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2023 Statewide Load Impact Evaluation of California Capacity Bidding Programs

EX-POST AND EX-ANTE LOAD IMPACTS

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Public Version. Redactions in 2023 Statewide Load Impact Evaluation of California Capacity Bidding Programs and Appendices.

Confidential content removed and blacked out XXX

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Abstract

This report documents the Program Year 2023 (PY2023) statewide load impact evaluation of the Capacity Bidding Program (CBP) operated by the three California investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The primary goals of this evaluation are to (1) estimate the ex-post load impacts for PY2024 and (2) estimate ex-ante load impacts for years 2024 through 2034.

CBP is an aggregator-based demand response (DR) program. As part of these programs[[1]](#footnote-2), DR aggregators contract with customers to act on their behalf in all aspects of the program, including receiving notices from the IOU, arranging for load reductions on event days, receiving incentive payments, paying incentives to participating customers, and paying penalties (if warranted) to the IOU. Each aggregator forms a portfolio of service accounts whose aggregated load reductions participate as a single resource for each program. Aggregators can nominate customer service accounts to various products depending on each program’s product[[2]](#footnote-3) offerings, including day-ahead (DA) and day-of[[3]](#footnote-4) (DO) notifications and corresponding event triggers. The terms and conditions of service can vary widely, depending on tariffs specific to each IOU and contracts between aggregators and customers.

In PY2023, the number of dispatched customer service accounts[[4]](#footnote-5) on a single event day ranged from one to 443 service accounts, depending on the program and product. Some programs dispatched as few as three event days, while others dispatched up to 53 event days. These events are dispatched for various combinations of distribution-based geographical locations or Sub-Load Aggregation Points (Sub-LAPs). Sub-LAP events are based on California Independent System Operator (CAISO) market awards and may not require the IOU to dispatch the entire available portfolio of nominated resources.

AEG estimated hourly ex-post load impacts for each program, product, and dispatched event in PY2023 using regression analysis of hourly load, weather, and event data. The estimated load impacts are reported by program, product, and event day. Load impacts for the average event day are also reported by industry type, CAISO local capacity area (LCA), and Sub-LAP where relevant. Estimated aggregate load impacts for an average non-residential CBP DA event were 20.5 MW for PG&E, XX MW for SCE, and 0.8 MW for SDG&E. Aggregate load impacts for Non-residential CBP DO events were XX MW for SCE and 1.7 MW for SDG&E, on average.

AEG developed ex-ante load impact forecasts by combining enrollment forecasts provided by the IOUs and per-customer load impacts generated from analysis of current and prior ex-post load impact estimates. The forecast numbers of nominated customer service accounts and aggregate ex-ante load impacts presented in the report reflect several program changes expected to be effective in 2024 and 2025.

Executive Summary

This report documents the Program Year 2023 (PY2023) statewide load impact evaluation of the Capacity Bidding Program (CBP) offered by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), the three California investor-owned utilities (IOUs).

The primary goals of the PY2023 load impact evaluation are as follows:

* Estimate hourly ex-post load impacts for each program,[[5]](#footnote-6) product[[6]](#footnote-7), and dispatched event in PY2023.
* Estimate hourly ex-ante load impacts for each program and product for the years 2024-2034.

We present the program description, evaluation methodology, ex-post load impacts, ex-ante load impacts, key findings, and recommendations in the following subsections.

Program Description

The Capacity Bidding Program is a statewide price-responsive and aggregator-managed demand response program launched in 2007. It is available within the service territories of the three California IOUs, although each IOU’s program differs slightly in program features and operations.

Aggregators. In CBP, aggregators contract with eligible residential[[7]](#footnote-8) and non-residential utility customers to act on their behalf in all aspects of the program. Aggregators receive dispatch notifications (day-ahead or day-of), incentive payments, and, where appropriate, penalties from the IOUs. Each aggregator forms a resource (i.e., a portfolio of customers) to provide load reduction during events. Each resource participates collectively, wherein load reduction is measured on an aggregate basis. The aggregators enroll customers under the terms of their contracts to provide the load reduction capacity and receive corresponding incentives. In other words, IOUs are not directly involved in the contracts between aggregators and customers unless a customer is classified as self-aggregated.

Eligibility. Aggregators must have internet access. Enrolled customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[[8]](#footnote-9) Customers enrolled in CBP may dually participate in an energy-only DR program (i.e., the program cannot have a capacity payment component) that does not have the same notification type (day-ahead or day-of).

Incentives. CBP provides monthly capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month, event duration, resource performance during the event, and the event notice option. Delivered capacity determines performance. If an aggregator’s delivered capacity is less than the tariff threshold (50% for SCE and SDG&E, 60% for PG&E), the aggregator is assessed a penalty. For months without dispatched events, CBP aggregators receive the full monthly capacity payment based and no energy payments.[[9]](#footnote-10) Additional energy payments ($/kWh) are made to the aggregator[[10]](#footnote-11) based on the measured kWh reductions (relative to the program baseline) achieved when an event is dispatched.[[11]](#footnote-12)

Programs, Products, and Events. All CBP events are determined by California Independent System Operator (CAISO) market awards at varying thresholds specified by program and product. Table ES - 1shows the description and details of products offered by each IOU.

* PG&E has two programs: Residential and Non-residential Day-Ahead. Both programs offer three products: Elect, Elect+, and Prescribed. PG&E operating hours are between 1:00 PM and 9:00 PM. Events are called Monday through Friday (option available to include weekends), excluding holidays, from May through October, with a maximum of six events and 30 hours per month (or possibly more hours under Elect and Elect+ Options if participants so choose).
* SCE has two programs: Non-residential Day-Ahead and Day-Of. Both programs offer one product: Day-Ahead 1-6 Hour and Day-Of 1-6 Hour. SCE operating hours (dispatch window) are between 3 PM and 9 PM. Events may be called Monday through Friday, excluding holidays, year-round, with a maximum of five events and 30 hours per month. Residential CBP is now open to aggregators, but SCE has not yet received nominations.
* SDG&E has two programs: Non-residential Day-Ahead and Day-Of. Across both program there are currently six products offered across Prescribed and Elect products. SDG&E’s Elect products are three price trigger options: $200/MWh, $400/MWh, and $600/MWh. Events may be called Monday through Friday, excluding holidays, from May through October, with a maximum of 24 hours per month. SDG&E can dispatch up to six event days per month with up to three consecutive event days per month.

Table ES - 1 Program Description

|  |  |  |  |
| --- | --- | --- | --- |
|  | PG&E | SCE | SDG&E |
| **Active Programs** | Residential Day Ahead  Non-Residential Day Ahead | Non-Residential Day Ahead  Non-Residential Day Of | Non-Residential Day Ahead  Non-Residential Day Of |
| **Products** | Prescribed DA  Elect DA  Elect+ DA | DA 1-6 Hour  DO 1-6 Hour | Prescribed DA 11-7/1-9 Hour  Prescribed DO 11-7/1-9 Hour  Elect DA 1-9 Hour  Elect DO 1-9 Hour  Price triggers: $200, $400, $600 |
| **Dispatch Window** | 1 PM – 9 PM | 3 PM – 9 PM | 11 AM – 7PM or 1 PM – 9 PM |
| **Event Trigger** | CAISO Market Awards | CAISO Market Awards | CAISO Market Awards |
| **Eligible Days** | May – October  non-holiday weekdays,  option for weekends | Year-Round  non-holiday weekdays | May – October  non-holiday weekdays |
| **Event duration** | 1-4 hours,  2-6 hours,  1-8 hours  or 1-24 hours | 1-6 hours | 2-4 hours |
| **Event day limit** | 6 events per month | 5 events per month | 6 events per month |
| **Event hour limit** | 30 hours per month | 30 hours per month | 24 hours per month |

**Program Nominations**

Figure ES - 1 Average Summer Nominations by Program

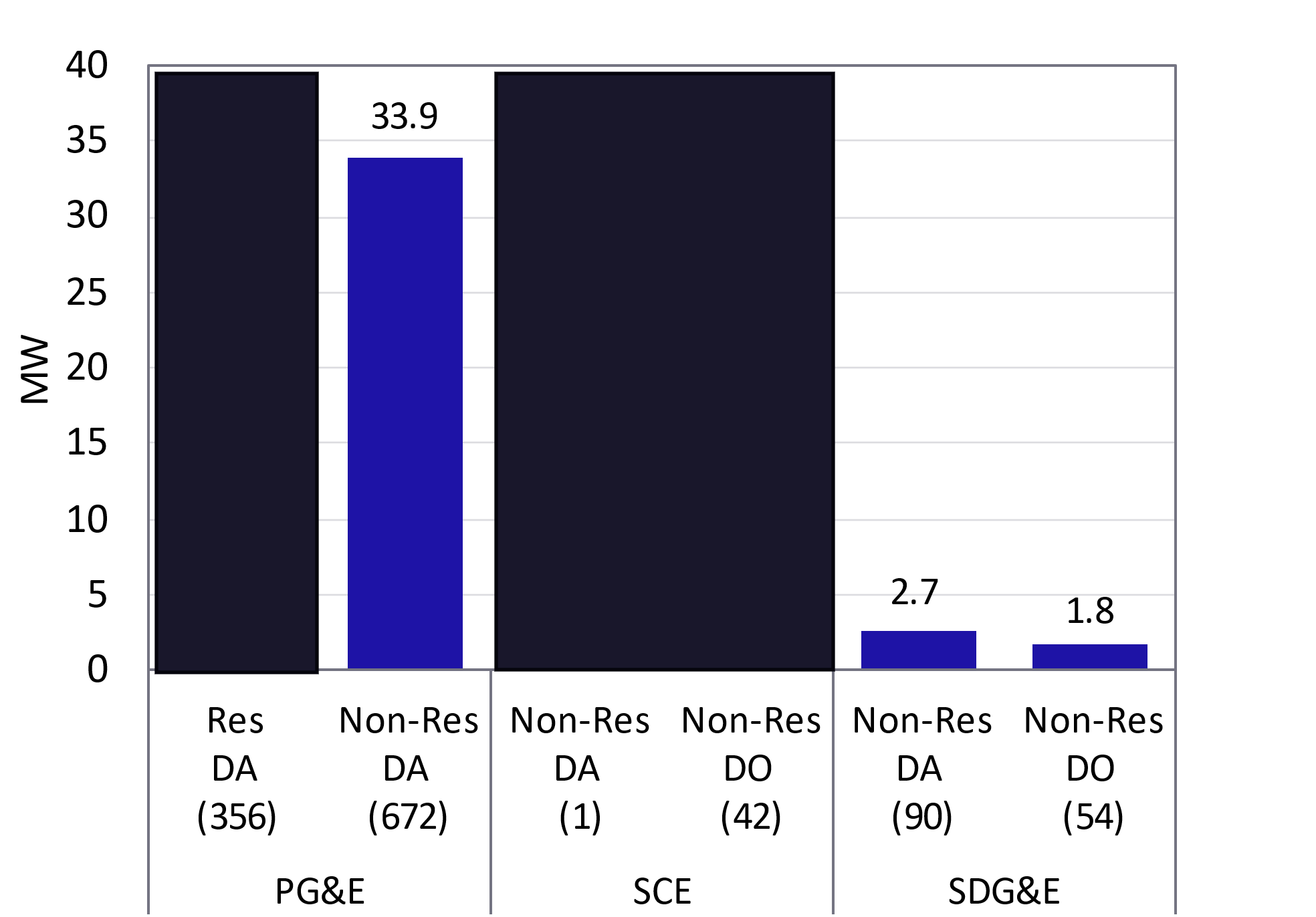


Figure ES - 1 shows the average summer[[12]](#footnote-13) nominations for each program in PY2023. These counts and capacity nominations represent the total resources available for dispatch during the PY2023 summer season.

Nomination vs. Dispatch

Throughout the report, we distinguish between nominations and dispatches. A **Nomination** is a monthly nominated resource by program, product, aggregator, and Sub-LAP. Each nominated resource has a corresponding capacity nomination (MW) and number of enrolled customers. A **Dispatch** is a group of customers called to a market-triggered event. For example, a dispatched resource, dispatched customers, or dispatched capacity. Not all nominated entities are dispatched.

Dispatched Events

Since CBP events are triggered by CAISO market awards specific to Sub-LAPs, not all available nominations are dispatched for each event. Some months may dispatch more events than others, and some events may dispatch all or a portion of nominations. Table ES - 2 compares the average summer nominations to the average summer dispatches for each program. Note that the dispatched capacity is also separate from the estimated ex-post impact presented in the subsequent section.

Table ES - 2 Average Summer Nominations v. Dispatch

| IOU | Program | Nomination | | Dispatched | | |
| --- | --- | --- | --- | --- | --- | --- |
| No. of  Accounts | Capacity (MW) | No. of  Accounts | Capacity (MW) | Number of Events |
| PG&E | Res DA | 356 | XXX | 236 | XXX | 8 |
| Non-Res DA | 672 | 33.9 | 430 | 23.8 | 12 |
| SCE | Non-Res DA | 1 | XXX | 1 | XXX | 15 |
| Non-Res DO | 42 | XXX | 42 | XXX | 49 |
| SDG&E | Non-Res DA | 90 | 2.9 | 84 | 2.0 | 7 |
| Non-Res DO | 54 | 1.8 | 51 | 1.8 | 5 |

Evaluation Methods

AEG used the same methodology across all programs to ensure consistency of results. Each program is modeled independently, modifying assumptions to account for program design and implementation specific to each IOU’s CBP tariff. With the addition of PG&E’s Residential participation in PY2020, it is important to highlight the key differences in the approach used for the two customer classes:

The Residential program analysis use a matched control group and aggregate hourly regression models. This approach is the best practice for participant populations with less variable loads, which can leverage the higher statistical power with more customers included in each model. A matched control group also more effectively estimates the counterfactual load without a randomized control trial.

The Non-residential program analyses use a within-subjects design using customer-specific hourly regression models. This method remains the most flexible, consistent, and appropriate solution for CBP’s evaluation goals and population distributions. Non-residential customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific regressions allow us to control for variation in load due to weather conditions, geography, time-related variables, and other unobservable customer-specific effects. This approach also allows for aggregating individual customer impacts to estimate load impacts at any level or customer segmentation.

AEG used the same hourly regression models to predict the ex-ante load impacts under the Utility and CAISO 1-in-2 and 1-in-10 weather scenarios. AEG estimated load impacts for all five hours of the Resource Adequacy (RA) window, developing IOU-specific adjustments based on historical performance and expected program changes through the 2024-2034 forecast horizon.

Ex-Post Load Impacts

Table ES - 3 presents the PY2023 average summer event day ex-post impacts by IOU and program at the aggregate and per-customer levels. We show the results for each program's reporting hour, which is 6:00 PM–7:00 PM for PG&E's Non-Residential DA; 5:00 PM–6:00 PM for SCE's Non-Residential DA and DO during the summer months, and 7:00 PM–8:00 PM for SCE’s non-summer months and all other programs . Note that AEG calculated the average event day using all events regardless of dispatched count and event window.

At the program level, we observe the following relative to previous program performance:

* PG&E’s average Non-residential delivery performance[[13]](#footnote-14) of 86% remains comparable to the previous year’s 89%, attributed to lower participation but a larger customer size.
* After skipping 2022, PG&E’s residential participation started again, with an average delivery performance of XX%. Although it is lower than 2021’s XX%, it remains comparable, considering that 2021 had all Net Energy Metering (NEM) customers and larger users, leading to a significant load drop during events. This may include customers with battery storage, although, at the time of analysis, this detail was not available.
* SCE experienced a notable decline in Non-residential CBP participation in both DA and DO programs. Non-residential DA only included one customer who delivered XXX, XXX impacts during the average summer. Non-residential DO performance depended heavily on one school customer, who has a relatively larger load than the others, and the program had a stable delivery rate at XX% during the summer month, and XX% at the non-summer month which outperformed 2020 and 2021.
* In its second year of the new Elect products, SDG&E showed significant improvements in both DA and DO programs. The DA program reached a 42% delivery performance, while the DO program achieved an impressive 95% delivery performance, both outperforming 2022 and even 2021.

Table ES - 3 Statewide CBP Ex-Post Impact Summary, Average Summer Event Day PY2023

| IOU | Program | No. of Accounts | Aggregate (MW) | | | Per-Customer (kW) | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatch Capacity | Load Impact | % Delivered | Ref. Load | Load Impact | % Impact |
| PG&E | Residential DA | 132 | XXX | XXX | XXX | XXX | XXX | XXX |
| Non-residential DA | 430 | 23.8 | 20.5 | 86% | 219.4 | 47.7 | 22% |
| SCE | Non-residential DA | 1 | XXX | XXX | XXX | XXX | XXX | XXX |
| Non-residential DO | 42 | XXX | XXX | XXX | XXX | XXX | XXX |
| SDG&E | Non-residential DA | 84 | 2.0 | 0.8 | 42% | 97.7 | 10.0 | 9% |
| Non-residential DO | 51 | 1.8 | 1.7 | 95% | 188.3 | 33.6 | 18% |

Table ES - 4 summarizes each CBP program’s PY2023 overall season performance using the following reporting metrics:

* Nominations – counts and total capacity,
* Overall Dispatched – average counts and capacity for all events dispatched,
* Reporting Hour Dispatched – average counts and capacity for all events dispatched during the most dispatched hour, and
* Ex-post load impacts – aggregate impacts, delivery performance relative to the overall dispatched capacity, and adjusted delivery performance relative to Reporting Hour Dispatched capacity.

Some key notes when reviewing Table ES - 4:

* We show the average dispatched counts and capacity, which is dependent on CAISO market awards. Low counts are not indicative of low participation but rather an indication of resource needs.
* The percent of dispatched capacity delivered (delivery performance) is the correct measure of the program’s effectiveness; 100% delivery performance means aggregators and customers curtailed the load obligations when asked to do so.
* The delivery performance metrics allow for an adjusted metric for dispatched capacity coincident with the reporting hour. Our definition of the average event day includes events that did not dispatch capacity during the reporting hour. Notably, for PY2023, the overall dispatched capacity aligned with the reporting hour dispatched capacity in all programs. Therefore, the delivery performance adjustment is not necessary for this particular year.

PY2023 ex-post load impacts and dispatched capacity for each event day are provided in the following sections: [PG&E Impacts by Event Day](#_PG&E_Impacts_by), [SCE Impacts by Event Day](#_SCE_Impacts_by), and [SDG&E Event Day Load Impacts](#_SDG&E_Event_Day).

