Application: A.22-05-XXX
Exhibit No.: SDGE-1B
Witness: E Bradford Mantz

PREPARED DIRECT 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

May 2, 2022

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I. INTRODUCTION

My 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. Additionally, my 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.[1]

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 an established foundation of the past. SDG&E proposes to sunset several programs that are

[1] SDG&E is requesting that its DR funding application be broken out into two phases: (1) Phase One to address SDG&E's DR programs and budgets for 2023; and (2) Phase Two to address SDG&E's DR programs, pilots and budgets for years 2024-2027. This testimony supports SDG&E's bridge funding request for program years 2024-2027. *See* Prepared Direct Testimony of E Bradford Mantz Chapter 1A for my direct testimony supporting SDG&E's DR budget request for bridge funding year 2023.

outdated or no longer cost effective and do not fit our customer base, as well as to propose new programs, pilots and studies.

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

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

SDG&E also will be requesting Commission approval to retire older programs that have either reached the end of the installed equipment's life cycle or that customers do not see the value nor want to participate in as described below. Additionally, to help move to a more innovative DR of the future concept, SDG&E is proposing new pilots like our Energy Storage, Vehicle Grid Integration (VGI) and Virtual Power Plant (VPP) pilots, which will inform us and help us ultimately design and launch future innovative DR programs that will position DR for the future and allow us to be a better source to grid reliability using new technology. As utilities and grid operators face new flexibility challenges, demand response is more important than ever. Applications for demand-side resources are evolving as a result.[2]

B. Portfolio Cost Effectiveness

Our portfolio cost effectiveness reflects the fact that DR is in a transition phase, meaning that DR programs of the past need to be revamped to become more innovative and focus on the utilization of new technology to help fit into the grid of the future. SDG&E's proposed DR portfolio, as filed in this application, achieves a total resource cost (TRC) cost effectiveness score of 0.2.[3] SDG&E acknowledges that this number does not rise to the Commission's and SDG&E's desired level of cost effectiveness that we envision for our programs.

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

SDG&E's plans continue to capitalize on advancements in technology and information systems to be able to open its programs to more customers and hopefully more participation to increase cost effectiveness. An example is building and upgrading our information technology (IT) systems to be able to signal, manage and settle VPPs, electric

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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* Prepared Direct Testimony of Brenda Getting Chapter 5B.

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

A major contributor to the lowering of our cost-effectiveness of our Supply Side DR programs[5] is the updated avoided capacity benefits in the Avoided Cost Calculator (ACC).[6] The new values are lower than the avoided capacity benefits used in the 2018 through 2022 program cycle, and they drop to $70 and $54 kW/year in 2026 and 2027 respectively. While SDG&E is not questioning the accuracy of those calculations, SDG&E notes that the new values have made DR less valuable and potentially less desirable or competitive. While it is important not to offer unnecessary demand response programs, SDG&E asserts its proposed programs still play a role in providing system reliability for the near future.

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[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] Prepared Direct Testimony of Brenda Gettig Chapter 5B.

As mentioned above, SDG&E continues to have challenges related to the customer mix in our service area. An example is that fourteen of our large customers who signed up for the Emergency Load Reduction Program (ELRP) Pilot in 2021 have stated that they clearly prefer newer programs that are "pay for performance" with higher incentives and no penalties like the ELRP and that is why they have not nor will not participate in any other DR programs. However, at this point there has been no evaluation, measurement or verification (EM&V) studies done to see if the ELRP is cost effective. The ELRP has been effective in bringing in incremental MW from customers that normally would not participate in DR programs. Their participation in the ELRP is assumed to have helped the grid.[7]

Although SDG&E is not satisfied with its current cost effectiveness scores, [8] the analysis provides a baseline to be used over the application's timeline to determine whether some programs modifications have worked and if other programs should be terminated. Also, SDG&E believes it is still premature to value SDG&E's cost effectiveness in light of the new ELRP emergency programs and because we have not seen the latest DRAM evaluation study which has been delayed.

For this application, SDG&E has adjusted its programs budget to allocate funding with an increased focus on recruiting new customers and aggregators to help grow its programs and pilots in an effort to increase our cost effectiveness. SDG&E's customer base is significantly different than the other IOUs, making it difficult to recruit new customers and make sizable gains in the programs load. Again, SDG&E's current customer mix does

[7] D.21-003-056, p. 5 (ELRP Subgroup A.1).

[8] Detailed Cost Effectives analysis is provided in the Prepared Direct Testimony of Brenda Gettig Chapter 5B supporting this application.

not include large commercial or industrial accounts but is instead made up of small to medium commercial accounts and our residential customer base, making it a challenge to find enough participating customers to have a large MW decrease during a DR event.

In this application, SDG&E is making a major transition to move DR from older established but non-effective programs to newer programs like our CBP Elect and the Smart Thermostat Program that were approved in the Summer Reliability OIR Phase II[9] to replace our older CBP options and our TI, TD and AC Saver options. We are also proposing new innovative pilots that are evaluating EVs, batteries, VPP's and other ideas to move us towards our goal of DR programs of the future. SDG&E requests that the commission consider our cost effectiveness in light of this massive transition to DR of the future.

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

II. SUPPLY-SIDE DEMAND RESPONSE PROGRAMS

SDG&E proposes to continue to grow and improve its supply-side portfolio of existing DR programs as resources that help meet grid needs and continue to give our customers options for being incentivized to reduce loads at critical times. SDG&E also proposes to retire some existing programs due to low or no customer participation. The

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

following section describes our existing supply-side DR Programs and SDG&E's proposed changes for 2024 -2027.

A. Base Interruptible Program (BIP)

1. Background

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

With its incentive structure, as well as its penalties for non-performance, and a short notification period, this program is most suitable for commercial customers who can shut down production quickly, with certainty, and usually without a significant cost to its business. In SDG&E's experience, large manufacturing or other large assembly line businesses, or businesses which operate production 24 hours a day, tend to be the best candidates for participation. SDG&E's effort to grow the program to become suitable for

[10] 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.

successful market participation has had disappointing results, with no additional customers joining the program. At the time of this filing, there are no customers currently enrolled in the program. SDG&E's territory is not a good target market for the program because it has a very limited amount of large industrial customers that can shed load quickly from which to draw participants for such an emergency type program. SDG&E has been challenged with growing the program even with increased marketing efforts including direct mail letters, emails, SDG&E's account executive consultations, and direct phone calls. SDG&E also made several modifications to the program's tariffs to make it more attractive for aggregators and opened the program to additional smaller customers that have a demand of less than 100kW.[11] Despite the additional efforts to educate and attract eligible SDG&E customers to join BIP, no customers have expressed an interest in signing up.

2. BIP Proposal for 2024-2027

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

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

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[11] D.21-03-056, Attachment 1. p. 19.

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

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

[12] 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.

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

tariff and are aware of the penalties in order to ensure the best customer experience possible. Below is a table that reflects enrollments in BIP from 2012 to 2021 showing total accounts and customers.[14] The reduction from 2018 to 2019 was due to customers no longer meeting their performance requirements.

Table EBM – 1
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

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

<u>First Quarter 2020:</u>

- SDG&E's "Save the Day" marketing campaign brought additional awareness to demand response programs, including BIP.
- One aggregator wanted to enroll a customer with 400kW load shed, however the customer was disqualified due to Rule 41 eligibility rules in 2020 per which a customer is not allowed to dually enroll in a demand response program if they are enrolled in any other demand response program or rate.[15]

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[14] A customer can have more than one account enrolled.

[15] 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

Second Quarter 2020:

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

Third Quarter 2020:

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

[16] 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

communications were sent to these potential customers. This included 218 letters sent on July 31, 2020, and 2,790 letters sent on August 14, 2020, which included a hyperlink to learn more about the program, as well as how-to sign up. The click rates, or the number of times customers clicked on the pertinent links for more information, for customers that clicked on the hyperlink were 0% for the letters sent in July. The rate was just 1.6% for August, meaning that both times very few customers clicked on the hyperlink to take them to the BIP landing page to get more information about the program or the call to sign up.[17] During this time frame in 2020, customers were utilizing digital content as their main source of information.

Q4 2020 and into Q1 2021:

- SDG&E launched a new tool to help the SDG&E account executives further identify and target potential BIP customers. This tool identifies current customers in SDG&E territory and takes into consideration their usage history in order to perform a propensity sensitivity analysis to see if the customer would benefit (and therefore enroll) based on actual enrolled customers in DR Programs. The tool also looks at their demand and the difference between the peak usage and non-peak usage to determine how much a customer could save if

[17] 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.

they joined a demand response program such as BIP and Capacity Bidding Program (CBP).

- 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 actually SDG&E unenrolled the last remaining two customers at their request in 2021.[18] 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."[19] The challenge of course is that if the incentives are raised, 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 quickly and within 20 minutes which make them likely candidates for BIP. For example, in PG&E's service territory there are around 300 customers enrolled in BIP, whereas SCE has

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

[19] K. Olson, Procurement Director.

over 200 customers.[20] Furthermore, SDG&E's territory has very few large manufacturers like the ones that are members of the California Large Energy Consumers Association (CLECA), and this limits the pool of eligible and willing customers to join BIP.

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

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

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

[20] 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.

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

B. Capacity Bidding Program (CBP)

1. Background

The Capacity Bidding Program is a voluntary demand response program that offers customers various product options by which they can earn incentive payments in exchange for reducing energy consumption when requested by the utility. This program is available to bundled customers and customers being billed on a utility commercial, industrial or agricultural rate schedule. It is also available to DA and CCA customers. Bundled customers receive capacity and energy payments from SDG&E and DA customers receive capacity payments, with energy-based compensation and savings subject to their contractual relationships with their DA providers.

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

In 2019, SDG&E called the maximum number of events[21] per month in September and October. In 2020, SDG&E called the maximum number of events allowed per month in

[21] 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.

July, August, September and October. SDG&E filed advice letters 3321-E,[22] 3306-E,[23] 3522[24] all with requests to limit events to address the expressed customer fatigue and reduce the number of events being called.

2. CBP Proposal for 2024-2027

For the 2024-2027 program cycle, SDG&E proposes to retire the traditional CBP products[25] while retaining and focusing on the new CBP Elect products that are closer aligned with the CAISO's peak times of 4pm to 9pm.

SDG&E is confident after speaking with and receiving feedback from its current CBP aggregators that retiring the existing traditional CBP products is welcomed and will encourage existing customers to transition to the new CBP Day-Ahead and Day-Of 1pm-9pm Elect products. It is encouraging to see a CBP product enhancement that has been so well received by all stakeholders.[26]

SDG&E forecasts that the addition of the CBP Elect option could bring an additional 5MWs of new load shed with up to ten new commercial customers.[27]

In order to continue to recruit new customers into CBP, SDG&E proposes to update the non-performance penalty of the CBP tariff. SDG&E's CBP's current program structure

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[22] 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.

[23] 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.

[24] AL 3522-E Mid-Cycle Update was filed on 3/27/2020 and is pending approval. In this AL SDG&E proposed to update price triggers to reduce the number of CBP events.

[25] Traditional CBP Day-Ahead and CBP Day-Of 11am-7pm and 1pm-9pm products.

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

[27] 5 MWs of new load shed is based off feedback via email received from aggregators.

penalizes customers who do not perform at least 75% of nominated load reduction. Current structure is shown in Table EBM-2.

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

The proposed changes are in Table EBM-3

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

The proposed changes to CBP are critical in helping to retain aggregators and customers while attracting new customers and aggregators to the program. These changes are vital to increase cost effectiveness because when additional customers join the program, kW enrolled increases and thus the cost effectiveness numbers improve.

3. CBP 2024-2027 Budget Proposal

Table EBM-4
CBP Budget

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

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

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

C. Capacity Bidding Residential (CBR) Pilot

1. Background

On March 26, 2021, the Commission authorized SDG&E's CBR Residential Pilot[28] with an approved budget of $708,000, including administrative costs and incentives.[29] D.21.12.015 approved the continuation of the CBP Residential Pilot through 2022.

SDG&E launched the pilot as quickly as it could during the summer of 2021.[30] However, because of the late start, the pilot did not have adequate preparation time to

[28] D. 21-03-056, Attachment 1, p. 9.

[29] D.17-12-003, p. 191, OP 22.

[30] The CBP Residential Pilot was not approved until March 2021.

implement and recruit aggregators and customers before the 2021 DR season, which started on May 1st. SDG&E's CBP aggregators are currently not positioned to handle residential customers and typically only work with Commercial and Industrial accounts. D.21-12-015 approved our request to continue the Pilot in 2022[31] and my testimony for 2023 also requests to continue the pilot and its evaluation[32]

2. CBP Residential Pilot Proposal

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

D. AC Saver Program (Smart Energy Program)

1. Background

Currently, SDG&E offers a program named AC Saver. AC Saver is a supply side DR program that is bid into the CAISO market. AC Saver participants have either a direct load control switch installed on their air-conditioner or a thermostat with settings that can be adjusted by the manufacturer. 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 program is usually activated when SDG&E bids in and then receives an award from CAISO,

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[31] D.21-12-015, Attachment 2, p. 6.

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

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

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

Participants with thermostats enroll in the program using the following process. Since customers must have a device that controls an air-conditioner to be eligible for AC Saver, customers must first register their thermostat through their thermostat manufacturer's website or app so that SDG&E knows that the thermostat is installed and online. Enrolling through the manufacturer also allows the manufacturer to adjust the thermostat settings when SDG&E activates the program. SDG&E's signaling platform then pulls in these pending enrollments from the manufacturer application programming interface (API)[33] and verifies customer eligibility. Eligible customers currently receive $50 from the SDG&E Technology Deployment program (TD) for completing this step. If the customer is already participating in a rate with events or DRAM when they register the thermostat, the customer remains enrolled on that program and receives the $50 TD payment only.[34] If the customer

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[33] 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.

[34] 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

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

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

In the last DR application, SDG&E expanded the AC Saver program from including only customers with direct load control switches to including both switches and thermostats.[35] In this application, SDG&E is requesting to expand the program even further by opening it up to customers with devices that control end uses other than air-conditioners. SDG&E's proposal to expand program eligibility is described in detail in the proposal section below. Since the program name "AC Saver" does not apply to controls of end uses other than air-conditioners, SDG&E proposes to rename this program the "Smart Energy Program."[36] This program will therefore be referred to as the Smart Energy Program (SEP) for the remainder of the testimony regardless of the time period being discussed.

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thermostat portal because the thermostat must be verified in order for the customer to be eligible.

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

36 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.

2. Smart Energy Program Proposals for 2024-2027

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

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

Each of these proposals are described in further detail below.

<u>Proposal 1</u>: SDG&E proposes to retire the direct load control switch portion of the Smart Energy Program

On February 1, 2016, in the SDG&E 2017 Demand Response Program Proposal, SDG&E proposed to allow the existing direct load control switches to continue to be part of the Demand Response portfolio through 2023 and to transition away from the older pager device technology to newer technology as these devices reach their end-of-life cycle.[37]

[37] 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.

D.16-06-026 approved this proposal.[38] In 2018, SDG&E continued with this approach in A.17-01-018.[39]

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

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

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

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

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

3. The current direct load control switches have been in field for a long time as most of the existing switches were installed between 2004 and 2010. Due to their age, the switches may fail. The switches are one way communication meaning we can signal them, but we have no way of monitoring them in an automated fashion to determine if they are failing or shutting off the customers' air conditioner. Since we cannot identify the customers with failing switches, we cannot unenroll these from the program or replace the switch. The result is that when switches fail, the average load impact per customer from the program goes down.

4. In addition, the number of customers participating in the program has declined between 2018 and 2022. SDG&E's goal for 2018-2022 was to maintain the existing switches because installing new switches was cost prohibitive. Over time customers move out and opt out of the program so with no new customers coming overall enrollment dropped.

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

Figure EBM-1

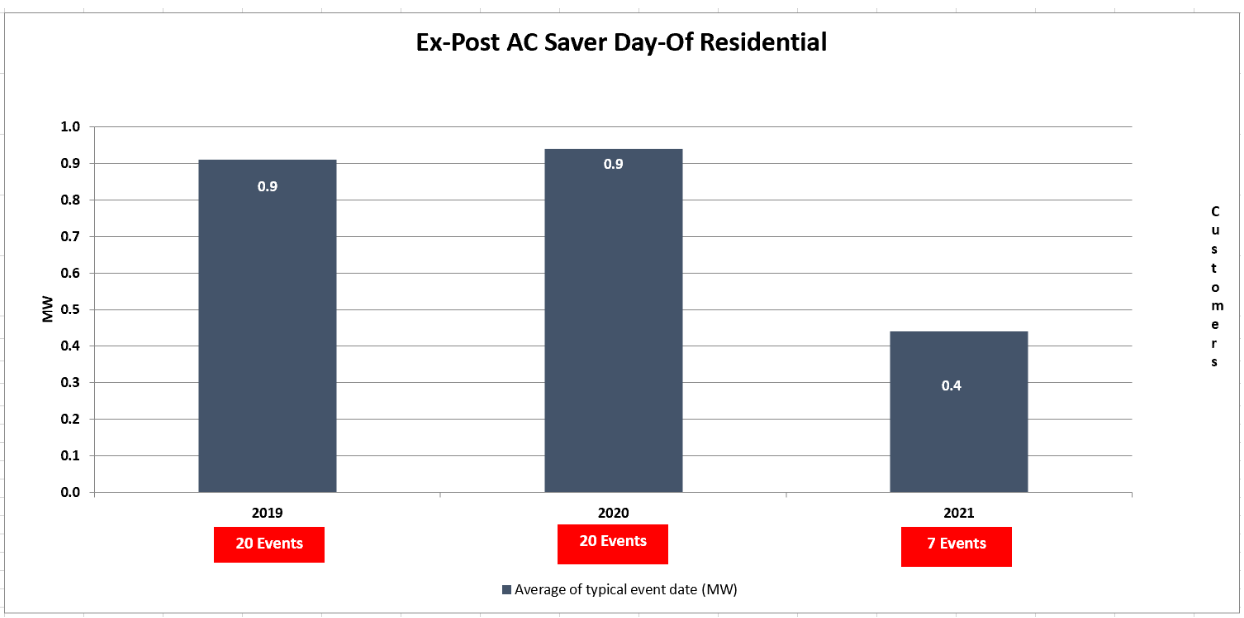
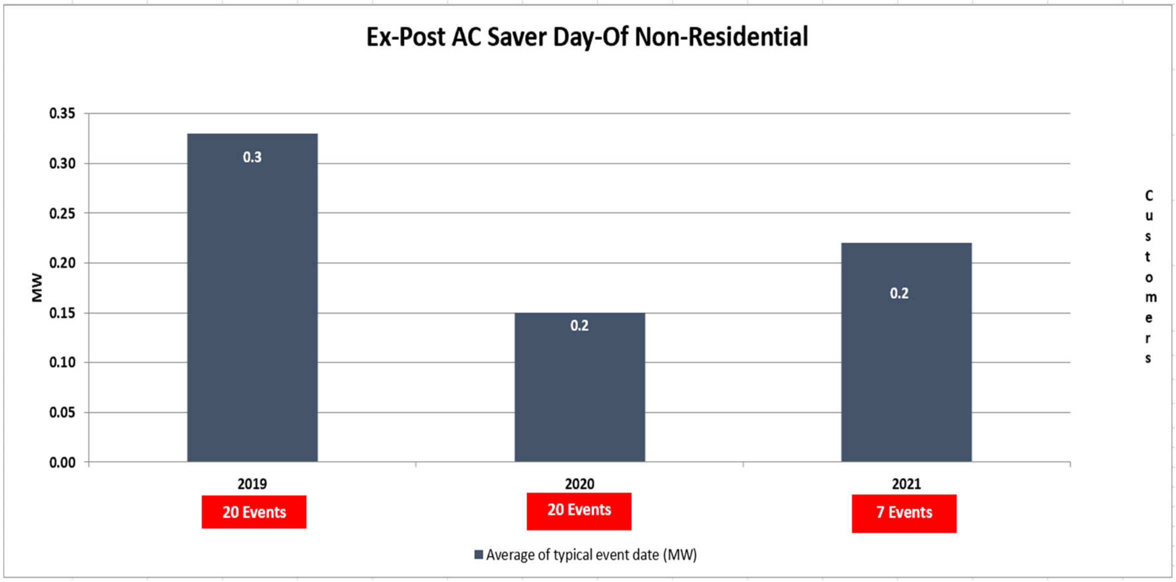


Figure EBM-2



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 but all were out of the cost-effective range.

Growing the program with new technology is also complex. To grow the program by installing new technology, SDG&E would need to do several things. SDG&E would need to fund the program to install direct load control devices to increase participation to get more load reduction, which will cost approximately $75 per device and a $110 installation fee per device. SDG&E will need continue to offer field services which cost approximately $133K to $150K for each year. SDG&E will also need continue to contract with a third-party vendor to maintain the devices and the customer facing program administration at a cost of approximately $537K to $604K each year. Upgrading one-way communication devices to 2-way communication would be very costly. As mentioned above, we issued an RFP in 2016 and SDG&E learned then that the costs would be exorbitant and would presumably be even higher today.

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

Table EBM-5
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

SDG&E plans to communicate to the existing direct load control participants numerous times in early 2024 through direct mail and email campaigns to encourage customers to enroll a thermostat or new device in the Smart Energy Program. Customer surveys show that 20% of participants with a direct load control switch already have a smart thermostat.

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

<u>Proposal 2</u>: Open up the Smart Energy Program to customers with any device that can curtail energy use during an event or control energy storage.

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

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

The minimum eligibility requirement for a device to qualify for an enrollment incentive should be that the device can either curtail an end use or control behind the meter energy storage. The device may either be directly controlled by SDG&E or by the device manufacturer so long as the vendor has signed the appropriate contracts with SDG&E. This is in line with the primary goal of SEP which is to compensate customers who already have a smart device for participating in a demand response program. To maximize participation in a bring you own device program it is important that devices that are commercially available and popular with customers. It is also important not to be too restrictive as to how the event is communicated to the device because new methods of communicating events to customers are emerging. For example, Fort Collins Utility is encouraging customers to use software called IFTTT to program their smart appliances to respond to time of use rates.[40] SDG&E is still exploring whether this software can be leveraged for event calling. However, if a method is found, the program devices' requirements should be flexible enough to incorporate new ideas for communicating events.

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

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

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

[40] https://ifttt.com/fcu_tod

thermostat.[41] When SDG&E brings on additional devices the annual incentive will be set at up to $50 times the average load reduction of the devices for that customer. SDG&E may but is not required to use information about the customer (*e.g.*, customer class, climate zone) to determine the average load reduction expected from the device for that customer. This will maintain the current successful straightforward payment structure while ensuring that the incentives are in line with the load reduction potential of the devices.

<u>Proposal 4</u>: Annual Smart Energy Program incentives should be made available to commercial customers.

The Smart Energy Program currently does not offer an annual incentive to commercial customers with thermostats due to numerous considerations. First, in 2017 when SDG&E proposed to expand the Smart Energy Program to any device that could control an air-conditioner,[42] the vast majority of commercial customers were not eligible because rates with events (like Critical Peak Pricing (CPP)) were the standard pricing plan for all commercial customers and customers could not participate in both the Smart Energy Program thermostat and a rate with events.

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

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[41] 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.

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

Things have changed. The percentage of commercial customers eligible for the Smart Energy Program has increased greatly in 2021. This occurred when the two Community Choice Aggregators [43](CCA's) in San Diego County initiated their commodity programs(CCA Programs) in which SDG&E commercial customers that were enrolled in a commodity rate with a DR component like Critical Peak Pricing (CPP) were unenrolled from their rate when they transitioned to CCA service, thus increasing the pool of eligible customers for participation in a non-rate IOU DR program. These transitions will be ongoing for the next several years as other communities join one of the CCA's. Customers participating in CCA service are not eligible for SDG&E's commodity rates with events because they purchase their energy from a provider other than SDG&E. Therefore, as of March 2022, only 60% of commercial customers were still enrolled on a rate with events. Since rates with events like CPP are not an option for CCA enrolled customers, the Smart Energy Program provides commercial customers receiving CCA service a way to participate and receive incentives. Another factor expected to further increase the number of commercial customers eligible for SEP over time is that a rate with events will soon no longer be the default rate for new small commercial customers.[44] Due to both community choice aggregation and the change in the standard pricing plan for new small commercial customers, we expect many more commercial's customers to be eligible for SEP commercial between 2023 and 2027 than there were in 2018-2020 and this supports our request to make the above-mentioned program changes.

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

[44] D.21-07-010, p. 30.

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

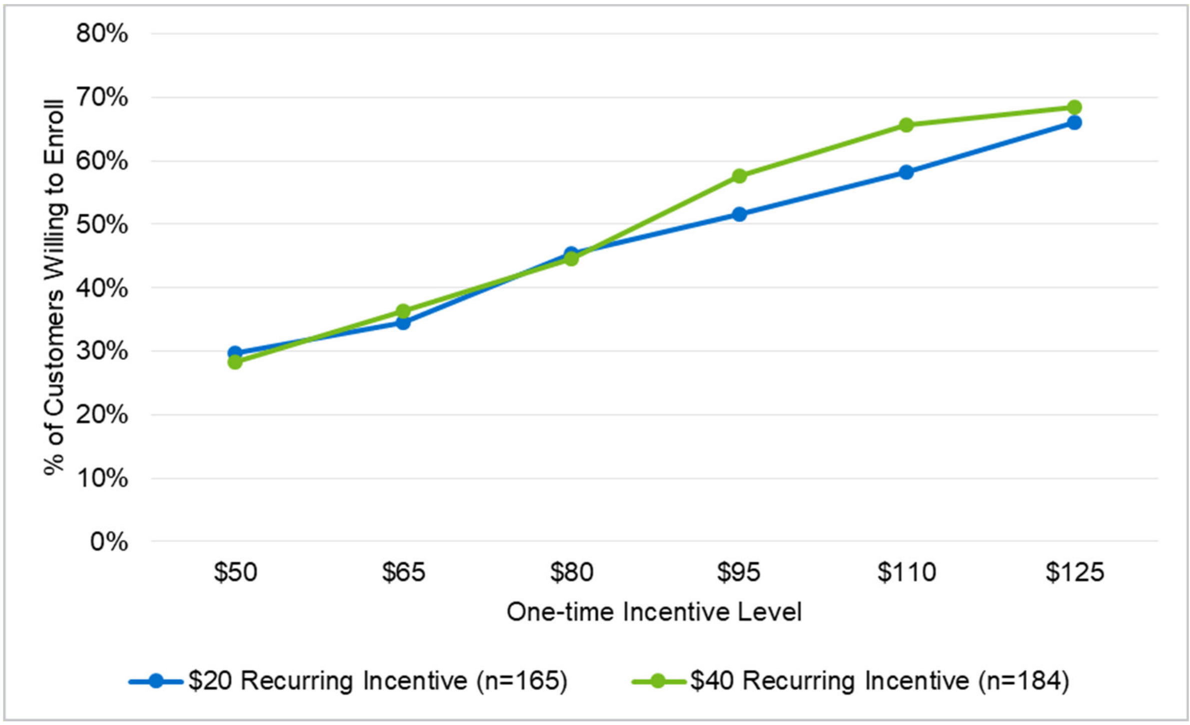
<u>Proposal 5</u>: SDG&E proposes to add an enrollment incentive of $200 per kW to the Smart Energy Program.

