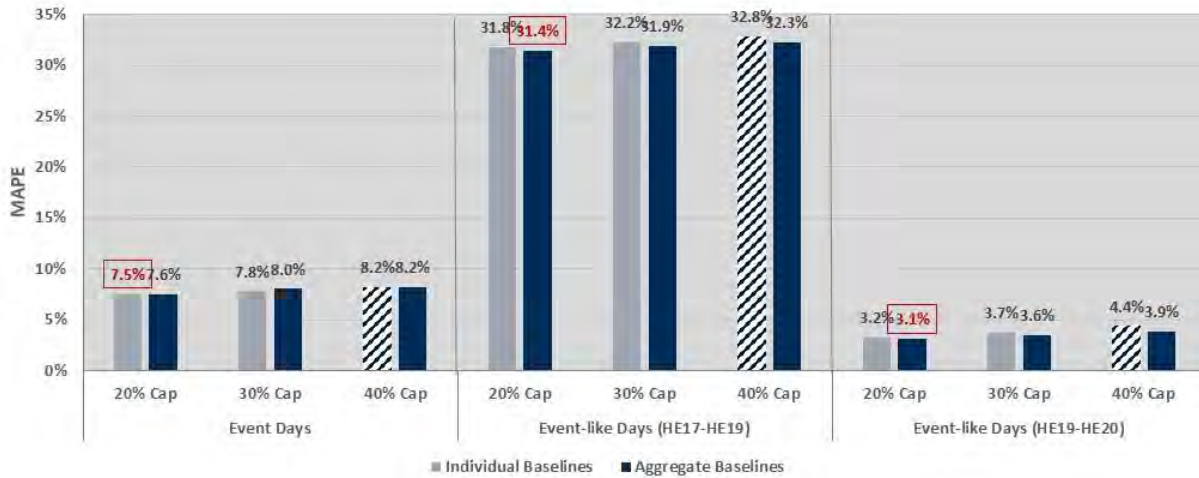
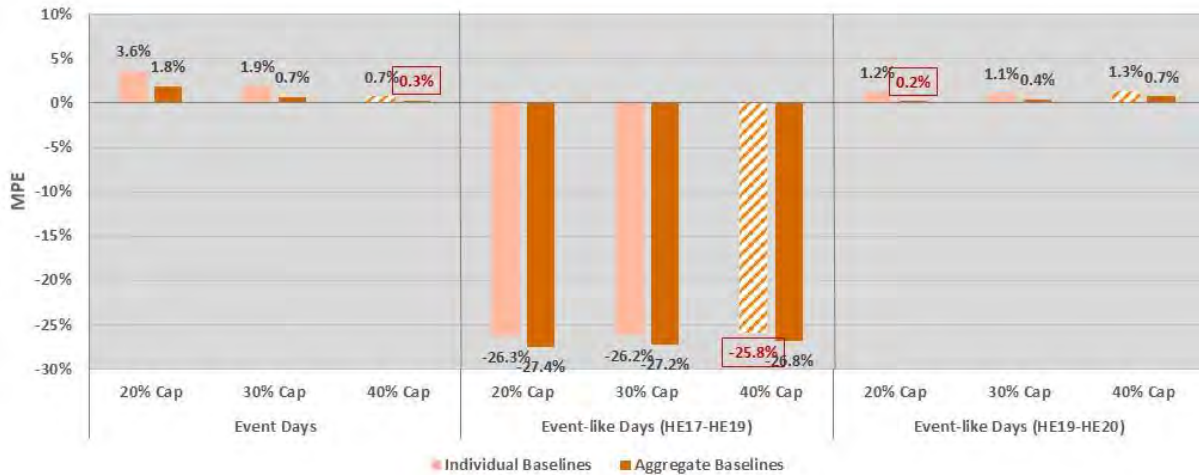


Figure 3-10 SDG&E Day Of Program: Bias Comparison – Resource-level



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)

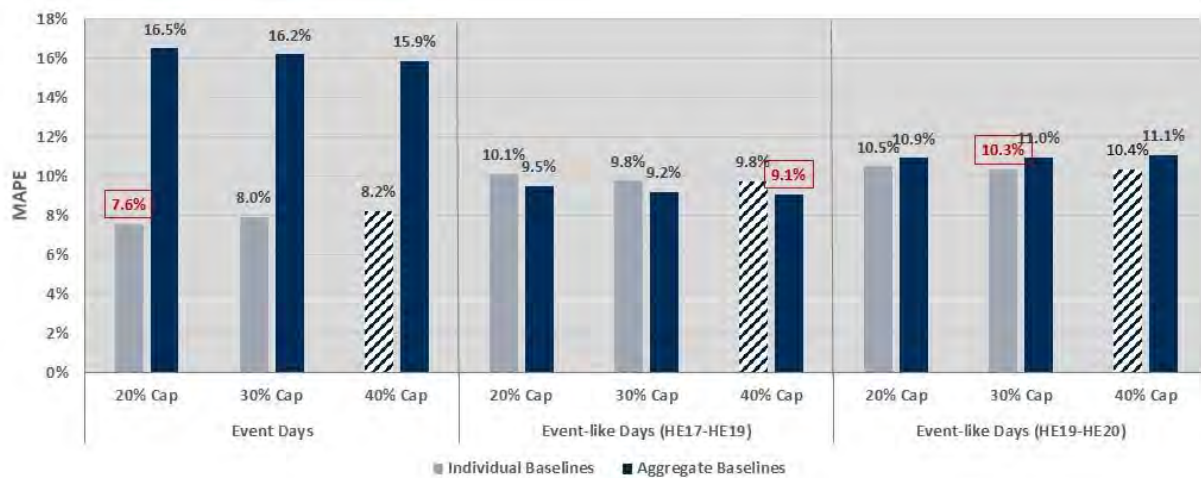
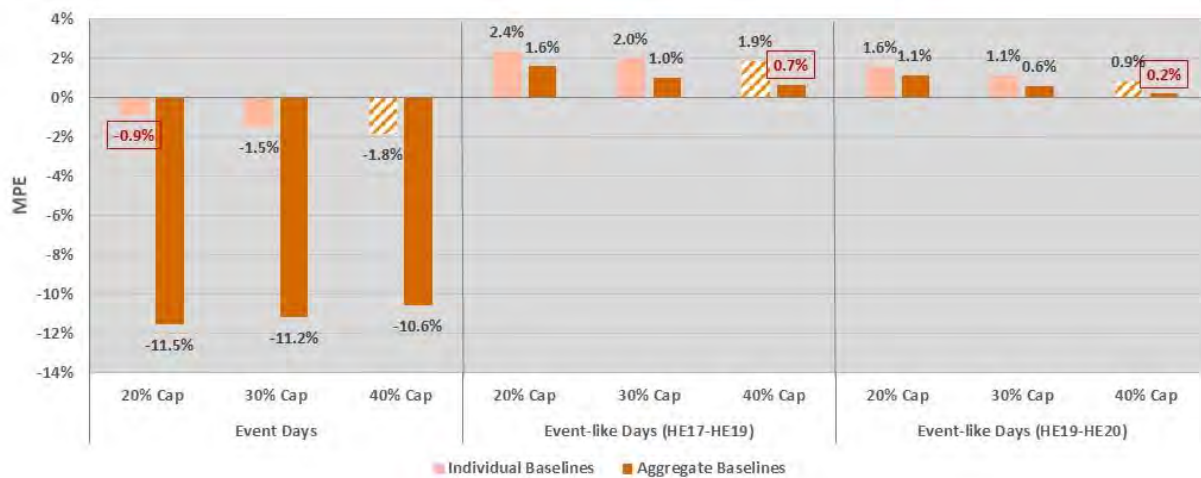


Figure A-2 PG&E Day Ahead Program: Bias Comparison – Resource-level (PY 2018)



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)

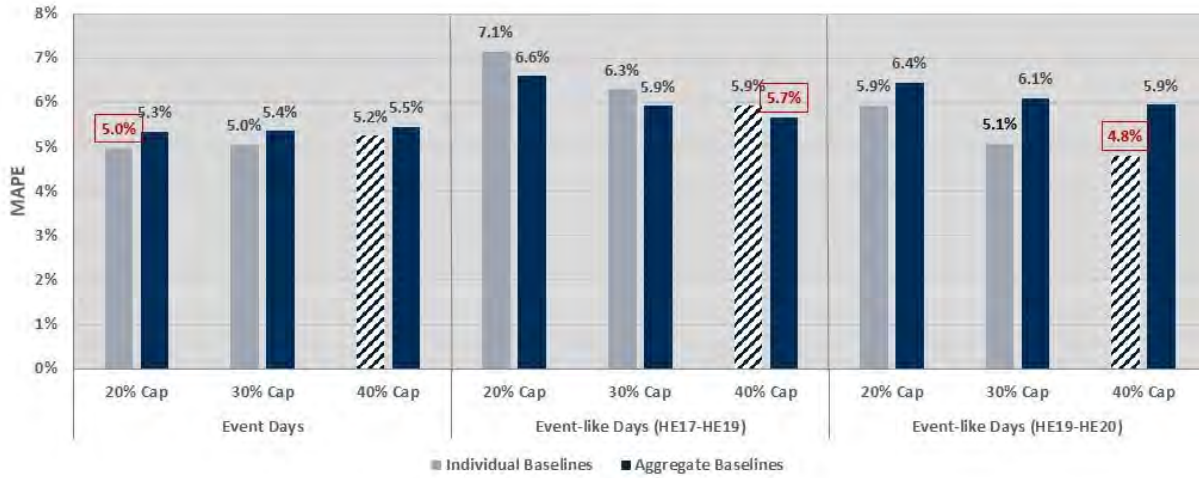
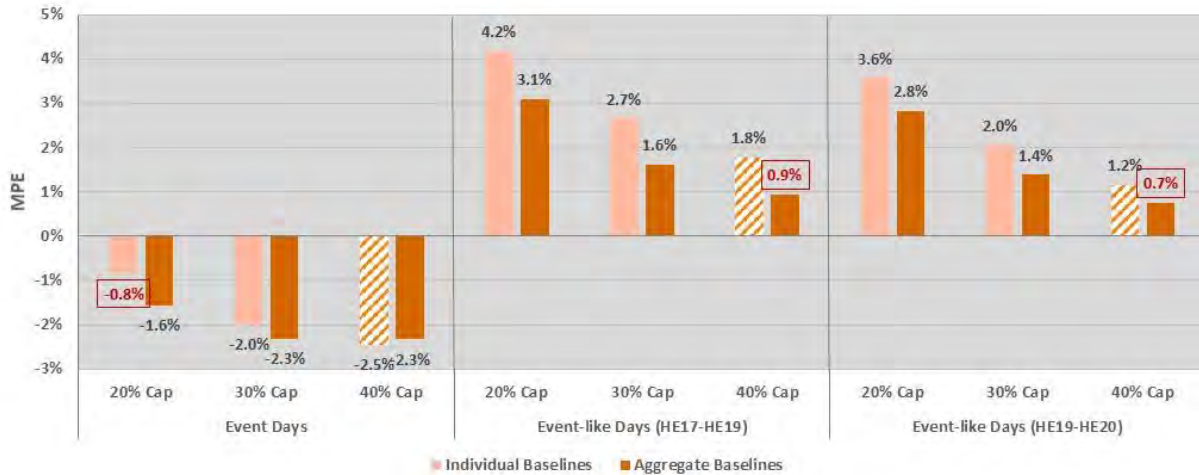