Table ES - 4 Statewide CBP Delivery Performance PY2023

| Program | | Nominations | | Overall Dispatched | | Reporting Hour Dispatched | | Ex-Post Load Impacts | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered |
| PG&E | Res DA | 356 | XXX | 236 | XXX | 236 | XXX | XXX | XXX |
| Non-res DA | 672 | 33.9 | 430 | 23.8 | 430 | 23.8 | 20.5 | 86% |
| SCE | Non-res DA | 1 | XXX | 1 | XXX | 1 | XXX | XXX | XXX |
| Non-res DO | 42 | XXX | 42 | XXX | 42 | XXX | XXX | XXX |
| SDGE | Non-res DA | 90 | 2.9 | 84 | 2.0 | 84 | 2.0 | 0.8 | 42% |
| Non-res DO | 54 | 1.8 | 51 | 1.8 | 51 | 1.8 | 1.7 | 95% |

Ex-Ante Load Impacts

Each program’s load impact forecast is based on IOU-specific assumptions that incorporate a combination of the following: aggregator/nomination outlook, delivery performance, ex-ante per-customer load impacts, enrollment growth, and an impact degradation[[14]](#footnote-15) rate across the RA window.

**PG&E’s forecast assumptions** are as follows:

* **Residential DA** – PG&E assumed a constant 0.7 MW nomination through the 11-year forecast. We maintained the 61% delivery performance, which is the minimum threshold before aggregators are charged a penalty. We also assume a maximum 4-hour event duration based on historical participation in the 1- to 4-hour product option.
* **Non-Residential DA** – PG&E kept 2022’s nominations for 2023, forecasting approximately 65 MW nominations for an August peak day. Based on PY2023 findings, we updated the achievement rate[[15]](#footnote-16) (90%), delivery performance (86%) and impact degradation rate (73% overall RA). We also assume a maximum 4-hour event duration based on historical participation in the 1- to 4-hour product option.

**SCE’s forecast assumptions** are as follows:

* Enrollment Outlook – consistent with the submitted DR Application A22-05-004:
  + Updated according to PY2023’s DO nominations
  + In 2024 through 2033, zero enrollment in non-summer months and the DO program.
  + In 2024, assume 100% of PY2023 DO summer participants will move to the DA summer program
  + In 2025, discontinue the current CBP program; introducing the new CBP Elect DA program and assume more enrollment than PY2023.
* Updated assumptions based on PY2023 performance – we assume the per-customer load impacts on reporting hour (HE18 for summer) as the maximum impact during the RA window. The impact degradation was updated to 64% (DA summer) overall RA window.

**SDG&E’s forecast assumptions** are as follows:

* **Delivery Performance** – we calculated program-level delivery performance based on PY2020 through PY2023 performance to produce modest estimates, given the inconsistent delivery performance over the last three years, 33% (Non-Residential DA) and 56% (Non-Residential DO).
* **Enrollment Growth** – we updated the enrollment forecast based on PY2023 nominations and assumed a 3% growth per year from 2024-2027 due to the CBP program improvements proposed by SDG&E and no additional growth from 2027-2034.
* **Impact Degradation Rate** – we updated impact degradation rate based on PY2023, as moving forward the program is expected to resemble what was observed in this year; the second year after it had been introduced.

Table ES - 5 summarizes the 11-year average Resource Adequacy (RA) window load impact forecast by IOU and program for an August peak day scenario, and Table ES - 6 summarizes the corresponding 11-year enrollment forecast.

Table ES - 5 Statewide CBP: 2024-2034 Load Impact Forecast, August Peak Day

| IOU | Program | Aggregate Load Impacts (MW) | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| 2024 | 2025 | 2026 | 2027 | 2028-2034 (Each Year) |
| PGE | Residential DA | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Non-residential DA | 39.9 | 39.9 | 39.9 | 39.9 | 39.9 |
| SCE | Non-residential DA | XXX | XXX | XXX | XXX | XXX |
| Non-residential Elect DA | XXX | XXX | XXX | XXX | XXX |
| SDG&E | Non-residential DA | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 |
| Non-residential DO | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 |

Table ES - 6 Statewide CBP: 2024-2034 Enrollment Forecast, August Peak Day

| IOU | Program | Number of Service Accounts | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| 2024 | 2025 | 2026 | 2027 | 2028-2034 (Each Year) |
| PGE | Residential DA | 3,158 | 3,158 | 3,158 | 3,158 | 3,158 |
| Non-residential DA | 1,130 | 1,130 | 1,130 | 1,130 | 1,130 |
| SCE | Non-residential DA | 42 | 0 | 0 | 0 | 0 |
| Non-residential Elect DA | 0 | 84 | 84 | 84 | 84 |
| SDG&E | Non-residential DA | 107 | 110 | 114 | 117 | 117 |
| Non-residential DO | 58 | 59 | 61 | 63 | 63 |

Table ES - 7 summarizes the average RA window load impact estimates for an August peak day in 2024 by IOU and program for each weather scenario.

Table ES - 7 Statewide CBP: RA Window Ex-Ante Impacts, August Peak Day, 2024

| IOU | Program | No. of Accounts | Per Customer  (kW) | Aggregate Impact (MW) | Percent Impact (%) | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Utility Peak | | CAISO Peak | |
| 1-in-2 | 1-in-10 | 1-in-2 | 1-in-10 |
| PGE | Residential DA | 3,158 | 0.2 | 0.7 | 18.0% | 16.2% | 18.3% | 17.2% |
| Non-residential DA | 1,130 | 35.3 | 39.9 | 19.4% | 19.3% | 19.3% | 19.3% |
| SCE | Non-residential DA | 42 | XXX | XXX | XXX | XXX | XXX | XXX |
| Non-residential Elect DA | 0 | XXX | XXX | XXX | XXX | XXX | XXX |
| SDG&E | Non-residential DA | 107 | 7.7 | 0.8 | 9.5% | 9.4% | 9.6% | 9.4% |
| Non-residential DO | 58 | 29.8 | 1.7 | 21.0% | 20.7% | 21.1% | 20.8% |

Because Non-residential CBP impacts are inherently nomination-driven, not weather-driven, we assumed constant non-residential per-customer load impacts across the weather scenarios. This assumption results in varying percent impacts across the months and weather scenarios. For Residential CBP impacts, we do not assume constant load impacts across months and weather scenarios. Instead, we assume constant percent impacts, accounting for the available load during each hour of the RA window. However, the differences between weather scenarios are minimal and cannot be distinguished at the per-customer or aggregate level.

Key Findings

PG&E Key Findings. The PY2023 load impact analysis has the following key findings for PG&E’s CBP:

Non-residential Day-Ahead

* Non-residential Day-Ahead delivered 86% of dispatched capacity for the average event. Although the delivery performance dropped slightly compared to PY2022, the program successfully drove substantial curtailment of over 20 MW during events and is collectively the largest CBP resource in the state.
* The program saw a reduction in the number of participants compared to PY2022, but an increase in average customer size.
* The hour from 6:00 PM 7:00 PM was the most dispatched event hour in PY2023 with an average of 23.8 MW load impacts and 430 participants.
* PG&E dispatched Sub-LAP-level events only in 2023.
* Based on the aggregator outlook, PG&E estimates approximately 65 MW capacity nominations in 2024, which aligns with last year’s forecast. This marks an increase compared to the forecast of 55 MW nominations in PY2021.

Residential Day-Ahead

* Residential Day-Ahead enrollment picked up again after the break in PY2022. Given the nature of PG&E’s service territory, a substantial portion of the residential CBP participants are customers on Net Energy Metering or electric vehicle rates.
* Selecting the reporting hour for Residential Day-Ahead posed a challenge, as the hour with the most dispatches did not align with the hours of highest impacts. AEG ultimately selected the hour from 7:00 PM-8:00 PM as the reporting hour, based on finding a balance between high dispatch and high impact. Furthermore, although the hour from 6:00 PM-7:00 PM stands as the most dispatched hour, during the October 19th event, customers appeared to fail to respond within the actual, single-hour event window, resulting in an unexpected increase in usage during that hour. The hour from 8:00 PM-9:00 PM showed the highest impact, however, it was only called on three out of the five event days.
* In PY2023, only one aggregator participated in Residential Day-Ahead. Thus, all CBP Residential Day-Ahead impacts are confidential.

SCE Key Findings. The PY2023 load impact analysis has the following key findings for SCE’s CBP:

* There was a notable decline in Non-residential CBP participation across both Day-Ahead and Day-Of programs, particularly during the summer season.
* Non-Residential Day-Ahead only included one customer who delivered XXX, XXX impacts ( XXX) during the average PY2023 summer event (a XXX delivery performance). This customer delivered XXX of their dispatched capacity during the average July event, but their underperformance during the August event (XXX of dispatched capacity) led to an overall negative impact for the PY2023 summer season. Upon examining the statistical significance, it was concluded that this impact was not significant, suggesting it is indifferent from zero.
* The estimated impacts for the Non-residential Day-Of program depended heavily on the performance of one school customer that had substantially larger load than the other customers in the program.
* During the summer season, the Non-residential Day-Of program experienced a decline in enrollment with 42 customers enrolled in the average month. However, the delivery performance remained at XXX, which is higher than 2020 and 2021.
  + The hour from 5:00 PM–6:00 PM was the most dispatched event hour in summer PY2023, and customers delivered the highest impacts during this hour of the average event day.
* The Non-Residential Day-Of program’s non-summer season remained a small collective resource but improved overall delivery performance from previous years. Non-Residential Day-Ahead did not have active non-summer participation.
* The hour from 7:00 PM–8:00 PM is the most dispatched event hour with the highest impact on the average event day for the non-summer season.[[16]](#footnote-17)
* SCE updated its ex-ante enrollment forecast to be consistent with the submitted DR Application A22-05-004, which includes the following assumptions:
* Updated according to 2023 Day-Of nominations,
* 2024 through 2033: zero enrollment in non-summer months and the Day-Of program
* 2024: assume 100% of Day-Of participants will move to the Day-Ahead program, and
* 2025: closing out the original CBP program; assume increase in enrollment due to the new CBP Elect DA program with 3 price triggers; $200, $400, and $600.
* 2023 impacts are confidential[[17]](#footnote-18).

SDG&E Key Findings. The PY2023 load impact analysis has the following key findings for SDG&E’s CBP:

* SDG&E Elect products entered their second year in PY2023. These include the Elect Day-Ahead 1-9 Hour and Elect Day-Of 1-9 Hour options, each with three price trigger options ($200/MWh, $400/MWh, and $600/MWh).
* SDG&E still offers its previously existing products as Prescribed options, with the following price triggers: $90/MWh (Prescribed Day-Ahead 11-7 Hour and 1-9 Hour), $115/MWh (Prescribed Day-Of 11-7 Hour), and $125/MWh (Prescribed Day-Of 1-9 Hour).
* The Elect Day-Of ($600) product only included five customers and average nominations of 0.1 MW across summer months. However, these customers were not dispatched as no events were called for this product.
* The Non-Residential Day-Ahead customers delivered 42% of dispatched capacity during the average PY2023 event. The improvement in delivery performance over the average PY2022 season (XXX in 2022 from three customers) can be largely attributed to customers’ performance in July, when customers delivered an average of 91% of the dispatched capacity, though performance in August (22% delivered of the 3.0 MW dispatched) still surpassed the average delivery seen in the 2022 summer.
* Non-residential Day-Of participants delivered 1.7 MW in PY2023, a 95% delivery performance. This marks a substantial improvement in the delivery performance of this program from PY2022 (65% delivery performance), especially considering that nearly all nominations were dispatched in each month. Customers performed similarly in both July and August with delivery performances of 101% and 91%, respectively.
* The hour from 7:00 PM–8:00 PM was the most dispatched event hour in PY2023. Across events, an average of 3.8 MW and 135 participants were dispatched during this hour.
* SDG&E dispatched events on five days in PY2023. For comparison, under the Prescribed product option, SDG&E historically dispatched around 20-30 events per program year under the $90-$125/MWh price triggers. In PY2023, more aggregators opted for the $400/MWh and $600/MWh price triggers, reducing the resources that qualify for dispatches.
* SDG&E updated the enrollment forecast based on the PY2023 nominations, increasing the growth rate to 3% between the 2024 and 2027 forecast years to account for the CBP program improvements proposed by SDG&E. SDG&E assumed the programs would not see any growth after 2027.

Recommendations

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs.

* Reevaluate the approach to reporting delivery performance. We have two considerations for future reports:
  + Consider including irradiance data. Based on the observed strong interest from customers with net metering, especially residential customers, we highly recommend incorporating irradiance data into the analysis. While it’s understood that energy production from solar panels is affected by multiple factors beyond just temperature, integrating irradiance data will significantly improve the accuracy of our predictions.
  + Identify customers with battery storage. The customers with battery storage have the capability to utilize charged batteries during the CBP events, presenting a challenge in accurately estimating load reduction from meter data. By pinpointing these specific customers and understanding their behavior and patterns during the events will help us to refine our predictions.
  + Re-**evaluate the approach of estimating Ex-Ante per-customer impact.** Considering that the ex-ante per-customer impact is derived from the Ex-Post but assumes a system-wide event is called. In reality, events are typically called at the Sub-LAP level (PG&E and SCE). Thus, the per-customer impact from the ex-post reporting hour may underestimate the actual impact. Therefore, reassessing the ex-ante impact based on the current Ex-Post is essential to ensure a more accurate estimation of the impact on individual customers.

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Introduction

This report documents the Program Year 2023 (PY2023) statewide load impact evaluation of the Capacity Bidding Program (CBP), an aggregator-based demand response (DR) program operated by the three California investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

## Research Objectives

This study's key objectives are estimating ex-post and ex-ante impacts for each IOU’s CBP program. More specifically:

* Estimate Ex-post load impacts for the average customer and all customers in aggregate for each hour of each event day and the average event day. We present all estimates at the program level and separately for each product offering. For the Non-residential programs, we provide estimates for the following customer segments: aggregator, size group, industry type, local capacity area (LCA), sub-load aggregation point (Sub-LAP), and enrollment in AutoDR or other DR programs. For Residential[[18]](#footnote-19) programs, we provide estimates for the following customer segments: aggregator, LCA, Sub-LAP, and CARE status.
* Estimate Ex-ante load impacts for the average customer and all customers in aggregate for the resource adequacy (RA) window[[19]](#footnote-20) (4:00 PM to 9:00 PM). We provide estimates for each year over an 11-year[[20]](#footnote-21) time horizon based on each IOU’s and CAISO’s 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day. We provide estimates for both program-specific and portfolio-adjusted scenarios. As applicable, we also provide estimates for the following customer segments: size group, LCA, Sub-LAP, and busbar.

## Program Description

The Capacity Bidding Program (CBP) is a statewide price-responsive program launched in 2007. It is available in the service territories of the three California IOUs: PG&E, SCE, and SDG&E, although each IOU’s program differs slightly in program features and operations.

Aggregators. In CBP, aggregators contract with eligible residential[[21]](#footnote-22) and non-residential utility customers to act on their behalf in all aspects of the demand response (DR) program. Aggregators receive dispatch notifications (day-ahead or day-of), incentive payments, and penalties from the IOUs. Each aggregator forms a resource, a portfolio of customers, to provide load reduction during events. Each resource participates collectively, wherein load reduction is measured on an aggregate basis. The aggregators enroll customers under the terms of their contracts to provide the load reduction capacity and receive corresponding incentives. In other words, IOUs are not directly involved in the contracts between aggregators and customers. CBP may have customers/participants classified as self-aggregated.

Eligibility. Aggregators must have Internet access. Enrolled customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[[22]](#footnote-23) Customers enrolled in CBP may dually participate in an energy-only DR program (i.e., cannot have a capacity payment component) that does not have the same notification type (Day-Ahead or Day-Of).

Incentives. CBP provides monthly capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, resource performance during an event, and the event notice option. Delivered capacity determines performance. If an aggregator’s delivered capacity is less than the tariff threshold (50% for SCE and SDG&E and 60% for PG&E), the aggregator is assessed a penalty. CBP aggregators receive the full monthly capacity payment for months without dispatched events based on their nominations with no energy payments.[[23]](#footnote-24) Additional energy payments ($/kWh) are made to the aggregator[[24]](#footnote-25) based on the measured kWh reductions (relative to the program baseline) achieved when an event is dispatched.[[25]](#footnote-26)

Product Offerings. We provide descriptions of each IOU’s PY2023 product offerings in Section 4 (PG&E), Section 5 (SCE), and Section 6 (SDG&E) of this report.

## Report Terminology

AEG made significant efforts to improve the overall clarity of the evaluation report over the years. These efforts include updating the terminology used in the report and carefully reviewing it for consistency. Table 1‑1 presents the key terms and corresponding definitions as used in this report.

Table 1‑1 Report Terminology

| Term | Definition |
| --- | --- |
| Program | **A combination of IOU, Customer Class, and Notification Type.** For example, SDG&E has two programs: (1) SDG&E Non-residential Day Ahead and (2) SDG&E Non-residential Day Of. |
| Product | **A product offering within each program.** For example, the PG&E Day Ahead program has three products: (1) Elect, (2) Elect+, and (3) Prescribed. |
| Customer class | Defined as **Residential or Non-residential**. |
| Nomination | **A monthly nominated resource by program, product, aggregator, and Sub-LAP.** Each nominated resource has a corresponding capacity nomination (MW) and enrolled customers. |
| Dispatched | **An entity called to a market-triggered event.** For example, a dispatched resource, dispatched customers, dispatched capacity, etc. Not all nominated entities are dispatched. |
| Average Event Day | For each product, calculated as **the average of all events dispatched** regardless of event hours and number of Sub-LAPS. The program-level average event day is the sum of all product-level average event days. Load impacts are reported for each program and product's most dispatched event hour. |
| Reporting Hour | **The hour reported for the ex-post average event day.** This hour is the most dispatched or highest impact event hour for each program and product. |
| DeliverY Performance | A percentage metric equal to the ex-post aggregate load impacts **divided by the overall dispatched capacity**. |
| Adjusted Delivery Performance | A percentage metric equal to the ex-post aggregate load impacts **divided by the reporting hour dispatched capacity**. We calculate an adjusted metric to measure performance because our definition of the average event day includes events that did not dispatch capacity during the reporting hour. |
| Impact Degradation Rate | **An assumption developed for a simulated 5-hour RA window** based on historical events. This assumption represents how customers, on average, can maintain impacts throughout events called for longer durations. |

## Other Report References

For reference, Table 1‑2 presents the eight industry-type definitions and corresponding North American Industry Classification System (NAICS) codes, and Table 1‑3 presents the three customer-size definitions.