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

[45] Changes in the annual incentive were surveyed only among residential customers only.

EBM-6 below illustrates these results, indicating enrollment payments are an effective method of encouraging customers to participate. Therefore, it is important to add an enrollment payment to the SEP program once the TD program is retired.

Figure EBM-3



<u>Proposal 6</u>: Consolidate the Smart Energy Program into one day-of product when the direct load control switches are retired.

Currently, the SEP has two products: (i) a day-of product for the switches (which SDG&E proposes to retire), and (ii) a day-ahead product for the thermostats. Once the switches are retired, SDG&E proposes that the program consist of only a day-of product that will encompass thermostats as well as any new devices that join the program. Keeping only a single product will prevent the program from being fragmented into smaller pieces dispatched at slightly different times. Keeping all of the technologies within the same product will also allow SDG&E to combine different technologies to provide a level load reduction over a full four-hour event if necessary. Accordingly, SDG&E proposes that the SEP consist of a single day-of product. The program should be classified as "day-of" because there is no requirement for customers to be notified of the event a day in advance.

3. Smart Energy Program 2024 – 2027 Budget Proposal

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

EBM - Table 7
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

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

SDG&E is required to offer the switch portion of the program, SDG&E further requests that the Commission remove the requirement for the switch portion of the program to be cost effective and for it to be removed from SDG&E's cost-effective calculations portfolio wide. SDG&E requests this since SDG&E does not believe that its overall portfolio cost effectiveness for its other DR programs should be negatively impacted by including the switch portion of the program when SDG&E has requested to end the program.

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

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

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

E. Heat Pump Water Heaters

SDG&E will enroll customers that have received the Small Generator Incentive Program (SGIP) Heat Pump Water Heater (HPWH) incentive into any of SDG&E's supply side DR programs.[46] SDG&E is not seeking any additional funding and will fund HPWH out of approved program funding. If additional funding is needed to bring HPWR into DR programs, SDG&E requests Commission approval to seek additional funding via Advice Letter submission.

III. LOAD MODIFYING DEMAND RESPONSE PROGRAMS

A. Emergency Load Reduction Program (ELRP) Pilot

1. Background

To comply with D. 21-03-056, Ordering Paragraphs 7 and 8, SDG&E launched the ELRP effective May 1, 2021, in compliance with the guidelines laid out in Attachment 1 of the same decision.[47] "The purpose of ELRP is to allow the large electric IOUs and CAISO to access additional load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages while minimizing costs to ratepayers."[48] The objective of the ELRP is to determine if it is a viable pathway to securing emergency resources outside of the existing market framework programs. Pilot eligibility spans a variety of customer groups from large non-residential customers not currently participating in market-based demand response programs, residential and non-residential aggregators for existing participants in other DR programs (BIP, CBP,) DR bid into the CAISO, otherwise known as Proxy Demand Response Resources (PDRs) and for VPPs which may include battery storage or electric vehicle fleets. Subsequently, the CPUC issued D.21-12-015 which modified subgroup A.4 VPP, added

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

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

48 D.21-03-056, Section 5, p. 18.

subgroup A.5 which focuses on vehicle to grid integration, and subgroup A.6 which is open to individual residential customers to the ELRP[49] and increased the incentive to $2 per kWh.[50]

The eight eligibility groups, as described in the decision[51] are:

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

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

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

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

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

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[49] D.21-12-015, Attachment 2, p. 7.

[50] D.21-12-015, Attachment 2, p. 13.

[51] D.21-12.015, Attachment 2, p. 2.

ELRP group A.6 is open to individual residential customers. In accordance with D.21-12-015, SDG&E will automatically enroll all its CARE/FERA and Peak Day behavioral program customers in the ELRP A6 group on May 1, 2022.[52] The A.6 subgroup will also be open on an opt-in basis to other eligible residential customers. Participants will receive a payment of $2 per kWh for incremental load reduction based on actual performance. The incremental load reduction is determined by subtracting the energy use during the event period to the energy use of the baseline.

The DRP's that are in Sub Group B.1, are authorized to invoice SDG&E for their reductions after the fact, two times per year.[53] ELRP events may be called from May to October triggered when a CAISO Day-Ahead (DA) or a Day-Of (DO) Notice is called by the CAISO.[54] Events may last from one (1) to five (5) hours, with an annual dispatch limit of sixty (60) hours. Events may be called any day of the week during the hours of 4pm to 9pm.[55] Courtesy notifications for events will be sent to participants via text, or call.

Initial feedback from our customers to SDG&E's Account Executives and other SDG&E ELRP staff say that they like the ELRP's design and the flexibility to shed load as well as being able to export to the grid. The ELRP also allows a customer the ability to use their Behind the Meter Generation (BTM) Rule 21 interconnected device as permitted.[56]

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[52] D.21-12-015, OP 28 and 36.

[53] D.21-12-015, Attachment 2, p. 19.

[54] CAISO Operating Procedures, System Emergency, Procedure 4420.

[55] D.21-12-015, Attachment 2, p. 2.

[56] D.21-12-015, Attachment 2, p. 5.

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

SDG&E started enrolling customers in ELRP A.1 in late June 2021 with favorable response from our largest customers. At the end of September of 2021 SDG&E had 12 customers enrolled in the ELRP with a combined load reduction of 42.5 MW. SDG&E lost one customer who was enrolled in the ELRP in August when they switched their participation from the ELRP to the California State Emergency Program (CSEP) based on the higher incentive payment. Since the 2022 ELRP enrollment period has not opened yet it is unclear if the customer will come back and enroll in the ELRP for 2022. Enrolments by month are shown in Table EBM-8 below.

Table EBM-8
ELRP Customer and MW

Month	Number of Customers Enrolled Per Month	MW Enrolled
Jun-21	**2**	**12**
Jul-21	**8**	**13**
Aug-21	**1**	**8**
Sep-21	**1**	**9**
Total	**12***	**42**

*Excludes one customer that switched from the ELRP to the CSEP[57] in August 2021.

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

- $2 per kWh for verified load drop
- No penalty for non-performance

[57] CSEP – California State Emergency Program. The program was available only from August 16th, 2021, through October 31st, 2021, before sunsetting.

- Allowed to use their (BTM) devices to either drop load or export load to the grid during times of need[58].

SDG&E has seen its largest customers who historically have not participated in any of SDG&E ‘s existing DR programs sign up and perform in the ELRP. As of September 30, 2021, they had participated in the three events called so far. Due to these customers participating these customers are providing new incremental kWh’s that SDG&E could not have counted on in the past. During last year’s events (2021) approximately 186,177 kWh of load shed was achieved to support the grid. There was no participation in ELRP from any of the other subgroup's A or B in 2021 so no data is available on the efficacy of these subgroups. In 2021 and 2022, SDG&E proactively reached out to CBP and Rule 32 DRPs who are contracted to deliver DR from the DRAM to encourage them to enroll in ELRP Subgroups B.1 or B.2. As of this filing for 2022 no DRAM Demand Response Providers or CBP Aggregators have said they are going to participate in the ELRP.

2. Proposals for ELRP 2024-2027

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

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

[59] D.21-12-015, pp. 130-131.

[60] D.21-12-015, Attachment 2, p. 20.

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

While D.21-03-056 allows for the use of back up generation (BUGs) in the ELRP,[61] this language can be somewhat confusing to participants and/or sends a mixed message as to whether the participants might ultimately be penalized for using BUGs. Indeed, there seems to be a desire from the Energy Division (ED) following the Decision to substantially limit the use of BUGs by employing onerous reporting requirements and calling for varying dispatch priorities. The reporting requirements set forth in the decision specified the following data to be provided: location, type of fuel used, minimum notification time required to dispatch the generator and the capacity of the generator. However, Energy Division staff asked that minimum notification time and ramp time also be reported and issued a detailed reporting template with additional information, some of which either doesn't exist for all participants (*e.g.*, energy output of unit) or is burdensome for the participants requested additional data be collected and provided outside of the decision's requirements. Collection of this information, and additional supplemental information that IOUs are requested to collect, is not only administratively burdensome but some participants are hesitant to provide all the data. Customers are concerned that the disclosure could open them up to additional inspections, scrutiny or future penalties from the California Energy Commission (CEC), California Public Utilities Commission (CPUC) or California Air Resources Board (CARB, which governs the use of generators).

SDG&E notes these restrictions and limitations complicate and/or reduce the effectiveness of the program. For example, notwithstanding the Decision's permitted use of

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[61] D.21-12-015, Attachment 2, p. 1.

behind the meter resources (BTM) in the ELRP, participants are still required to adhere to their current air quality district permit restrictions, which may limit the ability to utilize BUGs and in turn respond to ELRP events unless they receive a waiver of the air permit regulations by the Governor.[62]

Also, the Governor's "Proclamation of A State of Emergency" issued on July 30, 2021, authorized the use of BUGs for both the ELRP and the new California State Emergency Program.[63] However, the proclamation only authorized the use of behind the meter resources through October 31, 2021. For 2023 forward, the restrictions are in place that the use of behind the meter resources considered a prohibited resource are not allowed to be used during a ELRP event unless the Governor's Office provides an emergency waiver.[64] The State needs to find a better solution for approving the usage of customers behind the meter resources than the current policy of issuing limited, short-term one-off Executive Orders for each called ELRP DR event. Without an expanded waiver, similar to what is in the Governor's Emergency Proclamation but with a longer duration, it is very likely customers in the ELRP would need to hold off using their prohibited resources as to not exceed CARB's usage limits or lower their level of participating MWs by excluding their behind the meter resources. SDG&E submits that this is an extra burden that could

[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 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.*

impact the Commission's and the State of California's desire to get every available MW active to help the grid during an emergency. While SDG&E understands that some of these issues may fall outside of the CPUC's primary area of responsibility, the CPUC can take an instrumental role in trying to get these changes enacted and allow the ELRP to grow and provide the MW that are needed during statewide emergencies.

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

- 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.

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.[65] 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.[66] Although D.21-12-015 stated that subgroup A6 would also be in place for four years (2022-2025)[67] it only included administrative funding for 2022 and 2023.[68] Provided that the ELRP A6 administrative budget is extended to be available for 2024 and 2025, the balancing account caps included in D.21-12-015 include sufficient funding for SDG&E to continue the ELRP pilot through the end of 2025 (*see* Table EBM-9).

Table EBM-9

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

65 D.21-12-015, Attachment 2, p. 1.

66 D.21-12-015, OP 21.

67 D.21-12-015, Attachment 2, p. 1.

68 D.21-12-015, OP 21.

a. 2024-2025

SDG&E requests the Commission approve an additional allocation of $3.0 million dollars per year for 2024 & 2025 for administrative costs to administer the ELRP A.6 Residential program through the end of 2025.[69]

b. 2026 -2027

SDG&E supports the continuation of the ELRP and requests the Commission continue and extend all of the ELRP Subgroups through the end of 2027 and requests approval of additional funding to cover the years 2026 & 2027 in the amount of $71 million. As detailed in Table EBM-10 below.

Table EBM-10
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

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

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[69] 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).

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

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

IV. ENABLING TECHNOLOGY PROGRAMS AND EMERGING TECHNOLOGIES

A. Technology Deployment

1. Background

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

- TD is a "bring your own device" program (sometimes referred to as "BYOD"), which means that the purpose of the upfront payment is to incentivize customers to enroll a device of their choice in a demand response program.
- TD offers fixed incentives to customers who enroll an eligible device in a qualifying demand response program. The incentive per device is calculated by taking an average load impact per device and multiplying by $100. Load impacts may come from either measurement and evaluation results or engineering estimates. The

average load impact may be calculated either for all customers or by sub-group (*e.g.*, customer class or by climate zone).

- Customers are required to enroll in either a rate with events, the AC Saver Program, the Capacity Bidding Program (CBP), or a program run by a third-party with a DRAM contract in order to qualify.

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

TABLE EBM-10
Customers Receiving TD Incentive (2017 – July 2021)

Year	Number of customers who received a TD incentive
2017	6082
2018	6119
2019	4742
2020	6571
2021	3604

Numbers for 2022 were not available at the time of filing.

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.

The high enrolments are all the more encouraging because the BYOD model has far lower costs than a direct installation program.[70] 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.

However, the program has experienced challenges as well. A major challenge with the program is that thermostats customers purchase on their own through retail channels cannot be signaled directly by SDG&E as the thermostat settings must be adjusted by the manufacturer. The way enrollment and device signaling work in this situation is as follows. Customers must first register their thermostat through their thermostat manufacturer's website or app so that SDG&E knows that the thermostat is installed and online. SDG&E's signaling platform then pulls in these pending enrollments from the manufacturer application programming interface (API)[71] and verifies customer eligibility. In order to call an event SDG&E enters the event into our signaling portal which communicates the event to the manufacturer through the API and the manufacturer portal adjusts the thermostat settings. The signaling portal then retrieves data about the event from the manufacturer portal such as how many thermostats were online during the event. This model means that if the manufacturer decides to no longer participate in the program, then SDG&E can no longer adjust the thermostat settings.

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

[71] 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.

A second challenge has been explaining the complex program design to customers. Currently, a customer may qualify for the TD program by enrolling in the Smart Energy Program, a rate with events, DRAM, or CBP. Of these, 92% of TD customers enroll in what will be the Smart Energy Program, 4% enroll in a rate with events, 4% enroll in DRAM and none have enrolled in CBP. This program structure is too complex to convey briefly to customers in a thermostat enrollment "app" so the brief description shown describes the combined and SEP incentives. To explain the more complex program design more fully, SDG&E includes full detail of all the options on its program website, and when customers enroll in TD a program-specific welcome e-mail is sent out with the information applicable to the program the customer chose to enroll in. However, the inherent complexity of the program design is still a constant challenge.

2. Proposed TD Program Changes

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

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

The current program design in which TD customer can participate in either SEP, a rate with events, CBP, or pilots not subject to cost effectiveness (*e.g.*, DRAM) is also too complicated and causes issues. Given that the device settings can only be adjusted by the manufacturer allowing customers to meet the eligibility requirement for a TD incentive by participating in third-party programs (as contracted DRAM resources), it is not a good use of ratepayer funds and creates a confusing customer experience. If the aggregator or third party does not have a contract in place with the manufacturer, then they will be unable to adjust the device settings in which case the customer will not be participating in a demand response program using their technology. If the third party has an agreement with the manufacturer, then different issues arise. The thermostat manufacturers have stated that their automated platforms do not allow the same thermostat to be enrolled simultaneously in two conflicting demand response programs in order to prevent two different companies from sending conflicting commands to the same thermostat.[72] So, if the customer enrolls through the third-party thermostat portal the customer cannot then enroll in SDG&E's thermostat portal so that SDG&E can verify that the thermostat exists and is online. From a customer perspective, having to apply with both the third party and with SDG&E to get the full incentive available is cumbersome and confusing. In addition, third parties receive a capacity payment from SDG&E with the understanding that they are responsible for any incentives to the customer. When SDG&E pays a full incentive to the third party and an incentive to the customer, that results in an overpayment. Customers deserve a simple,

[72] OEM Terms and Conditions of Service.

straightforward program enrolling structure in which they enroll either or SDG&E or a third party but not both.

As SDG&E expands this program to additional devices, it is possible that some controls eligible for the program will be able to communicate through an open standard. 0In this case some of the problems with allowing customers participating in CBP or DRAM to receive a TD incentive listed above would not apply. However, offering customers the opportunity to participate in numerous program options still makes the program difficult to explain to customers. Many customers now enroll in the program through a device app. There is not a lot of space on a smart phone to explain a complicated program design. In one case a manufacturer has built the program enrollment process into their product initial set up process which has increased program participation tremendously. However, although a link to the SDG&E program website with full program information is made available, the messaging within the app focuses solely on the combined TD/SEP incentive as anything else would be too complex to explain. In order to maximize program participation SDG&E must offer straightforward program designs that are in line with modern program enrollment methods. Therefore SDG&E proposes to eliminate TD as a separate program and to add an enrollment payment to the SEP program.

B. Residential Smart Communicating Thermostat Program (SCT)

D.21-12-015 directed all three IOUs to offer a new Smart Communicating Thermostat (SCT) program.[73] The decision included the following description of the program:

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[73] D.21-12-015, OP 42.

The decision authorizes a budget of up to $22.5 million in technology incentives ($75 per measure) to develop a limited, two-year Residential (SCT) program for 2022-23 to incentivize the installation of up to 300,000 SCT in hot climate zones (Climate Zones 9, 10, 11, 12, 13, 14, and 15). This program will be run statewide within each IOU's service territory, and the IOUs may request up to an additional 10% of each IOU's proportional share of the technology incentive budget for administrative costs. Fifty percent of the technology incentive budget, or up to $11.25 million, will be available to third-party DRPs to provide rebates through third-party demand response programs. Third-party DRPs should have competitively equal access to the rebates as the IOUs. This program will require customer pre-enrollment in a market integrated supply-side Demand Response program. Eligible market integrated programs are Demand Response Auction Mechanism, Smart Energy Program, Capacity Bidding Program-Residential, and AC Saver. The technology incentive amount will be up to $75, limited to the full cost of the SCT. Prior to incentive payment, the IOUs must verify installation of an eligible thermostat and enrollment in an eligible IOU or third-party program. [74]

This program has not yet launched so no data is available to evaluate the efficacy of the program. SDG&E does not recommend continuing the SCT program beyond 2023 for Smart Energy Program customers since it would be duplicative of the SEP enrollment incentive. The CPUC has not yet determined whether or not DRAM will continue past 2023 so it is premature to determine whether or not SCT should continue to be made available to DRAM participants. Similarly, there is not enough information from the CBP residential plot yet to determine whether or not open up the CBP program to residential customers so it

[74] D.21-12-015, Attachment 1, p. 13.

is premature to determine whether or not SCT should be made available to residential CBP participants.

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

C. Technology Incentive Program (TI)

1. Background

SDG&E's Technology Incentives (TI) Program offers incentives for the purchase and installation of qualified demand response measures that provide verified, dispatchable, on-peak load reduction at customer-owned facilities. Eligible customers can receive up to $200 per kilowatt (kW) of verified, dispatchable, fully automated on-peak load reduction. The total of the earned incentive is limited to 75% of the total project cost.

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

During the 2015-16 program cycle, 99% of incentive payments were assigned to third-party contractors[75] and in 2017, the program began making the first of the 40% performance payments[76] resulting from 2015-2016 projects. During this time, it was discovered by SDG&E program staff administering the program that the majority of customers were either underperforming[77] or not performing at all and therefore were not eligible for their final 40% performance payments.

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

Contributing factors that led to contractors leaving the program.

- Contractors did not want to be responsible for the customers' event performance.
- Lowered incentive amount from $300/kW to $200/kW was not attractive.
- Claw back risk and penalties for non-performance by customer.

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

[76] 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.

[77] 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.

- Some contractors waited for over 2 years for their final payments and then were still not paid for balance of job because of non-performance by the customer.

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

<u>2017 (Bridge Year):</u>

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

<u>2018-22:</u>

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

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

Customer/Contractor Feedback:

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

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

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

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

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

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

2017 (Bridge Year):

- Reviewed SDG&E CAP audits for potential opportunities.

- Cold calls to over 500 small and medium unassigned commercial customers.
- Account Executive face to face meetings with large, assigned accounts
- Refresh of Trade Pros fact sheet and article
- Trade Pros Publications – TI Article

<u>2018:</u>

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

<u>2019:</u>

- Monthly Trade Pros training seminars at SDG&E's Energy Innovation Center
- Linked in email campaign
- E-Newsletter email blast campaign
- Demand Response Technology Incentives (TI) Program Qualitative Study (Travis Research)
- Technology Incentives web page redesign
- Demand Response "Save the Day" campaign.

- Account Executive face to face meetings with large, assigned accounts

2020-21:

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

Since 2019 SDG&E has only had one contractor submitting the majority of applications. The resulting projects (typically chain accounts) barely meet the minimum requirements for program participation and contribute little energy savings. Relying on one vendor to drive the program is not prudent.

In 2020, during the global COVID-19 pandemic, the program received several application cancellations due to business closures. These projects were part of the restaurant and hospitality sectors that were hit hard by the pandemic and the restrictions placed on businesses by state and local authorities due to COVID-19[78] mandates and restrictions. Since then, the applications received in late 2019 and early 2020 have been on perpetual hold. The majority of these are chain accounts and SDG&E has since learned from the contractor that the customer is not planning on completing the installations until the end of Q1 2022 at the earliest, if at all.

In Q3 2021, SDG&E saw the majority of the COVID-19 restrictions, lifted allowing businesses to reopen and contractors to get back to work. However, it has not translated into an influx of new projects. The 67 applications received in 2021 were from an energy consultant looking to leverage project dollars (incentives) in their quest to secure projects

[78] 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

from customers that have yet to be realized. In effect, SDG&E has received zero new projects in 2021 and none to date in 2022.

Table EBM-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

<u>Successes and Challenges:</u>

1. Sporadic program participation by contractors and customers over the years.
    a) With a limited number of projects completed, there is little contribution to other DR programs.
2. Poor customer performance.
    a) Average customer first year performance is less than 50% of original committed load shed test results.
    b) Since 2017, TI projects have contributed less than 75kW to the DR portfolio.
3. No customer retention in demand response programs after the 3-year program participation requirement is met.
4. Budget spend: (2017 – July 2021).
    a) Incentives paid: $6,300.00
    b) Administrative spend: $1.3M

2. Proposed TI Program Changes

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

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

1. Background

The Emerging Technology Demand Response (ET-DR) Program focuses on the identifying and evaluating emerging innovative technologies and strategies, a challenging and increasingly important area of demand response. The ET-DR Program focuses on demand response of the future for the San Diego region while also helping the State address challenging grid conditions. Given in today's evolving environmental conditions and during critical supply challenges, the opportunity for developing creative, innovative, flexible and cost-effective demand response solutions has never been greater. The ET-DR Program staff are energized and will continue to research companies and more complex technologies that promise significant demand reduction potential in the short or mid-term time horizon. Beyond the addition of smart devices and systems that provide the foundation a network of flexible behind-the-meter (BTM) resources to support DR of the future, the ET-DR Program will also seek to identify technologies that complement the changes throughout our core Demand Response Program portfolio such as Auto Demand Response, Integrated Distributed Energy Resources (IDER) proceeding, Microgrids and Virtual Power Plants. The Portfolio is centered on whole facility smart technologies that enhance ratepayers' ability to respond to changes in demand conditions that will help address supply challenges. The ET-DR program will explore and investigate how dynamic price signals combined with smart technologies and communication networks can be used in concert with dynamic price signals to enable and motivate bundled customers to provide grid-benefits when needed. At a minimum, each evaluation project will address the following:

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

The ET-DR 2018-2022 program cycle was very successful in the types of projects that were able to be initiated and completed during the program budgeted period. Some of the technologies researched throughout the 2018-2022 program cycle included: Smart Voice Assistant device, a time of use (TOU) messaging app and device, a Distributed Energy Resources (DER) Data Analytics tool to identify customers for Demand Response participation, an Electric Vehicle Charging impact study, a Thermal Storage for Refrigeration project and a Whole Home DR study.

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

SDG&E recently initiated an exciting new Virtual Power Plant project expected to be completed in 2023; however, SDG&E plans to build on the lessons learned and potentially do additional related research on Virtual Power Plants in 2024-2027. The ET-DR team is working with vendors to develop a Virtual Power Plant that will include a variety of devices across several customers. A Virtual Power Plant has the potential to grow into a vast collection of devices that could potentially be spread out across the SDG&E service area and serve as a grid resource for DR events as well as other grid needs. This type of project requires significantly more funding to not only install the various devices installed at customers' premises but also to ensure the devices can be signaled on a third party developed platform and controlled by SDG&E. This is an example of a more complex and technical project that requires additional funding due to the extensive coordination with external stakeholders and focus on multiple types of devices installed at customers' premises. The menu of devices offered will vary by customer based on their potential to participate in the Virtual Power Plant and could include Smart Thermostats, Water Heating Controllers, Electric Vehicle Charging Controllers and battery storage.

For more detailed information on these projects, please see the Demand Response Emerging Technology SDG&E Semi-Annual Reports, submitted to the Commission, dated March 31 and September 30 of each year within the program cycle.[79]

2. ET-DR Proposal for 2024-2027

The ET-DR proposal for 2024-2027 is a 77% budget increase from the 2019-2022 years approved in the 2018-2022 filing. Additional funding is needed to transition from the

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[79] *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.

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

3. ET-DR Proposed 2024-2027 Budget

Table EBM-12
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

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

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

V. PILOTS

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

1. Background

As of 2020, San Diego County has ~2,477,631 vehicles. Of that number, 51,616 are electrified with 32,057 battery electric vehicles (BEV), and 19,559 Plug-in Hybrid Electric Vehicles (PHEV).[80]

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

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

SDG&E's main strategy for managing electric vehicle loads to date has been to encourage electric vehicle owners to sign-up for time of use rates (TOU) designed for electric vehicles. With electric vehicle TOU rates, SDG&E does not directly manage vehicle charging. Instead, the TOU rates encourage customers to shift load from higher priced peak hours to lower priced off-peak and super off-peak hours. A TOU rate is considered "passive" demand response, leaving the control completely to the customers to

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[80] 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)).

take actions. Moreover, the TOU rates generally do not isolate the EV loads but apply to the whole home.

As of Q3, 2021, SDG&E estimated there are 48,446 residential light duty EV[81] in SDG&E's service territory. There are approximately 24,445 residential customer accounts enrolled on TOU rates designed for electric vehicles.[82] However, about 50% of the registered residential EVs in SDG&E's service area are not currently participating on an EV TOU rate.

Although SDG&E has implemented default TOU rates for residential customers, there are multiple advantages to having EVs directly respond to prices and active DR control signals rather than the passive response to TOU rates. An example is the shifting of charging times to the lower priced Super Off-Peak hours from the On Peak hours of 4 p.m. - 9 p.m.