Figure A-4 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



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)

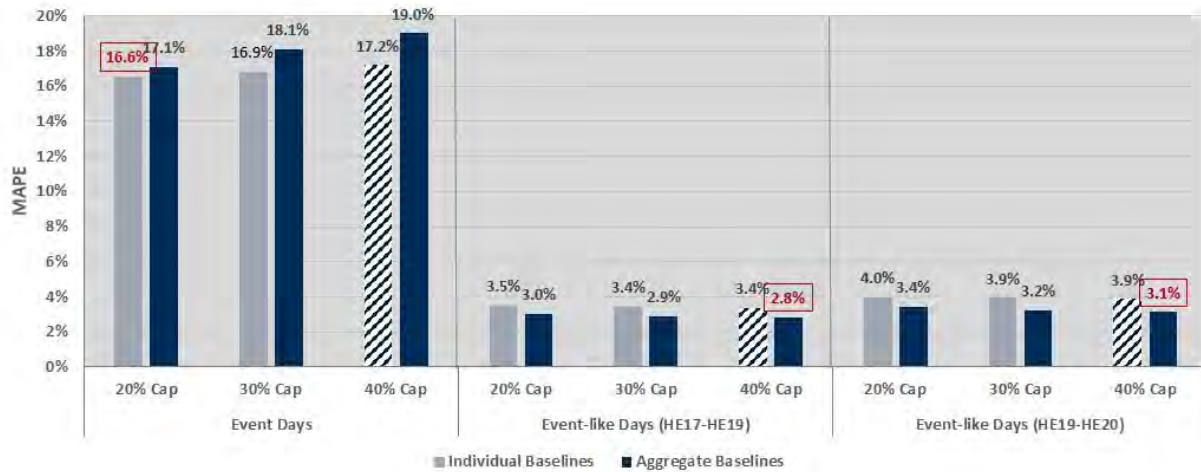
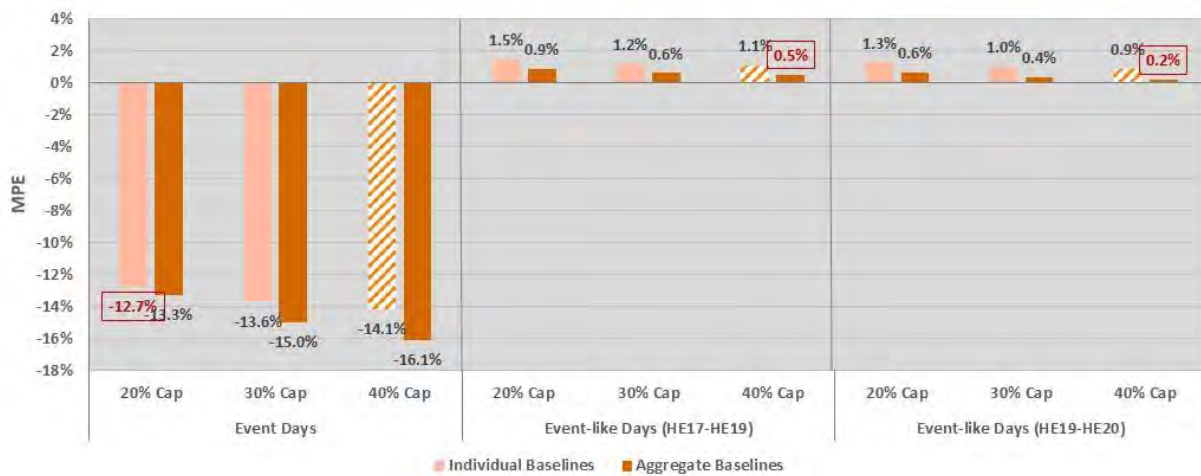


Figure A-6 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



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)

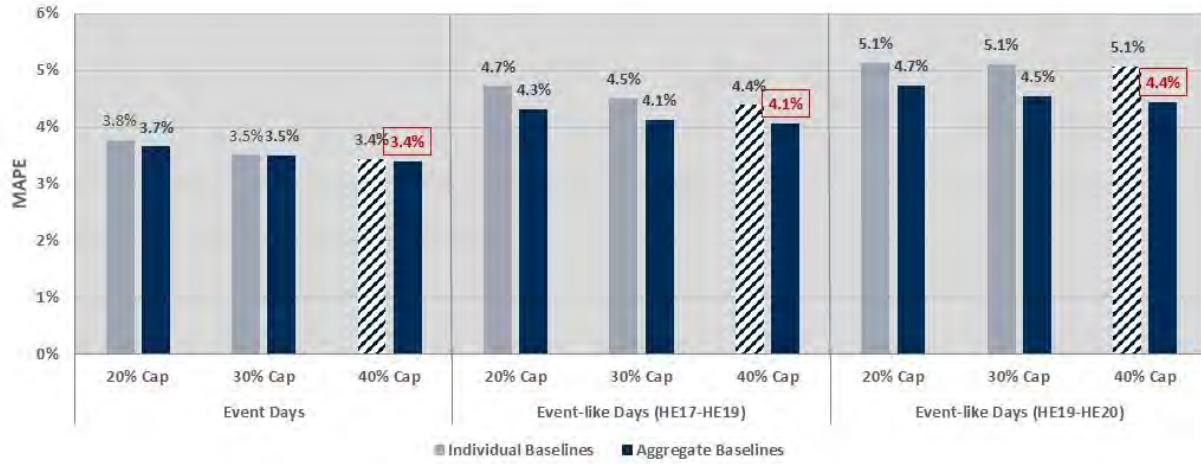
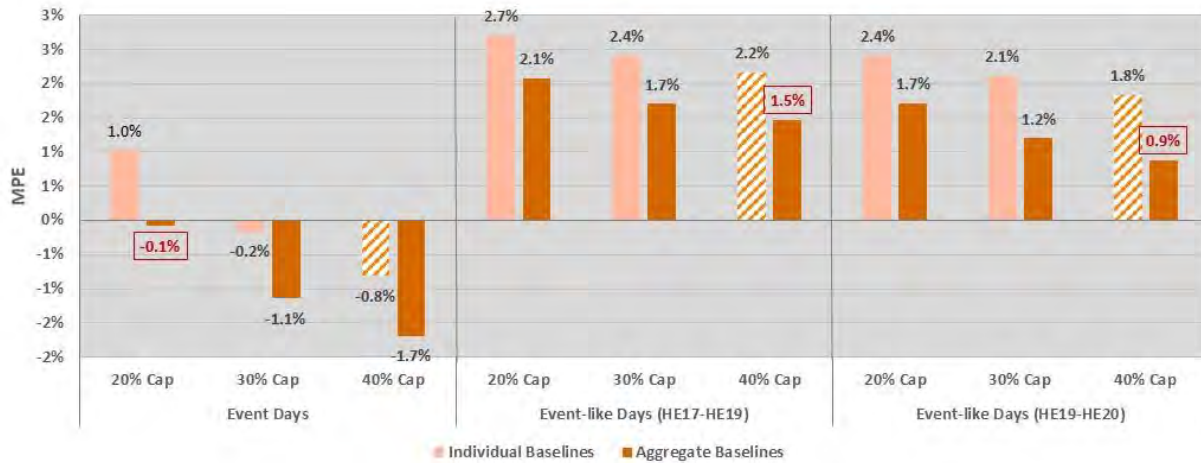


Figure A-8 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



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)