Table 1‑2 Non-Residential Industry Type Definitions

|  |  |
| --- | --- |
| Industry Type | NAICS Codes |
| 1. Agriculture, Mining & Construction | 11, 21, 23 |
| 2. Manufacturing | 31-33 |
| 3. Wholesale, Transport, Other Utilities | 22, 42, 48-49 |
| 4. Retail Stores | 44-45 |
| 5. Offices, Hotels, Finance, Services | 51-56, 62, 72 |
| 6. Schools | 61 |
| 7. Institutional/Government | 71, 81, 92 |
| 8. Other/Unknown | N/A |

Table 1‑3 Non-Residential Customer Size Definitions

|  |  |
| --- | --- |
| Customer Size Group | Maximum Demand |
| Large | 200 kW and above |
| Medium | 20 kW to 199.99 kW |
| Small | 19.99 kW and below |

## Report Organization

This report is organized into the following sections:

* Section 2 describes the methods used to estimate the ex-post and ex-ante load impacts.
* Section 3 presents state-level summaries for PY2023:
* Program participation,
* Ex-post load impact estimates,
* Ex-ante load impact estimates, and
* Key findings and recommendations.
* Sections 4 through 6 present IOU-level summaries for PY2023:
* Product descriptions and expected program changes,
* Program participation,
* Ex-post load impact estimates,
* Ex-ante load impact estimates, and
* Key findings.

# 

Study Methods

This section presents the methods used to estimate the ex-post and ex-ante load impacts for statewide CBP.

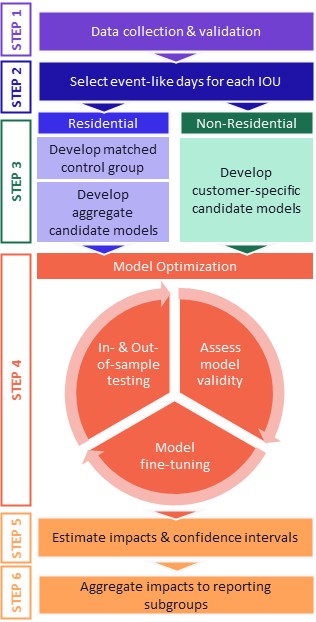
## Ex-Post Load Impact Analysis

We explicitly designed the PY2023 ex-post LI analysis to meet each of the objectives listed below, all objectives to be provided at the program level and separately for each product offering.

* To develop hourly load impact estimates for each event in PY2023 and estimate the average event day by season, as applicable,
* To provide estimates by various segments:
* Non-residential: aggregator, size group, industry type, local capacity area (LCA), sub-load aggregation point (Sub-LAP), and enrollment in AutoDR or other DR programs; and
* Residential: aggregator, LCA, Sub-LAP, and CARE status, and
* To estimate the distribution of load impacts by customer segment for the average event.

We used the same methodology across all programs to ensure consistency of results. Figure 2‑1 presents an overview of our ex-post analysis approach. Each program is modeled independently, modifying assumptions to account for unique program features (program design and implementation) specified within each IOU’s CBP tariff. With the addition of PG&E’s Residential participation in PY2020, it is important to highlight the key differences in the approach used for the two customer classes.

Figure 2‑1 Ex-Post Analysis Approach



The Residential[[26]](#footnote-27) program analysis used a matched control group and aggregate hourly regression models. This approach is the best practice for participant populations with less variable loads, which can leverage the higher statistical power with more customers included in each model. A matched control group also more effectively estimates the counterfactual load without a randomized control trial.

The Non-Residential program analyses continued to use a within-subject design using customer-specific hourly regression models. It remains the most flexible, consistent, and appropriate solution for CBP’s evaluation goals and population distributions. This approach has the following features:

* The individual customer impacts can be added together to estimate load impacts at any level or customer segmentation.
* Regression models can be easily used to control for variation in load due to weather conditions, geography, and time-related variables (day of the week, month, hour, etc.).
* Estimating models for each customer can also control for unobservable customer-specific effects that are more difficult to account for in aggregate regression models.
* Commercial and industrial customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific regressions allow us to capture differences between customers; therefore, they can better model changes in energy usage than an aggregated model.
* The data conforms to a repeated-measures design wherein events are dispatched on isolated days over the program year, and customers face similar TOU rates on all other days. A repeated-measures design means that all participants are subjected to the treatment simultaneously and repeatedly throughout the study. In this case, the control is defined as non-event days, i.e., an absence of treatment.

Each step in the ex-post analysis is detailed in the next subsections.

### Step 1: Data Collection and Validation

Data Collection. We collected the data items (listed below) from each IOU, as available, and constructed a database that houses the data collected to perform the analysis across all three IOUs. The database served as the foundation for the data validation process.

* Aggregator monthly bid and nomination data,
* Customer characteristics and participation information,
* Customer characteristics for residential[[27]](#footnote-28) non-participant pool,
* Local capacity area and local busbar identifier,
* CBP dispatched event data, including product, dates, time, and duration of each event, and trigger information,
* Other DR program event data (for dually enrolled participants),
* Post-event estimated load impacts provided to CAISO,
* Hourly interval usage data, and
* Actual hourly weather data by weather station

Data Validation. AEG’s validation process included screening the interval data for zero usage intervals, missing intervals, potentially erroneous peaks and valleys, and other erroneous intervals while being mindful of the risks posed by over-omitting data. We used this automated approach to flag possible erroneous intervals. We carefully considered how event days differ from non-event days and how each customer class may require a distinct set of screening algorithms. For example, non-residential participants can potentially have event days that contain zero intervals and outlier reads, depending on their curtailment approach. However, for residential participants, zero intervals and outlier reads more likely to indicate missing data or power outages. *With the addition of Residential participants in PY2020, AEG adjusted the omission rules for the residential participants since zero intervals in residential is more likely to indicate missing data or power outages.*

We documented the counts of intervals or customers removed from the analysis for each IOU, customer class, industry type, and customer size (as appropriate) during each step in the data validation process to determine the reasonableness of omissions from a top-down perspective. In addition, we spot-checked a small sample of dropped intervals from each segment to confirm the appropriateness of omissions in those cases and incorporated any updates to the data validation process, as needed, to ensure we used the best available data for the analyses.

### Step 2: Event-like Days Selection

The selection of comparable non-event days (i.e., event-like days) is essential to several evaluation activities. Event-like days were used in the following:

* Matched control group development. These event-like days served as the basis for matching participants to non-participants by ensuring that matched customers consume energy similarly on days comparable to event days.
* Out-of-sample testing. We used event-like days to test the predictive abilities of each model as part of our model optimization process, employed regardless of the analysis design.

The event-like days include 5 to 15 days (by IOU and customer class) comparable to dispatched CBP events in weather, day of the week, and month of the year. We selected the days that collectively minimize the Euclidean distance (ED)[[28]](#footnote-29) across multiple weather-based criteria. We describe the ED matching method in more detail in a subsequent subsection on Matched Control Group Development under Step 3. This approach identified sets of days as similar as possible to dispatched event days. We discuss selected event-like days in the [Model Validity Appendix](#ModelValidity).

### Step 3. Analysis Designs by Customer Class

This step discusses the analysis designs for both non-residential and residential customer classes.

#### Non-Residential Analysis Design

AEG continued using a within-subjects, customer-specific modeling approach for all non-residential participants across all three IOUs. Given the evaluation objectives and the potential differences across service territories, customer-specific models offer the most flexible, consistent, and appropriate solution for several reasons:

* Commercial and industrial customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific models allow us to capture differences between customers; therefore, they can better model changes in energy usage than an aggregated model. The models can easily control for variation in load due to weather conditions, geography, and time-related variables (day of the week, month, hour, etc.). They also control for unobservable customer-specific effects that are more difficult to account for in aggregate regression models.
* The data conforms to a repeated-measures design because the events are called only on isolated days over the program year, and the participants face similar TOU rates on all other days. A repeated-measures design means all participants are subjected to the treatment simultaneously and repeatedly throughout the study. In this case, the control is defined as an absence of the treatment or the non-event days.
* The models estimate individual customer impacts that can be summed together to estimate impacts for any reporting subgroup, including but not limited to IOU, program, product, aggregator, LCA, SubLAP, industry type, or customer type.

Develop Candidate Regression Models. It is not practical to develop models individually for thousands of participants; therefore, AEG developed a set of candidate models that will go through our model optimization process to select the best model for each participant.

In general, we think of regression models consisting of building blocks, which are, in turn, made up of one or more explanatory variables. The blocks can be generally categorized into either “baseline” variables or “impact” variables. They could consist of a single variable (e.g., cooling degree hours (CDH)) or a group of variables (e.g., days of the week). The baseline portion of the model explains variation in usage unrelated to DR events, while the impact portion explains the variation in usage related to a DR event.[[29]](#footnote-30) Table 2‑1 presents the explanatory variables used to create candidate models for the CBP participants.

Table 2‑1 Explanatory Variables Included in Candidate Regression Models

|  |  |  |
| --- | --- | --- |
| Variable Name | Variable Description | |
|  | ***Baseline Variables*** | |
| Weatheri,d | Weather-related variables, including average daily temperature, cooling degree hour (CDH) terms with base value of 70, and lagged versions of various weather-related variables | |
| Monthi,d | A series of indicator variables for each month | |
| DayOfWeeki,d | A series of indicator variables for each day of the week | |
| OtherEvti,d | Equals one on event days of other demand response programs in which the customer is enrolled | |
| AvgLoadi,d | The average of each day’s load in the specified window[[30]](#footnote-31) | |
|  | ***Impact Variables*** |
| Pi,d | An indicator variable for aggregator program event days | |
| P \* Monthi,d | An indicator variable for aggregator program event days interacted with the month | |
| P\*EventWindowi,d | An indicator variable for aggregator program event days interacted with an indicator for the window the event is called | |

With the different variables presented above, we developed sets of candidate models that represent a wide variety of customers and their impacts. Each IOU has customized sets of candidate models, but in general, the candidate models fit into two basic categories:

* Weather-sensitive models include weather effects and calendar effects. These models are less likely to require a load adjustment since much of the day-to-day variation in load is captured by weather terms.
* Non-weather-sensitive models include load adjustment and calendar effects.

#### Residential Analysis Design[[31]](#footnote-32)

AEG continued using a matched control group and aggregate modeling approach for all residential participants across all three IOUs, as applicable. This analysis design is appropriate for several reasons:

* Residential participants do not typically have highly variable loads. This approach allows for the effective use of aggregate models, which have higher statistical power with more customers included in the model.
* Using a matched control group enables us to estimate event-day impacts against counterfactual load developed from non-participant consumption on the actual event day.
* The models will estimate the load impacts for each combination of customer segments required in the CPUC LIP. The results for each combination can be easily aggregated to represent impacts for each customer segment required by the CPUC LIP.

Matched Control Group Development. To create the matched control group, we used a Stratified Euclidean Distance Matching (SEDM) approach that we have used successfully in previous statewide CBP evaluations. The SEDM approach includes the following steps.

Step 1: Define the populations (participant and non-participant) and the periods (treatment and pre-treatment). At this stage, we assessed the eligibility of participant and non-participant customers for matching based on the availability of event-like day usage data, dual participation in other DR programs, demographic information, etc. Next, we assigned the participant and eligible control group customers to strata based on categorized characteristics and will match participants to eligible control customers within their assigned strata. This stratified approach ensures that we match customers with similar characteristics, enabling us to better control some of the unobservable attributes that affect how customers use energy. Note that each stratum should have an appropriate ratio of eligible control customers to participants to ensure accurate matches. A large ratio of control customers to participants is recommended to yield better matches.

Step 2: Perform the one-to-one match based on the hourly demand data of event-like days.As discussed earlier, we use the event-like days to establish that the control and treatment customers would likely have consumed energy similarly on CBP event days in the absence of the program. We used an ED metric to determine the similarity in load shapes on event-like days between each treatment customer and eligible control customer, assessing the similarity in usage patterns using the following three demand variables: morning, midday, and late evening.

Within strata, we matched each treatment customer to every eligible control customer and calculated the ED according to the equation below.

We finalized the one-to-one match of control to treatment customers by selecting the control customer who minimizes the ED. Once the matching process was complete, we thoroughly reviewed the match using the appropriate t-tests and visual inspection of the event-like day load shapes.

Develop Candidate Aggregate Models. AEG developed a set of candidate models that will go through our model optimization process, similar to the process described for non-residential participants. These candidate models were developed for a matched control design using aggregate models. In other words, we included indicator variables for participants in the baseline block and potentially interaction variables with this participant indicator variable.

The PG&E Residential program required only a handful of model subgroups, needing around five candidate models. The model optimization process served as a starting point for our model selection, leveraging automated algorithms that we developed for previous C&I DR evaluations, and played a key role in assessing model validity to justify our confidence in our impact estimates.

### Step 4: Model Optimization and Selection

Figure 2‑2 Optimization Process

Our optimization process show in Figure 2‑2 incorporates the validation of the hourly regression models. The hourly regression models are designed to:

* Accurately predict the actual participant load on event days, and
* Accurately predict the reference load or participant usage on event days in the absence of an event.

After fitting each candidate model to a participant (non-residential) or segment (residential), we selected each participant/segment’s best model through a three-part optimization process, consisting of the following steps: (1) In-sample and out-of-sample testing; (2) assessing model validity; and (3) model fine-tuning. Each step of the three-part cycle is described below.

In-Sample and Out-of-Sample Testing. We used in-sample tests to assess how well each model performs on the CBP event days, helping us understand how well the model predicts the actual load. We used out-of-sample tests to assess how well each candidate model predicts customers’ loads on event-like days, indicating how well each model might predict the reference load.

* To perform the in-sample test, we fitted each candidate model to the entire data set. The fitted models were used to predict the usage on CBP event days. The models should be able to accurately predict customers’ actual consumption on these days, having controlled for the impacts of the event hours. We assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE)[[32]](#footnote-33) and mean percent error (MPE)[[33]](#footnote-34), respectively. We refer to these metrics as the in-sample MAPE and MPE.
* To perform the out-of-sample test, we fitted each candidate model to the data set, excluding event-like days. The fitted models were used to predict the usage on event-like days. We similarly assessed the accuracy and bias of the event-like day predictions by calculating the MAPE and MPE, which we refer to as the out-of-sample MAPE and MPE.

These two tests resulted in several in-sample and out-of-sample metrics. To determine the best model for each segment in terms of its ability to predict both the reference load and the actual load for each participant/segment with accuracy and limited bias, we combined the two tests into a single metric as follows:

The best model for each segment will minimize this overall metric.

Assessing Model Validity. AEG confirmed that all best models for each participant/segment collectively deliver acceptable levels of accuracy and bias by calculating the weighted average MAPE and MPE at the program level. Valid models will result in low or very close to zero MAPE and MPE. We present the metrics of the final models in the [Model Validity Appendix](#ModelValidity).

Model Fine-Tuning. We also routinely used visual inspection of the results as a simple but highly effective tool. During the inspection, we looked for specific aspects of the segment-level predicted and reference load shapes to determine how well the models performed. We used observations from these inspections to make any necessary edits to the model specifications obtained from the optimization process. For example:

* We checked to ensure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely little effect from the event. Large differences can indicate a problem with the reference load, either over or underestimating usage in the absence of the program.
* We closely examined the reference load for odd increases or decreases in the load that could indicate an effect not properly captured in the model.
* We also looked for bias both visually and mathematically. Identifying bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

### Step 5. Estimate Load Impacts and Confidence Intervals

The following example illustrates the process of estimating the impacts from the final model for a single modeling segment (i.e., one non-residential participant or one residential program). The process is the same for both residential and non-residential models, with the following differences:

* The non-residential load impacts were estimated individually for each participant from the customer-specific models.
* The residential load impacts were estimated for each combination of customer segments required in the CPUC LIP.

In this simple example below, ,, and , make up the baseline blocks of the model, and explain variations in unrelated to demand response events. The remaining variables,, and the interaction term are the impact blocks and explain the variation in related to a CBP event.[[34]](#footnote-35) An hourly model like the equation below can be equivalently estimated as one model with hourly dummy variables or as 24 separate hourly models.

Where:

is the consumption of customer in hour .

is the intercept.

is the coefficient associated with each explanatory variable.

is a vector of baseline explanatory variables (e.g., average load, baseline interactions, etc.).

is a vector of calendar variables (i.e., month, year, and day of the week).

represents the cooling degree hours for hour .

is a dummy variable indicating that hour was on a CBP event day.

is an interaction between the event indicator and baseline explanatory variables.

is the error for customer in time .

This type of time-series data is likely to have both autocorrelation and heteroskedasticity. To address autocorrelation, we used two techniques: (1) estimated 24 separate models for each hour to remove autocorrelation from hour to hour, and (2) incorporated seasonal indicators to minimize autocorrelation. To address heteroskedasticity, we used the Huber-White robust error correction.

Using the model above as an example, we estimated the load impacts as follows:

* First, we obtained the actual and predicted load for each segment on each hour and day based on the specification defined in the model equation.
* Next, we used the estimated coefficients and the baseline portion of the model to predict what this segment would have used on each day and hour if there had been no events. We call this prediction the reference load.
* We calculated the difference between the reference load (the estimate based on the baseline blocks) and the predicted load (the estimate based on the baseline + impact blocks) on each event day. This difference represents our estimated load impact for each segment.

To avoid confusion between the observed load and the predicted load, we re-estimated the reference load as the sum of the observed load and the estimated load impact.

Because the impacts are statistical estimates, establishing a range or confidence interval around the estimates is essential, resulting in the uncertainty-adjusted load impacts required by the CPUC LIP. We used a statistical package to output the standard errors of the point estimates. The standard errors can then be used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each segment.

### Step 6. Aggregate Load Impacts to Reporting Subgroups

For non-residential participants, we estimated the load impacts individually for each participant, which was easily aggregated to represent impacts for each of the required customer segments for each of the three IOUs. In some cases, we applied average per-customer impacts as a proxy for the impacts realized by one or more customers on a given event day if part of the data was invalid and, therefore, omitted during the data validation process. In these cases, we determined the aggregate impact for a particular subgroup based on the per-customer estimate of the customers with valid data within that subgroup and the total dispatched accounts associated with that grouping for the given event. This process allowed us to avoid under-reporting the impacts due to missing or invalid data.

For residential[[35]](#footnote-36) participants, we estimated the load impacts for each combination of customer segments required in the CPUC LIP. This resulted in a per-customer estimate for each combination of customer segments, which was easily aggregated to each customer segment by multiplying by the number of participants within each combination.

To estimate statistical certainty for each customer segment, we can assume that the estimates are independent across participants, and consequently, estimates are independent across modeling segments. Thus, the variance of the sum is the sum of the variances. We can follow this approach to obtain the confidence intervals for each customer segment and each IOU service territory.

#### Calculating Impacts for an Average Event Day

We defined the average event day consistently across the three IOUs. At the program and product level, we calculate the average event day as the average of all events dispatched regardless of customer count or Sub-LAP count for each program and product. If multiple event windows were dispatched on the same day, the multiple event windows are combined to give each event day equal weight. The average event day is calculated using aggregate-level results. The corresponding average customer count is calculated as a simple average of the customer counts of each dispatched event day.

For program-level results (e.g., PG&E Non-residential DA is a combination of Elect DA and Prescribed DA), we summed the average event day aggregate-level results and dispatched counts. We calculate the corresponding per-participant impacts from the summed values.