2. Need for an EV DR pilot

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

- It enables SDG&E to manage charging times for EVs that have not signed up for EV TOU rates and to test acceptance.
- Testing to see if we can further automate and deliver more flexible, reliable, and predictable load reductions from customers who elect to sign up for EV TOU rates.

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[81] SDG&E internal Clean Transportation Q3, 2021 data.

[82] *Id.*

- It provides SDG&E the ability to test the ability to test a staggering EV charging strategy to minimize the effect and stress on the grid from all of EV loads coming onto the grid at once during off peak hours.
- It enables SDG&E to build the control strategy to adjust EV charging in response to CAISO day-ahead market prices.
- It also provides the option to inform customers to use EVs to absorb and store excess solar energy.
- The load management technology also enables better feedback to customers about their EV charging patterns and the energy and emissions savings from using electricity as a fuel source instead of fossil-based fuels.

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

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

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

1. Use TOU rates to incentivize customers to shift charging to off-peak periods.[83][84]
2. Work with charging manufacturers to recruit existing sites and manage charging by adjusting or reducing energy use during demand response events.[85] and
3. Use automaker original equipment manufacturer (OEM) telematics to directly communicate with vehicles, access charging data,[86] and actively manage charging during demand response events.[87]

3. EV DR Pilot Overview

With the explosive growth of EVs and the increased amount of charging stations installed at residential homes,[88] SDG&E proposes an EV focused demand response pilot that

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[83] SDG&E's EV TOU rates: https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans

[84] Green Mountain Power Rate 72: *https://greenmountainpower.com/wp-content/uploads/2020/09/*Rate-72-EV-Off-Peak-Charging.pdf

[85] 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.

[86] BGE EV Pulse: https://landing.bge.ev-pulse.com/

[87] National Grid: https://www.nationalgridus.com/MA-Home/Connected-Solutions/EV-and-PHEV-Program

offers customers the options to optimize charging, receive incentives to offset their energy bill and to participate in demand response events that provide benefits to the grid.

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

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-2pm in Spring season to absorb excess solar generation.
3. Determine whether charge start times can be staggered to manage loads and avoid all vehicles coming online at the same time.
4. Validate the program design, incentive structure and cost effectiveness

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

4. Proposal for 2024-2026 Residential EV DR pilot

a. Solicit EV control platform vendors

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

[88] 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

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

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

b. Marketing

SDG&E will design marketing strategies to engage local EV customers and communities. SDG&E will utilize the digital and traditional marketing strategies and host customer education events where applicable. SDG&E will design a new website landing page for EV customers to enroll in the pilot directly.

c. Summer DR season offering

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

d. Spring DR season offering

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

e. Incentive structure and targeted participants

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

- 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 if they remain enrolled and participate in the Pilot.

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

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

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

1. Average time needed to sign up a customer

2. Customer participation

3. Customer drop-off rate

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

5. Budget Proposal for EV DR Pilot

SDG&E requests a budget of $3.3 million over the three years for the residential EV DR pilot. The table below includes the requested pilot budget for administration and incentives. SDG&E will administer a robust E&MV evaluation to evaluate the Pilot for possible enhancements and proposals to become a program in the 2028-2032 Funding Cycle.[89] Funding for the evaluation of the pilot

Table EBM-13
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

B. New Pilot – Battery Storage DR Pilot

1. Background

Battery storage in SDG&E's territory has grown substantially in recent years, with the current number of residential interconnections surpassing 62MW of installed capacity at over 9,100 premises.[90] The growth of residential battery installations has grown at an

[89] Prepared Direct Testimony of Lizzette Garcia -Rodriquez, Chapter 4B.

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

annual rate of 150%.[91] The vast majority – approximately 97% - of these installations have occurred at sites that also have solar installed on the premise.[92] Further, approximately 5.5% of all new residential solar installations are concurrently installed with battery storage.[93] With the high penetration of solar installations at residential sites in SDG&E's territory, there is substantial room for future growth in battery storage for this customer segment.

Residential battery installations are an attractive end-use for demand response; however, SDG&E currently does not have a residential or commercial DR program that is explicitly designed to target this technology. With the substantial growth in installations and customer interest in battery storage, there is a clear opportunity to develop and test a pilot demand response program that relies on this technology.

Preliminary evidence[94] suggests that residential battery storage can produce 5.5kW of load reduction per device when dispatched for 2-hour events. The limiting factors of load reduction are the length of the event, the amount of solar power available during the event, and the size of the batteries. The average size for residential battery installations in SDG&E's territory is approximately 5.7kW,[95] which is comparable to the average

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[91] *Id.*

[92] SGIP Database for Residential storage in SDG&E's territory, through September 2021. https://www.selfgenca.com/report/public/

[93] 2020 and 2021 residential solar and battery installations, per SDG&E's Interconnection Database, as of July 2021.

[94] 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

[95] SDG&E Emerging Tech Report, Behind—the-meter Battery Market StudyDR19SDG0002, Figure 5.

installation size used for the impact evaluation at National Grid (average size, 6.5kW, N=50). Given the number of installed residential batteries in SDG&E's territory, this study indicates that there is approximately 52MW of dispatchable and curtailable load currently available among residential customers. According to SDG&E's 2020 Behind-the-Meter Battery Market Study,[96] it stated that there is expected to be approximately 150MW of residential behind-the-meter battery capacity installed in SDG&E's territory by 2027 and up to 280MW by 2030.[97]

2. Storage DR Pilot Overview

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

While individual customers are using their batteries for various reasons such as peak shaving during on Peak hours, there is limited participation in the current DR programs or

[96] Emerging Technology Report, Behind-the-Meter Battery Market Study DR19SDG0002.
[97] *Id.*

pilots. At the same time, visibility into customer behind-the-meter (BTM) battery usage patterns is poor. This leads to a disconnect in quantifying the precise value of demand response, as customers may not be operating their battery in a way that is beneficial to the grid. There is a clear opportunity to learn more about how customers use their battery systems and determine how much demand response potential exists in this fast-growing resource.

The Battery Storage DR Pilot seeks to answer questions about how residential and small commercial customers with existing batteries currently use them, whether the existing storage systems can be successfully dispatched for demand response events or to respond to day-ahead market prices. In addition, the pilot will test how incentive levels and structures influence customer participation and identify the optimal incentive levels and structure. Finally, the pilot will study how settlement baselines should be modified to accurately capture the value of battery resources through a baseline accuracy simulation.

3. Battery Storage DR Pilot Objectives

SDG&E's Battery Storage DR Pilot will be available to residential and small commercial customers (with maximum monthly demand less than 20kW) and will enable them to use their existing battery technology to participate in DR events and respond to CAISO day-ahead prices as a VPP. As part of the pilot, SDG&E will undertake several research objectives to understand how customers use their 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, and what kinds of settlement baselines accurately capture these impacts for settlement in the CAISO market.

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.

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

The storage DR pilot has five specific evaluation objectives:

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

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

1. <u>Planning</u>: Contract with battery/inverter vendors, IT systems build, develop and deploy research survey

2. Learning: Recruit residential participants, gather baseline battery consumption data, finalize the first-year pilot design, and field enrollment survey.

3. Implementation: Run the pilot for residential customers and commercial customers.

4. To evaluate the success of the pilot a separate load impact analysis will be conducted at the end of the pilot in 2027 as described in the Load Impact Evaluation Plan that can be found in the Prepared Direct Testimony of Lizzette Garcia-Rodriguez (Chapter 4B) [98]

4. Proposed Budget for Battery Storage DR Pilot

Table EBM-14

	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

[98] Prepared Direct Testimony of Lizzette Garcia -Rodriquez, Chapter 4B.

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 their ability to meet customer, utility, and grid needs while others are not.[99] DERs can also encompass the best of auto DR (ADR) technologies and expand beyond simple heating, ventilation and air conditioning (HVAC) and smart communicating thermostats to include solar, storage, energy efficiency, and demand management energy resources that are creating new opportunities for commercial and residential customers.

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

With the key lesson learned so far from the ELRP, the pay for performance model with no penalties for non-performance is preferred. Large commercial customers in SDG&E'S service territory appreciate the flexibility and more control when participating in

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[99] *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.

demand response programs and SDG&E expects that small and medium commercial and industrial customers would appreciate the flexibility as well. Currently the ELRP load shed minimum is too large for small and medium commercial and industrial customers to participate.

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

The pilot as proposed would pay $1/kWh[100] for Day-Ahead or Day-Of participation of verified load shed per event with no penalties for non-performance and would be dispatched by the utility. SDG&E would trigger events on any day of the week, year-round including holidays. Direct Dispatch events shall be effective from 4:00 p.m. – 9:00 p.m. 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. The CAISO shall also be entitled to request that the utility, at its discretion, call a program event. Events may also be triggered for testing/evaluation purposes. The load shed will not be bid into the CAISO market, however.

This pilot is targeted at commercial and industrial customers that already own qualifying ADR technology enabled equipment 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 receiving an ADR

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

signal directly to their devices of an event initiated by SDG&E for demand response or grid emergencies.

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

The goal of this pilot is to:

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

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.

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

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).

Table EBM -15
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

The Pip for this Pilot is located in Appendix A.

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

1. Background

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

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

2. GICP Overview

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

<u>On-demand load reduction capability</u>. During blue sky conditions grid isolation technologies can be used to drop loads or island the location the grid due to economic needs or in response to CAISO alerts, warnings, emergencies. During island operation, microgrid

isolation technologies can be used to manage customer loads thereby extending the amount of time that the customer's BTM resources can keep the customer energized When operating in island mode as part of a multi-customer microgrid these devices have the ability to deliver locational load reductions thereby protecting the circuit and preventing customer BTM damage while providing increased service reliability by allowing customers to use their BTM devices to remain energized during outages or PSPS events.

Once proven and UL[101] certified, we believe the technology should be able to deliver local and grid related benefits.

3. GICP Objectives

The objective of the pilot will be to test new isolation technologies and assess if the technology works as designed and whether it can effectively and safely isolate homes or businesses with solar and/or battery storage or other devices from the grid. In addition, the pilot seeks to test and verify load reduction strategies while quantifying the magnitude of the load shed under different event scenarios such as the time of day, event duration and locational dispatch. The pilot will also test customer acceptance of the technology.

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

4. Implementation

SDG&E will issue a request for proposal (RFP) seeking a third-party implementer that can provide and install the approved grid isolation technology and they will also include all activities required to solicit and retain participants. SDG&E will retain dispatching of

[101] UL stands for "Underwriters Laboratories."

events and customer settlements for the pilot and will have final approval of all marketing and recruitment activities related to the pilot.

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

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

GICP events can be called at any time of the year, including weekends and holidays, for local system need, in response to CAISO emergencies, PSPS events, or for testing purposes. Events will typically last from one (1) to two (2) hours with a maximum event duration of four (4) hours. Day Ahead and Day Of advance notice of events will be provided to customers via text message and/or email.

The pilot has the following objectives:

1. Can participants effectively and safely isolate themselves 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 system under generation periods as well as 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 the technology provide similar or additional benefits when installed within Disadvantaged Communities (DACs)?

This pilot seeks to enroll between 50-100 locations for participation. As part of the pilot, SDG&E will first attempt to recruit participants in low income or disadvantaged communities. Ideal participants would have either solar, battery storage installed, or an electric vehicle (such as the Ford© F150 Lighting)[102] in order to be eligible for the pilot.

SDG&E seeks the Commission's approval to submit a Tier 2 advice letter to either 1) update and finalize the pilot after three years, or 2) 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.

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

5. GICP Proposed Budget

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

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[102] 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/

Table EBM-16
Proposed Budget Figure

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

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

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

1. Background

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

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–17
Rule 32 Enrollment Forecasts 2024-2027

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

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.[103]

[103] 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.

Table EBM –18
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.[104]

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

1. Background

D.14-12-024 approved SDG&E and the other IOUs to offer a two-year DRAM pilot for 2016 and 2017 to the third-party DRPs to participate directly in the CAISO market. Later the Commission issued D.16-06-029 and D.17-10-017 to extend the DRAM pilot into

[104] 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.

2018 and 2019. The Commission then issued decision D.19-07-009 to extend the DRAM pilot through 2023 and D.19-12-040 to further refine the DRAM.

2. Current Status

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

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

3. DRAM Independent Evaluation

D.19-07-009 authorized the IOUs to contract with a consultant to evaluate the continuation of the DRAM and assist the Commission's Energy Division in monitoring the Auction Mechanism.[105] The evaluation includes performance of delivery years 2018 through 2021, and the solicitation process for years 2019, 2020 and 2021. The final evaluation report was originally scheduled to be made available to all parties no later than December 1, 2021. However, due to the delay in receiving the final evaluation data, a decision by the Commission's Energy Division to include the entirety of the 2021 Auction Mechanism delivery period, as well as an ongoing delay in the receipt of outstanding data

[105] D.19-07-009, p. 112, OP 16.

requests, the CPUC granted an extension for the final report to be provided to Energy Division by May 23, 2022.

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

4. Customer Information Working Group (CIWG)

Resolution E-5110 issued on December 18, 2020, authorized the Energy Division to initiate a Customer Information WG no later than 60 days after the adoption of the Resolution. The WG is tasked to study The California Efficiency + Demand Management Council's proposal from the DRAM WG and produce a report by June 1, 2021.[106] The Resolution also ordered the IOUs to include the Customer Information Working Group report in their 2023-2027 DR Portfolio Applications.[107] The Customer Information WG was never initiated, therefore there is no report to include in this application.

VII. RELATED ACTIVITIES TO SUPPORT DEMAND RESPONSE

A. CAISO Market Integration Study Proposal

In D.14-03-026, the Commission bifurcated DR resources into supply-side DR resources (*i.e.*, resources bid into the CAISO wholesale energy market) and load-modifying DR resources (*i.e.*, resources reshape or reduce the net load curve).[108] Several months later,

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[106] Resolution E-5110, p. 49, OP 5.

[107] Resolution E-5110, p. 50, OP 6.

[108] D.14-03-026, OP 1.

the Commission issued D.14-12-024 which required full implementation of bifurcated DR to begin January 1, 2018 (*i.e.*, IOUs must integrate supply-side DR programs into the CAISO market by January 2018).[109]

Ahead of the schedule and timeline set forth by the Commission, SDG&E began integrating its supply-side programs into the CAISO market and fully integrated all of its supply-side DR programs in 2015.[110] SDG&E recognizes that Commission policy over the past decade has been focused on DR market integration into the CAISO market and has led the way in implementing this policy, being the first California utility to integrate its programs. However, as SDG&E gained experience with integrating and operating DR programs in the CAISO wholesale energy market, several significant issues with this approach have become clear. At its root, the main problem with integrating DR into the CAISO markets is that the rules of market integration were designed for traditional "perfect" generation resources, not for customer-backed resources. Although CAISO and the Commission have done an admirable job of creating initiatives and modifying certain policies and rules to better support DR market integration, there are still gaps and more improvements that can be made if it remains appropriate for DR to be integrated into the CAISO market. To this point, no in-depth analysis of the successes and failures of DR market integration has been undertaken in California. As this policy has now been in existence for close to a decade, it is an appropriate time to reflect on and analyze this paradigm.

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[109] D.14-12-024, OP 4.

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

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

1. Current Status of CAISO-Integrated DR Programs

SDG&E currently has approximately 15 MW of supply-side DR capacity, all of which is integrated into the CAISO market. SDG&E has integrated its core DR programs[111] since 2015, with full integration under CAISO rules being achieved in 2017.

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

In 2013, the Commission initiated Rulemaking (R.)13-09-011 to determine whether and how to bifurcate DR into load-modifying and supply-side resources, "with the intent of prioritizing demand response as a utility-procured resource, competitively bid into the California Independent System Operator wholesale electricity market."[112] The Commission identified the ultimate goal of this process as being "to enhance the role of demand response programs in meeting the state's long-term clean energy goals while maintaining system and local reliability."[113] Similarly, the Commission stated in a decision in that proceeding that

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[111] SDG&E's core DR programs include the Base Interruptible Program (BIP), AC Saver and the Capacity Bidding Program (CBP).

[112] 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.

[113] *Id.*

the goals of bifurcation "are to improve the efficiency of demand response and increase the use of all demand response programs…"[114]

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

3. CAISO Market Issues

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

<u>Issue 1: DR Should Not be Compared to "Perfect" Conventional Generation Resources</u>

Since market integration in 2015, SDG&E has seen its DR portfolio decrease from a peak of approximately 30MW to just under 12 MW in its core programs (BIP, AC Saver, and CBP) due to customer attrition as a result of over utilization of the programs leading to customer fatigue and dissatisfaction. Over-utilization of DR programs and the degradation of SDG&E's DR portfolio can largely be attributed to market bidding requirements and integration rules that cause multi-hour consecutive-day dispatches which ultimately results

[114] D.14-03-026, p. 7.

in over-utilization of the programs/customer fatigue/unenrollment. For instance, under the CAISO Must Offer Obligation (MOO), a perfect resource would be bid for all hours (*e.g.*, 24/7/365) with no minimum load/minimum cost ($0) and no dispatch restrictions (*e.g.*, can be dispatched multiple times in a single day, no hourly or consecutive dispatch limitations). Also, DR in the San Diego area is very weather sensitive, and this affects MW results. Since DR is a use-limited resource, only allowing one dispatch a day the CAISO is trying to reduce the capacity value of DR due to its use-limited nature, which has a cascading impact on the resource (*e.g.*, if the resource gets a lower value, then this makes the resource less cost-effective and could cause incentive reductions, thereby reducing enrollment and participation).

Issue 2: One Program Per Service Account

As described above, SDG&E's vision for DR is to emphasize DR focused on residential and small business customers. These types of customers often have more than one DR-supporting end-use in the home or business. For example, a home may contain a smart thermostat (SCT), clothes washer, clothes dryer, dishwasher, electric vehicle, water heater, pool pump, solar, and battery energy storage. As technology improves and prices decrease, SDG&E expects more homes to invest in these types of appliances. Currently, SDG&E's DR programs are constrained by the CAISO rule that requires one customer meter to participate in a DR program with one and only one DR device.[115] Although it is possible for multiple devices to be aggregated by responding to DR with smart plugs or devices from other OEM manufacturers, such operation is unwieldy and does not allow for the type of DR participation that SDG&E envisions in the future.

[115] CAISO Business Practice Manual (BPM) for Demand Response.

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

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

It would be cost-prohibitive to operate a DR program in the most efficient manner under current CAISO operations. DR resources are typically comprised of many customers providing load reduction and partially dispatching a DR resource, even if it wins a CAISO award for partial dispatch, would require a huge investment in systems and technology to allow SDG&E to revise the number of dispatched customers in each resource. For this reason, SDG&E bids its DR resources into the market during the RA window as "all or nothing" (known as "discrete dispatch"). This means that, when awarded, SDG&E will dispatch a DR program in its entirety. However, such bidding and use limitation can result in DR resources being dispatched and customers asked to curtail when the entire quantity of MW may not be needed.

4. Proposal For A CAISO Market Integration Study

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

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

SDG&E anticipates that this study would be modeled on the recent large-scale Demand Response Potential Study that was initiated in 2014. The three IOUs would co-fund the study and a consultant or consultants would be engaged to design and manage the study, compile data, interview stakeholders as necessary, and prepare recommendations. An advisory committee made up of representatives from the IOUs, the Commission's Energy Division, CAISO, and other stakeholders as appropriate would provide input on the study's direction and serve as contacts for the consultants to request data. SDG&E in consultation with PG&E and SCE, expect the study would likely cost approximately $3 million and divided 40/40/20 between the IOUs with SDG&E's share to be 20%. Because the study should inform the IOUs' next DR applications for the 2028-2032 cycle, the study should conclude no later than mid-2026.

Therefore SDG&E requests the CPUC approve the proposed study and the initial budget for the study and allow the IOUs to recover the costs through each IOU's balancing accounts.[116]

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

B. Bottoms Up DR Potential Study

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

- Understand SDG&E customer elasticity by end-use, by comparing disaggregated load data relative to changes in price, as a function of customer sector, hour of day/day of week, use of automation/technology, historical EE upgrades, temperature, trailing consumption, historical demand, and other exogenous variables.
- Identify usage patterns of specific behind-the-meter (BTM) devices that can help improve customer load elasticity.
- Determine how the load-reduction potential of these devices could be optimally leveraged via the strategic deployment of enabling technology.

- Develop a supply curve of end-use loads that can be leveraged at each hour of the peak.
- Convert learning into actionable program design and/or operational insights.

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

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

Therefore, SDG&E requests the CPUC agree to and approve the study and approve the initial budget for it and allow SDG&E to recover costs. SDG&E would not attempt the study unless it is approved for all the IOUs and appropriately co-funded.[117]

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

There are a number of activities that support the DR programs with costs which are not related specifically to singular programs. They are general administration and support

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

areas that support the entire portfolio. These activities include regulatory policy support, financial analysis, budget management, reporting support, and systems support of SDG&E's business systems which directly serve DR programs. SDG&E requests funding at the following levels for each of the years in the cycle as follows:

Table EBM-19
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

Policy and Financial Support includes the discreet costs related to regulatory policy staff who oversee and respond to DR data requests, compile DR filings and Commission reports, participate in Commission-created or required working groups and work with the DR team to ensure compliance. It also includes costs related to the financial staff who track DR budgets and track actual expenses, oversee the financial reporting of the DR portfolio and advise the DR team on financial matters. System Support and Maintenance expenses include the costs directly related and limited to supporting the systems that serve SDG&E's DR team and its DR customers. The proposed budget is based on the anticipated scope and capabilities required to effectively and centrally integrate, manage, and operate SDG&E's portfolio of DR programs. These costs take into consideration some fundamental and high-level assumptions, based on the DR program proposals.

VIII. MID-CYCLE REVIEW

D.16-09-056 ordered the first mid-cycle review advice letter from the IOUs to update the Commission on their portfolios during 5-year cycles. The decision also stated that the utilization of such mid-cycle advice letters themselves should be reviewed in this instant application.[118] SDG&E filed its mid-cycle review (AL 3522-E) as required in March of 2020, to inform the Commission of its progress and to propose modest program changes midway through the 5-year DR cycle 2018 to 2022. However, that AL has not yet been approved by the Commission at the time of this filing. Thus, the mid-cycle review of SDG&E's programs has not proven to be an effective use of either the IOUs' or the Energy Division's time and resources. SDG&E therefore proposes that no mid-cycle review be required in 2023-2027. SDG&E notes that program changes can already be proposed via advice letter and that avenue remains open to the IOUs. Further, the IOUs all report their monthly activity and spending in their required reporting to the Commission. As such, there are other mechanism by which the IOUs can update the Commission or propose program changes without the need for submitting formal mid-cycle reviews which are time-consuming to prepare and review.

IX. ZIGBEE TECHNOLOGY UPDATE

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

[118] D.16-09-056, p. 59, OP 9.

A. Background

ZigBee technology was a common, if not the premier, meter communication functionality offered in the initial roll outs of smart meters, such as SDG&E's.[119] It was the communications technology that was contained in SDG&E's meters that were initially installed between 2009 and 2011. All of SDG&E's approximately 1.4 million meters today use ZigBee. This technology also was originally utilized by SDG&E in its retail enablement[120] of the Home Area Network (HAN) devices and early programmable controllable thermostats (SCTs) that were paired with a customer's meter in order to share data. First generation HAN devices were connected to meters directly by the IOU, after testing by the IOU and approved to link with SDG&E's smart meter network. The devices provide near real time usage data to devices in the home. SDG&E also used ZigBee to communicate other data to the HAN in early pilots; most often pricing or bill total estimates when paired with device algorithms that calculated usage and multiplied it by per kW rate, etc. This was done to display a proxy for billing information to test customer awareness of energy usage, enable greater understanding of energy usage and its relation to price, and to test behavior.[121]

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

[120] 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.

[121] 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

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

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

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

SDG&E's initial smart meter roll out is nearing the end of its life. Installations of SDG&E's first smart meters will be almost 20 years old by the time this instant DR cycle ends in 2027. SDG&E has issued a Request for Proposals (RFP) for new smart meters with the view to have new meters to be available in 2023 and beyond in the event older meters start to fail. In its own research, SDG&E has learned that none of the major smart meter

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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.

vendors today utilize ZigBee technology as they once did, including SDG&E's current meter vendor, Itron.[122]

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

SDG&E's proposal to discontinue support for ZigBee devices is driven mostly by the meter market. SDG&E's decision to not support ZigBee is not an indication that SDG&E does not support energy usage data being shared, or customers having access to that data. It is an indication that the technology landscape has merely changed since smart meters were first deployed and paired with devices using Zigbee. The technology has moved away from ZigBee.

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[122] 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.

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

X. CONCLUSION

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

This concludes my prepared direct testimony.

XI. WITNESS QUALIFICATIONS

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

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

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.

<u>Program Termination Rationale and Expected Outcomes</u>

- **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

<u>Program Transition Strategy</u>

- **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. <u>Notification Times</u>

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. <u>Incentives</u>

Aggregators will receive capacity and energy payments per the terms of the CBP Tariff[1] in return for their participation in the program.

7. <u>Marketing, Education & Outreach</u>

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. <u>EM&V</u>

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. **Curtailment 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 PROGRAM~~SAVER~~(SEP)

~~AIR CONDITIONER (AC) SAVER~~

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. ~~N~~

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 ~~N~~

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

(Continued)

SCHEDULE ~~AC~~ SMART ENERGY PROGRAM~~SAVER~~(SEP)

~~AIR CONDITIONER (AC) SAVER~~

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)

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	T, C
Real Time Market	130,000	130,000	130,000	35,000	35,000	35,000	130,000	T, C

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

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 chanells 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

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]

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[1] D.19-07-009 at page 3.
[2] D.17-12-003 at Finding of Fact 149.
[3] *Id*. at Conclusion of Law 74.
[4] *Id*. at page 153.
[5] D.19-07-009, page 4.
[6] See Administrative Law Judge's Ruling Directing Responses to Questions and Filing of Previous Demand Response Baseline Development and Implementation Costs, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M279/K201/279201986.PDF
[7] The following parties filed opening comments: Council, OhmConnect, PG&E, SDG&E, and SCE. The following parties filed reply comments: Council, OhmConnect, PG&E, and SCE.
[8] D.19-07-009, Ordering Paragraph (OP) 19.
[9] *Id*. at 86.

PURPOSE

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

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

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

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

CHRONOLOGY OF WORK DONE

Participants

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

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

Stakeholder Meetings

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

External Consultant

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

REQUIRED ISSUES

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

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

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[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.caiso.com/Documents/Section4-Roles-and-Responsibilities-asof-Jan1-2021.pdf.