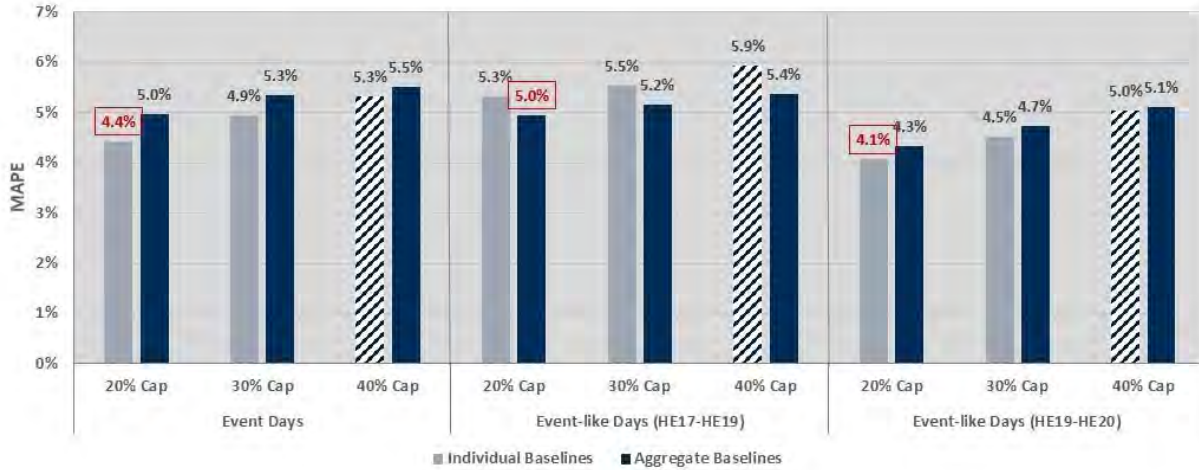
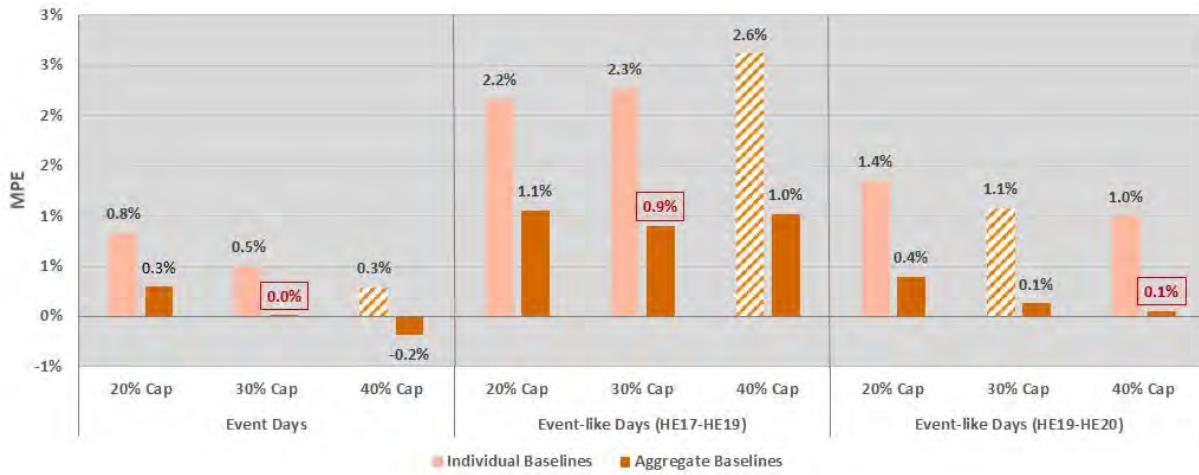


Figure A-10 SCE Day Of Program: Bias Comparison – Resource -level (PY 2018)



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)

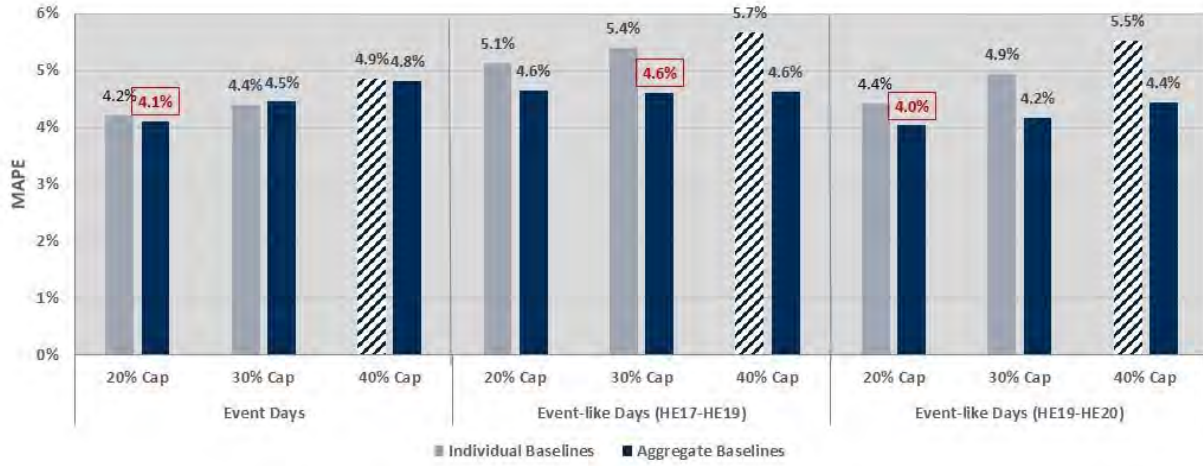
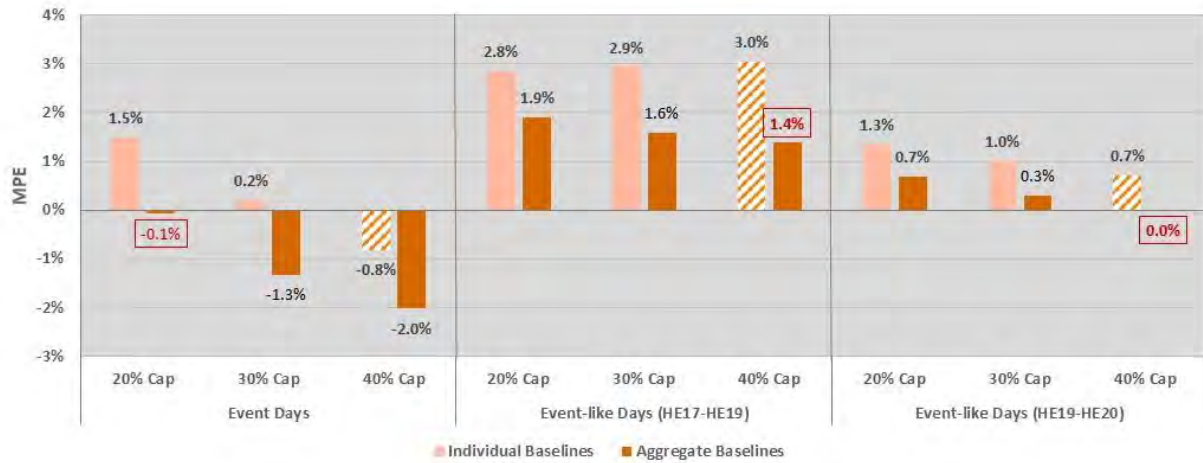


Figure A-12 SCE Day Of Program: Bias Comparison – Resource -level (PY 2019)



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)

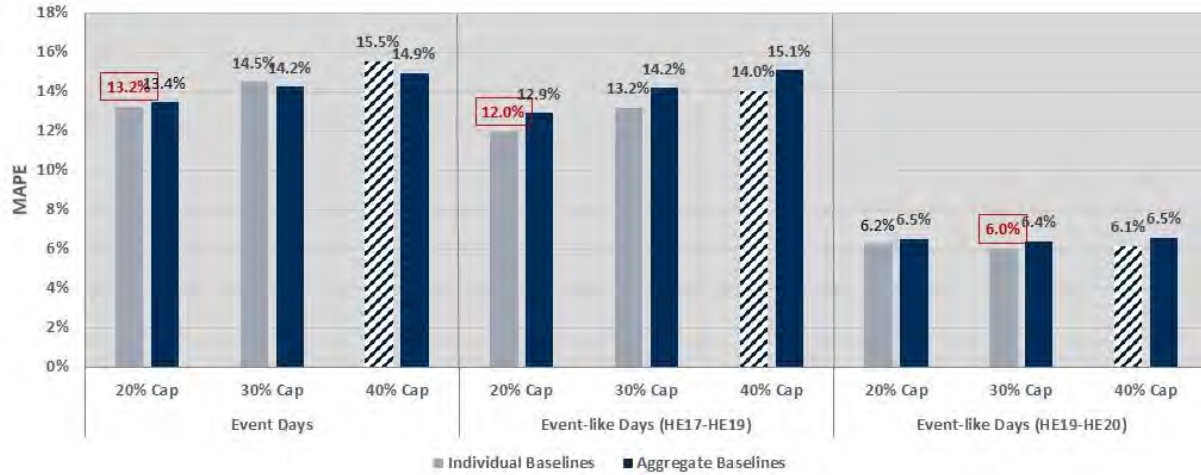
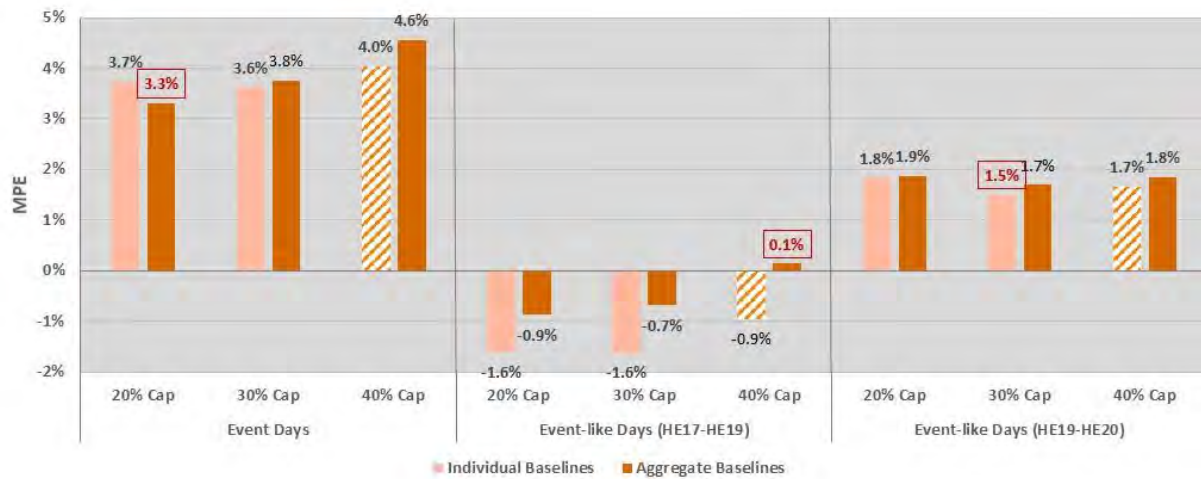