As in previous years, different sets of service accounts were dispatched for each event; therefore, the average is made up of different customer groups across different days. These differences in customer groups can prove problematic when attempting to sum average impacts and customer counts across the multiple combinations of segments presented in this analysis. The approach we used to determine the average involved taking the average of each segment's aggregate impact. Another option would be to create the averages first at the lowest level of disaggregation and then sum them to the desired aggregation level. Though both approaches are equally valid, they often differ slightly. Therefore, when viewing the average event day impact results in Chapter 4, one may notice that the sum of the subgroup level impacts does not always equal the program level impacts.

#### Reporting Metrics for Program Performance

We developed the following reporting metrics to evaluate each CBP program’s overall season performance. The reporting metrics include the following:

* Nomination – represents the monthly program enrollment and available capacity for dispatch. The overall program nomination is the average monthly nomination by season.
* **Dispatched** – represents the resources called to a market-triggered event. We show this metric as follows:
* Overall dispatched capacity – the average of the overall event day dispatched capacity regardless of event hours; reported as a monthly average or overall season average,
* Reporting hour dispatched capacity **–** the average of the event day dispatched capacity for the reporting hour[[36]](#footnote-37); reported as a monthly average or overall season average,
* Ex-post average event day – represents the average ex-post load impacts of all events dispatched regardless of event hours; reported as a monthly average or overall season average,
* Delivery performance – a percentage metric of the ex-post average event day load impacts relative to the dispatched capacity. We express the delivery performance as follows:
* Overall delivery performance – measured relative to overall dispatched capacity:
* Adjusted delivery performance – measured relative to the reporting hour dispatched capacity. We calculate an adjusted metric to measure performance because ur definition of the average event day includes events that did not dispatch capacity during the reporting hour.

#### ***Estimating*** Incremental Impacts for Technology-Enabled Participants

AEG did not perform this analysis this year. In previous program years, only SDG&E’s AutoDR and TA/TI participants have shown statistically significant incremental impacts. In PY2023, SDG&E did not have CBP participants also enrolled in AutoDR or TA/TI.

## Ex-Ante Load Impact Analysis

We designed the PY2023 ex-ante LI analysis to meet the objectives listed below. All objectives are provided at the program level.

* To develop hourly load impact estimates for the average customer and all customers in aggregate for the resource adequacy (RA) window (4 PM to 9 PM) [[37]](#footnote-38),
* To provide estimates for each year over an 11-year[[38]](#footnote-39) time horizon based on each IOU’s and CAISO’s 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day,
* To provide estimates for both program-specific and portfolio-adjusted scenarios, and
* To provide estimates by various segments: size group, LCA, Sub-LAP, and busbar.

We used the same methodology across all programs to ensure consistency of results. Figure 2‑3 presents an overview of our ex-ante analysis approach.

Figure 2‑3 Ex-Ante Analysis Approach

Diagram

Description automatically generated

### Step 1. Develop Forecast Assumptions

We collected the data items (listed below) from each IOU for the ex-ante LI analysis:

* IOU and CAISO 1-in-2 and 1-in-10 hourly weather scenarios for monthly peak day and typical event day, and
* Eleven-year enrollment forecast data for each program and reporting subgroup.

Through continued discussions with each IOU regarding each program’s proposed and approved program changes, we developed forecast assumptions specific to each IOU. We discuss program-specific assumptions in each IOU’s Ex-Ante Analysis subsection, but they generally fall under the following:

* Updated assumptions on the shape of the impacts across the 5-hour RA window based on historical events called for longer durations for each IOU and program,
* Ex-post analysis findings on delivered capacity,
* Program changes such as product offerings, event durations, dispatch windows, resource requirements, event triggers, event notification procedures, etc., and
* Aggregator feedback to IOU program managers on forecasted participant recruitment and deliveries.

Impact Degradation Across the RA Window. We developed assumptions to simulate the 5-hour RA window based on historical events for each IOU and program. The assumptions represent how, on average, customers can maintain impacts throughout events called for longer durations. To develop these assumptions, we used the following approach:

1. Calculated hourly impacts as a percent of the estimated reference load,
2. Calculated the average hourly percent impacts by product, program, and program year,
3. Compared the average hourly percent impacts and discussed the findings with each IOU to determine the appropriate set of assumptions for each product and program. We discuss each program/product-specific assumption in Section 5.
4. We express the shape as the percent of the maximum impact in each subsequent event hour. In Table 2‑2 below, we present an example of the impact degradation shape for SCE’s Non-residential DA and DO programs developed in PY2020.

Table 2‑2 Example: SCE Ex-Ante Impact Degradation Shape by Product

| Program | Season | Percent of Maximum Impact | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| HE17 | HE18 | HE19 | HE20 | HE21 |
| Non-res DA | Non-Summer | 86% | 100% | 72% | 44% | 16% |
| Summer | 100% | 79% | 61% | 58% | 48% |
| Non-res DO | Non-Summer | 100% | 90% | 34% | 75% | 19% |
| Summer | 100% | 71% | 57% | 41% | 50% |

Ex-Ante Adjustments. AEG will remain mindful that ex-ante forecast is evaluated under current circumstances and will work with each IOU to determine if additional adjustments should be applied to each program year’s ex-ante. For instance, when the COVID-19 global pandemic commenced in March 2020, AEG reviewed the necessity of further adjustments linked to the pandemic's economic impact. While no definitive findings were established to validate assumptions or changes reflecting COVID-19 conditions, the acknowledgement of this evaluation remains appropriate.

### Step 2. Use Ex-Post Regression Models

We used the ex-post hourly regression models to apply developed forecast assumptions and predict weather-adjusted impacts for each weather scenario. This step produced a set of impacts under each of the different weather scenarios required by the CPUC LIP, typical event day, and monthly peak for both IOU and CAISO 1-in-2 and 1-in-10 weather years. To do this, we carried out the following steps:

* Apply Assumptions and Weather-Adjust Impacts. We assembled an input dataset that includes the appropriate forecast assumptions and required weather scenarios for each non-residential participant with a customer-specific model and each combination of residential customer segments required in the CPUC LIP.
* Generate Per-Customer Ex-Ante Load Impacts. Using the final ex-post hourly regression models, we predicted two scenarios of an average customer load for each participant and subgroup: (1) Reference Load – assuming a non-event day; and (2) Predicted Load – assuming a CBP event day. We then calculated the ex-ante load impact for each participant and segment by subtracting the weather-adjusted predicted load from the weather-adjusted reference load. We applied the impact degradation shape to the ex-ante load impact to develop a load impact estimate for all hours of the RA window (HE18 – HE22 for March, April and May, HE17 – HE21 otherwise).[[39]](#footnote-40)
* Assess Uncertainty and Produce Confidence Intervals. Similar to the ex-post analysis, it is vital to establish a confidence interval around the estimates resulting in the uncertainty-adjusted load impacts required by the CPUC LIP. We used a statistical package to output the standard errors of the point estimates. The standard errors can then be used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each subgroup and participant.

### Step 3. Create 11-Year Annual Forecast

Non-residential participant ex-ante load impacts can be grouped together to produce per-customer average impacts for each combination of non-residential customer segments required in the CPUC LIP. Both residential and non-residential per-customer estimates were multiplied to program enrollment counts to create an annual forecast of load impacts over the next 11 years. We included a “back-cast,” which consists of weather-adjusted ex-post estimates of the current program year. Each IOU provided an 11-year enrollment forecast, while the “back-cast” used actual program year enrollment counts.

### Step 4. Aggregate Load Impacts to Reporting Subgroups

Once ex-ante load impact forecasts have been predicted for each combination of customer segments for each of the desired weather scenarios, it becomes a relatively simple exercise to aggregate the load impacts and generate per-customer average impacts for each of the CPUC LIP required customer segments.

To estimate statistical uncertainty for each customer segment, we can assume that the estimates are independent across participants, and consequently, estimates are independent across customer segments. Thus, the variance of the sum is the sum of the variances. We followed this approach to obtain the confidence intervals for each customer segments and each IOU service territory.

AEG recognizes that there is also be an error in the enrollment forecast. The uncertainty associated with the enrollment forecast was not provided to AEG and is not incorporated into the ex-ante load impact estimates.

Statewide Results & Key Findings

This section presents PY2023 CBP statewide ex-post load impact estimates, ex-ante load impact estimates, and key findings.

## Statewide Ex-Post Analysis

In 2023, PG&E offered only Day-Ahead programs. SCE and SDG&E offered both Day-Ahead and Day-Of programs. All three IOUs had Non-residential active programs,[[40]](#footnote-41) whereas only PG&E had active residential participation in PY2023.

At the program level, we observe the following:

* PG&E’s average delivery performance[[41]](#footnote-42) of 86% remains comparable to the previous year’s 89%, attributed to lower participation but a larger customer size.
* After skipping 2022, PG&E’s residential participation started again, with an average delivery performance of XXX. Although it is lower than 2021’s XXX, it remains comparable, considering that 2021 had all NEM customers and larger users.
* SCE experienced a notable decline in Non-residential CBP participation in both DA and DO programs. Non-residential DA only included one customer who delivered small, negative impacts during the average summer. Non-residential DO performance depended heavily on one school customer, who has a relatively larger load than the others, and the program had a stable delivery rate at XXX during the summer month, and XXX at the non-summer month which outperformed 2020 and 2021.
* In its second year of the new Elect products, SDG&E showed a significant improvement in both DA and DO programs. The DA program reached a 42% delivery performance, while the DO program achieved an impressive 95% delivery performance, both outperforming 2022 and even 2021.

presents the PY2023 average summer event day impacts by IOU and program at the aggregate and per-customer levels. We show the results for the reporting hour for each program, which is 6:00 PM–7:00 PM for PG&E's Non-Residential Day-Ahead; 5:00 PM–6:00 PM for SCE's Non-Residential Day-Ahead and Day-Of programs during the summer months, and 7:00 PM–8:00 PM for all other programs. Note that we calculate the average event day using all events regardless of dispatched count and event timing (see [Average Event Calculation](#AverageEvent)).

Table 3‑1 Statewide CBP Impacts Summary, Average Summer Event Day PY2023

| IOU | Program | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| DispatchCapacity | Load Impact | % Delivered | Ref.  Load | Load Impact | % Impact |
| PG&E | Residential DA | 132 | XXX | XXX | XXX | XXX | XXX | XXX |
| Non-residential DA | 430 | 23.8 | 20.5 | 86% | 219.4 | 47.7 | 22% |
| SCE | Non-residential DA | 1 | XXX | XXX | XXX | XXX | XXX | XXX |
| Non-residential DO | 42 | XXX | XXX | XXX | XXX | XXX | XXX |
| SDG&E | Non-residential DA | 84 | 2.0 | 0.8 | 42% | 97.7 | 10.0 | 10% |
| Non-residential DO | 51 | 1.8 | 1.7 | 95% | 188.3 | 33.6 | 18% |

Table 3‑2 summarizes each CBP program’s PY2023 overall season performance using the following reporting metrics: average nomination, average overall and reporting hour dispatch, the ex-post load impacts, and the overall and adjusted delivery performance. Each metric is described in more detail in Section 2, [Reporting Metrics for Program Performance](#ReportingMetrics).

Some key notes when reviewing Table 3‑2:

* We show the average dispatched counts and capacity, which is dependent on CAISO market awards. Low counts are not indicative of low participation but rather an indication of necessity.
* Delivered dispatched capacity is the correct measure of the program’s success (delivery performance or % delivered). 100% delivery performance means aggregators and customers curtailed the load obligations when asked to do so.
* The delivery performance metrics allow for an adjusted metric for dispatched capacity coincident with the reporting hour. Our definition of the average event day includes events that did not dispatch capacity during the reporting hour.

Table 3‑2 Statewide CBP Delivery Performance PY2023

| Program | | Nominations | | Overall Dispatched | | Reporting Hour Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered |
| PG&E | Res DA | 356 | XXX | 132 | XXX | 132 | XXX | XXX | XXX |
| Non-res DA | 672 | 33.9 | 430 | 23.8 | 430 | 23.8 | 20.5 | 86% |
| SCE | Non-res DA | 1 | XXX | 1 | XXX | 1 | XXX | XXX | XXX |
| Non-res DO | 42 | XXX | 42 | XXX | 42 | XXX | XXX | XXX |
| SDGE | Non-res DA | 90 | 2.9 | 84 | 2.0 | 84 | 2.0 | 0.8 | 42% |
| Non-res DO | 54 | 1.8 | 51 | 1.8 | 51 | 1.8 | 1.7 | 95% |

## Statewide Ex-Ante Analysis

Each program’s load impact forecast is based on IOU-specific assumptions that incorporate a combination of the following: aggregator/nomination outlook, delivery performance, ex-ante per-customer load impacts, enrollment growth, and an impact degradation rate across the RA window.

PG&E’s forecast assumptions are as follows:

* Residential Day-Ahead – PG&E assumed a constant 1 MW nomination through the 11-year forecast. We maintained the 61% delivery performance, which is the minimum threshold before aggregators are charged a penalty. We also assume a maximum 4-hour event duration based on historical participation in the 1- to 4-hour product option.
* Non-Residential Day-Ahead – PG&E forecasted capacity nominations to 65 MW for an August peak day. Based on PY2023 findings, we updated the achievement rate[[42]](#footnote-43) (90%), delivery performance (86%) and impact degradation rate (73% overall RA). We also assume a maximum 4-hour event duration based on historical participation in the 1- to 4-hour product option.

SCE’s forecast assumptions are as follows:

* Enrollment Outlook – consistent with the submitted DR Application A22-05-004:
* Updated according to PY2023’s Day-Of nominations.
* In 2024 through 2033, zero enrollment in non-summer months and the Day-Of program.
* In 2024, assume 100% of PY2023 Day-Of summer participants will move to the DA summer program.
* In 2025, discontinue the current CBP program; introducing the new CBP Elect Day-Ahead program and assume more enrollment than PY2023.
* Updated assumptions based on PY2023 performance – we assume the per-customer load impacts on reporting hour (5:00 PM-6:00 PM for summer) as the maximum impact during the RA window. The impact degradation was updated to 64% (Day-Ahead summer) overall RA window.

SDG&E’s forecast assumptions are as follows:

* Delivery Performance – we calculated program-level delivery performance based on PY2020

through PY2023 performance to produce modest estimates, given the inconsistent delivery

performance over the last three years, 35% (Non-Residential DA) and 66% (Non-Residential DO).

* Enrollment Growth – we updated the enrollment forecast based on PY2023 nominations and assumed a 3% growth per year from 2024-2027 due to the CBP program improvements proposed by SDG&E and no additional growth from 2027-2034.
* Impact Degradation Rate – we updated impact degradation rate based on PY2023, as moving forward the program is expected to resemble what was observed in this year; the second year after it had been introduced.

Table 3‑3 summarizes the 11-year average Resource Adequacy (RA) window load impact forecast by IOU and program for an August peak day scenario, and Table 3‑4 summarizes the corresponding 11-year enrollment forecast.

Table 3‑3 Statewide CBP: 2024-2034 Load Impact Forecast, August Peak Day

| IOU | Program | Aggregate Load Impacts (MW) | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| 2024 | 2025 | 2026 | 2027 | 2028-2034 (Each Year) |
| PGE | Residential DA | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Non-residential DA | 39.9 | 39.9 | 39.9 | 39.9 | 39.9 |
| SCE | Non-residential DA | XXX | XXX | XXX | XXX | XXX |
| Non-residential Elect DA | XXX | XXX | XXX | XXX | XXX |
| SDG&E | Non-residential DA | 0.8 | 0.8 | 0.9 | 0.9 | 0.9 |
| Non-residential DO | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 |

Table 3‑4 Statewide CBP: 2024-2034 Enrollment Forecast, August Peak Day

| IOU | Program | Number of Service Accounts | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| 2024 | 2025 | 2026 | 2027 | 2028-2034 (Each Year) |
| PGE | Residential DA | 3,158 | 3,158 | 3,158 | 3,158 | 3,158 |
| Non-residential DA | 1,130 | 1,130 | 1,130 | 1,130 | 1,130 |
| SCE | Non-residential DA | 42 | 0 | 0 | 0 | 0 |
| Non-residential Elect DA | 0 | 84 | 84 | 84 | 84 |
| SDG&E | Non-residential DA | 107 | 110 | 114 | 117 | 117 |
| Non-residential DO | 58 | 59 | 61 | 63 | 63 |

Table 3‑5 summarizes the average RA window load impact estimates for an August peak day in 2023 by IOU and program for each weather scenario.

Table 3‑5 Statewide CBP: RA Window Ex-Ante Impacts, August Peak Day, 2024

| IOU | Program | # of Accts | Per Customer  (kW) | Aggregate Impact (MW) | Percent Impact (%) | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Utility Peak | | CAISO Peak | |
| 1-in-2 | 1-in-10 | 1-in-2 | 1-in-10 |
| PGE | Residential DA | 3,158 | 0.2 | 0.7 | 17.3% | 18.3% | 17.1% | 20.2% |
| Non-residential DA | 1,130 | 35.3 | 39.9 | 19.3% | 19.3% | 19.3% | 19.4% |
| SCE | Non-residential DA | 42 | XXX | XXX | XXX | XXX | XXX | XXX |
| Non-residential Elect DA | 0 | - | - | - | - | - | - |
| SDG&E | Non-residential DA | 107 | 7.7 | 0.8 | 9.5% | 9.4% | 9.6% | 9.4% |
| Non-residential DO | 58 | 29.8 | 1.7 | 21.0% | 20.6% | 21.1% | 20.8% |

Note that since Non-residential CBP impacts are inherently nomination-driven, not weather-driven, we assumed constant non-residential per-customer load impacts across the weather scenarios. This assumption results in varying percent impacts across the months and weather scenarios.

## Key Findings by IOU

This section discusses the key findings for each IOU.

### PG&E Key Findings

The PY2023 LI analysis has the following key findings for PG&E’s CBP:

#### Non-residential Day-Ahead

* Non-residential Day-Ahead delivered 86% of dispatched capacity for the average event. Although the delivery performance dropped slightly compared to PY2022, the program successfully drove substantial curtailment during events of over 20 MW and is collectively the largest CBP resource in the state.
* Despite a reduction in the number of participants compared to PY2022, PY2023 saw an increase in the customer size.
* The hour from 6:00 PM–7:00 PM was the most dispatched event hour in PY2023, with an average of 23.8 MW load impacts and 430 participants.
* PG&E dispatched Sub-LAP-level events only in 2023.
* Based on aggregator outlook, PG&E estimates approximately 65 MW capacity nominations in 2024, which aligns with last year’s forecast. This marks an increase compared to the forecast of 55 MW nominations in PY2021.