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

APPENDIX

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

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

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

AEG
Applied Energy Group

BASELINES COMPARATIVE ANALYSIS

2019 Statewide Load Impact Evaluation of the
California Capacity Bidding Programs

October 1, 2020

BASELINES COMPARATIVE ANALYSIS

Report prepared for:
PACIFIC GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON
SAN DIEGO GAS & ELECTRIC COMPANY

Energy Solutions Delivered.

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SUMMARY AND KEY FINDINGS

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

Research Objectives

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

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

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

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

Research Methodology

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

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

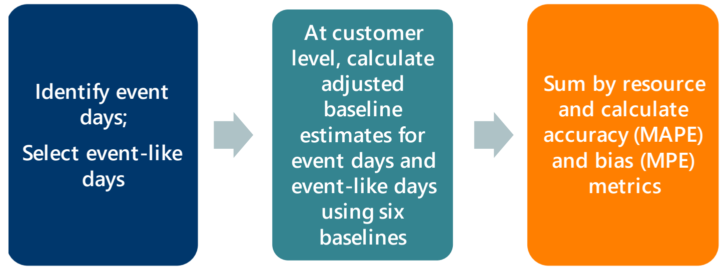
[2] Aggregate baselines are performed at the resource level, which is comparable to Product+Aggregator+Sub-LAP level.

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

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

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

Figure 1-1 Description of Analysis Steps



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

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

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

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

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

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

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

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

Key Findings

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

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

Table 1-1 Accuracy and Bias – All Programs

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

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

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

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

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

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

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

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

Table 1-2 Average Decrease in Effectiveness – Aggregate Baselines

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

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

Recommendation and Rationale

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

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

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

Recommendation

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

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

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

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

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

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

Rationale

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

Comparing Effectiveness Across Baselines

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

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

Individual vs. Aggregate Baselines?

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

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

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

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

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

Which adjustment cap is the most appropriate?

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

2

STUDY METHODS

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

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

Calculating the 10-in-10 Day Matching Baseline

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

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

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

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

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

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

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

8. If the day-of adjustment ratio exceeds adjustment cap, limit the adjustment ratio to the cap, where X can be 20%, 30%, 40%. The adjustment cap is up =1+X and down =1-X.

9. Apply the day-of adjustment ratio to the overall unadjusted baseline to produce the adjusted baseline estimate.

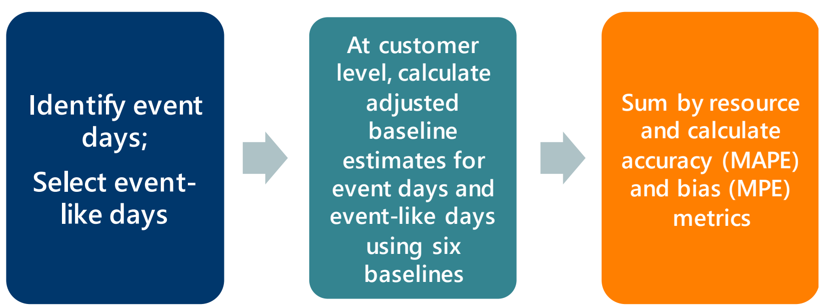
10. Calculate the Actual Load Reduction as the difference between the adjusted baseline and actual electricity use for each event hour.

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

Comparative Analysis

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

Figure 2-1 Description of Analysis Steps



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

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

Selecting Event-Like Days

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

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

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

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

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

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

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

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

In the figures below, we show comparisons of the distributions of average daily temperature of event days and event-like days. We show one comparison for each utility by program year, because the selection was done at the utility level instead of the program or product level. We use this approach to accommodate customer moves between products or programs and the automation process of running individual customer regression models.

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

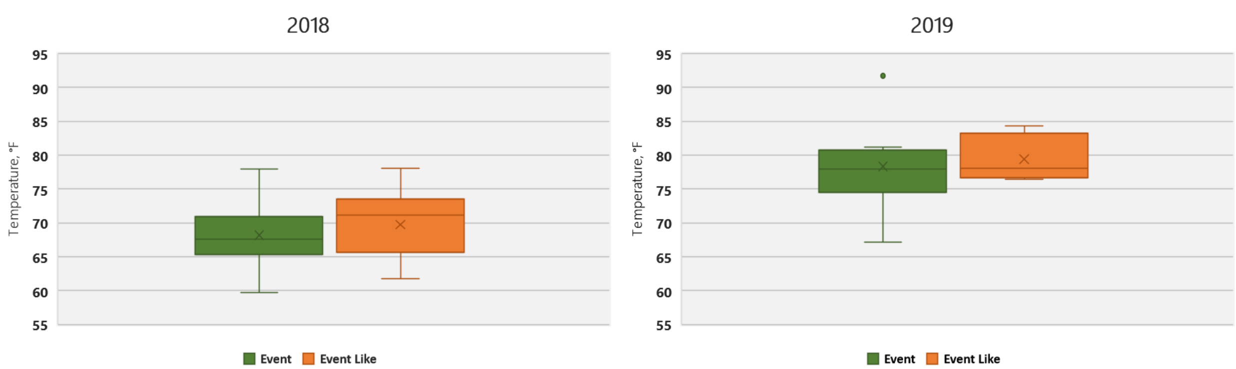


Figure 2-3 SCE Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019

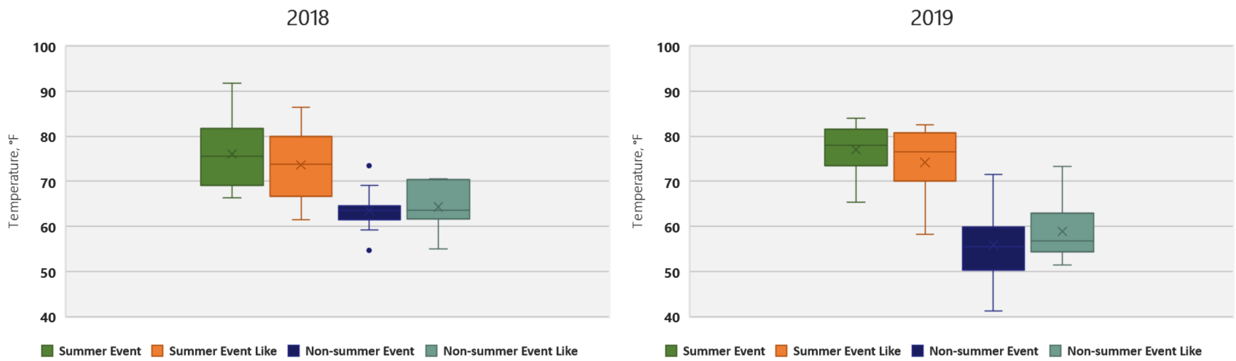
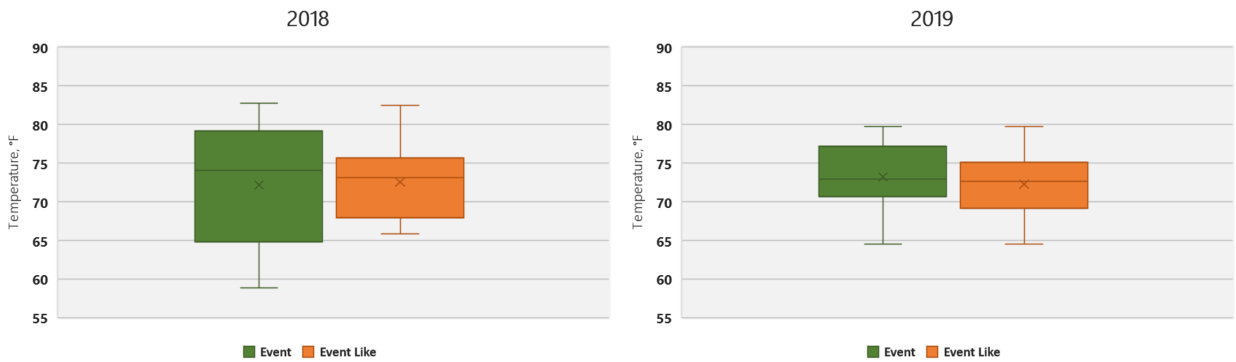


Figure 2-4 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days, 2018 and 2019



Calculating the Baselines

Using the 10-in-10 day matching baseline methodology discussed above, we calculated the six baselines[13] for three scenarios resulting in 18 individual calculations:

- Event days in PY2018 and PY2019 over the actual event window.
- Event-like days in PY2018 and PY2019 assuming three-hour events were called from HE17-HE19 or 4 PM to 7 PM.
- Event like days in PY2018 and PY2019 assuming two-hour events were called from HE19-HE20 or 6 PM to 8 PM.

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

[13] We estimated the baselines for six variations, calculating the adjustment ratio at both aggregate and individual levels, applying 20%, 30%, and 40% adjustment caps.

Calculating Accuracy and Bias

Once we calculated the six baselines for each of the three scenarios, we compared the various estimates using measures of accuracy and bias. The mean absolute percent error (MAPE) measures accuracy, which is the measure of how close the estimate is to the known value. The mean percent error (MPE) measures bias, which is when estimates are always higher or lower than the known value. Equations (4) and (5) show the MAPE and MPE, respectively.

$$MAPE = \frac{100\%}{n}\sum_{h=1}^{n}\left|\frac{Actual_h - Estimate_h}{Actual_h}\right| \quad (4)$$

$$MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h} \quad (5)$$

For both metrics, the goal is be low or very close to zero to ensure high accuracy or low bias estimates.

The actual load for event-like days ($Actual_h$in Equations 4 and 5) is simply the load on each day since no event was called on those days. For event days, we defined the actual load as the estimated reference load in the ex-post analysis since we do not know the true value of the load in the absence of an event.

To compare the six baselines, AEG calculated the MAPE and MPE at the simulated resource level, which is the combination of product, aggregator, and sub-LAP. In doing so, we are establishing an apples-to-apples comparison between the six baselines for each scenario, where in the MAPE and MPE point estimates tell us, on average, for a resource, how close is the estimated baseline to the true value for that group. In the next section, we will also discuss further the rationale behind the comparison approach.

Example Calculation

An important distinction in the analysis is the difference between the individual baseline and the aggregate baseline. Below, Table 2-1 provides a simple numerical example of how the MAPE and MPE are calculated for an individual baseline estimate vs. an aggregate baseline estimate for a single ratio cap value. The example includes two resources, Resource 1 with three customers, and Resource 2 with only a single customer. The adjustment ratios for customers in Resource 1 (shown in red text) illustrate the differences between the individual and aggregate baselines. The method score (highlighted in blue) compares the effectiveness of the two baselines.

Table 2-1 Resource-level Comparison: Calculation Example

Individual Baseline					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.14	155.51				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.26	178.44				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.30	184.61	508.56	518.56	2.0%	-2.0%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.4%*	*2.4%*

Aggregate Baseline					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.23	167.41				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.23	174.67				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.23	174.67	508.56	516.75	1.6%	-1.6%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.2%*	*2.6%*

A few key notes on the example above:

- The MAPE and MPE are calculated for each resource and event day. The average MAPE and MPE for each IOU and program (Day Ahead or Day Of) is calculated to achieve the accuracy and bias score for each of the six baselines. In this approach, each resource and event day is given equal weight in each IOU and program.
- Resource 1 demonstrates the difference between an individual adjustment versus an aggregate adjustment (shown in red text). In the individual baseline method, the adjustment ratio is determined at the customer level, while in the aggregate baseline method, the adjustment ratio is determined at the aggregate level.
- Resource 2 contains a single customer, thus the estimates in the individual and aggregate baselines are the same.

Exclusions

During review of results and discussions with the IOUs, AEG excluded the data points that met the following criteria:

- Negative MAPE – this occurs only in the event day scenarios and is caused by negative values in the ex-post estimated reference load. This indicates significant modeling errors in the ex-post regression models.
- Missing MAPE or MPE – this is caused by missing hourly usage data.
- Outlier MAPE – outliers were determined by looking at the distribution of the MAPE at the customer level by IOU and program, identifying customers and events with highly erratic loads. This criterion excluded four customers from all three IOUs and around 1% of total data.

3

RESULTS AND COMPARISONS

The comparisons presented in this section were derived using the approach described in Section 2,Calculating Accuracy and Bias. The approach used to do the comparisons in this analysis was formulated with careful consideration of how the Capacity Bidding Program is implemented.

Recall that retail settlement payments for each event day are done at the aggregator level. Under the CBP tariff, aggregators are responsible for (1) customer recruitment and contracting, (2) resource MW nominations, (3) resource MW curtailment, and (4) customer payment disbursement. So, in theory, aggregators can collectively nominate 10 customers as a resource for 2 MW curtailment, but on any given event, only dispatch 3 out of the 10 customers to deliver the 2 MW curtailment.

Because of the resource nomination component of the CBP tariff, AEG and the IOUs agree that the measure of accuracy and bias should be performed at the resource level, acknowledging that the resource is nominated and dispatched as a unit.

Summary of Findings

The following section discusses the results at the State level, i.e., for all IOUs and programs, five[14] programs altogether.

Event-like Day Results

In this subsection, we discuss the "winning" baseline, looking only at the event-like day scenarios. We find the results from these scenarios highly valuable since the MAPE and MPE, i.e., accuracy and bias, were calculated using actual load data[15]. In these simulations, we are testing how effectively the six variations of the 10-in-10 day matching baselines estimate the actual load of the event window.

Table 3-1 shows the most effective baseline from the five programs.[16] This summary accounts for each program's two top (or most effective) ranking baselines for both accuracy and bias and shows the strength of their score in parenthesis. For example, looking at all programs and all event-like day scenarios, aggregate baseline with 20% adjustment cap ranked 1st or 2nd in accuracy in 3 out of 5 programs (shown in red text). Similarly, looking at all programs and event-like day HE17-HE19 scenarios, aggregate baseline (regardless of the adjustment cap) ranked 1st or 2nd in bias in 3 out of 5 programs (shown in blue text). Five is the highest possible score, where all five programs favored a specific baseline. One is the lowest score, which indicates that each of the five programs favored different baselines.

Looking at Table 3-1, we can conclude the following:

- Aggregate baselines, regardless of the adjustment cap, give estimates with better accuracy and less bias.
- The lower adjustment cap (20%) gives estimates with the better accuracy, however the higher adjustment caps (30% and 40%) minimize the bias.

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

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

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

Because aggregate baselines resulted in the better accuracy and bias overall, we wanted to further explore differences in adjustment caps for only aggregate baselines. Table 3-2 shows the average loss in accuracy and increase in bias when selecting an adjustment cap for the aggregate baseline. For example, if the 30% adjustment cap is selected, we see a 0.49% decrease in accuracy and 0.33% increase in bias, for both HE17-HE19 and HE19-HE20 event windows, on average (shown in red text). Looking at Table 3-2, we see decreases in effectiveness that are all under 1%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap.

Table 3-1 Accuracy and Bias – Event-like Day Scenarios

Event-like Day Scenario	Best Accuracy			Least Bias		
	Overall*	**Ind v. Agg***	**Adj Cap**	**Overall***	**Ind v. Agg**	**Adj Cap**
Event-like Days (HE17-HE19)	Agg 20% Agg 30% (3)	Agg (4)	20% (2.5)	Agg 30% Agg 40% (3)	**Agg (3)**	40% (2.5)
Event-like Days (HE19-HE20)	Agg 20% Ind 20% (3)	Ind, Agg (2.5)	20% (3)	Agg 30% (5)	Agg (4.5)	30% (3)
All Event-like days	**Agg 20% (3)**	Agg (3.25)	20% (2.75)	Agg 30% (4)	Agg (3.75)	30% (2.5)

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

Table 3-2 Average Decrease in Effectiveness – Event-like Days – Aggregate Baselines

Event-like Day Scenario	Lost Accuracy			Increased Bias		
	Agg 20%	**Agg 30%**	**Agg 40%**	**Agg 20%**	**Agg 30%**	**Agg 40%**
Event-like Days (HE17-HE19)	0.24%	0.49%	0.78%	0.76%	0.46%	0.38%
Event-like Days (HE19-HE20)	0.27%	0.48%	0.75%	0.59%	0.21%	0.18%
All Event-like days	0.26%	**0.49%**	0.76%	0.68%	**0.33%**	0.28%

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

Results for All Scenarios

Similar to the previous subsection, Table 3-3 shows the most effective baseline from all three IOUs and programs, looking at only event days and all three scenarios overall, and Table 3-4 shows the average loss in accuracy and increase in bias when selecting an adjustment cap for the aggregate baseline.

Comparisons on the event day scenarios shift the results to show better accuracy using the individual baselines. However, the aggregate baselines still show the least bias, consistent with the event-like day scenarios. The event day scenarios also show higher decreases in effectiveness when selecting the aggregate baseline, on average, but they are still relatively small with all decreases under 3%.

When looking at all scenarios, the aggregate baseline methodology, regardless of the adjustment cap, still gives estimates with better accuracy and less bias, showing very low decreases in effectiveness, all under 1.3%, on average.

Table 3-3 Accuracy and Bias – Event Days and Overall

Scenario	Best Accuracy Overall	Best Accuracy Ind v. Agg	Best Accuracy Adj Cap	Least Bias Overall	Least Bias Ind v. Agg	Least Bias Adj Cap
Event Days	Ind 20% (5)	Ind (3.5)	20% (2)	Agg 20% Agg 30% Agg 40% Ind 20% (1)	Agg (3)	20% (2)
All Scenarios	Ind 20% (3.3)	Agg (2.7)	20% (3.2)	Agg 30% (3.3)	Agg (3.5)	30% (2.2)

Table 3-4 Average Decrease in Effectiveness – Event Days and Overall – Aggregate Baselines

Scenario	Lost Accuracy Agg 20%	Lost Accuracy Agg 30%	Lost Accuracy Agg 40%	Increased Bias Agg 20%	Increased Bias Agg 30%	Increased Bias Agg 40%
Event Days	1.47%	1.94%	2.28%	2.24%	2.27%	2.37%
All Scenarios	0.66%	0.97%	1.27%	1.20%	0.98%	0.98%

As mentioned in the Section 1 (Research Objectives), one of the issues for investigation in this analysis is to consider whether the wholesale and retail baselines should be aligned or if they can be different. In Table 3-5 below we present a comparison of both the current wholesale baseline (aggregate with 20% cap) and the current retail baseline (individual with 40% cap). The values shown in the table indicate a ranking out of 6, with 1 ranking the highest (most accurate or least biased) and 6 ranking the lowest. The current retail baseline ranks 4.4-4.7 out of 6 in accuracy and 3.2-3.6 out of 6 in bias across all programs while the current wholesale baseline ranks 2.3-3.0 out of 6 in accuracy and 3.6 out of 6 in bias. This indicates that aligning the wholesale and retail baselines to both be aggregate baselines with 20% cap would result in more accurate estimates and similar bias, at the resource level.

Table 3-5 Comparison of Current Wholesale Baseline vs. Current Retail Baselne – Average Ranking

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

Program-level Comparisons

In this subsection, we present the comparisons by program for all three IOUs. Each program will have two graphs, all following a uniformed color scheme: blue for accuracy and orange for bias. In addition, each graph will have the following components:

- A separate block, indicating each of the three event scenarios: (1) Event days; (2) Event-like days assuming HE17-HE19 event window; and (3) Event-like days assuming HE19-HE20 event window.
- The best score for each scenario shown in red text and red box.
- The current retail settlement baseline (Individual Baselines with 40% adjustment cap) shown in a striped pattern fill.

The program-level comparisons show how both the participant population and the timing of event window can drive the effectiveness of the six baselines.

PG&E Results

Starting in PY2018, PG&E only offers Day Ahead product offerings.

Day Ahead Program

The DA program results cover 55 event days and 29 event-like days across PY2018 and PY2019. Across both program years, the DA program includes 12 unique resources and 948 unique customers. Figure 3-1 and Figure 3-2 show the accuracy and bias comparison for all three scenarios, respectively.

For PG&E DA, we can conclude the following:

- The event-like day scenarios show consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline has low sensitivity to the timing of the event window (HE17-HE19 v. HE19-HE20).
    - The two event-like day scenarios have very consistent bias comparisons, showing less bias using the aggregate baseline (dark orange bars are consistently lower), with the 40% adjustment cap showing the least bias in both individual and aggregate baselines. The event-like days also show all positive MPE estimates, indicating that the estimates are lower, on average, than the actual event-like day loads.
    - Looking at accuracy, the HE17-HE19 event window show results consistent to bias, showing the best accuracy using the aggregate baseline with 40% adjustment cap.
    - The HE19-HE20 event window simulation shows slightly different accuracy results, with the individual baselines showing better accuracy. Also note that the aggregate baseline with 40% adjustment cap shows the lowest accuracy. This is due to the results from PY2018 event-like days (see Figure A-1 and Figure A-3), which is an indicator that the customer mix, i.e., population distribution, can largely influence the effectiveness of the baseline.
- The event days show results comparable to the HE19-HE20 event-like day scenarios, despite the differences in magnitude, showing better accuracy using the individual baselines. This is due to PG&E DA calling 30 out of 55 events that start on HE19. It is also interesting to note that the event days show the 20% adjustment cap to perform the highest effectiveness.

Figure 3-1 PG&E Day Ahead Program: Accuracy Comparison – Resource-level

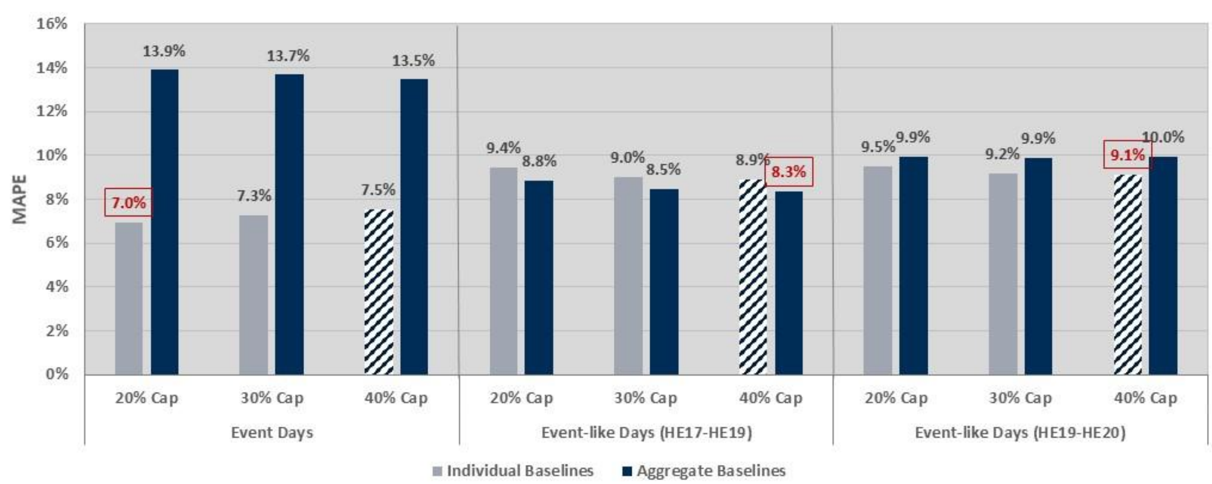
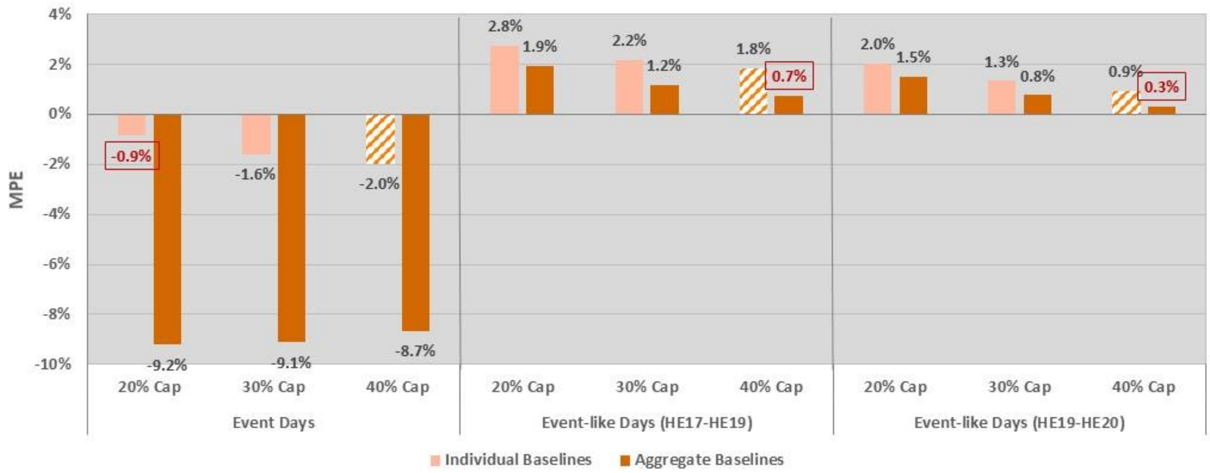


Figure 3-2 PG&E Day Ahead Program: Bias Comparison – Resource-level



SCE Results

Day Ahead Program

The DA program results cover 44 event days and 42 event-like days across PY2018 and PY2019. Across both program years, the DA program includes five unique resources and 385 unique customers. Figure 3-3 and Figure 3-4 show the accuracy and bias comparison for all three scenarios, respectively.

For SCE DA, we can conclude the following:

- The event-like day scenarios show very consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17 -HE19 v. HE19-HE20).
    - The two event-like day scenarios have very consistent accuracy and bias comparisons, showing better effectiveness using the aggregate baseline (dark blue and dark orange bars are consistently lower), with the 40% adjustment cap showing the best accuracy and least bias in both individual and aggregate baselines.
    - The event-like days also show all positive MPE estimates, indicating that the estimates are consistently lower, on average, than the actual event-like day loads.
- The event days show conflicting results, and this is largely driven by the PY2018 results (shown in Figure A-5), which show the best effectiveness using the individual baselines with 20% adjustment cap. The PY2019 event day comparisons, however, show results more consistent with the event-like days, showing the best accuracy using the aggregate baseline with 40% adjustment cap. It is also interesting to note that the PY2019 event days show the 20% adjustment cap to give the least bias.