Figure A-14 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



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)

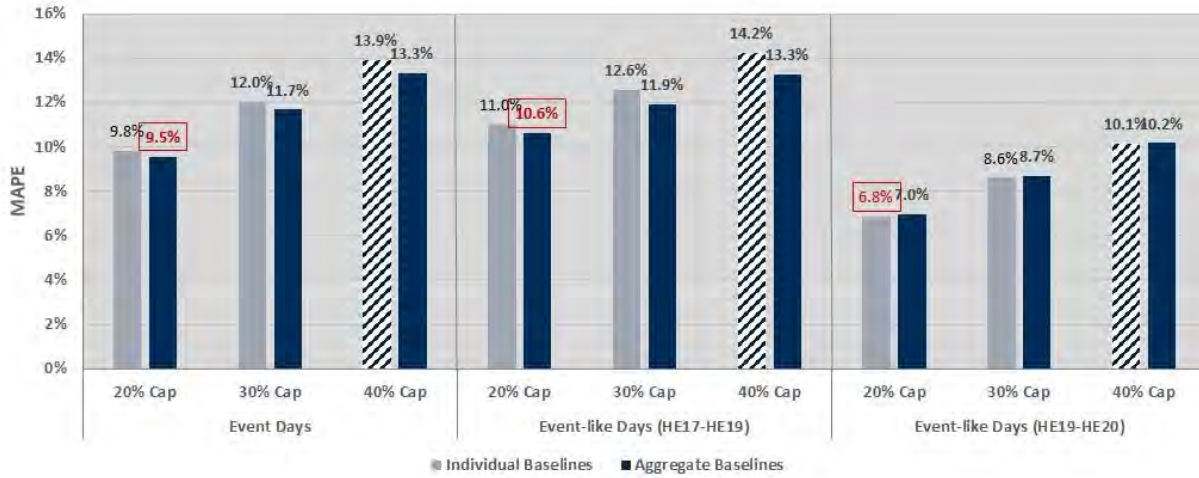
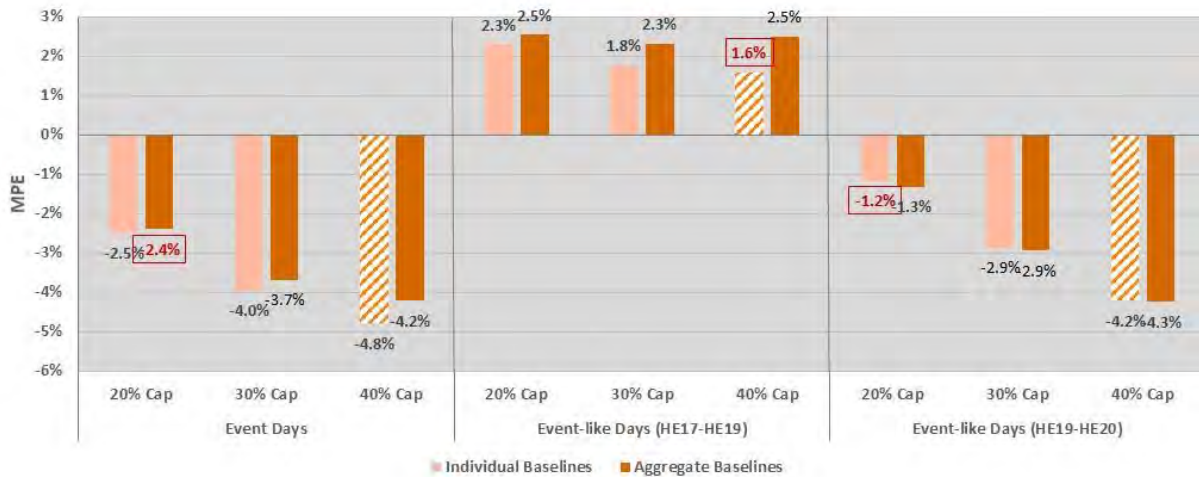


Figure A-16 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



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)

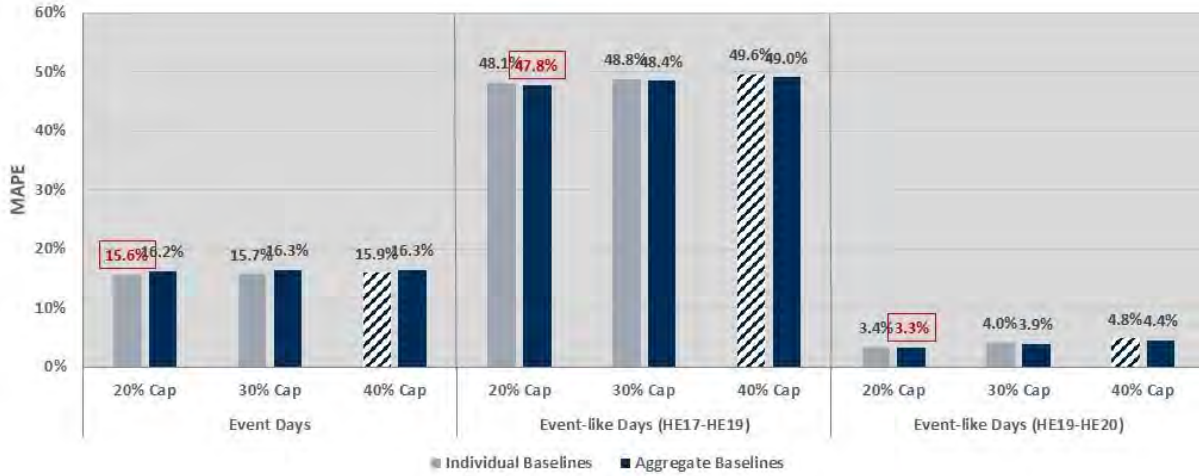


Figure A-18 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2018)



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)



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



CAPACITY BIDDING PROGRAM: BASELINE COMPARATIVE ANALYSIS

Abigail Nguyen, Project Manager

Analysis Objectives

Comparative Analysis

Results by Program

Key Findings & Recommendations



Analysis Objectives

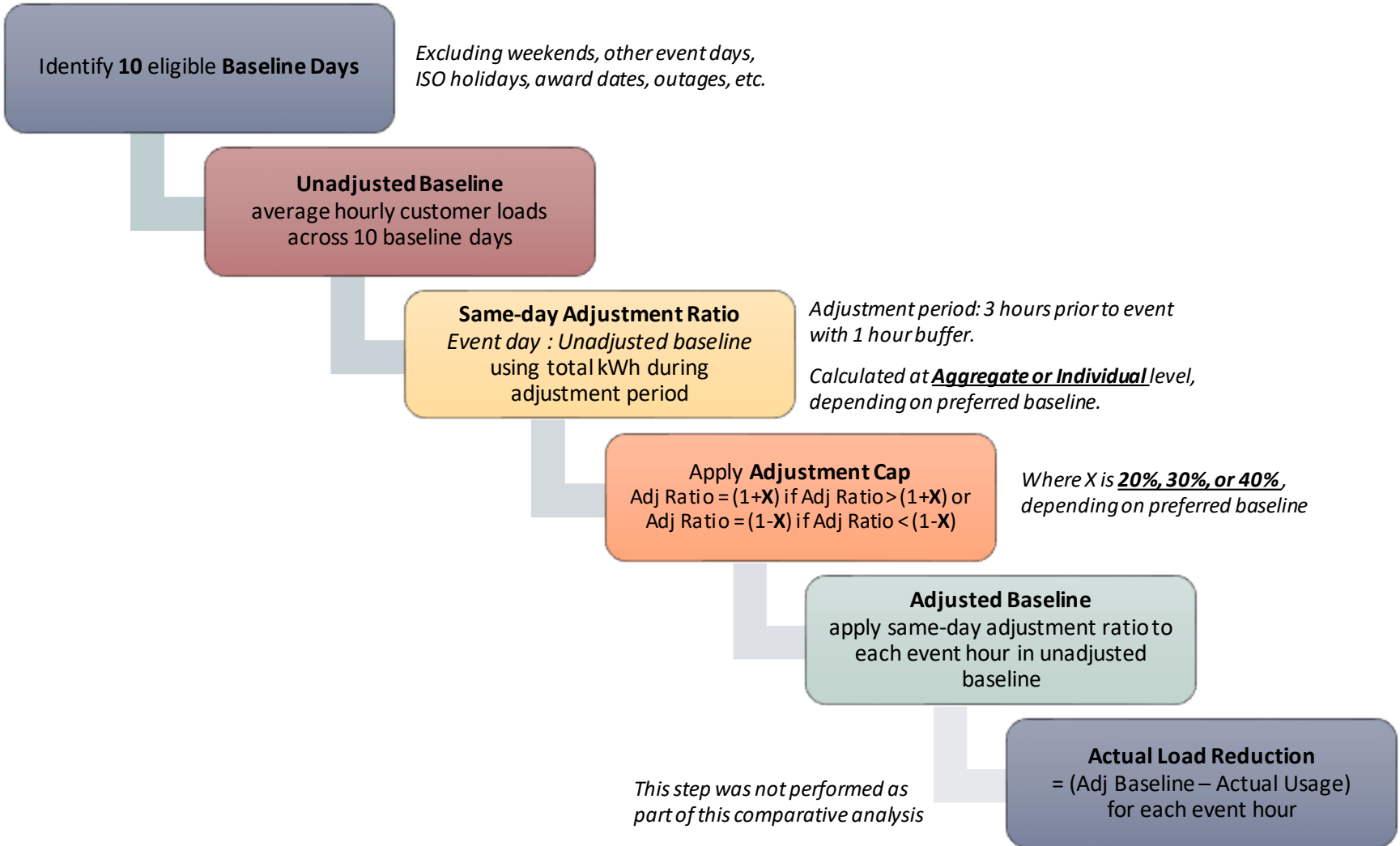
D. 19-07-009 Issues to Investigate

1. Assess if an adjustment cap of $\pm 40\%$ is still suitable for retail settlement baselines when the day-of adjustment for wholesale settlement baselines is $\pm 20\%$.
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