#### Residential Day-Ahead

* Residential Day-Ahead enrollment picked up again after the break in PY2022 and delivered an average performance of XXX. Given the nature of PG&E’s service territory, a substantial portion of the residential CBP participants are the customers with Net Energy Metering or on the EV rate.
* Selecting the reporting hour for Residential Day-Ahead posed a challenge, as the hour with the most dispatches did not align with the hours of highest impacts. AEG ultimately selected HE20 as the reporting hour, based on finding a balance between high dispatch and high impact. Furthermore, although HE19 stands as the most dispatched hour, during the October 19th event, customers appeared to fail to respond within the actual, single-hour event window (HE19), resulting in an unexpected increase in usage during that hour. HE21 showed the highest impact. However, it’s essential to acknowledge that HE21 was only called on three out of the five event days.
* In PY2023, one aggregator participated in Residential Day-Ahead. Thus, all CBP Residential Day-Ahead impacts are confidential.

### SCE Key Findings

The PY2023 LI analysis has the following key findings for SCE’s CBP:

* There was a notable decline in Non-residential CBP participation across both Day-Ahead and Day-Of programs particularly during summer season. This decline can be attributed in part, to SCE having a few major contributor aggregators, which enrolled only minimal numbers of customers in 2023.
* The Non-Residential Day-Ahead only included one customer who delivered small, negative impacts (XXX MW) during the average PY2023 summer event (a XXX delivery performance). This customer delivered XXX of their dispatched capacity during the average July event, but their underperformance during the August event (XXX of dispatched capacity) led to an overall negative impact for the PY2023 summer season. Upon examining the statistical significance, it was concluded that this impact was not significant, suggesting it is indifferent from zero.
* The estimated impacts for the Non-residential DO program depended heavily on the performance of one school customer that had substantially larger load than the other customers in the program.
* During the summer season, the Non-residential DO experienced a decline in enrollment with 42 customers enrolled in the average month. However, the delivery performance remained at XXX , which is higher than 2020 and 2021.
  + HE18 (5 PM – 6 PM) was the most dispatched event hour in summer PY2023, and customers delivered the highest impacts during this hour of the average event day.
* Non-Residential DO’s non-summer season remained a small collective resource but improved overall delivery performance from previous years. Non-Residential DA did not have active non-summer participation.
* HE20 (7 PM – 8 PM) is the most dispatched event hour and with the highest impact on average event day, in 2023 for the non-summer season.[[43]](#footnote-44)
* SCE updated the ex-ante enrollment forecast to be consistent with the submitted DR Application A22-05-004, which includes the following assumptions:
* Updated according to 2023 DO nominations,
* 2024 through 2033: zero enrollment in non-summer months and the DO program
* 2024: assume 100% of DO participants will move to the DA program, and
* 2025: closing out the original CBP program; assume increase in enrollment due to the new CBP Elect DA program with 3 price triggers; $200, $400, and $600.
* 2023 impacts are confidential[[44]](#footnote-45).

### SDG&E Key Findings

The PY2023 LI analysis has the following key findings for SDG&E’s CBP:

* SDG&E Elect products entered their second year in PY2023. These include the Elect DA 1-9 Hour and Elect DO 1-9 Hour options, each with three price trigger options ($200/MWh, $400/MWh, and $600/MWh).
* SDG&E still offers their previously existing products as Prescribed options, with the following price triggers: $90/MWh (Prescribed DA 11-7 Hour and 1-9 Hour), $115/MWh (Prescribed DO 11-7 Hour), and $125/MWh (Prescribed DO 1-9 Hour).
* The Elect DO ($600) product only included five customers and average nominations of 0.1 MW across summer months. However, these customers were not dispatched as no events were called for this product.
* The Non-Residential DA customers delivered 42% of dispatched capacity during the average PY2023 event. The improvement in delivery performance over the average PY2022 season (XXX in 2022 from three customers) can be largely attributed to customers’ performance in July, when customers delivered an average of 91% of the dispatched capacity, though performance in August (22% delivered of the 3.0 MW dispatched) still surpassed the average delivery seen in the 2022 summer.
* Non-residential DO participants delivered 1.7 MW in PY2023, a 95% delivery performance. This marks a substantial improvement in the delivery performance of this program from PY2022 (65% delivery performance), especially considering that nearly all nominations were dispatched in each month. Customers performed similarly well in both July and August with delivery performances of 101% and 91%, respectively.
* HE20 (7 PM – 8 PM) was the most dispatched event hour in PY2023. Across events, 3.8 MW and 135 participants were dispatched during the average HE20 even hour.
* SDG&E dispatched events on five days in PY2023. For comparison, under the Prescribed product option, SDG&E historically dispatched around 20-30 events per program year under the $90-$125/MWh price triggers. In PY2023, more aggregators opted for the $400/MWh and $600/MWh price triggers, reducing the resources that qualify for dispatches.
* SDG&E updated the enrollment forecast based on the PY2023 nominations, increasing the growth rate to 3% between the 2024 and 2027 forecast years to account for the CBP program improvements proposed by SDG&E. SDG&E assumed the programs would not see any growth after 2027.

## Recommendations

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs.

* Reevaluate the approach to reporting delivery performance. We have two considerations for future reports:
  + Consider including irradiance data. Based on the observed strong interest from customers with net metering, especially residential customers, we highly recommend incorporating irradiance data into the analysis. While it’s understood that energy production from solar panels is affected by multiple factors beyond just temperature, integrating irradiance data will significantly improve the accuracy of our predictions.
  + Identify customers with battery storage. The customers with battery storage have the capability to utilize charged batteries during the CBP events, presenting a challenge in accurately estimating load reduction from meter data. By pinpointing these specific customers and understanding their behavior and patterns during the events will help us to refine our predictions.
  + Re-**evaluate the approach of estimating Ex-Ante per-customer impact.** Considering that the ex-ante per-customer impact is derived from the Ex-Post but assumes a system-wide event is called. In reality, events are typically called at the Sub-LAP level (PG&E and SCE). Thus, the per-customer impact from the ex-post reporting hour may underestimate the actual impact. Therefore, reassessing the ex-ante impact based on the current Ex-Post is essential to ensure a more accurate estimation of the impact on individual customers.

Pacific Gas & Electric

This section presents Pacific Gas & Electric’s (PG&E) PY2023 Capacity Bidding Program (CBP) descriptions and expected program changes, participation, ex-post load impact estimates, ex-ante load impact estimates, and key findings.

## PG&E Program Description

PG&E’s CBP only offers Day Ahead (DA) notification. Aggregators nominate a monthly capacity amount for one of three options: Prescribed, Elect, and Elect+.

* Prescribed DA: PG&E sets the CAISO market bid price and dispatch strategy within specified operating hours (1-4 hours and 2-6 hours).
* Elect DA: Aggregators set their own CAISO market bid price within specified operating hours (1-4 hours, 2-6 hours, and 1-8 hours).
* Elect+ DA: Similar to Elect, where aggregators set their own CAISO market bid price, but Elect+ includes additional hours outside the minimum specified operating hours (1-4 hours, 2-6 hours, and 1-24 hours).

The PG&E CBP operating hours span from 1 PM to 9 PM. Events can be called Monday through Friday, excluding holidays, from May through October, with a maximum of six events and 30 hours per month (or possibly more hours under Elect and Elect+ Options if the participants choose).

In PY2021, PG&E introduced a product option for resource participation on weekends.

### Program Changes

* In PY2023, residential customers enrolled in CBP Elect DA 1-4 hour product and participated in events called in October.

## PG&E Program Nominations

Table 4‑1 shows the total number of accounts and nominated capacity enrolled in PG&E’s CBP products in each month. The 672 non-residential DA customers nominated 33.9 MW per month, on average. Nominations ranged from just under 24 MW in May (505 accounts) to over 40 MW in July (779 accounts). The 356 Residential DA customers nominated a total of XXX MW in October (the only month of their event participation in PY2023).

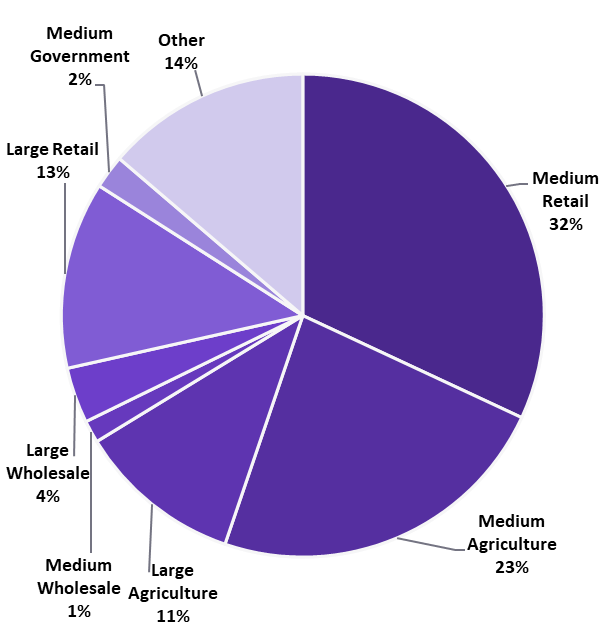
Table 4‑2 and the accompanying figure show the size and industry distribution of non-residential enrollees. Most enrollments came from the retail (47%) and agriculture (36%) industries, consistent with the PY2022 enrollment group.

Table 4‑1 PG&E Monthly Nominations

| Month | Residential DA | | Non-Residential DA | |
| --- | --- | --- | --- | --- |
| Enrolled  Accounts | Nominated Capacity (MW) | Enrolled  Accountsa | Nominated Capacity (MW) |
| May | - | - | 505 | 23.7 |
| June | - | - | 576 | 28.6 |
| July | - | - | 779 | 40.3 |
| August | - | - | 790 | 38.7 |
| September | - | - | 778 | 34.3 |
| October | 356 | XXX | 601 | 37.8 |
| Avg. Summer | **356** | XXX | **672** | **33.9** |

Table 4‑2 PG&E Non-Residential Enrollment

| Industry Type | Size Groupa | | | Totalb |
| --- | --- | --- | --- | --- |
| Small | Medium | Large |
| Agriculture, Mining & Construction | 13 | 156 | 74 | **243** |
| Manufacturing | 1 | - | 18 | **19** |
| Wholesale, Transport, Other Utilities | 3 | 10 | 25 | **38** |
| Retail Stores | 20 | 214 | 84 | **318** |
| Offices, Hotels, Finance, Services | 11 | 14 | 5 | **30** |
| Schools | 1 | - | 1 | **2** |
| Institutional/ Government | 2 | 15 | 1 | **18** |
| Other/Unknown | 1 | 1 | - | **2** |
| Total | **52** | **410** | **208** | **670** |



|  |
| --- |
| aAEG binned customers by the size of their maximum hourly consumption on non-event days into small (<20 kW), medium (≥20 kW and <200 kW), and large (≥200 kW) groups.  bThe enrollment counts presented in this table represent the number of unique accounts enrolled. These counts may appear lower than those in the nominations table above. This is because a single unique account can nominate multiple months during the season. |

## PG&E Key Findings

AEG identified the following key findings for the non-residential DA and residential DA offerings based on the PY2023 evaluation.

Non-residential DA

* Non-residential DA delivered 86% of dispatched capacity for the average event. Although the delivery performance dropped slightly compared to PY2022, the program successfully drove substantial curtailment during events of over 20 MW and is collectively the largest resource in the state.
* Despite a reduction in the number of participants compared to PY2022, PY2023 saw an increase in the customer size.
* HE19 (6 PM – 7 PM) was the most dispatched event hour in PY2023 with an average of 23.8 MW load impacts and 430 participants dispatched. Notably, only one event was called in October, and it occurred as a one-hour event in HE19, which led HE19 to be the most dispatched event hour.
* PG&E’s CBP dispatched Sub-LAP-level events only in 2023.
* Based on aggregator outlook, PG&E estimates approximately 65 MW capacity nominations in 2024, which aligns with last year’s forecast. This marks an increase compared to the forecast of 55 MW nominations in PY2021.

Residential DA

* Residential DA enrollment picked up again after the break in PY2022. A substantial portion of the residential CBP participants are the customers with Net Energy Metering or on the EV rate.
* Selecting the reporting hour for Residential DA posed a challenge, as the hour with the most dispatches did not align with the hours of highest impacts. AEG ultimately selected HE20 as the reporting hour, based on finding a balance between high dispatch and high impact. Furthermore, although HE19 stands as the most dispatched hour, during the October 19th event, customers appeared to fail to respond within the actual, single-hour event window (HE19), resulting in an unexpected increase in usage during that hour. HE21 showed the highest impact. However, it’s essential to acknowledge that HE21 was only called on three out of the five event days.
* In PY2023, one aggregator participated in Residential DA. Thus, all CBP Residential DA impacts are confidential.

## PG&E Ex-Post Analysis

This section describes the PY2023 events, summarizes the ex-post impacts estimated for PY2023 dispatched events, and compares the ex-post to the PY2022 ex-ante forecast for 2023.

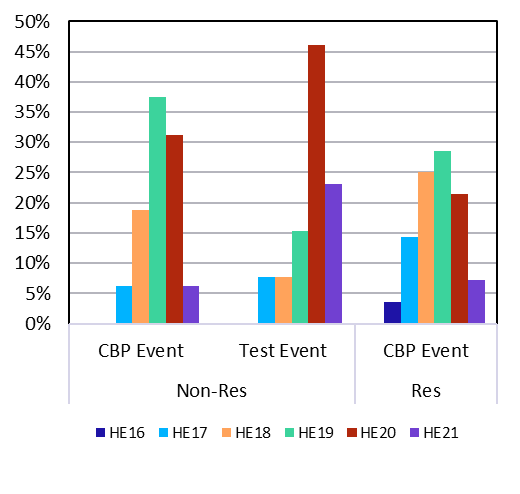
### Dispatched Events

In 2023, PG&E dispatched Sub-LAP-level events only. Table 4‑3 shows the total dispatched event days and hours by month, season, and product. The Non-residential Elect DA participants experienced three event days (eight event hours total) and three test[[45]](#footnote-46) events (nine test hours). Residential Elect DA customers participated in five event days totaling 20 event hours over the program year.

As in previous years, events were dispatched at various times and durations within the 1-9 PM dispatch window. The accompanying figure shows the distribution of hours dispatched across events (weighted by dispatched customers). HE19 was the most-dispatched hours in PY2023 for Non-Residential DA participants and Residential DA customers, respectively. For Residential DA customers, the hour of highest impacts (HE20), which also comprised many event windows, was selected as the reporting hour.

| Month | Non-Res CBP Event | | Non-Res Test Event | | Res CBP Event | |
| --- | --- | --- | --- | --- | --- | --- |
| Total  Event Days | Total  Event Hours | Total  Event Days | Total  Event Hours | Total Event Days | Total Event Hours |
| May | - | - | - | - | - | - |
| Jun | - | - | 1 | 4 | - | - |
| Jul | - | - | 2 | 5 | - | - |
| Aug | 2 | 7 | - | - | - | - |
| Sep | - | - | - | - | - | - |
| Oct | 1 | 1 | - | - | 5 | 20 |
| Total | 3 | 8 | 3 | 9 | 5 | 20 |

Table 4‑3 PG&E Event Summary



### Load Impact Summary

Table 4‑4 summarizes PY2023 impacts for the average event day, by product, for the reporting hour (HE19 for non-residential products and HE20 for the residential product). Specifically, it shows:

* The average number of accounts dispatched across events.
* The total dispatched capacity, load impact, and delivery performance for the average event day.
* The reference load (e.g., the estimated counterfactual load had the customer not been dispatched) and load impact per-customer for the average event day.

The non-residential day-ahead product delivered 20.5 MW out of 23.8 MW dispatched on average across event days during HE 19, an average delivery performance of 86%. Residential DA delivered XXX MW out of a dispatched XXX MW, a delivery performance of XXX).

Table 4‑4 PG&E Impacts Summary, Average Event Day PY2023

| Program &  Product | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Non-Res Elect DA 1-4 Hour | 126 | 14.0 | 12.2 | 87% | 420.1 | 96.4 | 23% |
| Non-Res Elect DA 1-4 Hour with Weekends | 303 | 9.8 | 8.3 | 85% | 135.8 | 27.5 | 20% |
| Total Non-Res DA | **430** | **23.8** | **20.5** | **86%** | **219.2** | **47.7** | **22%** |
| Res Elect DA 1-4 Hour | 236 | XXX | XXX | XXX | XXX | XXX | XXX |
| Total Res DA | **236** | XXX | XXX | XXX | XXX | XXX | XXX |

Table 4‑5 and Table 4‑6 show the number of accounts and capacity nominated for each month, the amount dispatched across all event days and event hours and for the most-dispatched hour, and the estimated ex-post impacts.

Non-residential DA participants delivered 20.5 MW in total on the average event day, achieving an 86% delivery performance rate. Most dispatched events occurred in August, where the average event dispatched 34.1 MW—86% of which (29.2 MW) participants delivered. The October events dispatched fewer customers, but these customers delivered 96% of the 3.1 MW dispatched for the average event. Since all non-residential DA resources were dispatched during the most dispatched hour, AEG did not make any adjustments to the delivery performance. [[46]](#footnote-47)

The Residential DA product was only nominated and called for events in October. On the average event day, customers delivered an estimated XXX MW, a delivery performance of XXX Similarly, AEG did not make any adjustments to the Residential DA product delivery performance.[[47]](#footnote-48)

Table 4‑5 PG&E Non-Residential DA Monthly Summary

| Month | Nominations | | Dispatched | | HE19 Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered | Adj. % Delivered |
| May | 505 | 23.7 | - | - | - | - | - | - | - |
| June | 576 | 28.6 | - | - | - | - | - | - | - |
| July | 779 | 40.3 | - | - | - | - | - | - | - |
| August | 790 | 38.7 | 635 | 34.1 | 635 | 34.1 | 29.2 | 86% | 86% |
| September | 778 | 34.3 | - | - | - | - | - | - | - |
| October | 601 | 37.8 | 19 | 3.1 | 19 | 3.1 | 3.0 | 96% | 96% |
| Overall | **672** | **33.9** | **430** | **23.8** | **430** | **23.8** | **20.5** | **86%** | **86%** |

Table 4‑6 PG&E Residential DA Monthly Summary

| Month | Nominations | | Dispatched | | HE20 Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered | Adj. % Delivered |
| May | - | - | - | - | - | - | - | - | - |
| June | - | - | - | - | - | - | - | - | - |
| July | - | - | - | - | - | - | - | - | - |
| August | - | - | - | - | - | - | - | - | - |
| September | - | - | - | - | - | - | - | - | - |
| October | 356 | XXX | 236 | XXX | 236 | XXX | XXX | XXX | XXX |
| Overall | **356** | XXX | **236** | XXX | **236** | XXX | XXX | XXX | XXX |

#### Hourly Load Impacts

Figure 4‑1, Figure 4‑2, and Figure 4‑3 show hourly load profiles for the average Non-Residential Elect Day-Ahead customer, Non-Residential Elect Day-Ahead with Weekends customer, and Residential Day-Ahead customer, respectively.[[48]](#footnote-49) Each shows the estimated reference load (i.e., what the customer would have consumed had an event not been called), the actual observed load, and the estimated load impacts for the average event day. The highlighted hours indicate that at least one group of customers was dispatched during that hour. The vertical dotted lines show the most dispatched hour (HE19 for Non-Residential DA and HE20 for Residential DA).