Figure 3-3 SCE Day Ahead Program: Accuracy Comparison – Resource-level

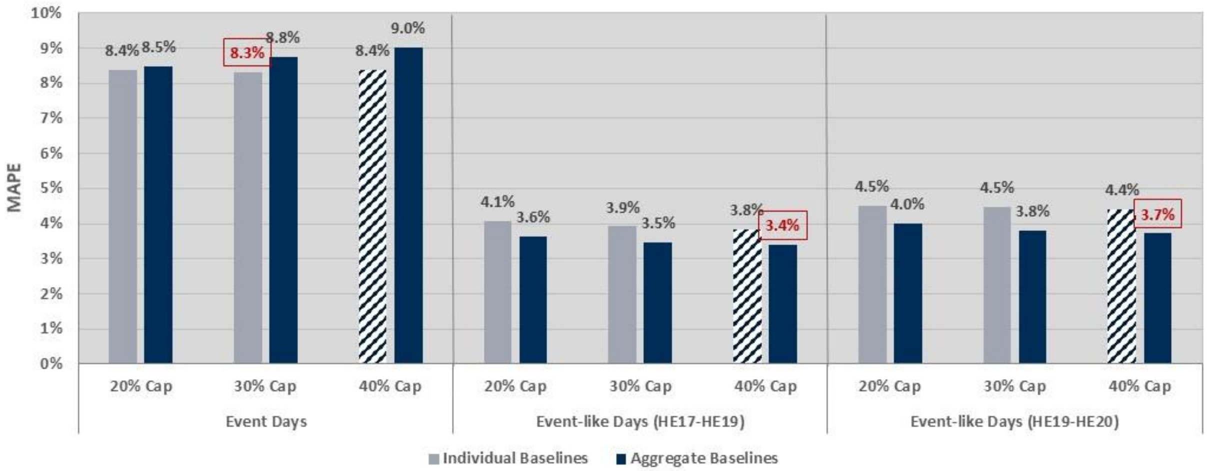
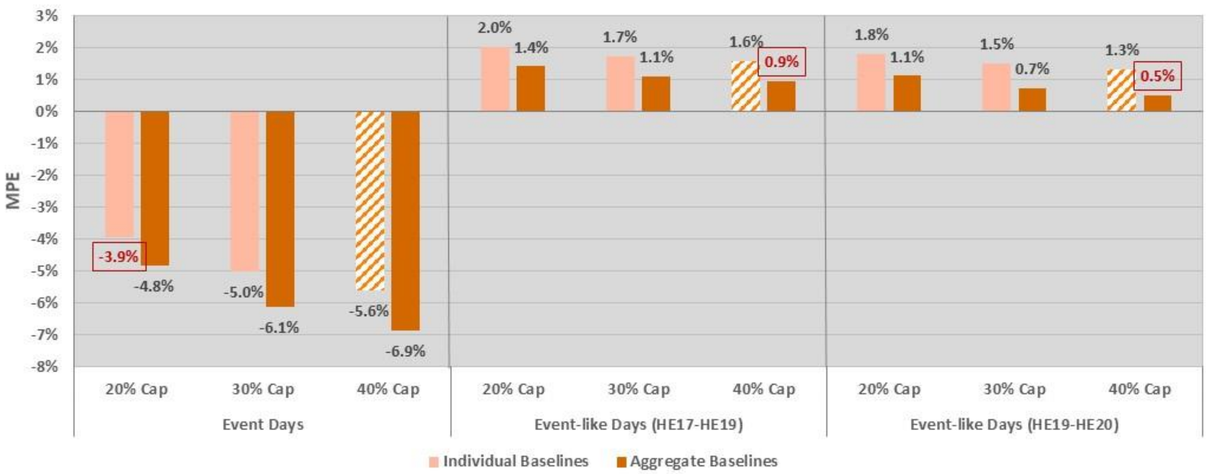


Figure 3-4 SCE Day Ahead Program: Bias Comparison – Resource-level



Day Of Program

The DO program results cover 49 event days and 42 event-like days across PY2018 and PY2019. Across both program years, the DA program includes 6 unique resources and 368 unique customers. Figure 3-5 and Figure 3-6 show the accuracy and bias comparison for all three scenarios, respectively.

For SCE DO, we can conclude the following:

- The event-like day scenarios show very consistent results, indicating that the effectiveness of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20).
    - Like SCE DA, the two event-like day scenarios have very consistent accuracy and bias comparisons, showing better effectiveness using the aggregate baseline (dark blue and dark orange bars are consistently lower). However, the 20% adjustment cap shows the best accuracy, while the higher adjustment caps (30% and 40%) show less bias in both individual and aggregate baselines.

- The event-like days also show all positive MPE estimates, indicating that the estimates are consistently lower, on average, than the actual event-like day loads.

- Similar to PG&E DA, the event days show results comparable to the HE19-HE20 event-like day scenario, showing better accuracy using the individual baselines. This is due to SCE DO calling 38 out of 49 events that start on HE19. Also comparable to the HE19-HE20 event-like day scenario, individual baseline with 20% adjustment cap gives the most bias.

Figure 3-5 SCE Day Of Program: Accuracy Comparison – Resource-level

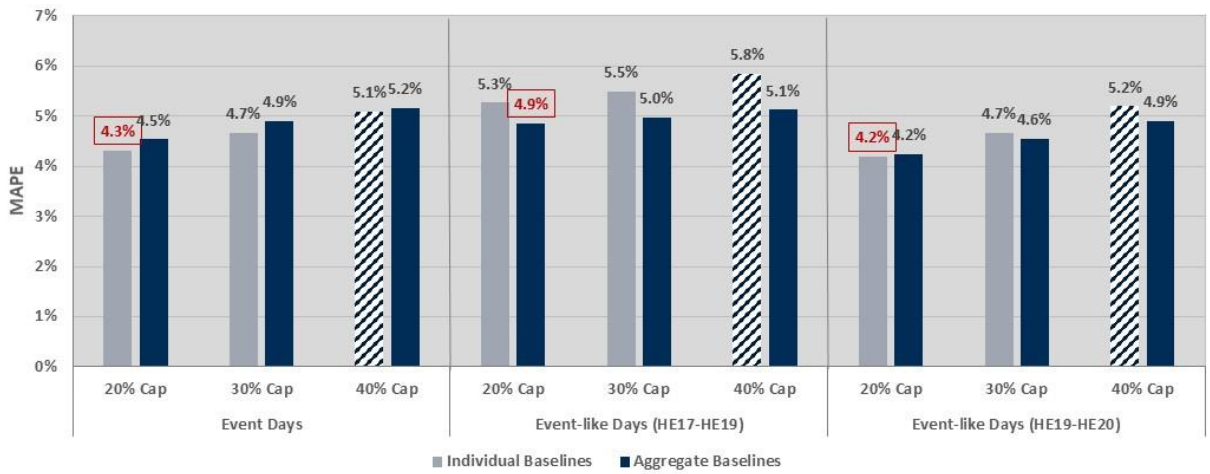
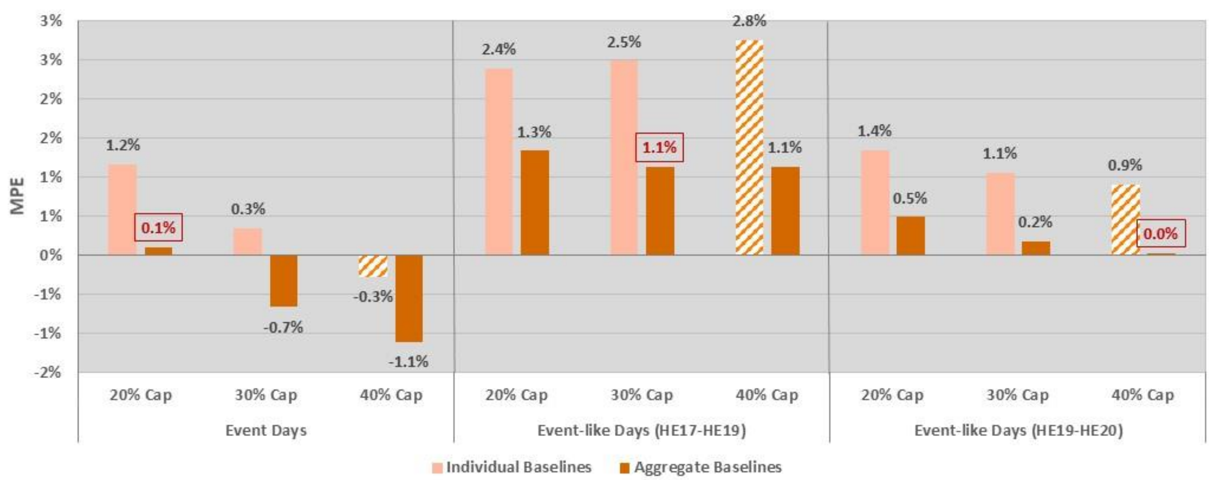


Figure 3-6 SCE Day Of Program: Bias Comparison – Resource-level



SDG&E Results

Day Ahead Program

The DA program results cover 48 event days and 36 event-like days across PY2018 and PY2019. Across both program years, the DA program includes seven unique resources and 75 unique customers. Figure 3-7 and Figure 3-8 the accuracy and bias comparison for all three scenarios, respectively.

For SDG&E DA, PY2018 and PY2019 have some conflicting results, and these are apparent in the overall comparisons. Recall that SDG&E DA experienced large customer unenrollment in the middle of PY2018.

All PY2018 participants are included in the event-like day scenarios regardless of mid-year unenrollment, thus the drastic change in the participant population between PY2018 and PY2019 ultimately drives the differences in the results. Referring to the program year graphs will be helpful in the discussion of the results. The graphs are in the Appendix, Figure A-13 through Figure A-16.

- All scenarios show consistent accuracy results but conflicting bias results. This is largely driven by conflicting bias results from the two program years.
- For event-like days, this indicates that the accuracy of the 10-in-10 day matching baseline is not sensitive to the timing of the event window (HE17-HE19 v. HE19-HE20). On the other hand, bias comparisons show some sensitivity to the timing of the event window.
    - The two event-like day scenarios have very consistent accuracy comparisons, showing better accuracy using the individual baseline (light blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines.
    - Looking at bias, the event-like day scenarios show very conflicting results. In this case, it may be helpful to only look at PY2019 results (shown in Figure A-16), since it is more representative of the participant population in future years. PY2019 bias comparisons for SDG&E DA also show less bias using the individual baseline (light orange bars are consistently lower). However, the effect of the adjustment cap is different in the two event window simulations, showing least bias at 40% adjustment cap for HE17-HE19 events and least bias at 20% adjustment cap for HE19-HE20 events.
- Similar to the event-like day scenarios, the event days show better accuracy using the 20% adjustment cap, but instead showing better accuracy using the aggregate baseline (dark blue bars are consistently lower). Again, we see conflicting bias results for the event days. Thus looking only at PY2019 results (shown in Figure A-16), we see less bias using the aggregate baseline (dark orange bars are lower) and the least bias using the 20% adjustment cap.

Figure 3-7 SDG&E Day Ahead Program: Accuracy Comparison – Resource-level

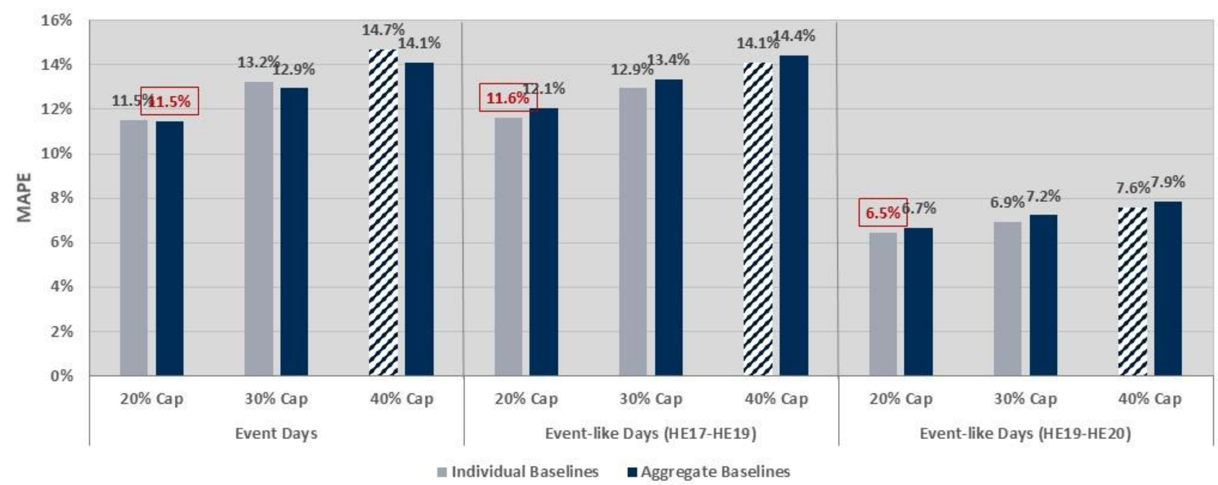
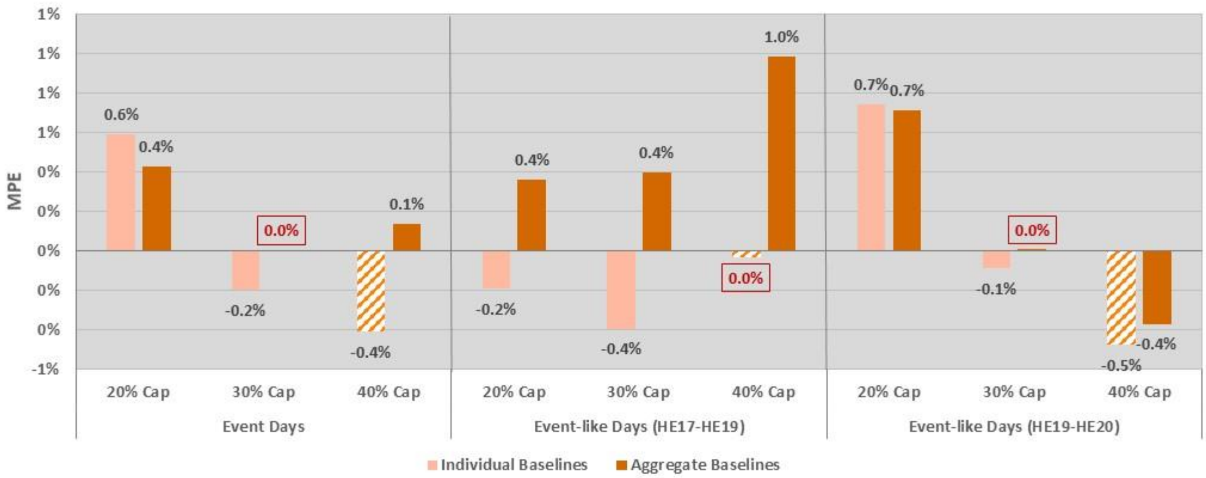


Figure 3-8 SDG&E Day Ahead Program: Bias Comparison – Resource-level



Day Of Program

The DO program results cover 19 event days and 36 event-like days across PY2018 and PY2019. Across both program years, the DO program includes seven unique resources and 201 unique customers. Figure 3-9 and Figure 3-10 show the accuracy and bias comparison for all three scenarios, respectively.

SDG&E DO did not experience a drastic participant turnover in PY2018 and PY2019, thus we do not see the same results like in SDG&E DA. However, looking at the event-like day comparisons, the overall results for both program years seem to indicate the sensitivity to the timing of the event window. This is also driven by conflicting results from PY2018 and PY2019 and referring to the program year graphs will also be helpful in the discussion of the results. The graphs are in the Appendix, Figure A-17 through Figure A-16.

- The event-like day comparisons for PY2018 and PY2019 show different results:
  - PY2018 comparisons (shown in Figure A-17 and Figure A-18) indicate that both accuracy and bias of the baselines are sensitive to the timing of the event window. However, recall that SDG&E DO only called 3 events in PY2018, all starting on HE18 and that event-like days were selected to be the most comparable to events. It is possible that PY2018 participants have highly variable loads during HE17-HE19 even on non-event days, making it difficult to effectively estimate the event window load through the 10-in-10 day matching baseline.
  - PY2019 comparisons (shown in Figure A-19 and Figure A-20), on the other hand, show very consistent results between the two event-like day scenarios. Both event window scenarios show better accuracy using the aggregate baseline (dark blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Bias comparisons also show preference to the 20% adjustment cap.
- The event day comparisons for PY2018 and PY2019 also show different results:
  - PY2018 comparisons (shown in Figure A-17 and Figure A-18) have results consistent with PY2018 event-like days with HE19-HE20 event windows, showing better accuracy using the individual baseline (light blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Again, likely driven by the combination of events called in PY2018 and typical participant loads during HE18-HE21.

- PY2019 comparisons (shown in Figure A-19 and Figure A-20), on the other hand, show very consistent results with the two event-like day scenarios. In PY2019, SDG&E DO called a comparable number of events starting on HE17 and HE18. PY2019 events show better accuracy using the aggregate baseline (dark blue bars are consistently lower), with the 20% adjustment cap showing the best accuracy in both individual and aggregate baselines. Bias comparisons also show preference to the 20% adjustment cap.

Figure 3-9 SDG&E Day Of Program: Accuracy Comparison – Resource-level

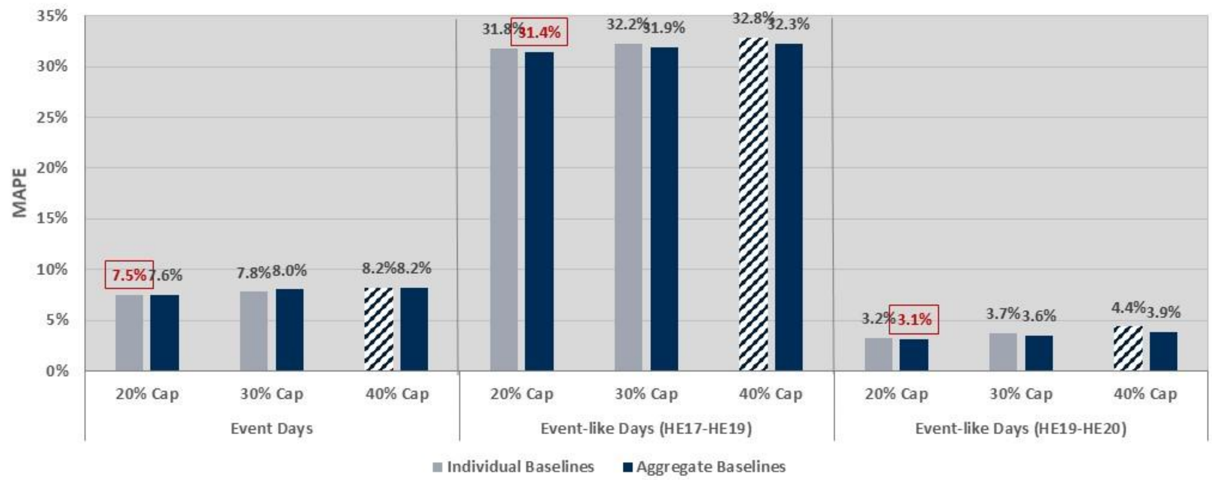
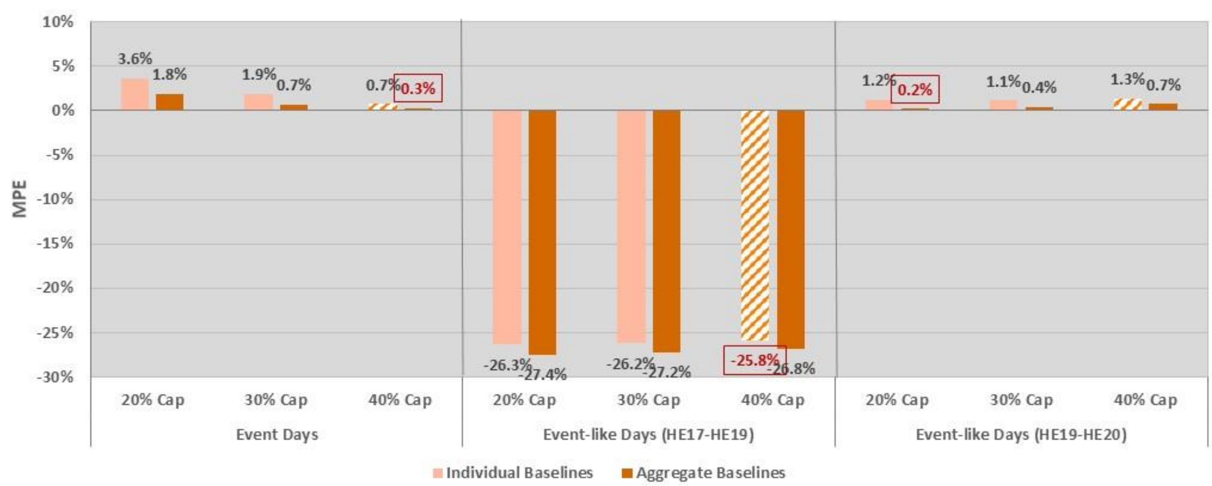


Figure 3-10 SDG&E Day Of Program: Bias Comparison – Resource-level



A

ADDITIONAL TABLES AND GRAPHS

PG&E Results by Program Year

Day Ahead Program

The PG&E DA program PY2018 results cover 46 event days and 23 event-like days and include 11 unique resources and 561 unique customers.

Figure A-1 PG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

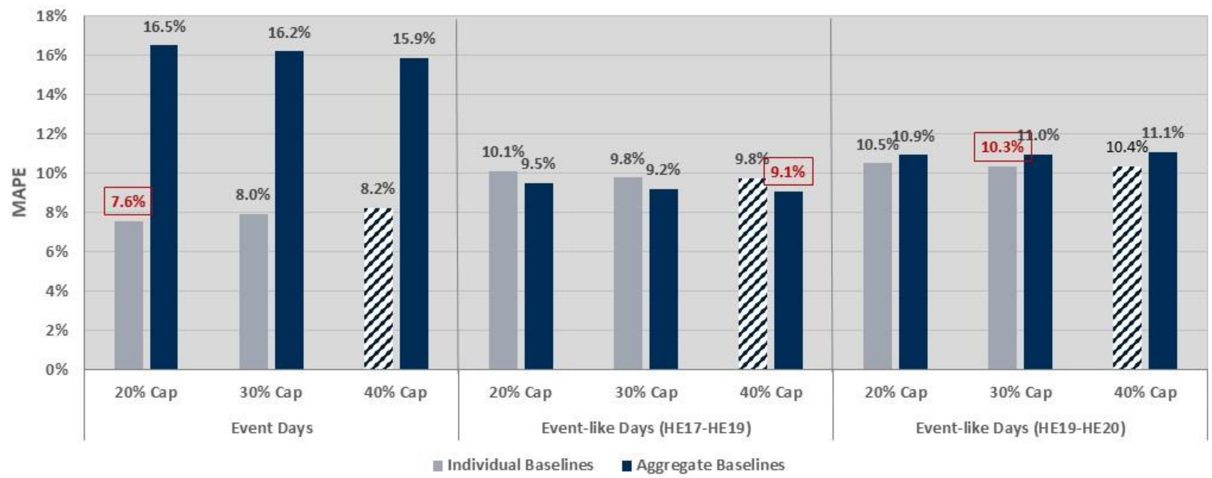
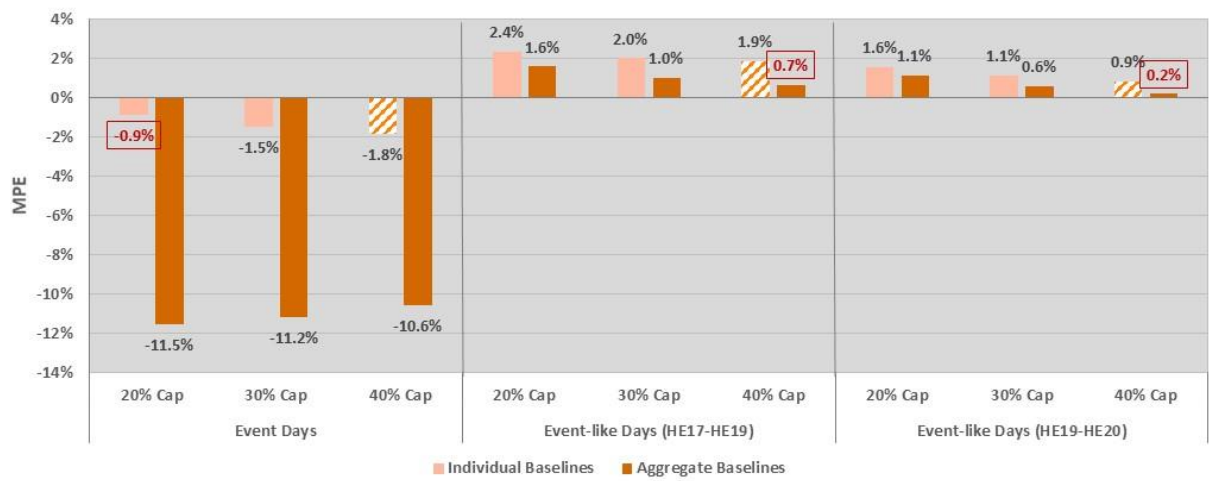


Figure A-2 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The PG&E DA program PY2019 results cover 9 event days and 6 event-like days and include 10 unique resources and 793 unique customers.