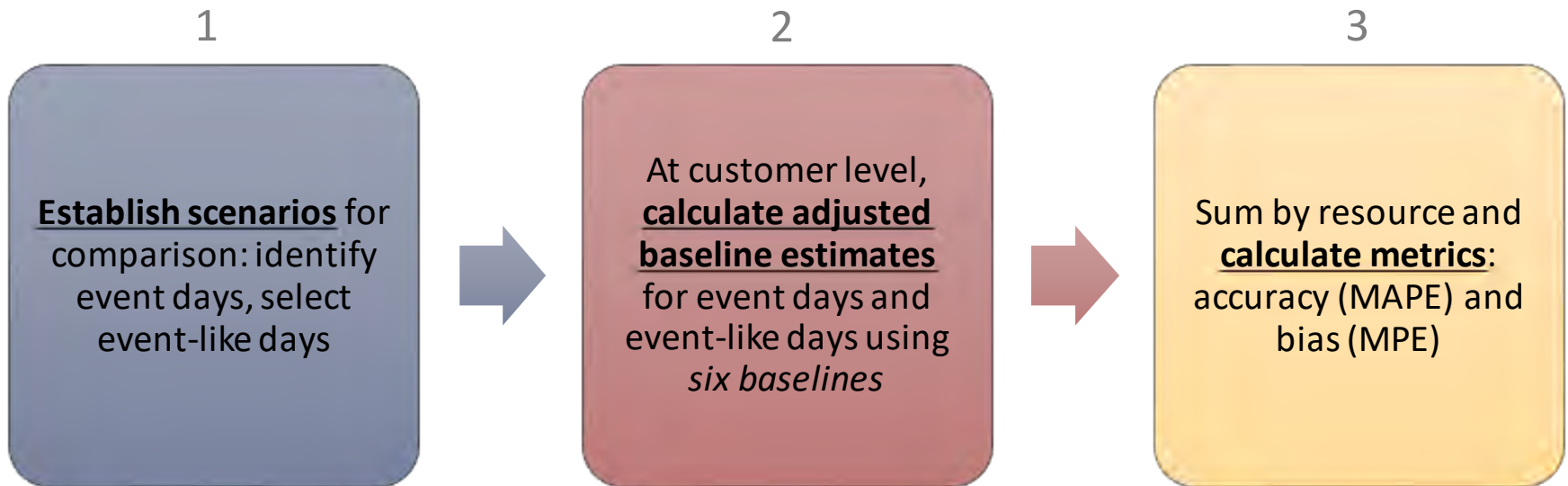
10/10 DAY MATCHING BASELINE





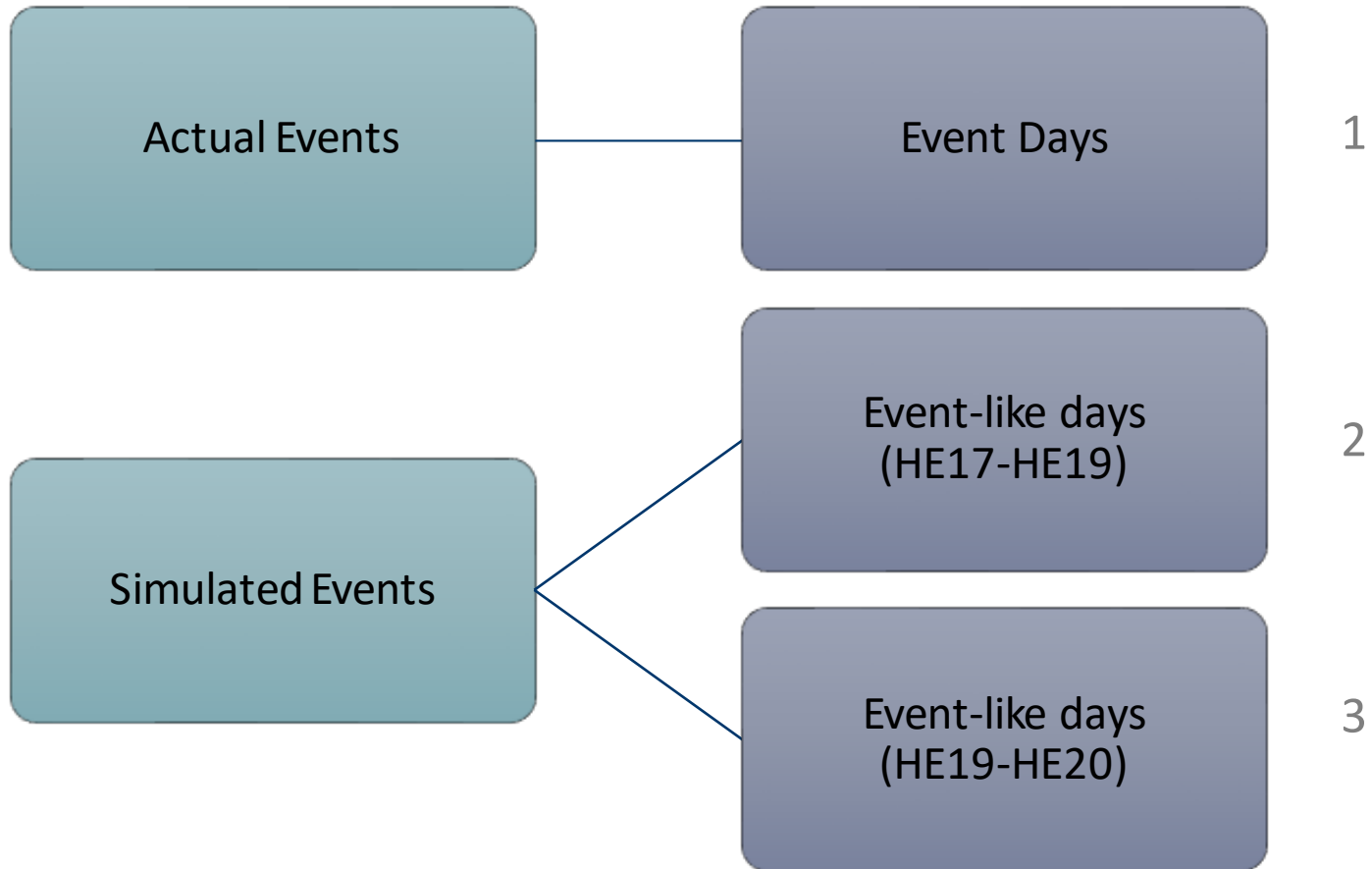
Comparative Analysis

OVERVIEW OF COMPARATIVE ANALYSIS

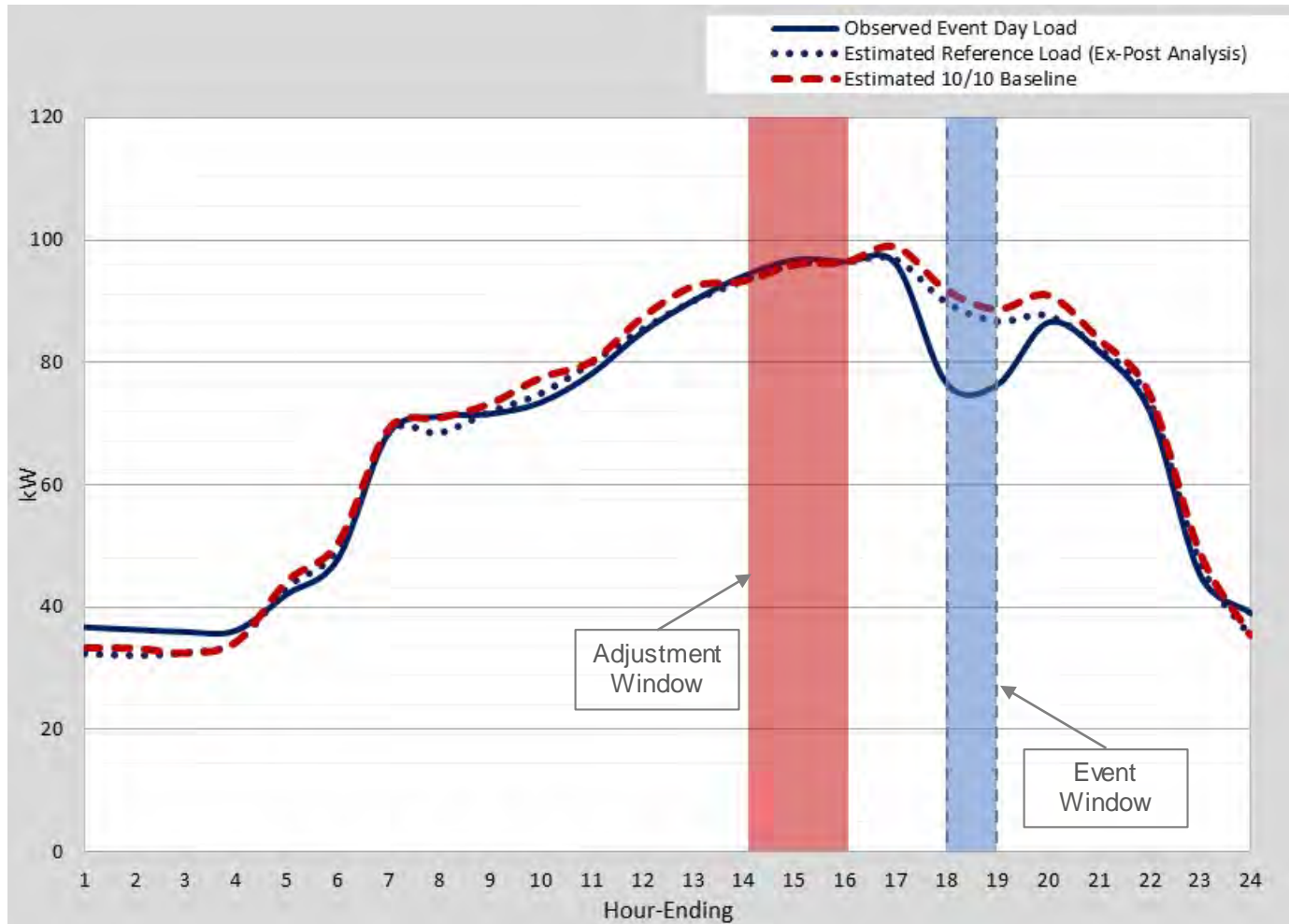


ESTABLISH THREE SCENARIOS

PY2018 and PY2019



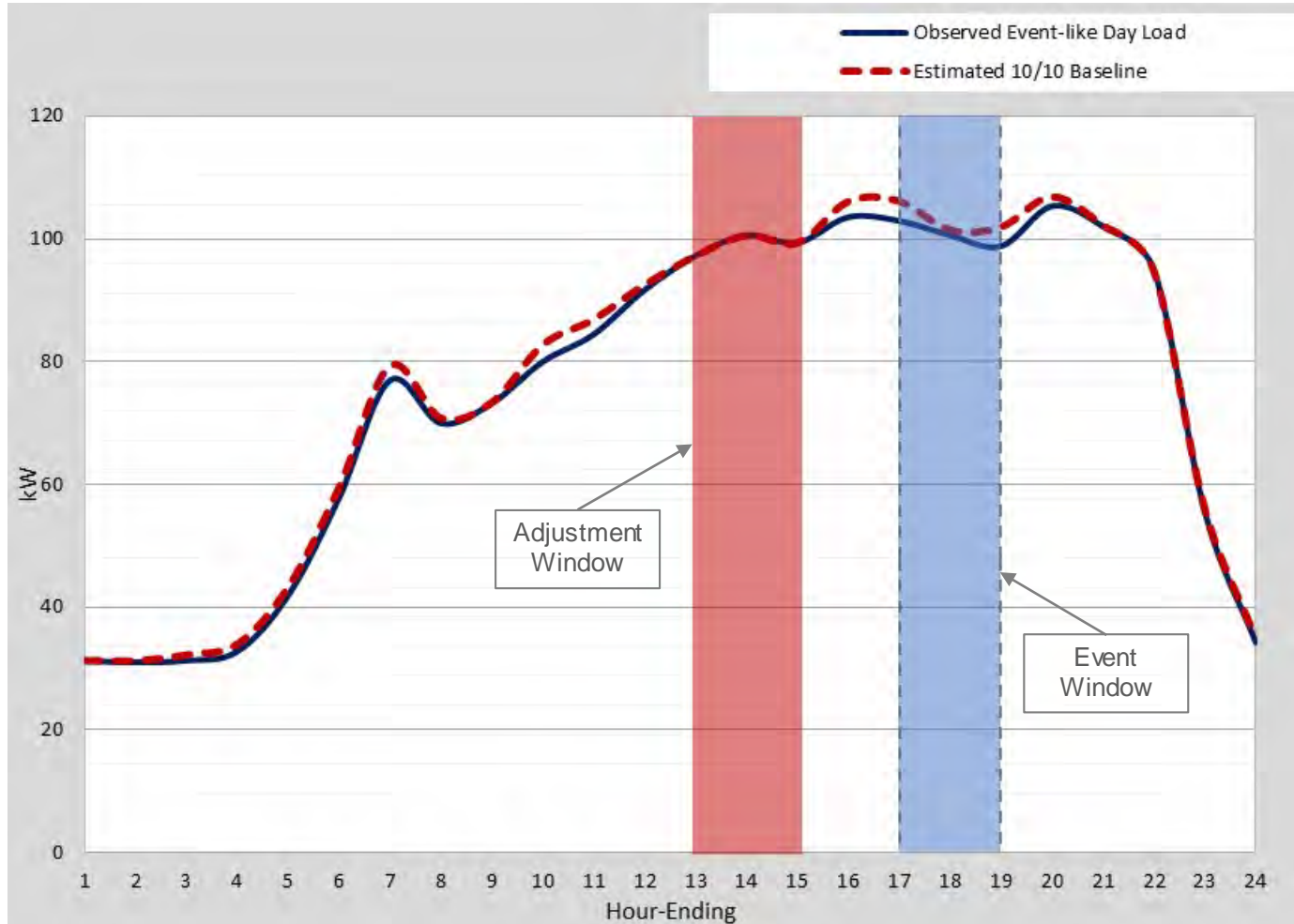
EVENT DAY SCENARIO



EBM - C-60