Figure 4‑1 PG&E Non-Residential Elect Day Ahead: Hourly Per-Customer Impact, Average Event

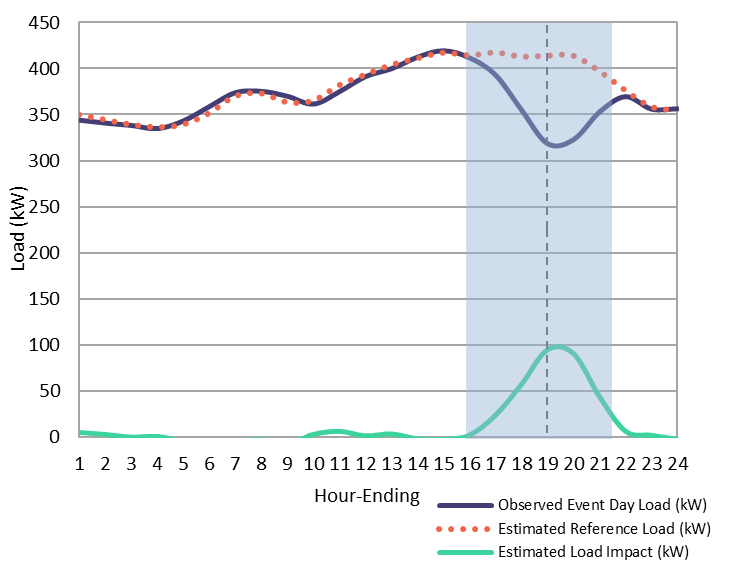


Figure 4‑2 PG&E Non-Residential Elect Day Ahead with Weekends: Hourly Per-Customer Impact, Average Event

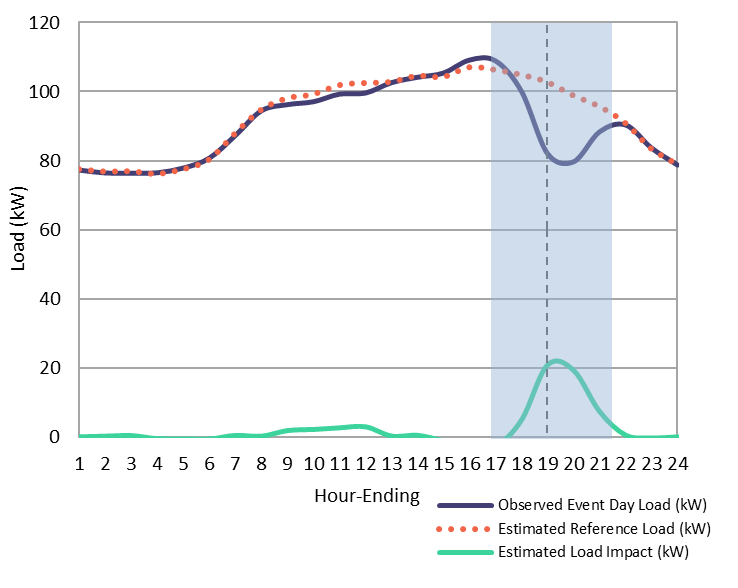


Figure 4‑3 PG&E Residential Elect Day Ahead: Hourly Per-Customer Impact, Average Event

#### Load Impacts by Industry, LCA, and Sub-LAP

Table 4‑7, Table 4‑8, and Table 4‑9 show the impacts for the average event day by industry, LCA, and Sub-LAP, respectively.[[49]](#footnote-50)

Table 4‑7 PG&E Impacts by Industry

| Industry | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Agriculture, Mining & Construction | 182 | 19.6 | 10.7 | 107.7 | 58.5 | 54% | 93 |
| Manufacturing | 13 | XXX | XXX | XXX | XXX | XXX | 93 |
| Wholesale, Transport, other utilities | 31 | 11.8 | 7.5 | 382.7 | 242.8 | 63% | 96 |
| Retail stores | 286 | 31.2 | 1.0 | 109.3 | 3.5 | 3% | 90 |
| Offices, Hotels, Finance, Services | 30 | 17.8 | 1.3 | 595.0 | 44.7 | 8% | 92 |
| Schools | 2 | XXX | XXX | XXX | XXX | XXX | 97 |
| Institutional/Government | 18 | XXX | XXX | XXX | XXX | XXX | 87 |
| Other or unknown | 2 | XXX | XXX | XXX | XXX | XXX | 90 |
| Total Non-Residential DA | **430** | **94.3** | **20.5** | **219.2** | **47.8** | **22%** | **91** |
| Total Residential DA[[50]](#footnote-51) | **236** | XXX | XXX | XXX | XXX | XXX | **79** |

Table 4‑8 PG&E Impacts by LCA

|  | Local Capacity Area | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact (MW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | | Ref.  Load | Impact |
| Non-Residential DA | Greater Bay Area | 183 | 42.2 | 2.6 | 230.8 | 14.4 | 6% | 80 |
| Greater Fresno Area | 110 | XXX | XXX | XXX | XXX | XXX | 104 |
| Humboldt | 12 | XXX | XXX | XXX | XXX | XXX | 70 |
| Kern | 31 | XXX | XXX | XXX | XXX | XXX | 103 |
| Northern Coast | 42 | XXX | XXX | XXX | XXX | XXX | 87 |
| Sierra | 34 | XXX | XXX | XXX | XXX | XXX | 100 |
| Stockton | 24 | XXX | XXX | XXX | XXX | XXX | 93 |
| Other | 203 | XXX | XXX | XXX | XXX | XXX | 96 |
| Total Non-residential DA | | **430** | **94.3** | **20.5** | **219.2** | **47.7** | **22%** | **91** |
| Residential DA | Greater Bay Area | 235 | XXX | XXX | XXX | XXX | XXX | 80 |
| Other | 1 | XXX | XXX | XXX | XXX | XXX | 73 |
| Total Residential DA | | **236** | XXX | XXX | XXX | XXX | XXX | **79** |

Table 4‑9 PG&E Impacts by Sub-LAP

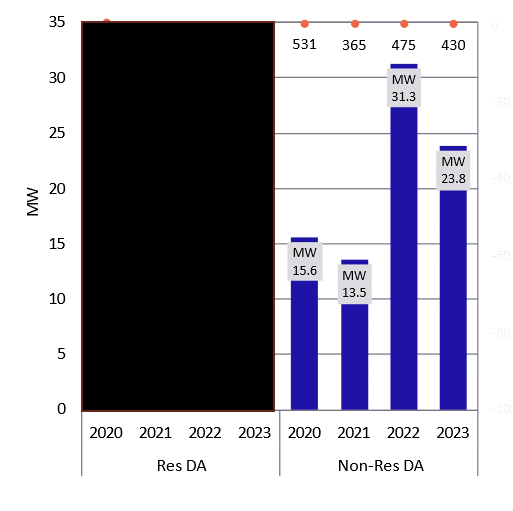
|  | Sub-LAP | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact (MW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Non-residential DA | PGCC | 38 | 7.3 | 1.4 | 191.5 | 36.1 | 19% | 67 |
| PGEB | 65 | XXX | XXX | XXX | XXX | XXX | 89 |
| PGF1 | 114 | XXX | XXX | XXX | XXX | XXX | 104 |
| PGFG | 9 | XXX | XXX | XXX | XXX | XXX | 79 |
| PGHB | 12 | XXX | XXX | XXX | XXX | XXX | 70 |
| PGKN | 31 | XXX | XXX | XXX | XXX | XXX | 103 |
| PGNB | 21 | XXX | XXX | XXX | XXX | XXX | 86 |
| PGNC | 13 | XXX | XXX | XXX | XXX | XXX | 96 |
| PGNP | 94 | XXX | XXX | XXX | XXX | XXX | 95 |
| PGP2 | 16 | XXX | XXX | XXX | XXX | XXX | 79 |
| PGSB | 48 | XXX | XXX | XXX | XXX | XXX | 84 |
| PGSF | 15 | XXX | XXX | XXX | XXX | XXX | 67 |
| PGSI | 34 | XXX | XXX | XXX | XXX | XXX | 100 |
| PGST | 24 | XXX | XXX | XXX | XXX | XXX | 93 |
| PGZP | 105 | XXX | XXX | XXX | XXX | XXX | 97 |
| Total Non-residential DA | | **430** | **94.3** | **20.5** | **219.2** | **47.7** | **22%** | **91** |
| Residential DA | PGEB | 153 | XXX | XXX | XXX | XXX | XXX | 83 |
| PGP2 | 92 | XXX | XXX | XXX | XXX | XXX | 77 |
| PGSB | 111 | XXX | XXX | XXX | XXX | XXX | 78 |
| Total Residential DA | | **236** | XXX | XXX | XXX | XXX | XXX | **79** |

### Comparison of Ex-Post Impacts

This section discusses how the PY2023 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast.

Figure 4‑4[[51]](#footnote-52) and Table 4‑10 show PG&E’s average program nominations for PY2020 through PY2023 for the residential and non-residential DA products.

Figure 4‑4 PG&E Annual Nominations



Notably, the PY2023 Non-Residential DA enrolled fewer nominations compared to PY2022, though it still surpassed the nominations in PY2020 and PY2021 by over half. The number of customers, as opposed to the size of enrolled customer nominations, appears to drive the decrease from PY2022: AEG estimated higher reference loads for PY2023 customers compared to PY22, indicating that these customers had more potential to curtail their load during events. This could explain the comparable delivery performance to 2022 despite the decreases in participation.

Similarly, the average nomination per Residential DA customer substantially increased from PY2020, when 623 customers nominated XXX MW in total. In PY2023, 236 customers nominated more than those of PY2022. During the October 19th one-hour event (HE19), customers appeared to respond approximately an hour later, in HE20.

Table 4‑10 PG&E: Current v. Previous Ex-Post, Average Event Day

| Program | Year | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Non-Residential  DA | 2020 | 531 | 15.6 | 10.0 | 64% | 120.5 | 18.9 | 16% | 85 |
| 2021 | 365 | 13.5 | 13.0 | 96% | 81.6 | 35.6 | 44% | 87 |
| 2022 | 475 | 31.3 | 28.0 | 89% | 150.9 | 58.9 | 39% | 96 |
| **2023** | **430** | **23.8** | **20.5** | **86%** | **219.2** | **47.2** | **22%** | **91** |
| Residential DA | 2020 | 623 | XXX | XXX | XXX | XXX | XXX | XXX | 86 |
| 2021 | 21 | XXX | XXX | XXX | XXX | XXX | XXX | 70 |
| 2022 | - | **-** | - | - | - | - | - | - |
| **2023** | **236** | XXX | XXX | XXX | XXX | XXX | XXX | **79** |

Table 4‑11 shows the PY2023 ex-post impacts compared to PY2022 ex-ante impacts on an aggregate and per-customer basis for the average, e.g., typical, event day. Comparisons between the ex-ante and ex-post may not be reasonable for a few reasons:

* The ex-ante impacts forecasted performance for a system-level dispatch. However, PG&E only dispatched events for specific Sub-LAP in PY2023, and not for the system as a whole. Therefore, the ex-post per-customer impacts reflect the specific Sub-LAPs that were called for events. Furthermore, since CBP is dependent on the CAISO market conditions and PG&E’s PY2023 did not include any aggregators on the Prescribed option, all 2023 bids into the CAISO market were set by aggregators.
* The 2022 ex-ante aggregate impacts assumed a sizeable increase in enrollment for the non-residential DA, but PY2023 actual enrollment turned out to be half of what was anticipated.

Despite these fundamental differences, AEG estimated higher per-customer impacts in PY2023 than assumed for ex-ante purposes in PY2022. This indicates that the program managed to recruit or retain higher-performing customers in 2023, which offset some of the decreased impacts due to the low enrollment.

Table 4‑11 PG&E Current Ex-Post (Largest Dispatched Event) v. Prior Ex-Ante (PG&E 1-in-2, Typical Event Day, 2023)

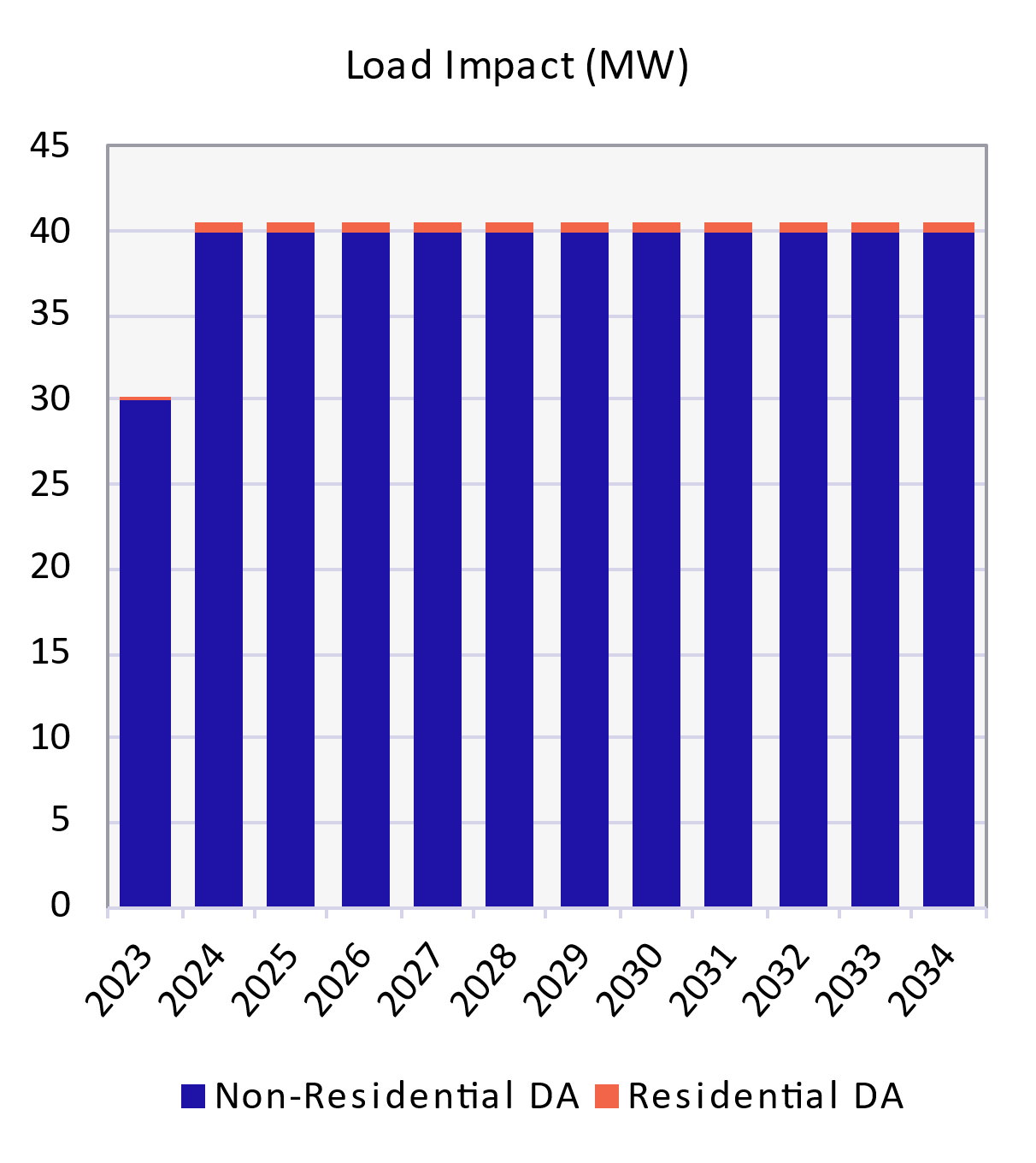
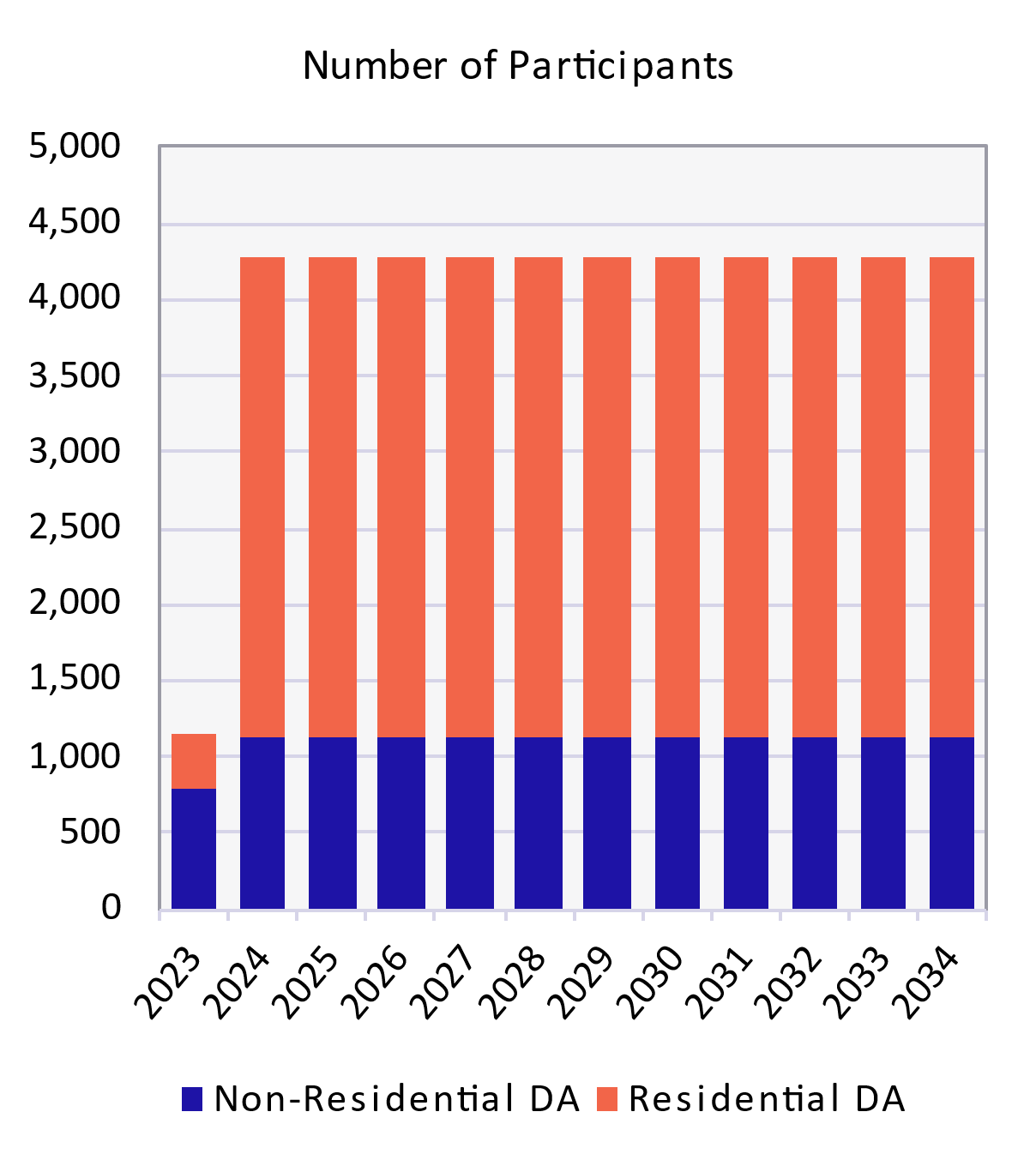
| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Non-Residential DA | PY2022 Ex-Ante | 980 | 164.3 | 33.5 | 167.6 | 34.2 | 20% | 87 |
| **Current Ex-Post** | 430 | 94.3 | 20.5 | 219.2 | 47.7 | 22% | 91 |
| Residential DA | PY2022 Ex-Ante | 1,743 | 1.2 | 0.3 | 0.7 | 0.2 | 26% | 80 |
| **Current Ex-Post** | 236 | XXX | XXX | XXX | XXX | XXX | 79 |

## PG&E Ex-Ante Analysis

### Enrollment and Load Impact Summary

PG&E forecasts growth in 2024 relative to 2023 and maintains a constant forecast through the remainder of the forecast horizon. This assumption is applied to both Residential and Non-residential Day-Ahead programs. Figure 4‑5 shows PG&E’s CBP Day-Ahead enrollment and load impact forecast for an August peak day under the PG&E 1-in-2 weather scenario.