Figure A-3 PG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

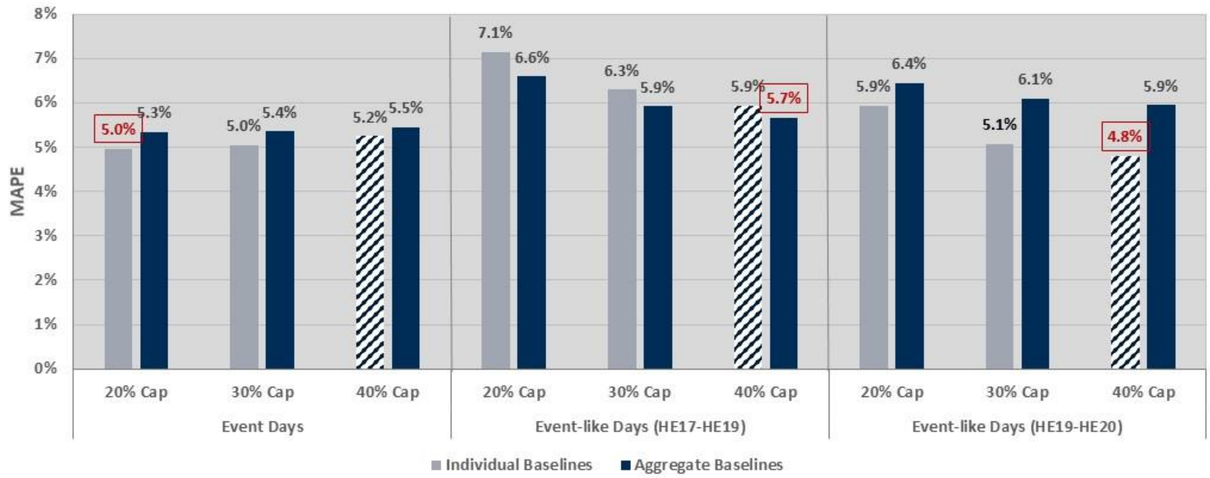
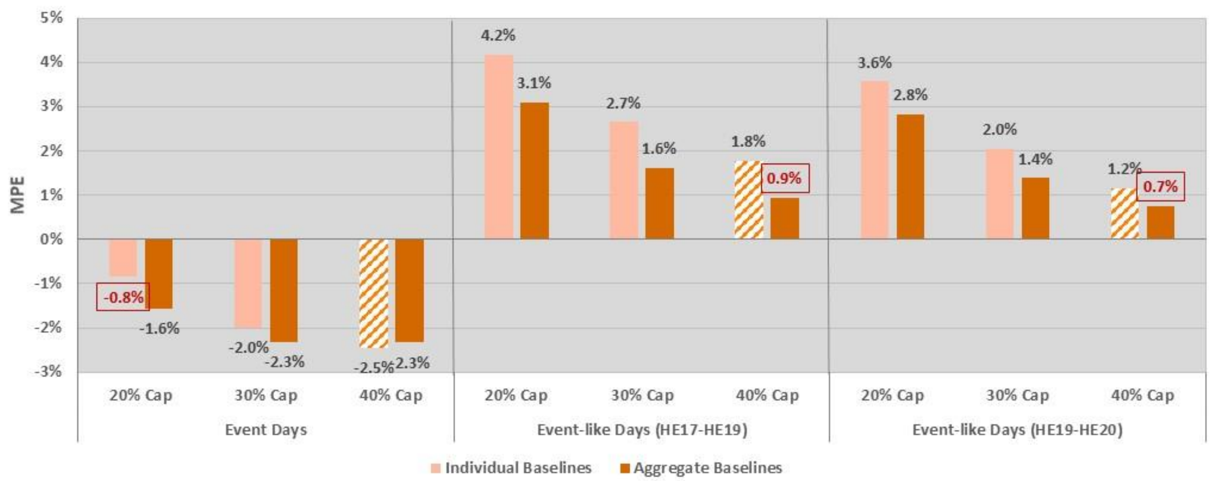


Figure A-4 PG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



SCE Results by Program Year

Day Ahead Program

The SCE DA program PY2018 results cover 23 event days and 29 event-like days and include 3 unique resources and 74 unique customers.

Figure A-5 SCE Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

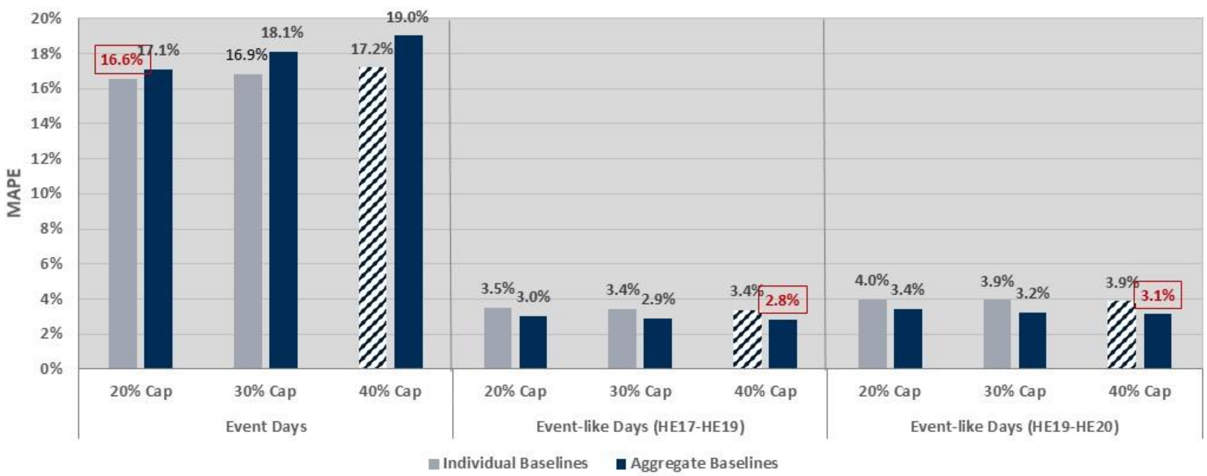
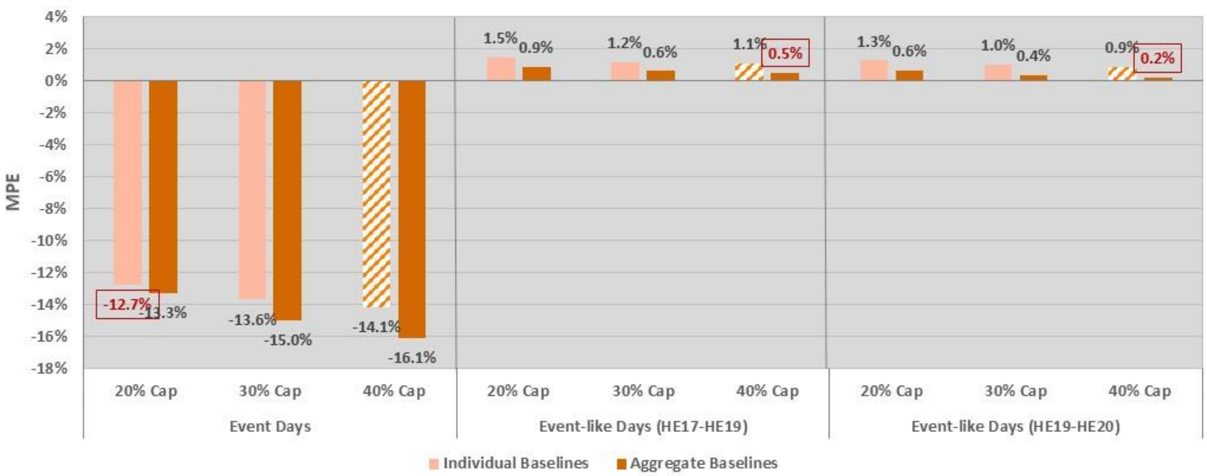


Figure A-6 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The SCE DA program PY2019 results cover 21 event days and 13 event-like days and include 4 unique resources and 399 unique customers.

Figure A-7 SCE Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

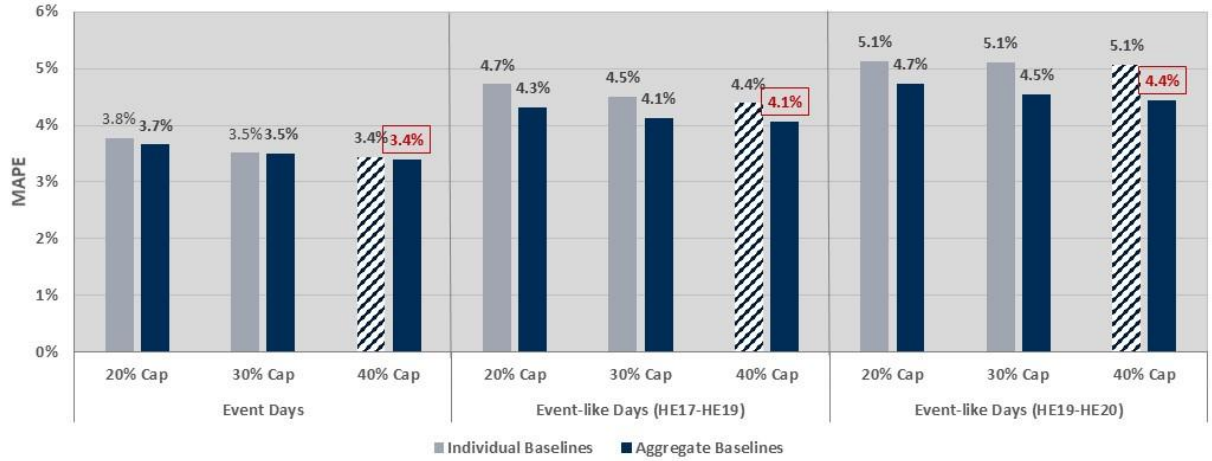
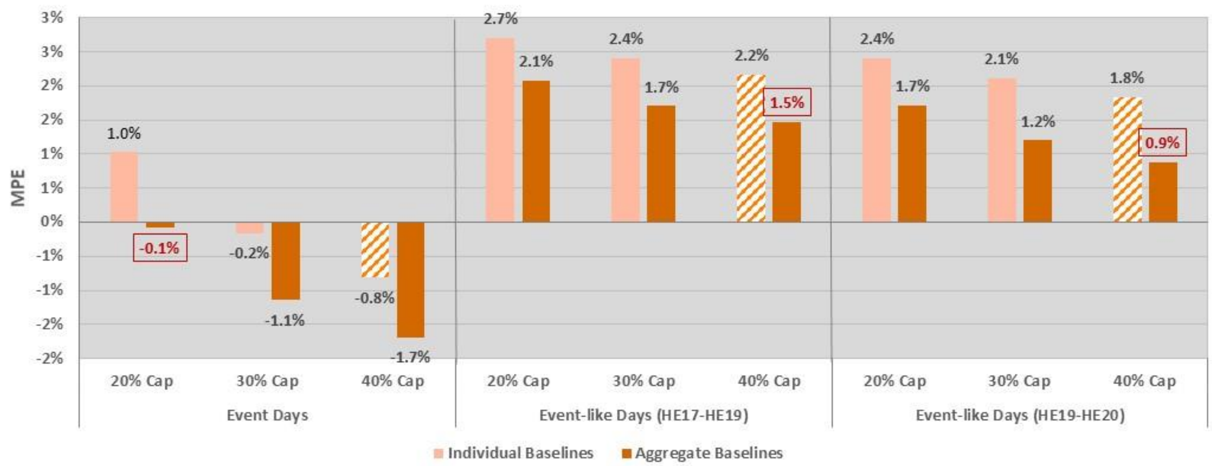


Figure A-8 SCE Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



Day Of Program

The SCE DO program PY2018 results cover 25 event days and 29 event-like days and include 5 unique resources and 308 unique customers.

Figure A-9 SCE Day Of Program: Accuracy Comparison – Resource-level (PY 2018)

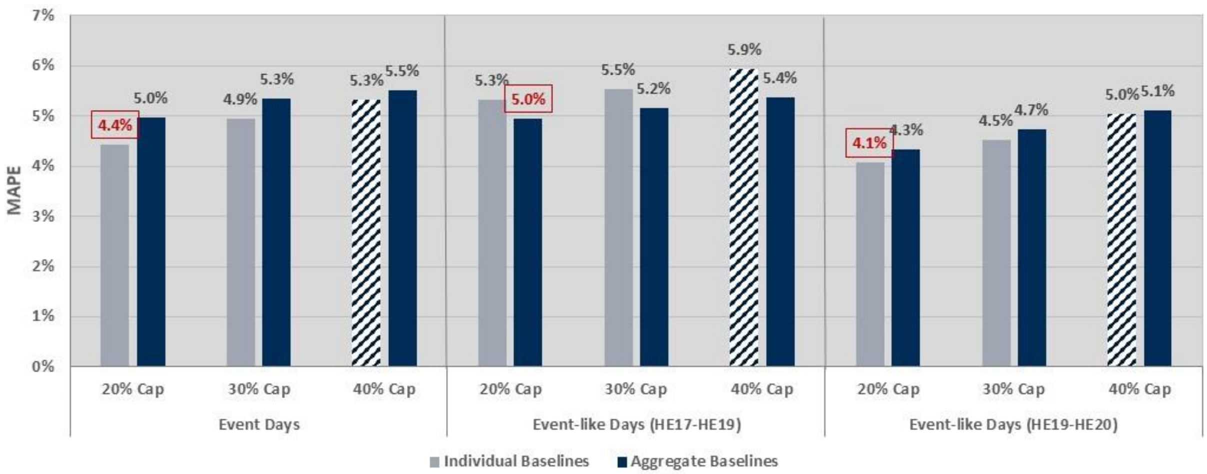
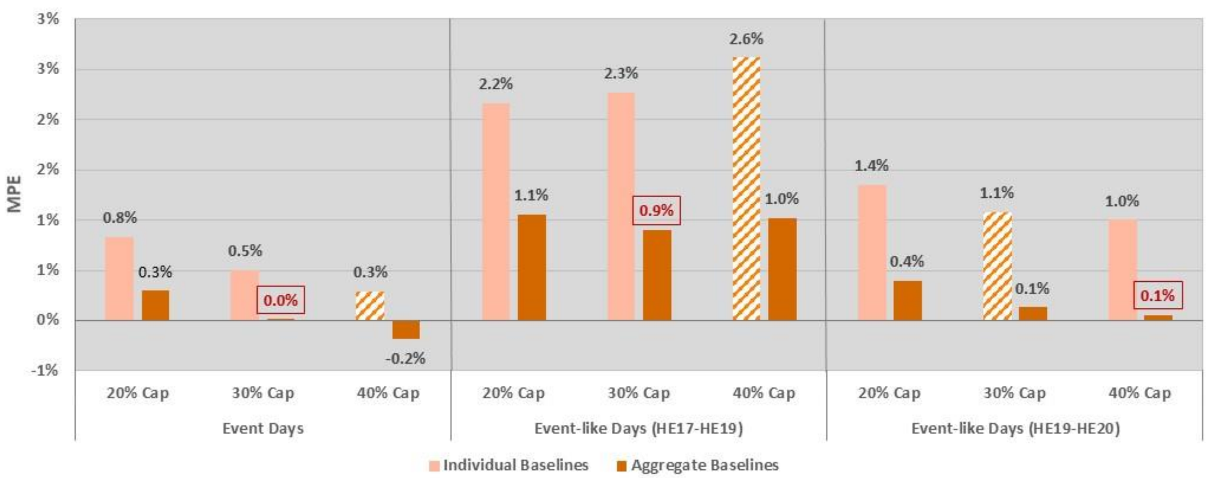


Figure A-10 SCE Day Of Program: Bias Comparison – Resource -level (PY 2018)



The SCE DO program PY2019 results cover 24 event days and 13 event-like days and include 5 unique resources and 203 unique customers.

Figure A-11 SCE Day Of Program: Accuracy Comparison – Resource -level (PY 2019)

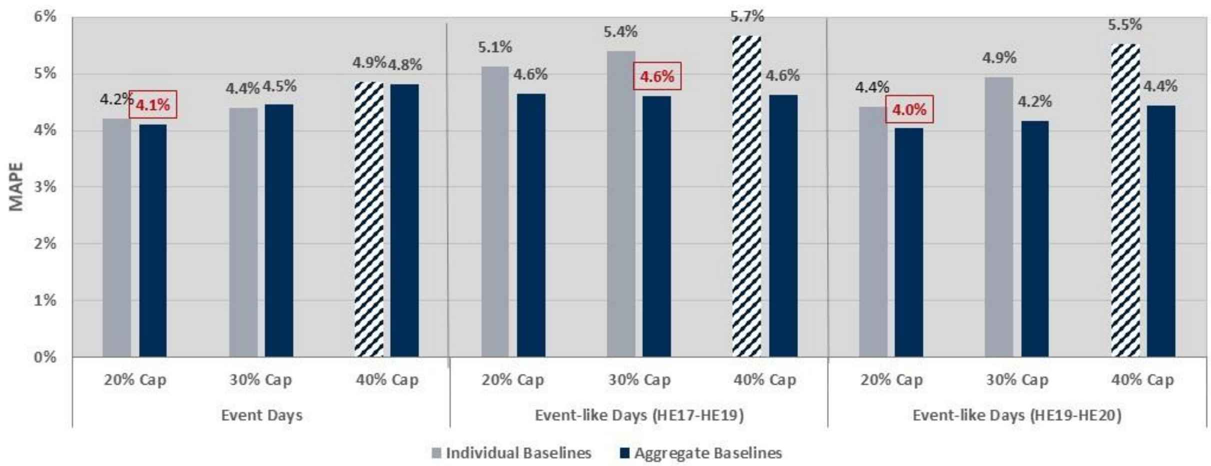
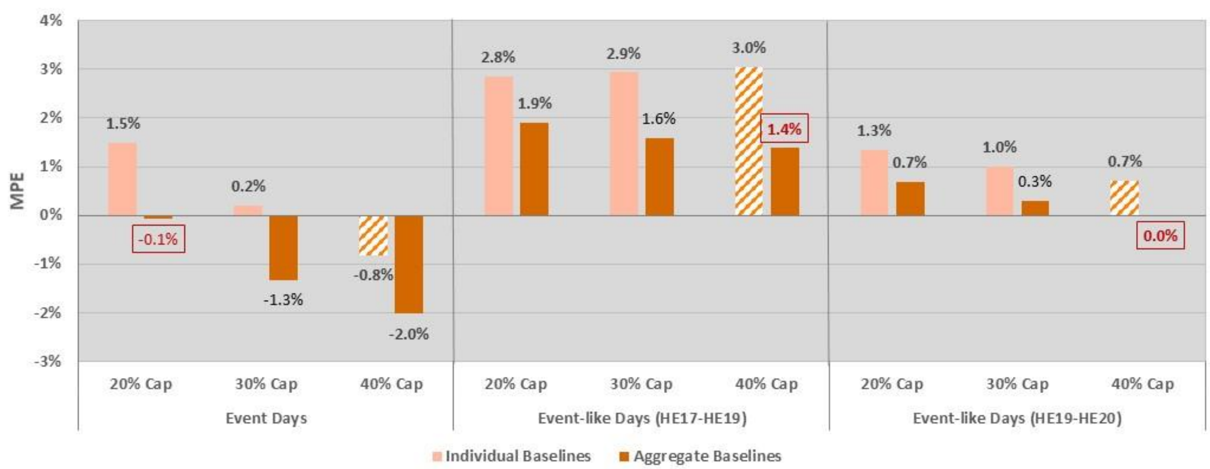


Figure A-12 SCE Day Of Program: Bias Comparison – Resource -level (PY 2019)



SDG&E Results by Program Year

Day Ahead Program

The SDG&E DA program PY2018 results cover 26 event days and 23 event-like days and include 4 unique resources and 68 unique customers.

Figure A-13 SDG&E Day Ahead Program: Accuracy Comparison – Resource-level (PY 2018)

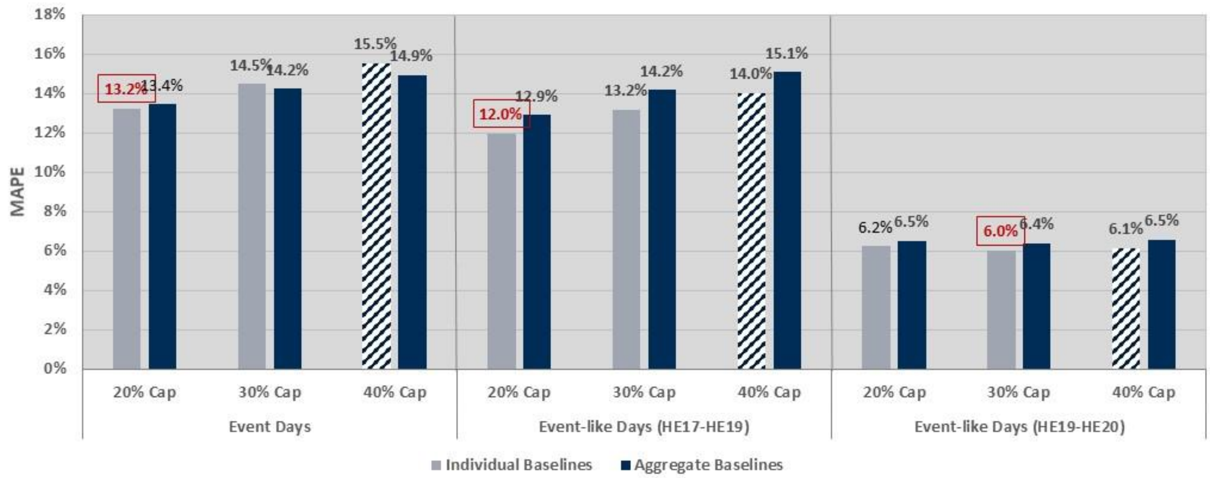
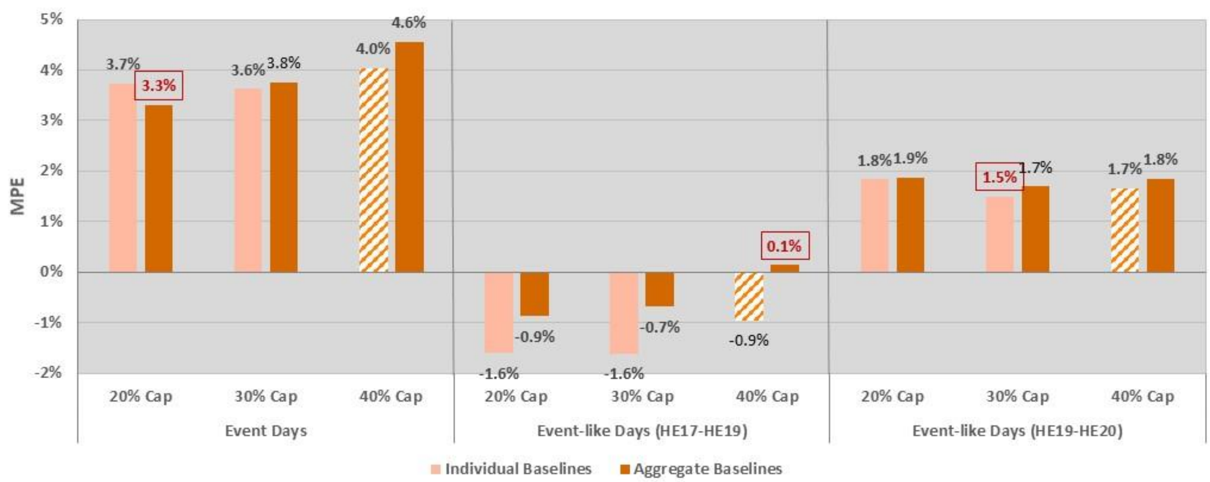


Figure A-14 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2018)



The SDG&E DA program PY2019 results cover 22 event days and 13 event-like days and include 6 unique resources and 11 unique customers.

Figure A-15 SDG&E Day Ahead Program: Accuracy Comparison – Resource -level (PY 2019)

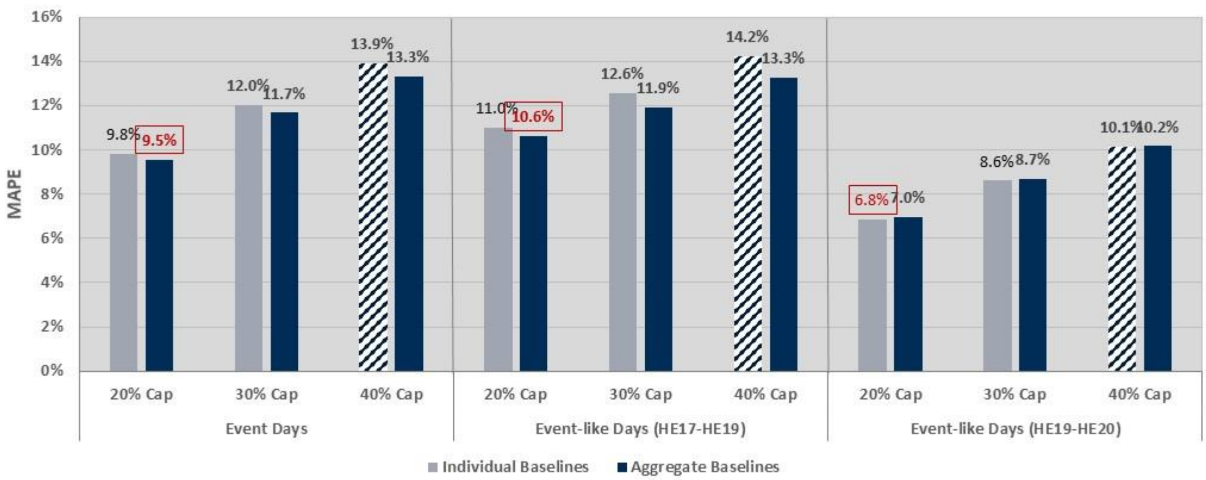
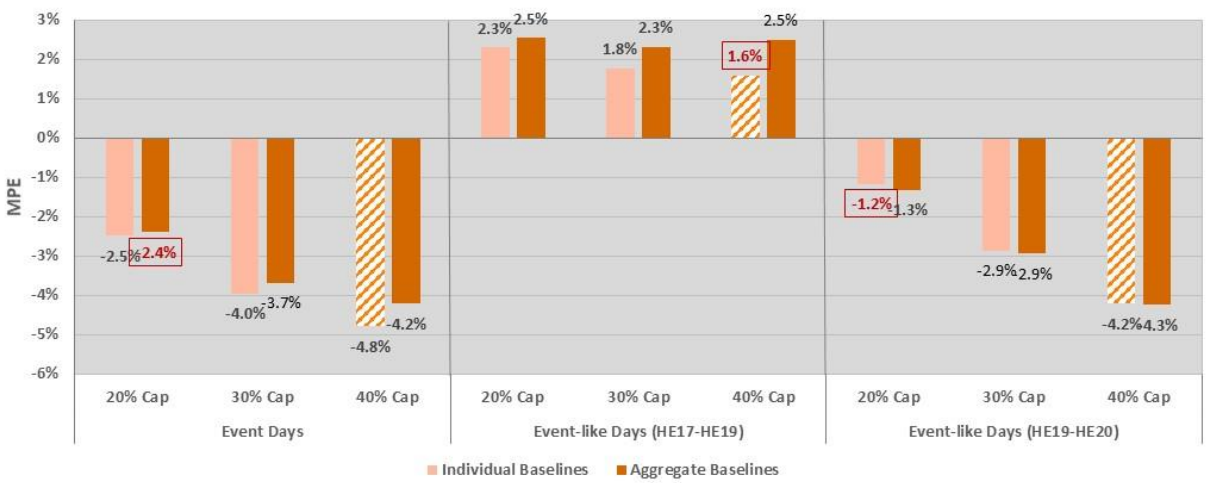


Figure A-16 SDG&E Day Ahead Program: Bias Comparison – Resource -level (PY 2019)



Day Of Program

The SDG&E DO program PY2018 results cover 3 event days and 23 event-like days and include 5 unique resources and 186 unique customers.