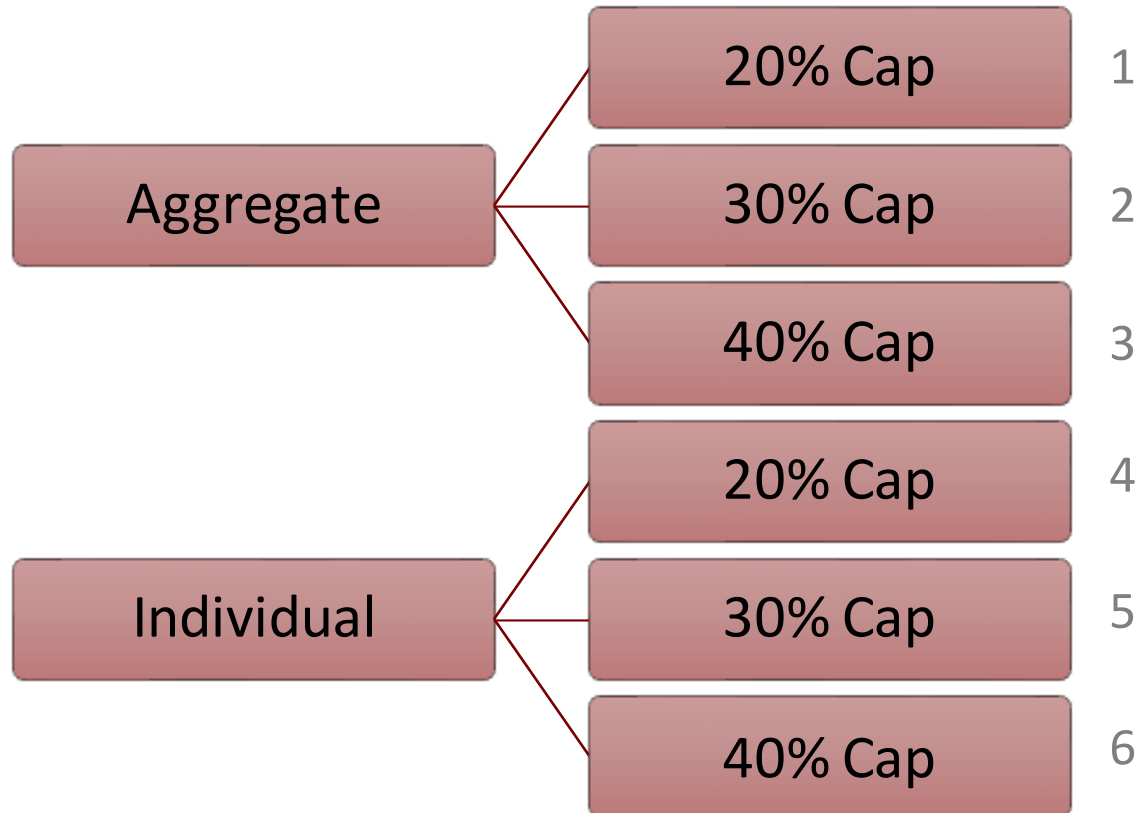
EVENT-LIKE DAY SCENARIO

HE17-HE19



EBM - C-61

SIX BASELINES



ACCURACY

- Mean Absolute Percent Error

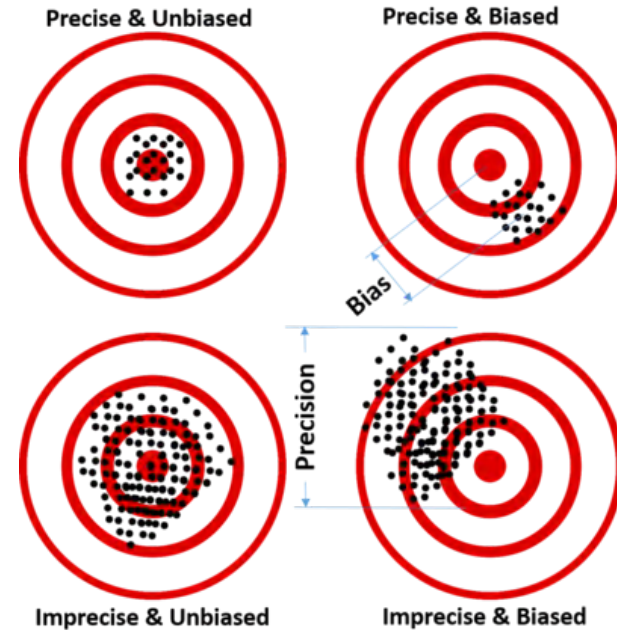
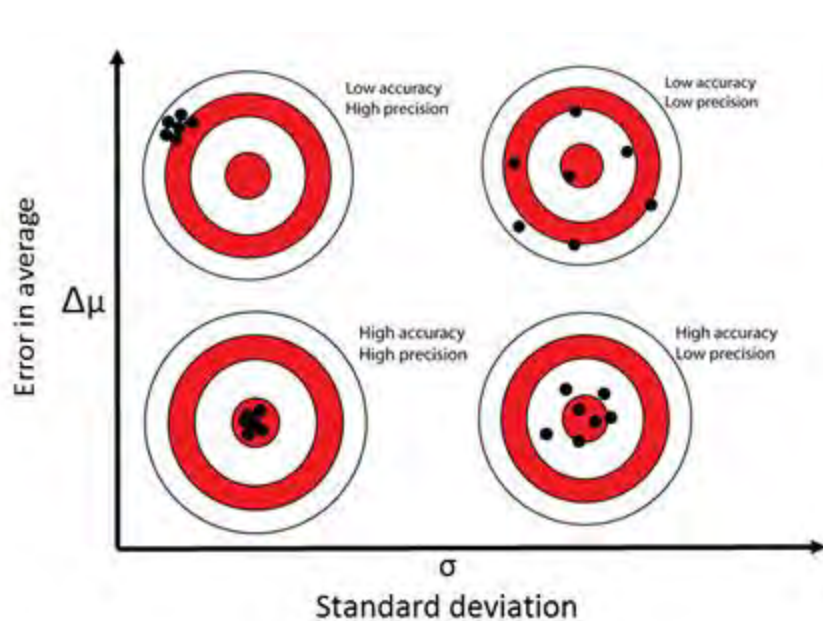
$$MAPE = \frac{100\%}{n} \sum_{h=1}^n \left| \frac{Actual_h - Estimate_h}{Actual_h} \right|$$