Figure 4‑5 PG&E CBP Enrollment and Load Impact Forecast (PG&E 1-in-2, August Peak Day)



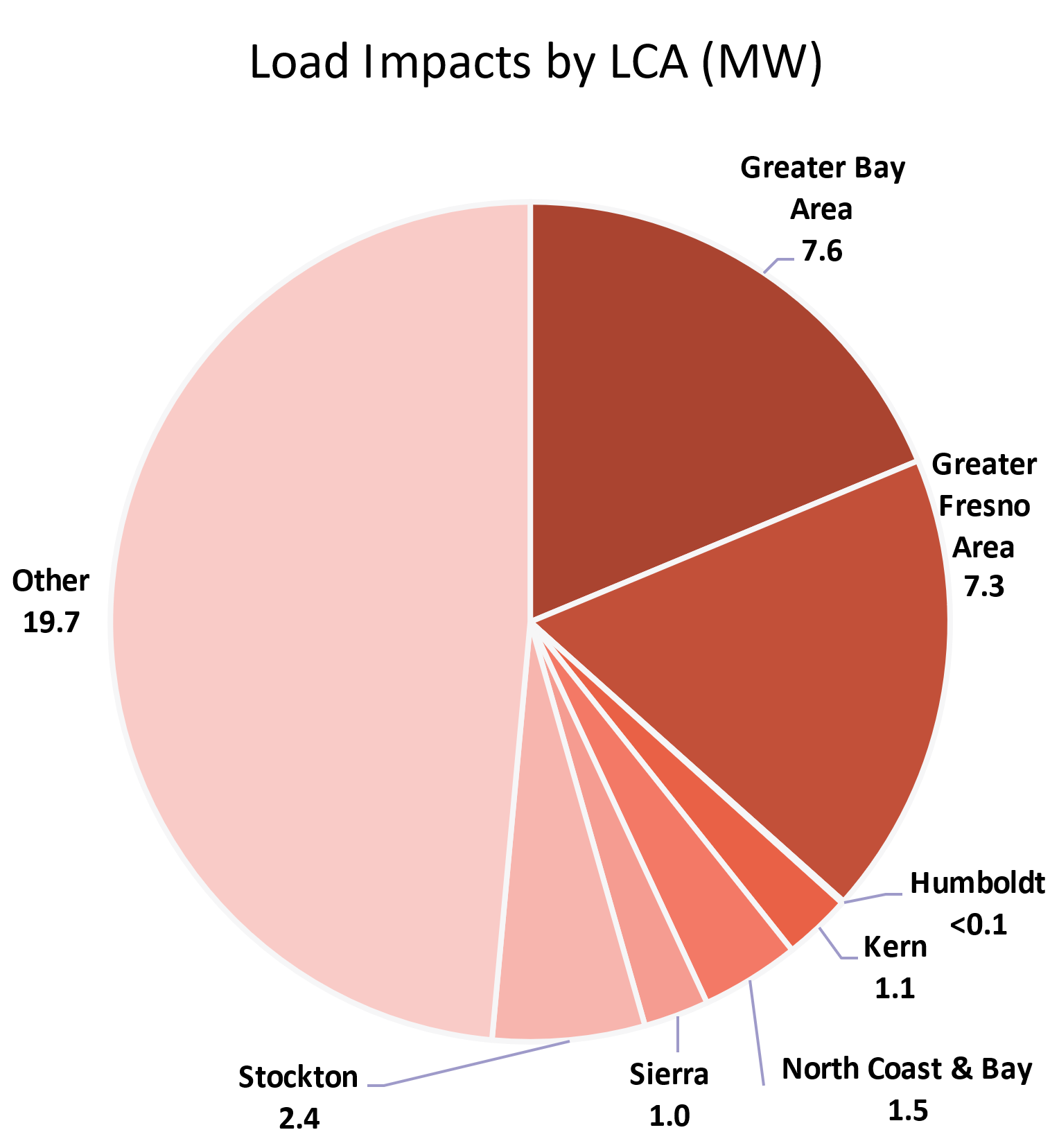
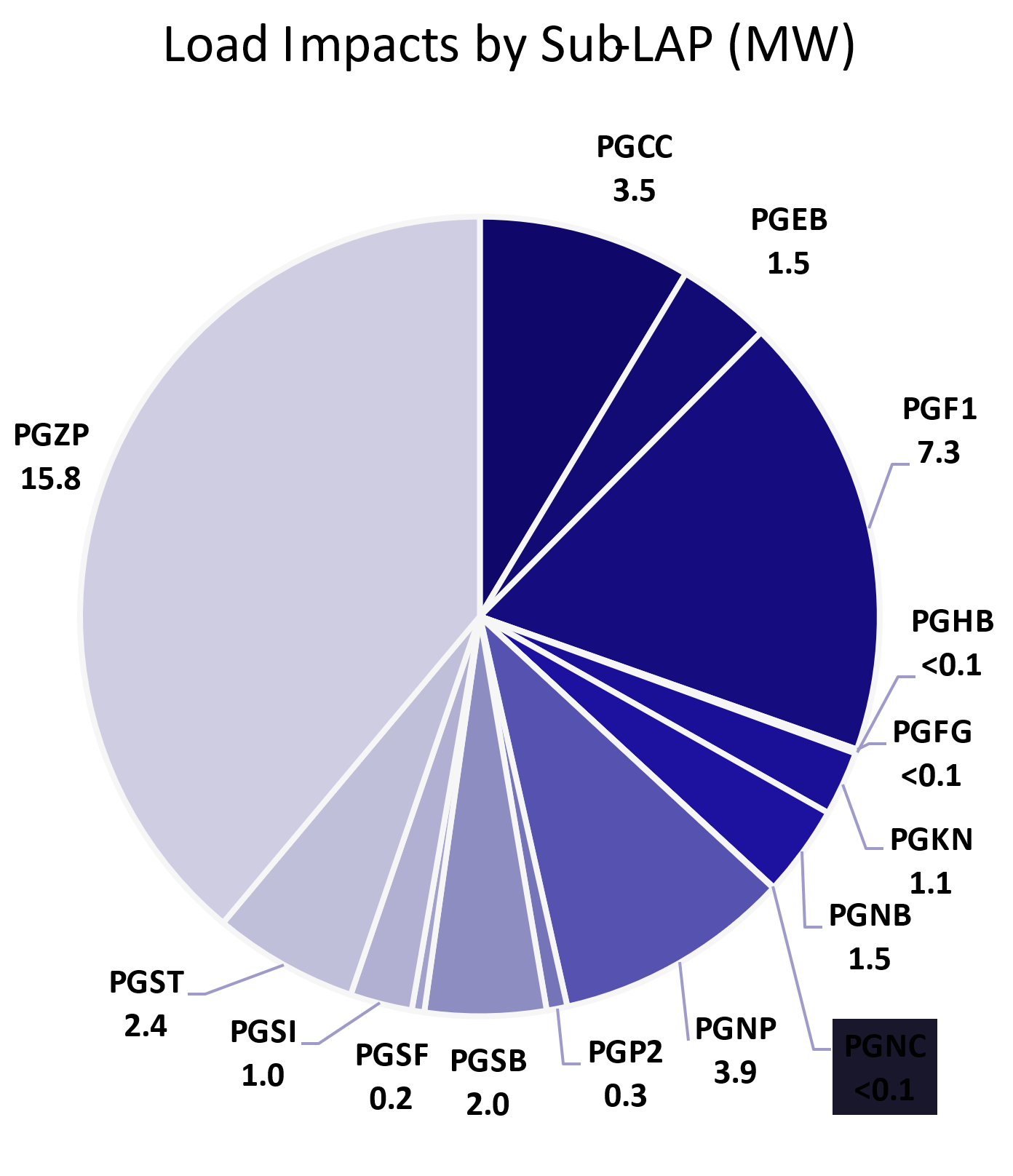
summarizes the average RA window load impact forecasts for PG&E’s CBP Day-Ahead program on an August peak day in 2024. The table includes the per-customer, aggregate, and corresponding percent impacts under the utility and CAISO 1-in-2 and 1-in-10 weather scenarios.

Table 4‑12 PG&E: RA Window Ex-Ante Impacts for an August Peak Day, 2024

| Program | # of Accts | Per-Customer Impact (kW) | Aggregate Impact (MW) | Percent Impact  (%) | | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Utility Peak | | CAISO Peak | |
| 1-in-2 | 1-in-10 | 1-in-2 | 1-in-10 |
| Residential Day-Ahead | 3,158 | 0.2 | 0.7 | 18.0% | 16.2% | 18.3% | 17.2% |
| Non-Residential Day-Ahead | 1,130 | 35.3 | 39.9 | 19.4% | 19.3% | 19.3% | 19.3% |

illustrates the average RA window load impact distribution by LCA and Sub-LAP for Non-residential CBP Day-Ahead on an August peak day in 2024. The results shown are for 1-in-2 weather conditions for the utility peak.

Figure 4‑6 PG&E: Total CBP RA Window Load Impacts by LCA and Sub-LAP (PG&E 1-in-2, August Peak Day, 2024)



### Forecast Assumptions

This section discusses the assumptions used to develop the Residential and Non-residential Day-Ahead forecasts.

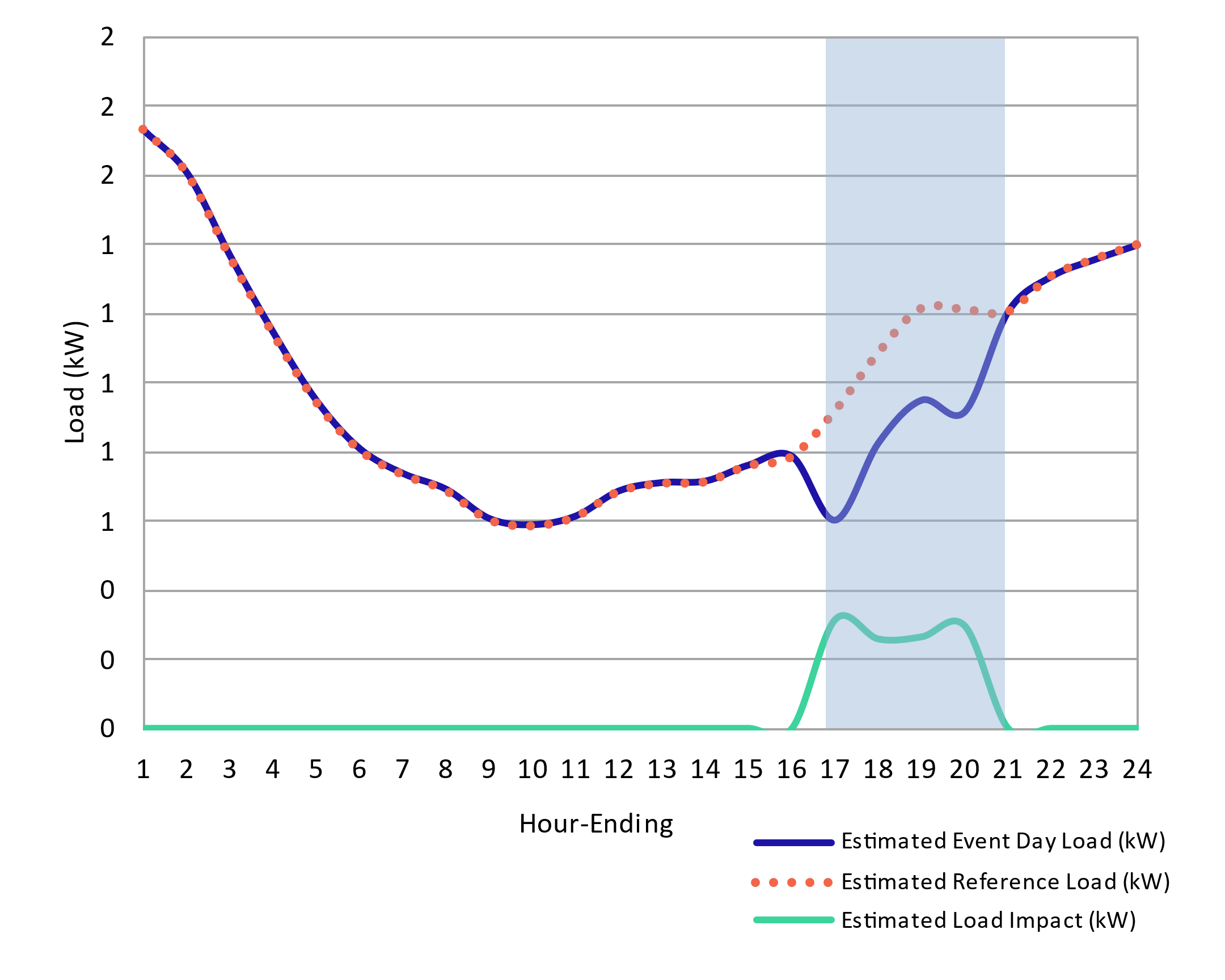
Residential Day-Ahead Forecast Assumptions. The residential forecast uses a combination of the following:

* Capacity nomination forecast (MW) based on aggregator outlook – PG&E assumed a monthly 1 MW nomination through the 2024-2034 forecast.
* Delivery performance – PG&E maintained a 61% minimum delivery performance, which is the minimum threshold before aggregators are charged a penalty.
* Impact by customer – AEG assumed the maximum Ex-Post impact for each customer throughout the entire event window (4:00 PM- 9:00 PM). This event window encompassed all events called during the 2023 summer season.
* Impact degradation rate – AEG developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the five-hour RA window. The approach used to develop these assumptions is discussed in Section 3 [Impact Degradation Across the RA Window](#ImpactDeg). For PG&E Residential, AEG used PY2023 data to update the impact degradation rate. Table 4‑13 shows the shape of the RA window impacts as a percent of the maximum impact for Residential DA.
* Four-hour RA window response – historical participation shows a preference for products with 1- to 4-hour event durations. As a result, we assume that the Residential Day-Ahead program can respond for a maximum of four hours and assume zero impacts during the fifth hour of the RA window (9:00 PM-10:00 PM for May, 8:00 PM-9:00 PM otherwise).

These assumptions result in a flat 0.7 MW forecast for an August peak day from 2024-2034. Residential Day-Ahead has historically produced low deliveries, resulting from aggregator inexperience in the operation of the residential CBP product and a low rate of automation. The residential program is relatively new, and after navigating the learning curve, PG&E anticipates growth in residential enrollment. Particularly, customers on Net Energy Metering (NEM) and electric vehicle (EV) rates have expressed interest in the program. With this in mind, PG&E is expecting higher enrollment in the future, which will further support the MW nominations.

Figure 4‑7 shows PG&E’s Residential Day-Ahead per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2024 for the PG&E 1-in-2 weather condition. The hours highlighted in the blue show the RA window, 4:00 PM-9:00 PM.

Figure 4‑7 PG&E Residential Day Ahead: Hourly Per-Customer Load Impacts (PG&E 1-in-2, August Peak Day, 2024)



Non-Residential Day Ahead Forecast Assumptions. The non-residential forecast uses a combination of the following:

* Capacity nomination forecast (MW) based on aggregator outlook – PG&E kept 2022’s nominations for 2023, forecasting approximately 65 MW nominations for an August peak day. This forecast shows an increase from PY2021’s 55 MW average summer nomination.
* Delivery performance – PG&E assumes 90% achievement rate and 86% delivery performance based on the PY2023 findings.
* Impact by customer – AEG assumed the maximum Ex-Post impact for each customer throughout the entire event window (HE17-HE21). This event window encompassed all events called during the 2023 summer season, excluding test events.
* Impact Degradation Rate – we developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the 5-hour RA window. The approach used to develop these assumptions is discussed in Section 3 [Impact Degradation Across the RA Window](#ImpactDeg). For PG&E, AEG used PY2021 through PY2023 data to update the impact degradation rate. shows the shape of the RA window impacts as a percent of the maximum impact for non-residential Day-Ahead.