Figure A-17 SDG&E Day Of Program: Accuracy Comparison – Resource-level (PY 2018)

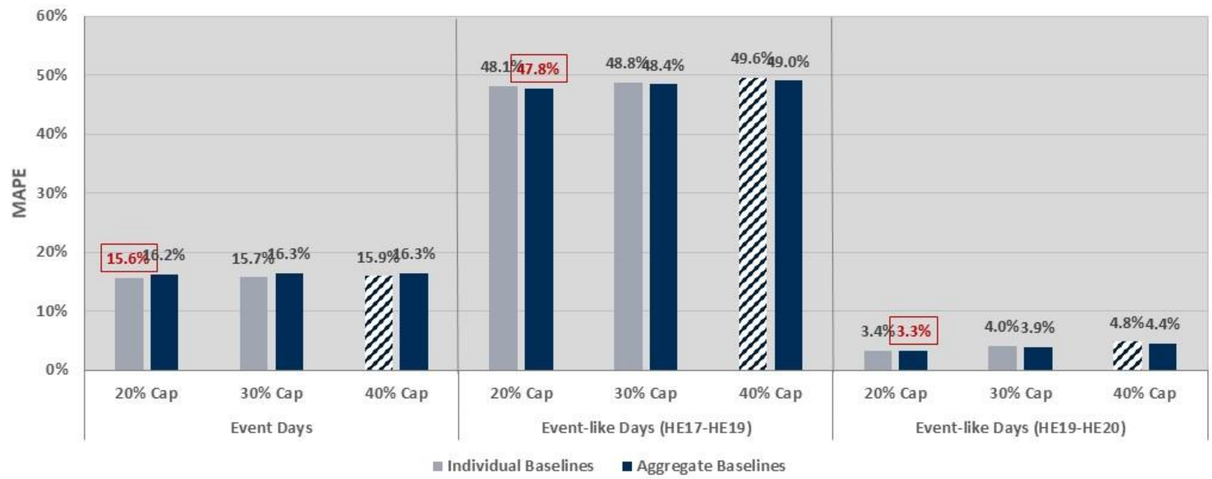
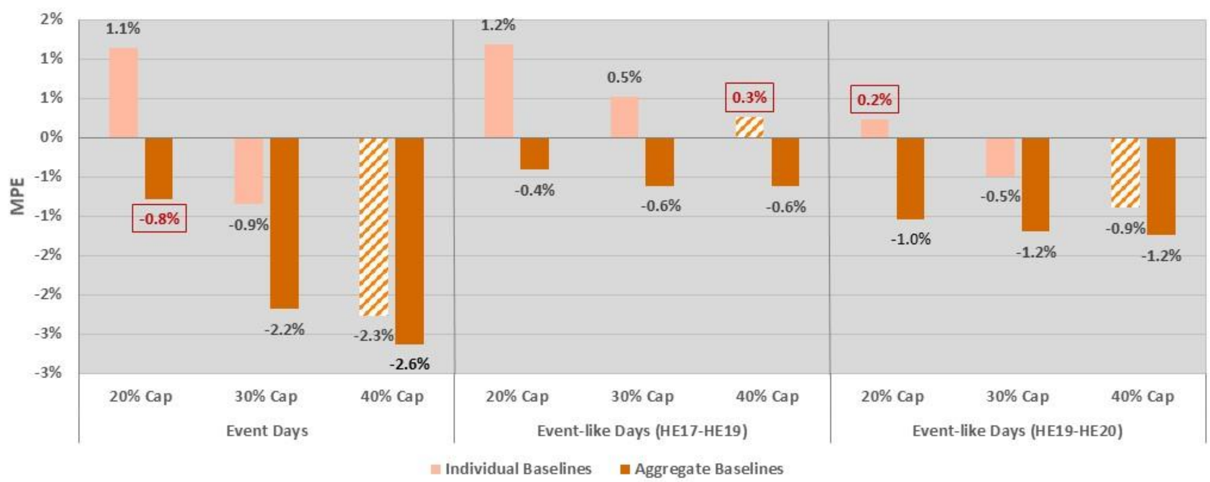


Figure A-18 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2018)

The SDG&E DO program PY2019 results cover 16 event days and 13 event-like days and include 6 unique resources and 193 unique customers.

Figure A-19 SDG&E Day Of Program: Accuracy Comparison – Resource -level (PY 2019)

Figure A-20 SDG&E Day Of Program: Bias Comparison – Resource -level (PY 2019)



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

AEG
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CAPACITY BIDDING PROGRAM: BASELINE COMPARATIVE ANALYSIS

Abigail Nguyen, Project Manager

AGENDA

Analysis Objectives

Comparative Analysis

Results by Program

Key Findings & Recommendations

Applied Energy Group

Analysis Objectives

ANALYSIS OBJECTIVES

AEG Applied Energy Group

D. 19-07-009 Issues to Investigate

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

Issues Addressed by this Analysis

Directly addresses #1 and #5 by performing comparative analysis

10/10 DAY MATCHING BASELINE

Identify **10** eligible **Baseline Days**

Excluding weekends, other event days, ISO holidays, award dates, outages, etc.

Unadjusted Baseline
average hourly customer loads across 10 baseline days

Same-day Adjustment Ratio
Event day : Unadjusted baseline
using total kWh during adjustment period

Adjustment period: 3 hours prior to event with 1 hour buffer.

Calculated at ***Aggregate or Individual*** *level, depending on preferred baseline.*

Apply **Adjustment Cap**
Adj Ratio = (1+**X**) if Adj Ratio > (1+**X**) or
Adj Ratio = (1-**X**) if Adj Ratio < (1-**X**)

Where X is ***20%, 30%, or 40%****, depending on preferred baseline*

Adjusted Baseline
apply same-day adjustment ratio to each event hour in unadjusted baseline

Actual Load Reduction
= (Adj Baseline – Actual Usage) for each event hour

This step was not performed as part of this comparative analysis

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Comparative Analysis

OVERVIEW OF COMPARATIVE ANALYSIS

1

Establish scenarios for comparison: identify event days, select event-like days

2

At customer level, **calculate adjusted baseline estimates** for event days and event-like days using *six baselines*

3

Sum by resource and **calculate metrics**: accuracy (MAPE) and bias (MPE)

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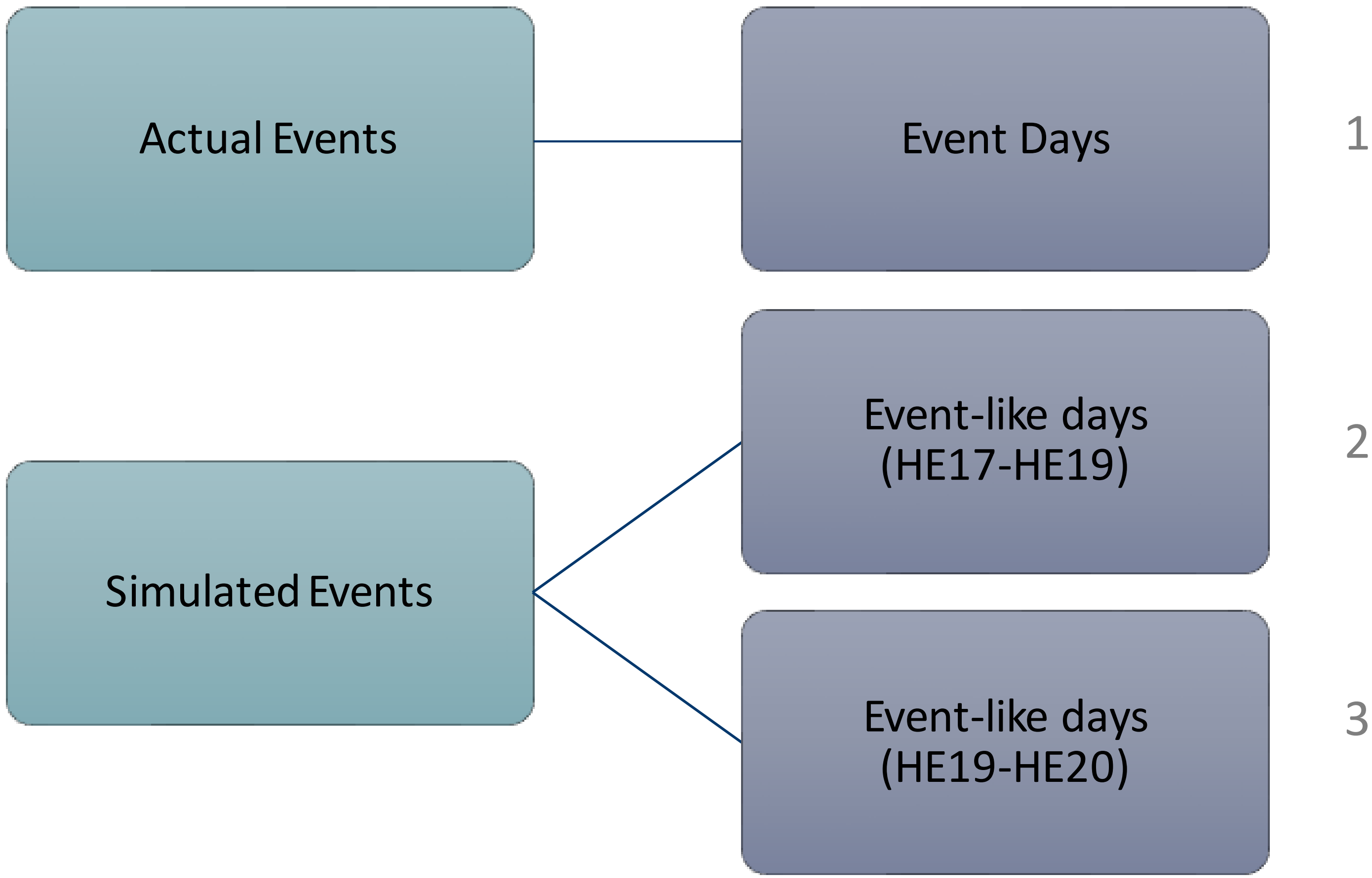
ESTABLISH THREE SCENARIOS
PY2018 and PY2019



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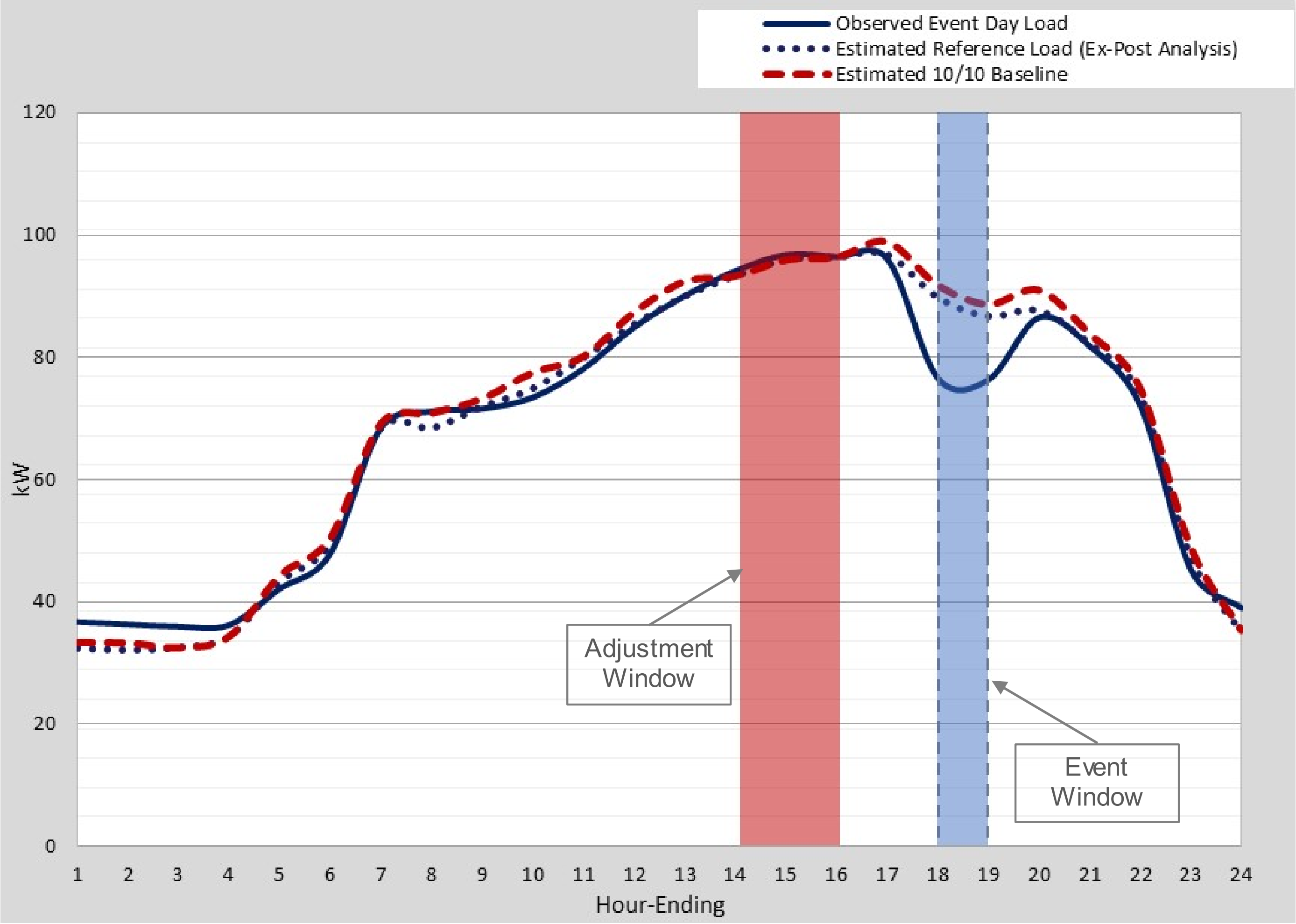
EVENT DAY SCENARIO



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EVENT-LIKE DAY SCENARIO
HE17-HE19

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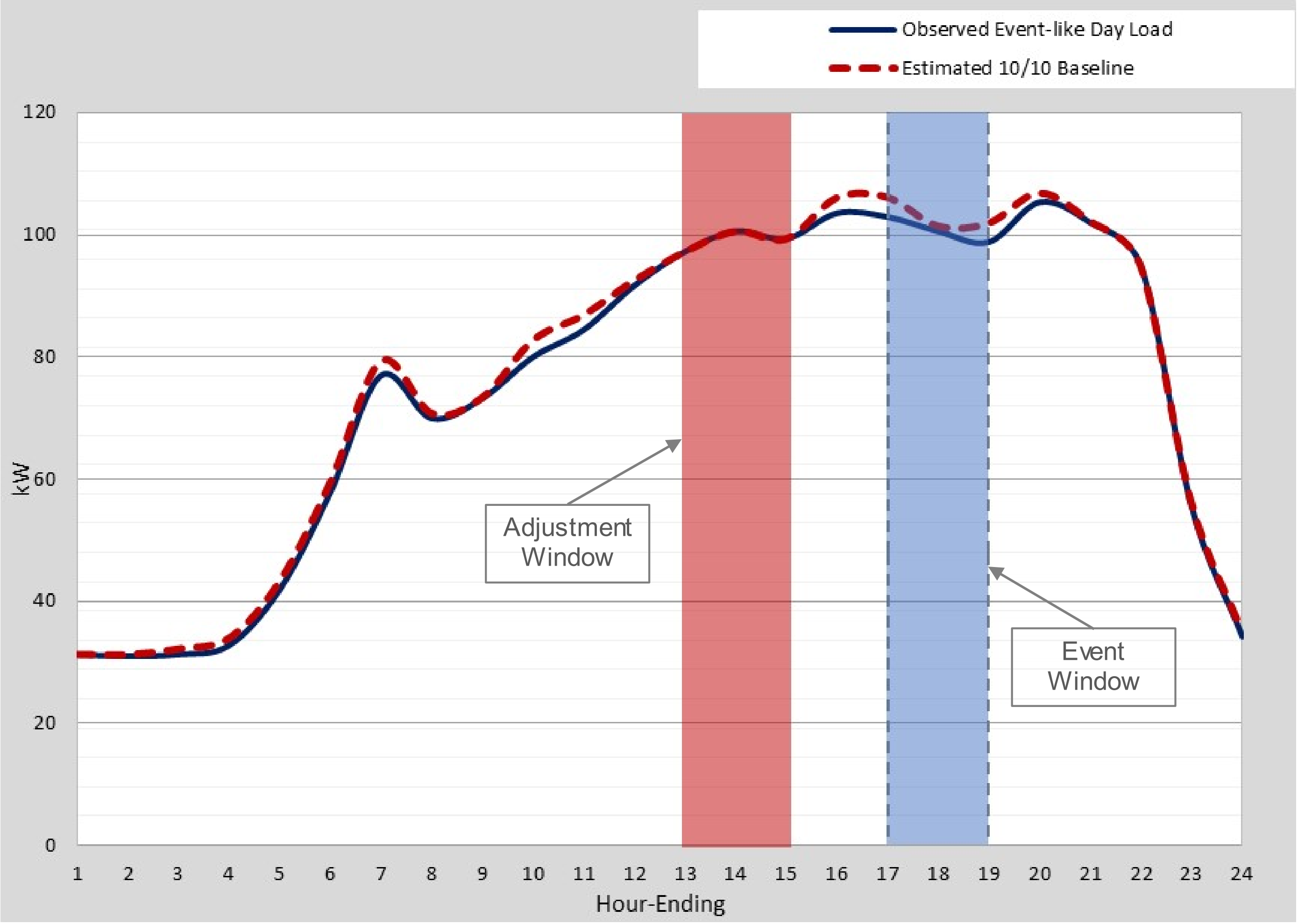

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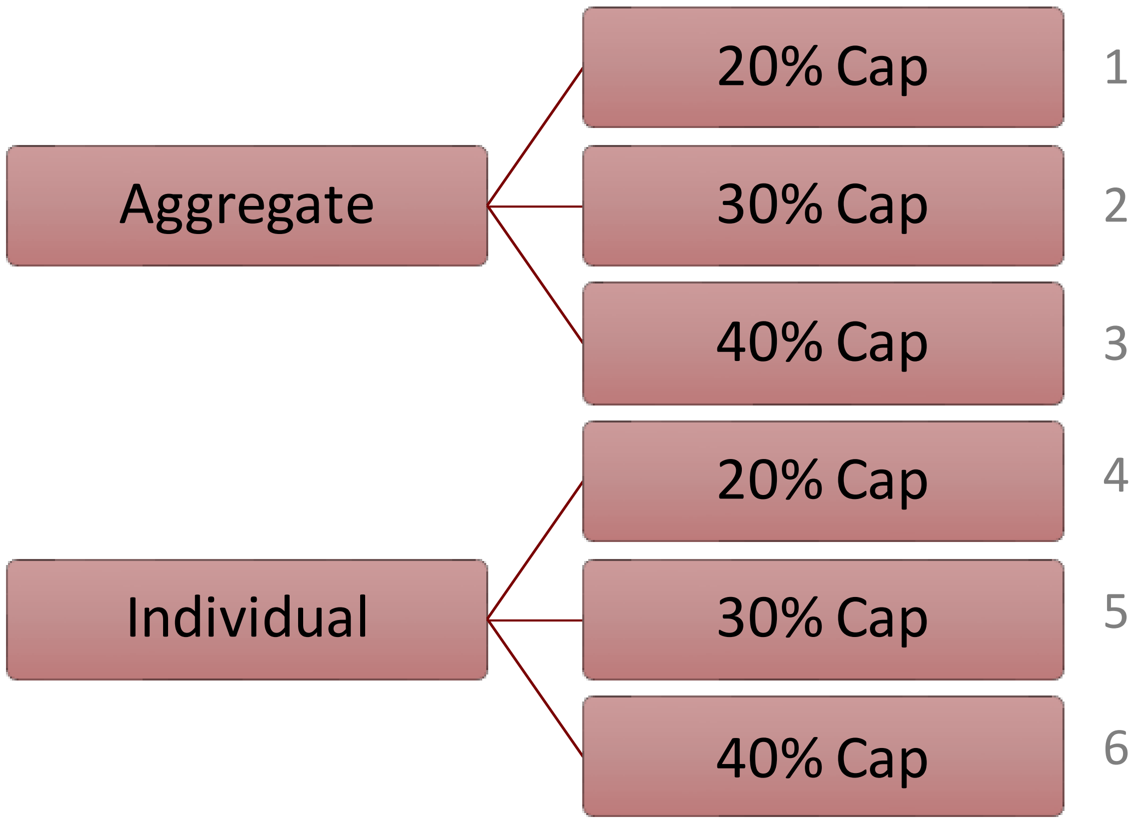
SIX BASELINES



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COMPARISON METRICS

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

$$MPE = \frac{100\%}{n}\sum_{h=1}^{n}\frac{Actual_h - Estimate_h}{Actual_h}$$

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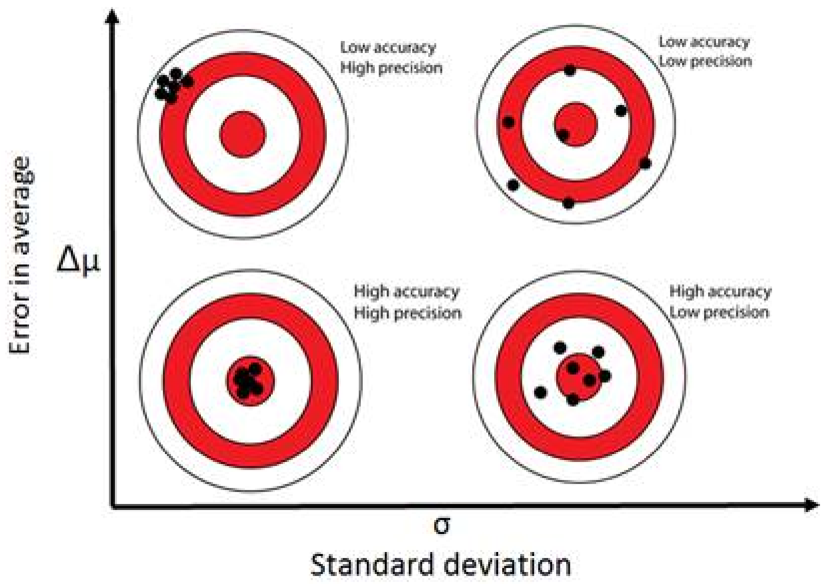
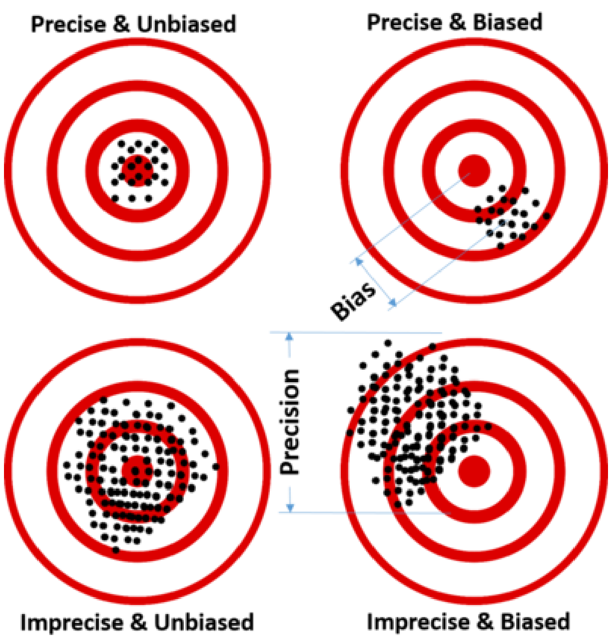
ACCURACY, PRECISION, BIAS





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

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EXAMPLE CALCULATION

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Individual Baseline					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.14	155.51				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.26	178.44				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.30	184.61	508.56	518.56	2.0%	-2.0%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.4%*	*2.4%*

Aggregate Baseline					Actual Load	Unadjusted Baseline	Adjustment Ratio	Adjusted Baseline	Resource Actual Load	Resource Adjusted Baseline	MAPE	MPE
Resource 1	Aggregator 1	Sublap 1	Customer 1	Event 1	155.28	136.10	1.23	167.41				
Resource 1	Aggregator 1	Sublap 1	Customer 2	Event 1	176.64	142.01	1.23	174.67				
Resource 1	Aggregator 1	Sublap 1	Customer 3	Event 1	176.64	142.01	1.23	174.67	508.56	516.75	1.6%	-1.6%
Resource 2	Aggregator 2	Sublap 2	Customer 4	Event 1	173.04	146.95	1.10	161.17	173.04	161.17	6.9%	6.9%
										Method Score	*4.2%*	*2.6%*

A few key notes on the example above:

- This is a simple example showing an individual baseline versus an aggregate baseline using the same adjustment cap.
- Resource 1 demonstrates the difference between an individual adjustment versus an aggregate adjustment (shown in red text).
- Resource 2 contains a single customer, thus the estimates in the individual and aggregate baselines are the same.
- The APE and PE are calculated for each resource and event day.
- The Method Score is the MAPE and MPE for each IOU and program. The simple example assumes that these four observations make up one program.

KEY POINTS ON METRIC DEVT & OVERALL ANALYSIS APPROACH

Retail settlement payments for each event day are made at the aggregator level.

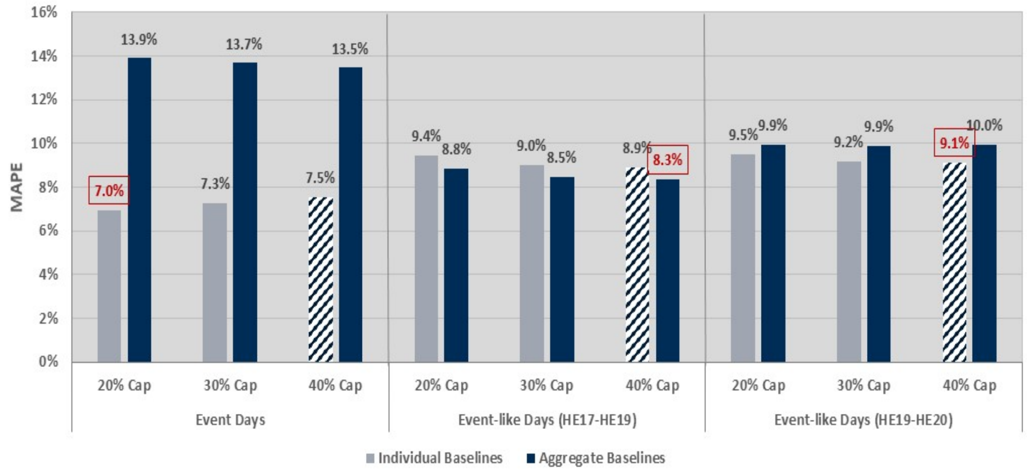
Under the CBP tariff, aggregators are responsible for:
(1) customer recruitment and contracting,
(2) resource MW nominations,
(3) resource MW curtailment, and
(4) customer payment disbursement.