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

<u>Individual Baseline</u>					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%
<i>Method Score</i>											4.4%	2.4%
<u>Aggregate Baseline</u>					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%
<i>Method Score</i>											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.

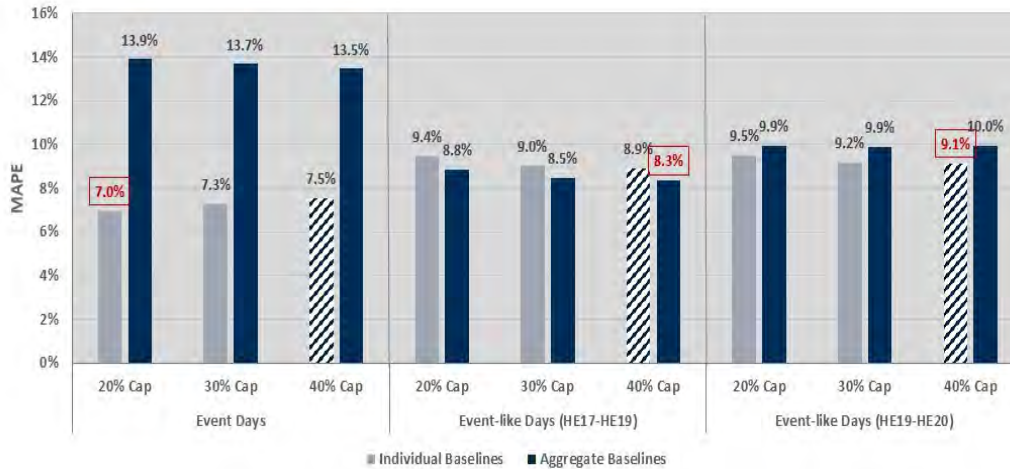
A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.



Results by Program

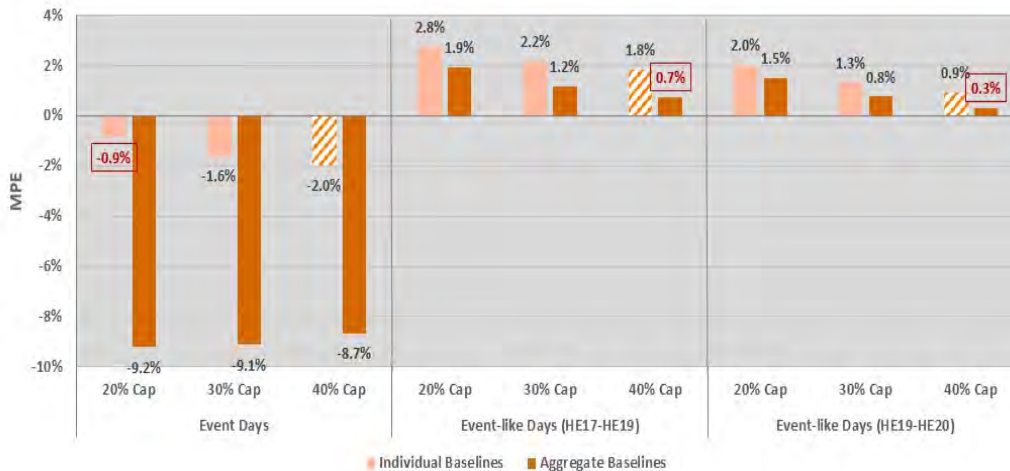
PG&E DAY AHEAD PY2018 & PY2019

Accuracy 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.

Bias Comparison



Day Of

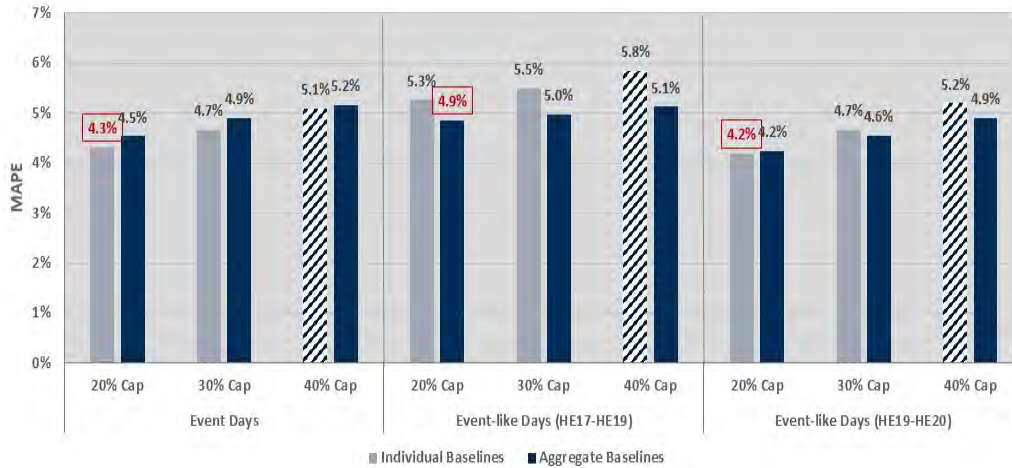
- Like PG&E DA, shows consistent results between PY2018 and PY2019.
- However, results are not consistent with PG&E—top baselines are not the same.

Day Ahead

- Year-to-year results demonstrate how baseline effectiveness can be driven by the participant population.

SCE DAY OF PY2018 & PY2019

Accuracy Comparison



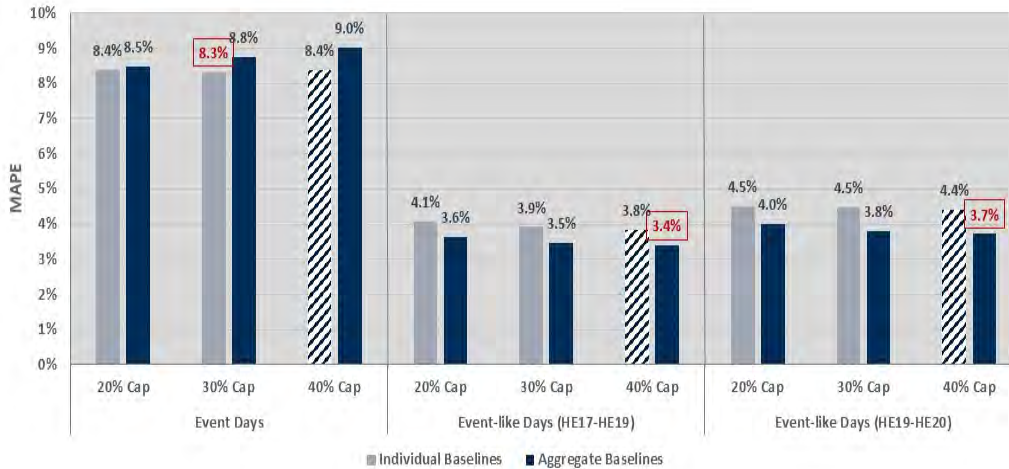
Bias Comparison



- 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

Accuracy Comparison



Bias Comparison

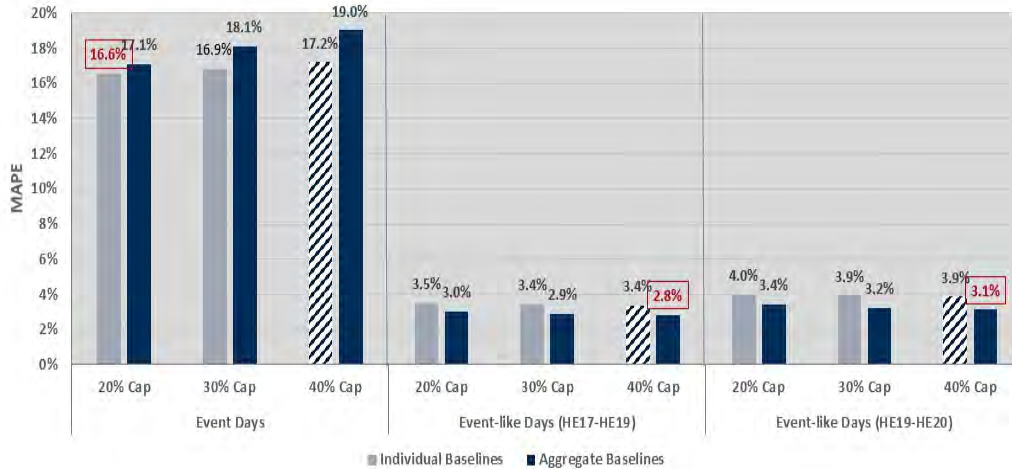


- Covers 44 events & 42 event-like days; 5 resources; 385 customers.
- Again, event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20). Both show Aggregate with 40% cap as most accurate and least bias.
- Event days show conflicting results, mainly driven by PY2018 event day data.

SCE DAY AHEAD

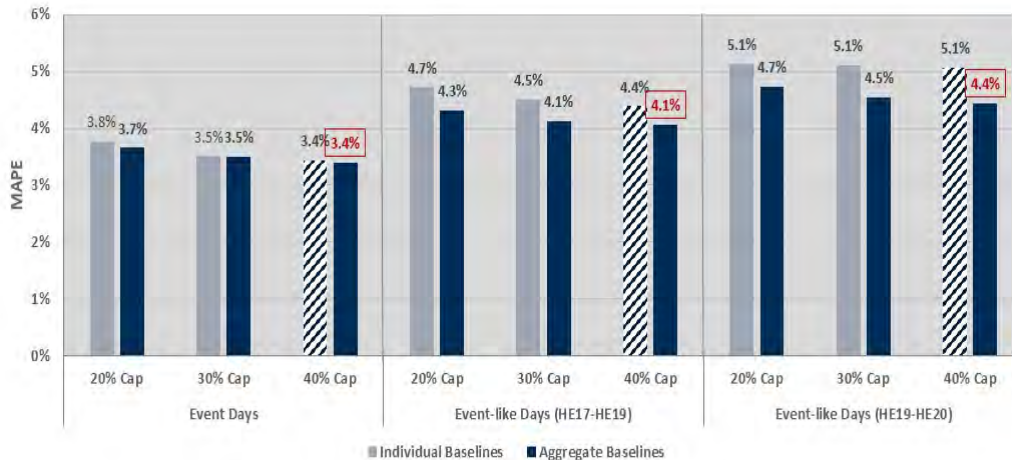
PY2018 versus PY2019

PY2018 Accuracy Comparison



- 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.

PY2019 Accuracy Comparison



Day Ahead

- Another example of year-to-year results demonstrating how baseline effectiveness can be driven by the participant population.

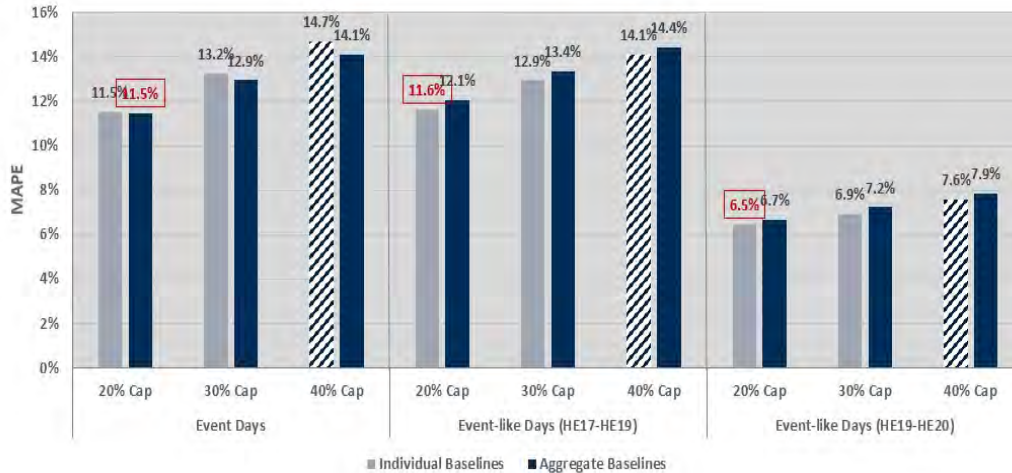
Day Of

- 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



- 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.

Bias Comparison



SDG&E DAY AHEAD

PY2018 versus PY2019

PY2018 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.

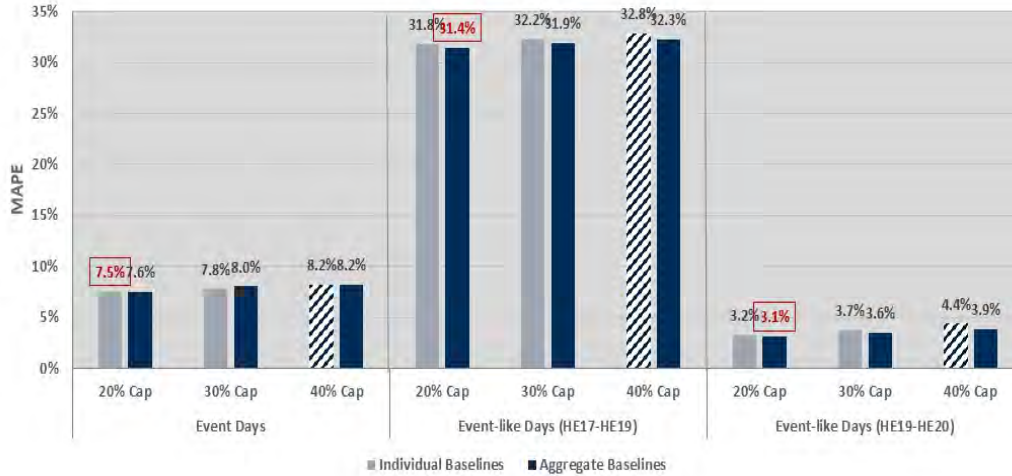
PY2019 Bias Comparison



EBM - C-75

SDG&E DAY OF PY2018 & PY2019

Accuracy Comparison



- 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.

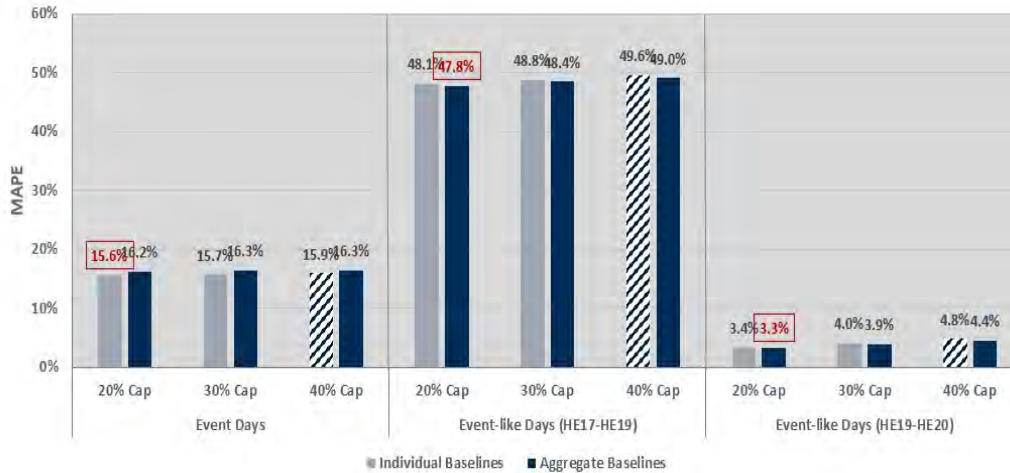
Bias Comparison



EBM - C-76

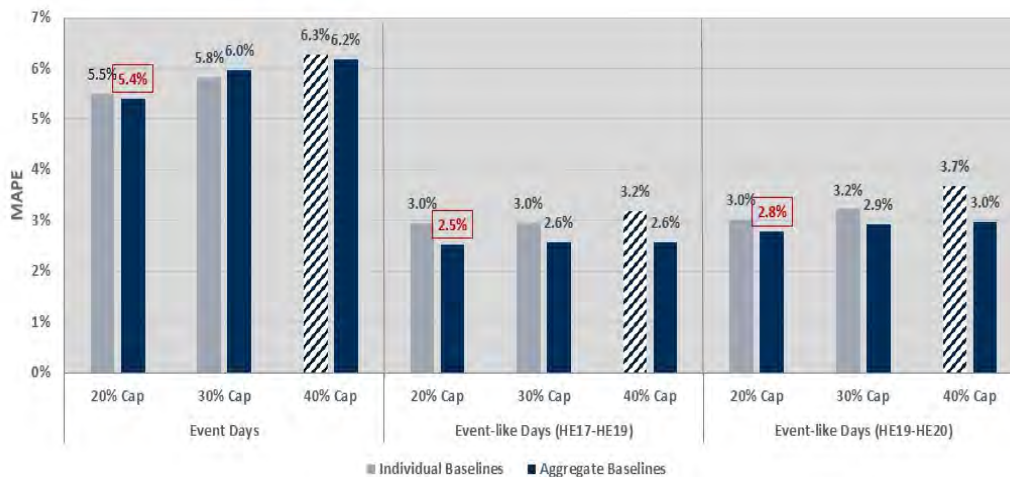
SDG&E DAY OF PY2018 versus PY2019

PY2018 Accuracy Comparison



- PY2018 shows event-like days with very high sensitivity to the timing of the event.
- PY2019 shows all three scenarios with very consistent results.

PY2019 Accuracy Comparison



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Key Findings and Recommendations

BEST ACCURACY & LEAST BIAS

Scenario	Best Accuracy			Least Bias		
	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)

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

Scenario	Lost Accuracy			Increased Bias		
	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

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 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.

RECOMMENDATION

Individual v. Aggregate Baselines?

AEG recommends using the **Aggregate Baseline**.

	Pros	Cons
Individual Baselines	<ul style="list-style-type: none"> Provides more accurate estimates for individual customers. 	<ul style="list-style-type: none"> Provides less accurate estimates at the resource level. Is not in alignment with the wholesale settlement baseline.
Aggregate Baselines	<ul style="list-style-type: none"> Provides more accurate estimates at the resource level. Aligns with the wholesale settlement baseline. 	<ul style="list-style-type: none"> Provides less accurate estimates for individual customers.

RECOMMENDATION

Which Adjustment Cap?



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.



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