A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

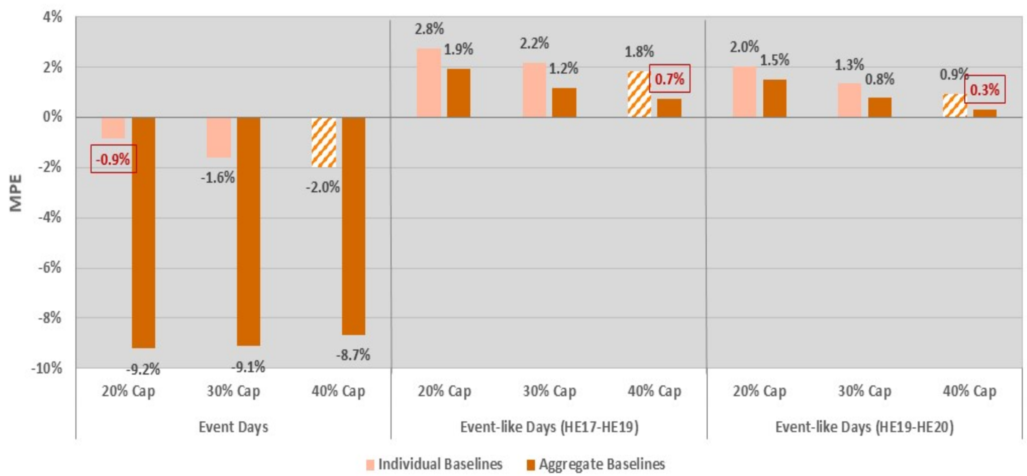
Results by Program

PG&E DAY AHEAD
PY2018 & PY2019

Accuracy Comparison



Bias Comparison



- Covers 55 events & 29 event-like days; 12 resources; 948 customers.
- Event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20).
- Event days and event-like days with HE19-20 simulation show similar results (better accuracy using individual baselines) – this is because PG&E DA called 30 events that start on HE19. Both scenarios use the same adjustment windows.

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SCE PROGRAMS

Day Of

- Like PG&E DA, shows consistent results between PY2018 and PY2019.
- However, results are not consistent with PG&E—top baselines are not the same.

Day Ahead

- Year-to-year results demonstrate how baseline effectiveness can be driven by the participant population.

SCE DAY OF

PY2018 & PY2019

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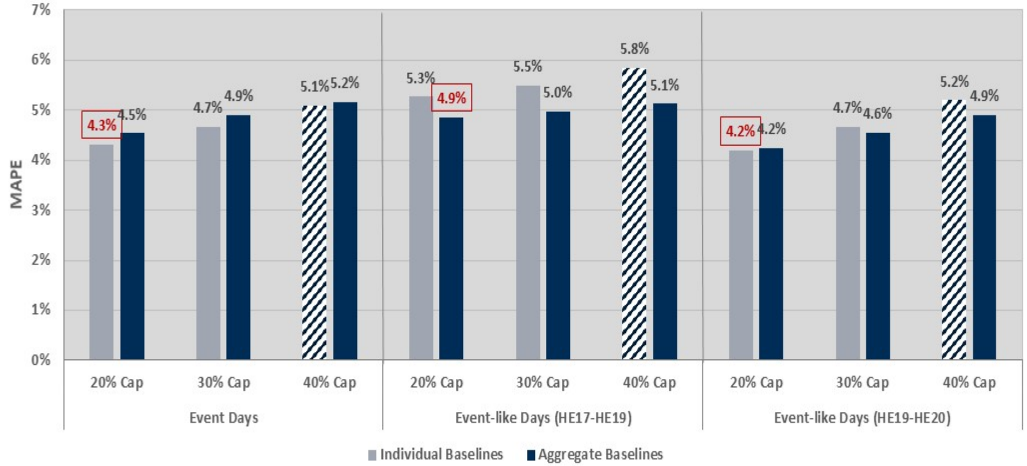
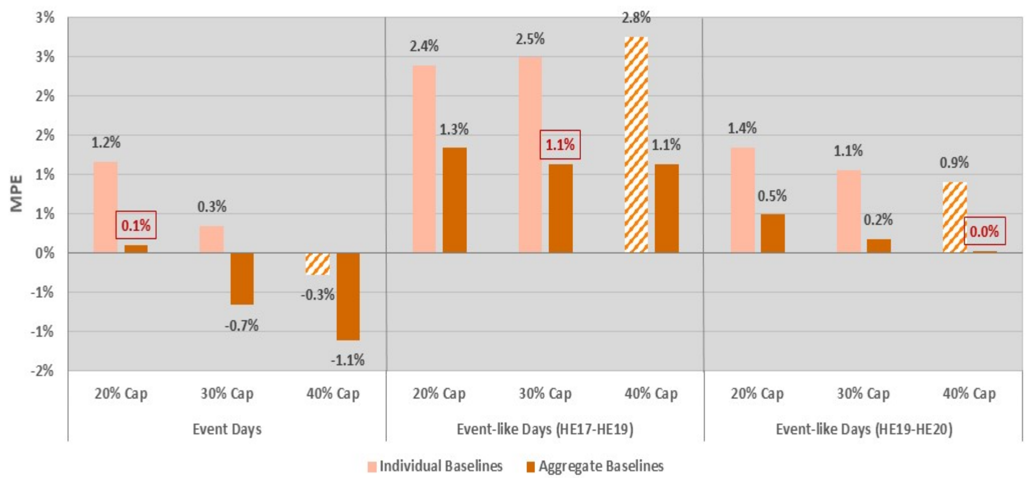
Accuracy Comparison



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.

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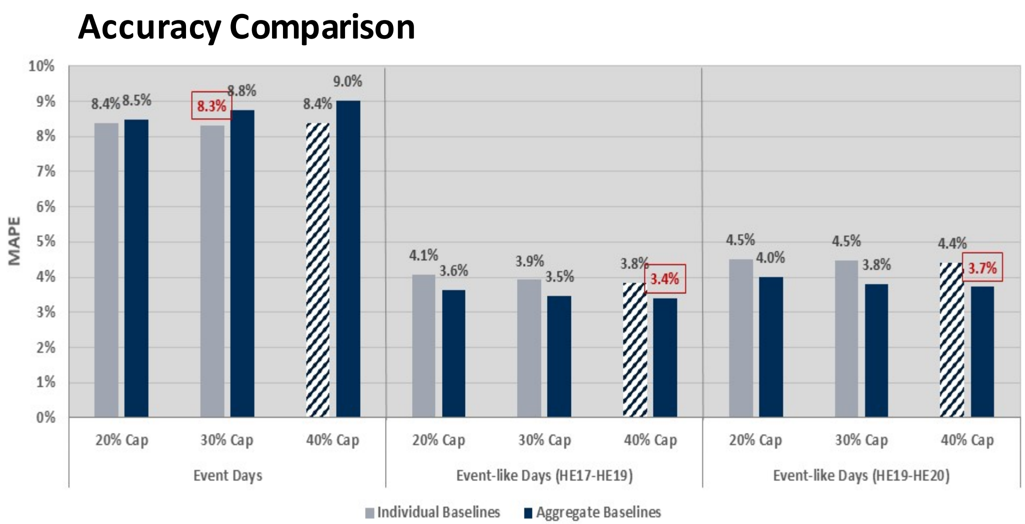
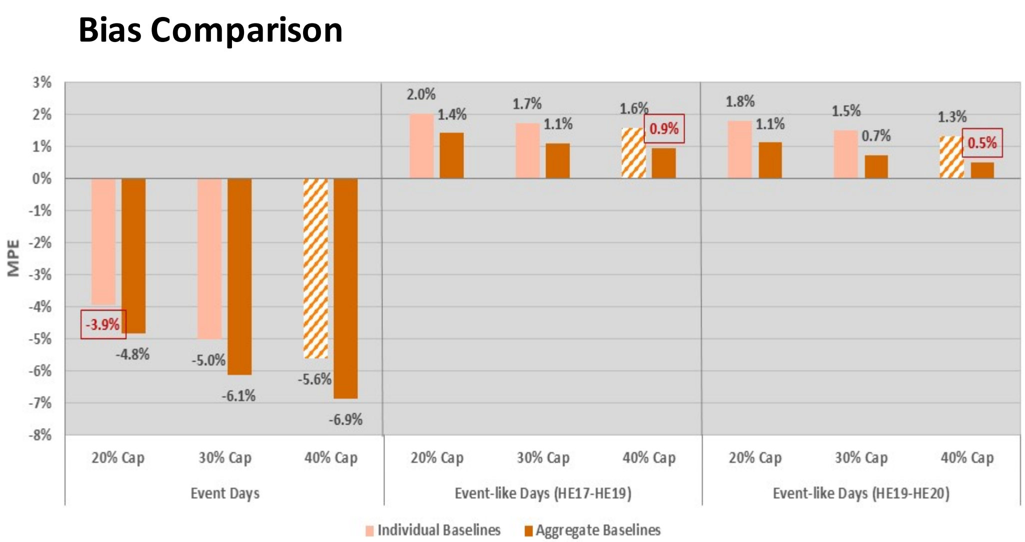
SCE DAY AHEAD

PY2018 & PY2019





- Covers 44 events & 42 event-like days; 5 resources; 385 customers.
- Again, event-like day scenarios show similar results, indicating that baselines have low sensitivity to the timing of the event (HE17-19 v. HE19-20). Both show Aggregate with 40% cap as most accurate and least bias.
- Event days show conflicting results, mainly driven by PY2018 event day data.

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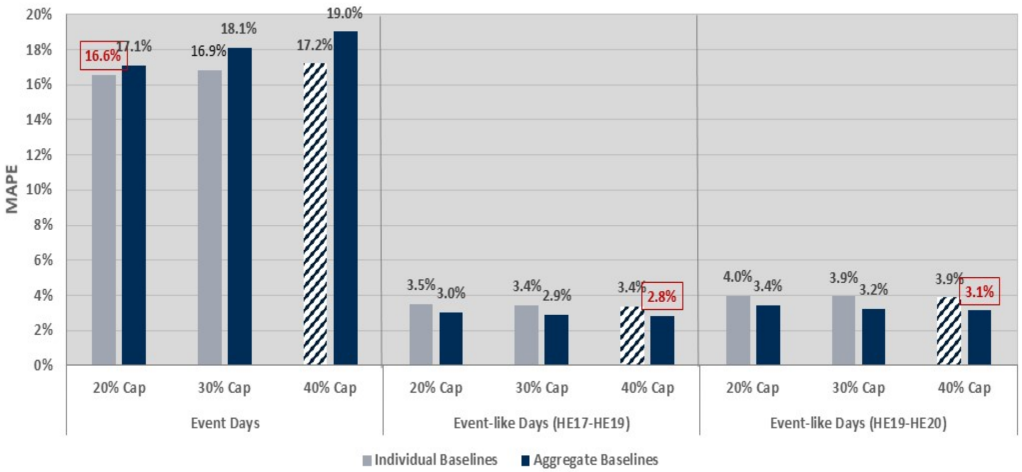
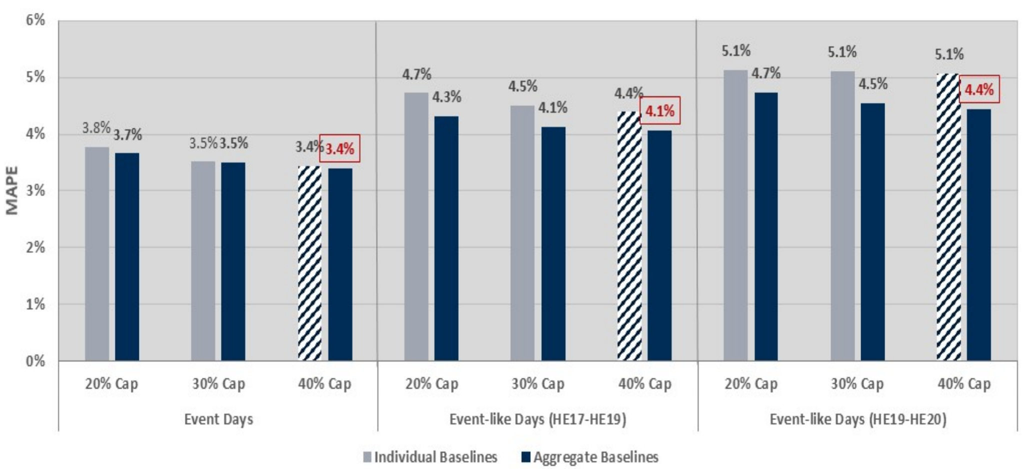
SCE DAY AHEAD

PY2018 versus PY2019





- 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.

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SDG&E PROGRAMS

Applied Energy Group

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.

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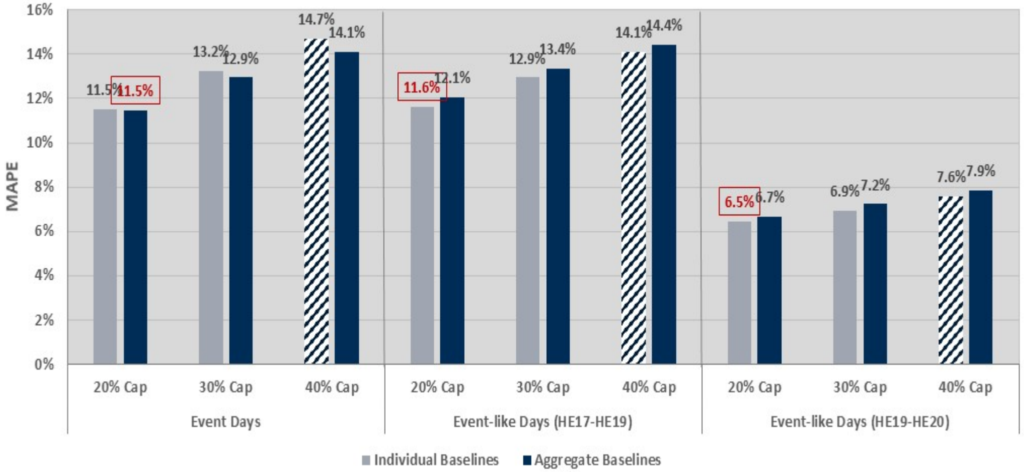
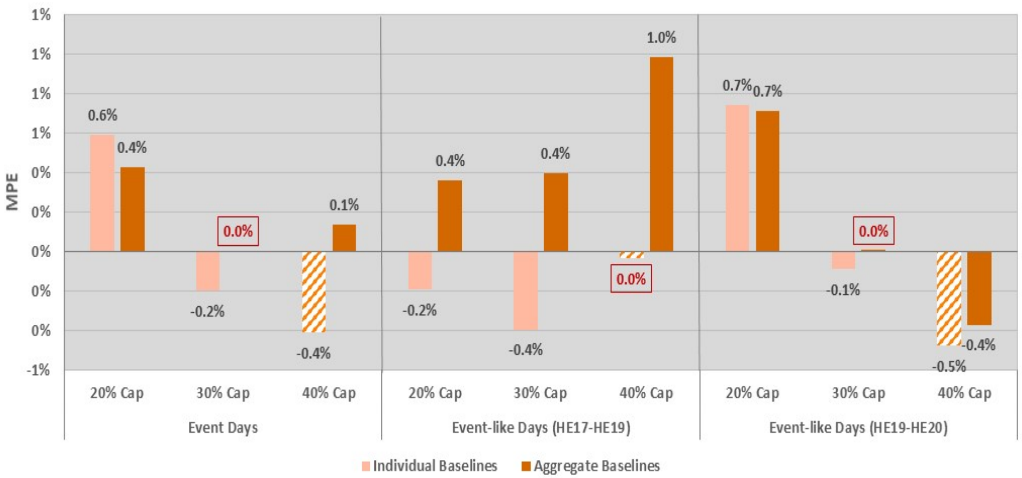
SDG&E DAY AHEAD
PY2018 & PY2019

Accuracy Comparison



Bias Comparison



- Covers 48 events & 36 event-like days; 7 resources; 75 customers.
- Consistent accuracy results, but conflicting bias results – largely driven by the differences in participant populations between PY2018 and PY2019.

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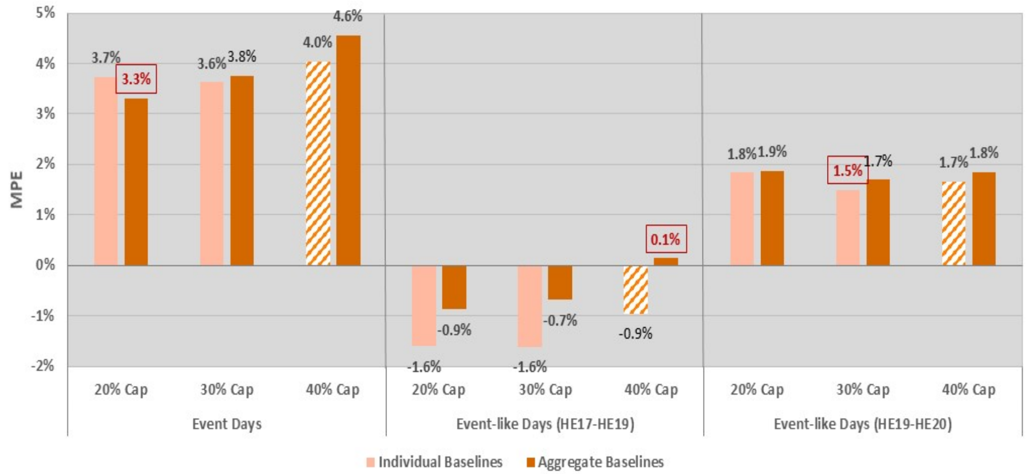
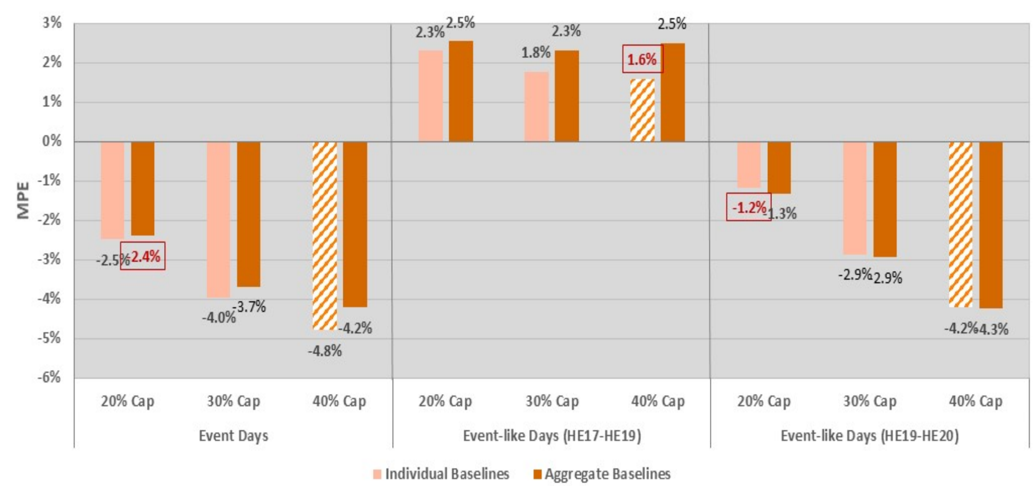
SDG&E DAY AHEAD

PY2018 versus PY2019

PY2018 Bias Comparison



PY2019 Bias Comparison



- PY2018 and PY2019 results show how directional bias and magnitude can be driven by the participant population.
- These two participant populations also show bias sensitivity to event window placement.

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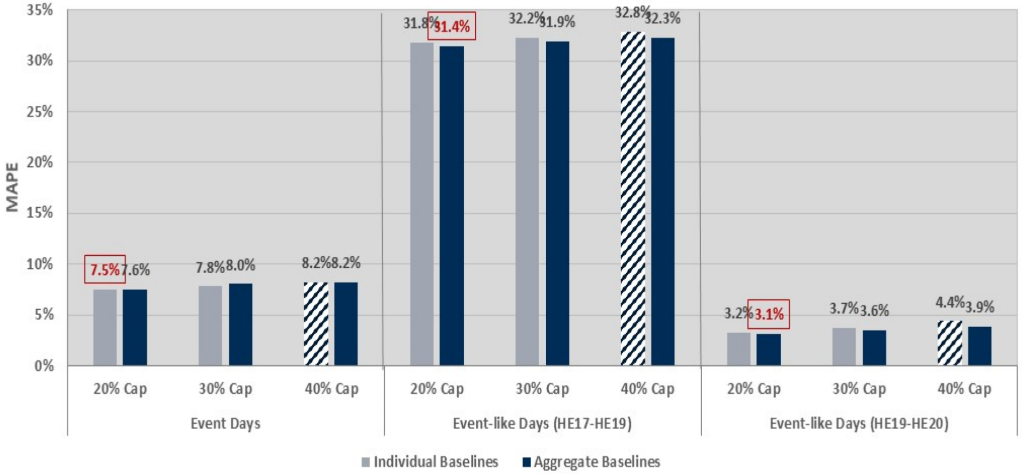
SDG&E DAY OF
PY2018 & PY2019

Accuracy Comparison



Bias 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.

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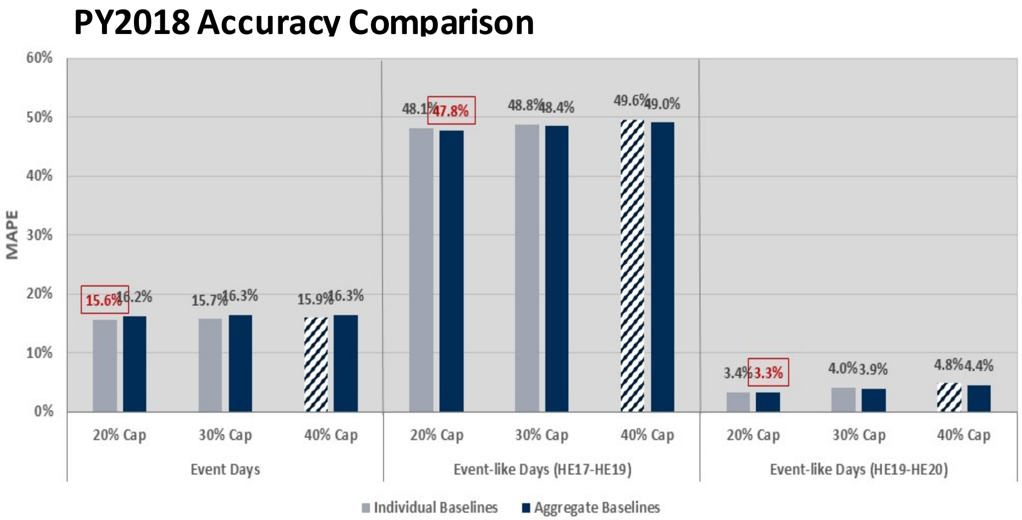
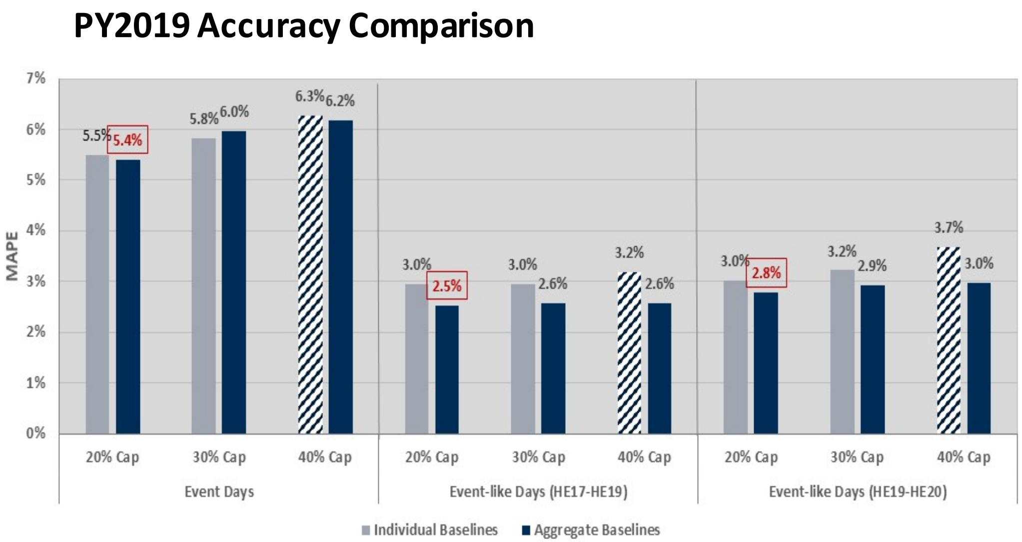
SDG&E DAY OF
PY2018 versus PY2019





- PY2018 shows event-like days with very high sensitivity to the timing of the event.
- PY2019 shows all three scenarios with very consistent results.

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Key Findings and Recommendations

BEST ACCURACY & LEAST BIAS

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

Score in parenthesis indicates a ranking out of 5, where 5 is the highest possible score and 1 is the lowest score.

5 = all five programs favored the same baseline
1 = each of the five programs favored different baselines

- BIAS – Aggregate baselines consistently give the least bias; 30% adjustment cap shows the least bias in 2.2 out of 5 programs, considering all scenarios.
- ACCURACY – event-like days scenarios show better accuracy using aggregate baselines, while event day scenarios show better accuracy using individual baselines. All show better accuracy using the 20% adjustment cap.

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AVG DECREASE IN EFFECTIVENESS
Aggregate Baselines

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

Shows the average loss in accuracy and increase in bias when selecting an aggregate baseline in lieu of the top effective baseline for each program and scenario.

- Decreases in effectiveness are all under 2.3%, indicating that both accuracy and bias are not highly sensitive to the adjustment cap.
- Event day scenarios (which shows better accuracy using individual baselines) show relatively small "losses" in accuracy, showing 1% to 2.5% decreases in accuracy.

RECALL KEY POINTS ON ANALYSIS APPROACH

AEG Applied Energy Group

Retail settlement payments for each event day are made at the aggregator level.

Under the CBP tariff, aggregators are responsible for:
(1) customer recruitment and contracting,
(2) resource MW nominations,
(3) resource MW curtailment, and
(4) customer payment disbursement.

A resource can be made up of several customers, at an aggregator's discretion. A resource can be utilized for DR curtailment also at an aggregator's discretion, using all or only select customers within a resource.

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RECOMMENDATION

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.

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RECOMMENDATION

Individual v. Aggregate Baselines?

AEG recommends using the **Aggregate Baseline**.

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

EBM - C-83

RECOMMENDATION

Which Adjustment Cap?

20% Cap
- best accuracy

30% Cap
- least bias

AEG recommends using the **20% Adjustment Cap**.

- Both accuracy and bias are not highly sensitive to the adjustment cap – differences in effectiveness, on average, is so small between the three adjustment caps.
- Wholesale settlement already uses the 20% cap – the advantages of aligning the two settlement baselines outweigh the small decrease in effectiveness.

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