Table 4‑13 PG&E CBP: RA Window Shape of Impacts

| Program | Percent of Maximum Impact | | | | | |
| --- | --- | --- | --- | --- | --- | --- |
| 5:00 PM | 6:00 PM | 7:00 PM | 8:00 PM | 9:00 PM[[52]](#footnote-53) | Overall RA Window |
| **Res Day-Ahead** | 100% | 82% | 84% | 94% | 0% | 72% |
| **Non-Res Day-Ahead** | 100% | 91% | 85% | 87% | 0% | 73% |

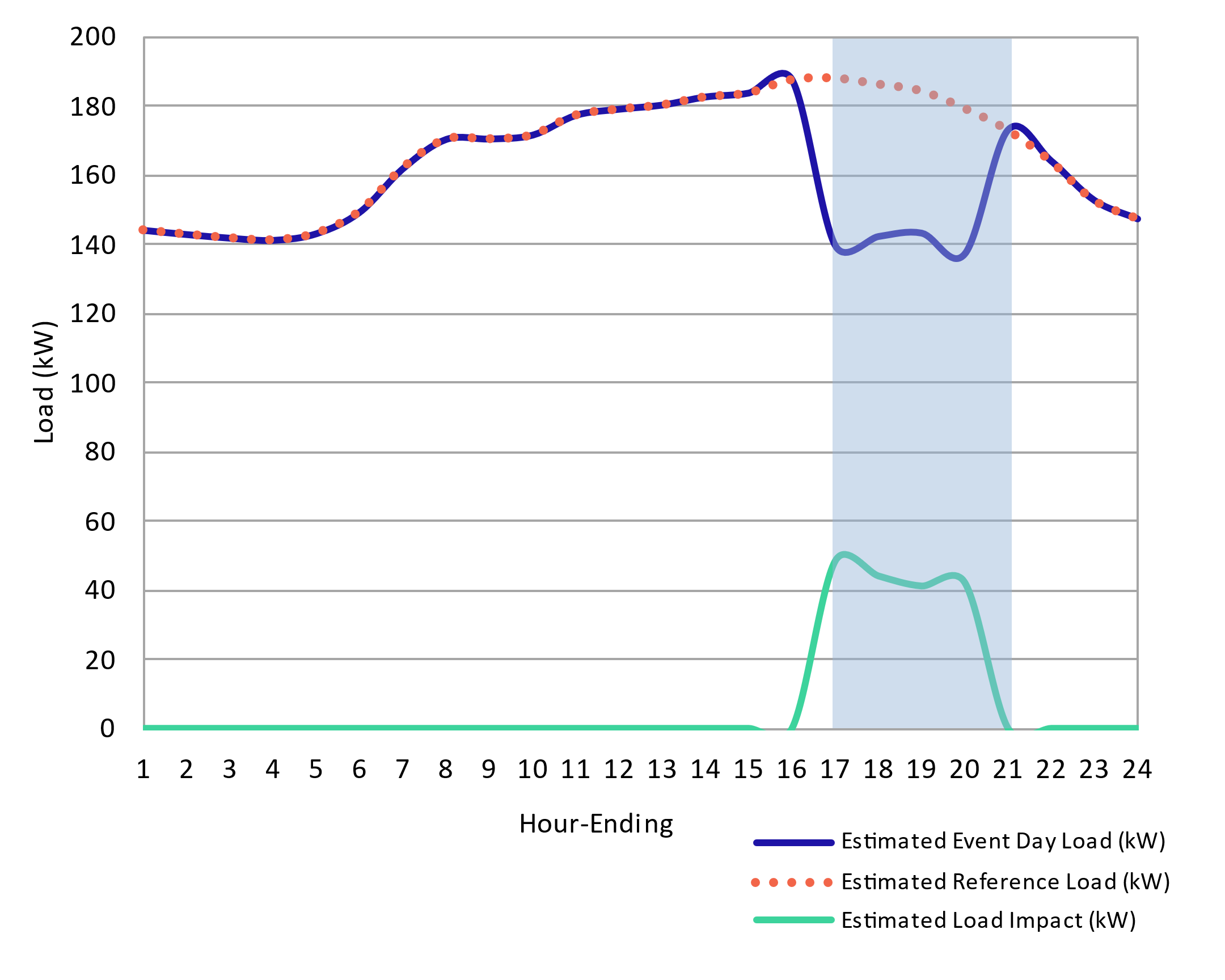
* Four-hour RA window response – historical participation shows a preference for products with 1- to 4-hour event durations. As a result, AEG assumes that the Non-residential Day-Ahead program can respond for a maximum of four hours and assumes zero impacts during the fifth hour of the RA window (9:00 PM-10:00 PM for May, 8:00 PM-9:00 PM otherwise).

These assumptions result in a flat 39.9 MW load impact forecast for an August peak day from 2024-2034.

PG&E expects the program to produce more reliable MW nominations due to key program changes implemented in PY2022, especially the $650/MWh bid cap.

Figure 4‑8 shows PG&E’s Non-residential Day-Ahead per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2024 for the PG&E 1-in-2 weather condition. The hours highlighted in blue show the RA window, 4:00 PM-9:00 PM.

Figure 4‑8 PG&E Non-Residential Day-Ahead: Hourly Per-Customer Load (PG&E 1-in-2, August Peak Day, 2024)



### Comparison of Ex-Ante Impacts

This section discusses how the PY2023 ex-ante load impacts compare to:

* PY2023 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios, and
* PY2022 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

Table 4‑14 compares the current ex-post estimates with the current ex-ante estimates. The current ex-post estimates show average load impacts for PY2023 dispatched events, while the current ex-ante estimates show how the program would have performed in a 1-in-2 weather year for a system-level event. Note that the ex-ante estimates in this comparison are for a 2023 typical event day on the maximum impact hour (4:00 PM-5:00 PM), which is most comparable to the ex-post average event day reporting hour: (6:00 PM-7:00 PM) for Non-residential and 7:00 PM-8:00 PM for Residential. Note, In ex-post PG&E only dispatched events for specific Sub-LAPs in PY2023, rather than for the entire system. Therefore, the ex-post per-customer impacts reflect the specific Sub-LAPs that were called for events while ex-ante estimates the system-level event.

For Non-residential Day-Ahead, this comparison indicates that PY2023 participants had the potential to deliver over 41 MW if the market triggered a system-level event. This expectation accounts for the anticipated participation of more large customers.

For Residential Day-Ahead, the comparison shows that PY2023 participants could achieve a higher impact of 0.1 MW. This forecast is based on the assumption that after the learning curve, the dispatch and response will better align, leading to improved performance.

Table 4‑14 PG&E: Current Ex-Ante (PG&E 1-in-2, 2023 Typical Event Day, Maximum Impact) v. Current Ex-Post (Average Event Day, HE19)

| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Residential Day-Ahead | **Current Ex-Ante** | **356** | 0.3 | 0.1 | 0.9 | 0.3 | 36% | **85** |
| Current Ex-Post | 236 | XXX | XXX | XXX | XXX | XXX | 79 |
| Non-Res Day-Ahead | **Current Ex-Ante** | **790** | **164.2** | **41.3** | **207.9** | **52.3** | **25%** | **90** |
| Current Ex-Post | 430 | 94.3 | 20.5 | 219.2 | 47.7 | 22% | 91 |

Table 4‑15 compares the previous ex-ante forecast to the current ex-ante forecast, both for the year 2024. This comparison demonstrates how the program forecast was updated since last year. These changes are the following:

* The Residential forecast was updated to account for higher enrollment and aggregate load impacts, but with smaller per-customer impacts.
* The Non-residential enrollment forecast has been updated to reflect slightly higher per-customer load impacts and increased customer enrollment, leading to higher aggregate load impacts.

Table 4‑15 PG&E: Current v. Prior Ex-Ante (PG&E 1-in-2, August Peak Day, 2024), RA Window

| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Res DA | **PY2023 Forecast** | **3,158** | **4.0** | **0.7** | **1.3** | **0.2** | **18%** | **84** |
| PY2022 Forecast | 1,743 | 1.2 | 0.3 | 0.7 | 0.2 | 39% | 84 |
| Non-Res DA | **PY2023 Forecast** | **1,130** | **206.1** | **39.9** | **182.4** | **35.3** | **19%** | **84** |
| PY2022 Forecast | 980 | 164.3 | 33.5 | 167.6 | 34.2 | 21% | 84 |

## PG&E Ex-Post Impacts by Event Day

Table 4‑16, Table 4‑17, and Table 4‑18 show the average event hour impacts for the Non-Residential DA (without and with weekends) and Residential DA programs. PG&E also dispatched a number of test[[53]](#footnote-54) events for the Non-residential DA, and those results are presented in Table 4‑19 and Table 4‑20. Each table includes:

* The average number of accounts dispatched for the event.
* The total dispatched capacity, load impact, and delivery performance.
* The reference load (e.g., the estimated counterfactual load had the customer not been dispatched) and load impact per-customer.
* The average event window temperature.

Table 4‑16 PG&E Non-Residential Elect Day Ahead: Impacts by Event

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Event | **19** | **126** | **14.0** | **12.2** | **87%** | **420.1** | **96.4** | **23%** | **91** | Yes |
| Aug 15, 2023 | 19 - 20 | 186 | XXX | XXX | XXX | XXX | XXX | XXX | 94 | Yes |
| Aug 16, 2023 | 17 - 20 | 19 | 0.9 | 1.8 | 199% | 1109.2 | 93.7 | 8% | 84 | Yes |
| 18 - 20 | 4 | XXX | XXX | XXX | XXX | XXX | XXX | 93 | Yes |
| 18 - 21 | 151 | XXX | XXX | XXX | XXX | XXX | XXX | 92 | Yes |
| 19 - 20 | 12 | XXX | XXX | XXX | XXX | XXX | XXX | 95 | Yes |
| Oct 4, 2023 | 19 - 19 | 7 | XXX | XXX | XXX | XXX | XXX | XXX | 86 | Yes |

Table 4‑17 PG&E Non-Residential Elect Day Ahead with Weekends: Impacts by Event

| Event Day | Event Win-dow | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Event | **19** | **303** | **9.8** | **8.3** | **85%** | **135.8** | **27.5** | **20%** | **90** | Yes |
| Aug 15, 2023 | 19 - 20 | 443 | 13.3 | 12.2 | 92% | 128.1 | 27.7 | 22% | 92 | Yes |
| Aug 16, 2023 | 17 - 20 | 29 | XXX | XXX | XXX | XXX | XXX | XXX | 84 | No |
| 18 - 20 | 66 | XXX | XXX | XXX | XXX | XXX | XXX | 89 | Yes |
| 18 - 21 | 127 | 4.0 | 1.0 | 24% | 125.7 | 7.6 | 6% | 81 | Yes |
| 19 - 20 | 233 | 8.5 | 7.7 | 91% | 136.8 | 33.1 | 24% | 95 | Yes |
| Oct 4, 2023 | 19 - 19 | 12 | XXX | XXX | XXX | XXX | XXX | XXX | 87 | Yes |

Table 4‑18 PG&E Residential Elect Day Ahead: Impact by Event

| Event Day | Event Win-dow | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Event | 20 | 236 | XXX | XXX | XXX | XXX | XXX | XXX | 79 | Yes |
| Oct 3, 2023 | 16 - 19 | 92 | XXX | XXX | XXX | XXX | XXX | XXX | 73 | Yes |
| 18 - 20 | 111 | XXX | XXX | XXX | XXX | XXX | XXX | 74 | Yes |
| Oct 4, 2023 | 18 - 21 | 245 | XXX | XXX | XXX | XXX | XXX | XXX | 80 | Yes |
| 17 - 20 | 111 | XXX | XXX | XXX | XXX | XXX | XXX | 85 | Yes |
| Oct 5, 2023 | 18 - 21 | 245 | XXX | XXX | XXX | XXX | XXX | XXX | 85 | Yes |
| 17 - 20 | 111 | XXX | XXX | XXX | XXX | XXX | XXX | 88 | Yes |
| Oct 6, 2023 | 17 - 20 | 153 | XXX | XXX | XXX | XXX | XXX | XXX | 90 | Yes |
| Oct 19, 2023 | 19 - 19 | 111 | XXX | XXX | XXX | XXX | XXX | XXX | 83 | Yes |

Table 4‑19 PG&E Non-Residential Day Ahead Test Events

| Event Day | Event Win-dow | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Jun 30, 2023 | 17 - 18 | 15 | 2.4 | 1.4 | 59% | 1292.9 | 93.1 | 7% | 86 | Yes |
| Jun 30, 2023 | 19 - 20 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 98 | No |
| 20 - 20 | 131 | 14.1 | 10.0 | 71% | 166.1 | 76.3 | 46% | 88 | Yes |
| Jul 27, 2023 | 19 - 20 | 4 | XXX | XXX | XXX | XXX | XXX | XXX | 88 | Yes |
| 20 - 20 | 98 | XXX | XXX | XXX | XXX | XXX | XXX | 80 | Yes |
| 20 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 67 | Yes |
| Jul 28, 2023 | 20 - 21 | 5 | XXX | XXX | XXX | XXX | XXX | XXX | 99 | Yes |

Table 4‑20 PG&E Non-Residential Day Ahead with Weekends Test Events

| Event Day | Event Win-dow | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Jun 30, 2023 | 17 - 18 | 14 | XXX | XXX | XXX | XXX | XXX | XXX | 86 | Yes |
| 19 - 20 | 14 | XXX | XXX | XXX | XXX | XXX | XXX | 98 | Yes |
| 20 - 20 | 102 | XXX | XXX | XXX | XXX | XXX | XXX | 88 | Yes |
| Jul 27, 2023 | 19 - 20 | 27 | XXX | XXX | XXX | XXX | XXX | XXX | 87 | Yes |
| 20 - 20 | 252 | XXX | XXX | XXX | XXX | XXX | XXX | 82 | Yes |
| 20 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | XXX | 67 | Yes |
| 21 - 21 | 12 | XXX | XXX | XXX | XXX | XXX | XXX | 61 | Yes |
| Jul 28, 2023 | 20 - 21 | 50 | XXX | XXX | XXX | XXX | XXX | XXX | 90 | Yes |

### Additional Event Day Impacts for AutoDR Participants

The Automated Demand Response (AutoDR) program provides customers with incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electricity controls and management strategies.

In PY2023, the Elect DA product offering recruited AutoDR participants. Table 4‑21 and Table 4‑22 show the per-customer and aggregate ex-post impacts by PY2023 event day for the AutoDR participants in the Elect DA without and with weekend options, respectively. For comparison, we included the aggregate load shed test, which confirmed the load curtailment achievable by AutoDR customers during events. We indicated test[[54]](#footnote-55) events using red text—these test events have been excluded from the average event day.

Table 4‑21 PG&E Non-Residential Elect Day Ahead: AutoDR Participant Impacts by Event

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Load Shed Test | Load Impact | % Load Shed Test | Reference Load | Load Impact | % Impact |
| Avg. Event | 19 | 21 | 3.3 | 2.6 | 78% | 539.8 | 121.7 | 23% | 97 |
| 30-Jun-23 | 17 - 18 | 3 | XXX | XXX | XXX | XXX | XXX | XXX | 86 |
| 20 - 20 | 15 | 1.7 | 0.4 | 22% | 206.8 | 23.8 | 12% | 88 |
| 27-Jul-23 | 20 - 20 | 10 | XXX | XXX | XXX | XXX | XXX | XXX | 84 |
| 28-Jul-23 | 20 - 21 | 3 | XXX | XXX | XXX | XXX | XXX | XXX | 99 |
| 15-Aug-23 | 19 - 20 | 21 | 3.3 | 2.4 | 73% | 564.4 | 114.5 | 20% | 97 |
| 16-Aug-23 | 17 - 20 | 3 | XXX | XXX | XXX | XXX | XXX | XXX | 85 |
| 18 - 21 | 16 | XXX | XXX | XXX | XXX | XXX | XXX | 97 |
| 19 - 20 | 2 | XXX | XXX | XXX | XXX | XXX | XXX | 94 |

Table 4‑22 PG&E Non-Residential Elect Day Ahead with Weekends: AutoDR Participant Impacts by Event

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Load Shed Test | Load Impact | % Load Shed Test | Reference Load | Load Impact | % Impact |
| Avg. Event | 19 | 99 | XXX | XXX | XXX | XXX | XXX | XXX | 99.3 |
| 30-Jun-23 | 17 - 18 | 6 | XXX | XXX | XXX | XXX | XXX | XXX | 85.9 |
| 30-Jun-23 | 19 - 20 | 2 | XXX | XXX | XXX | XXX | XXX | XXX | 95.8 |
| 20 - 20 | 50 | 2.4 | 3.2 | 132% | 92.5 | 64.2 | 69% | 94.8 |
| 27-Jul-23 | 19 - 20 | 2 | XXX | XXX | XXX | XXX | XXX | XXX | 87.3 |
| 20 - 20 | 53 | 1.9 | 0.9 | 45% | 66.1 | 16.3 | 25% | 89.4 |
| 28-Jul-23 | 20 - 21 | 2 | XXX | XXX | XXX | XXX | XXX | XXX | 80.5 |
| 15-Aug-23 | 19 - 20 | 99 | XXX | XXX | XXX | XXX | XXX | XXX | 99.5 |
| 16-Aug-23 | 17 - 20 | 6 | XXX | XXX | XXX | XXX | XXX | XXX | 84.5 |
| 18 - 20 | 8 | XXX | XXX | XXX | XXX | XXX | XXX | 84.1 |
| 18 - 21 | 6 | 0.1 | 0.0 | 27% | 110.9 | 5.4 | 5% | 82.8 |
| 19 - 20 | 79 | 5.9 | 5.7 | 96% | 141.2 | 72.0 | 51% | 99.6 |

### Additional Summary of Dispatched Events

Table 4‑23 shows the number of Sub-LAPs, the event hours, and the number of accounts dispatched on each event day. This table includes test events (shown in red and removed from all averages). For reference, Table 4‑1 presents the total monthly enrollment for the Non-Residential DA and Residential DA products, which would be comparable to dispatched counts for a system-level event, i.e., all nominated customers are dispatched.

Table 4‑23 PG&E Dispatched Events

| Date | Day of  Week | # of  Sub-LAPs | Event Hours  (HE) | # Accounts | |
| --- | --- | --- | --- | --- | --- |
| Non-Residential Elect DA | Residential Elect DA |
| Avg. Event | **-** | **14** | **19/20** | **132** |  |
| June 30, 2023 | Friday | 11 | 17-18, 19-20, 20-20 | 277 | - |
| July 27, 2023 | Thursday | 12 | 19-20, 20-20, 20-21, 21-21 | 402 | - |
| July 28, 2023 | Friday | 2 | 20-21 | 55 | - |
| August 15, 2023 | Tuesday | 14 | 19-20 | 629 | - |
| August 16, 2023 | Wednesday | 15 | 17-20, 18-20, 18-21, 19-20 | 641 | - |
| October 3, 2023 | Tuesday | 2 | 16-19, 18-20 | 0 | 203 |
| October 4, 2023 | Wednesday | 4 | 17-20, 18-21, 19-19 | 19 | 356 |
| October 5, 2023 | Thursday | 3 | 17-20, 18-21 | 0 | 356 |
| October 6, 2023 | Friday | 1 | 17-20 | 0 | 153 |
| October 19, 2023 | Thursday | 1 | 19-19 | 0 | 111 |

# 

Southern California Edison

This section presents Southern California Edison’s (SCE) PY2023 Capacity Bidding Program (CBP) descriptions and expected program changes, participation, ex-post load impact estimates, ex-ante load impact estimates, and key findings.

**SCE Program Description**

SCE’s two CBP programs, Non-Residential DA and Non-Residential DO, offer one product each:

* DA 1-6 Hour – day-ahead notifications with events lasting 1-6 hours.
* DO 1-6 Hour – day-of notifications with events lasting 1-6 hours.

Effective January 19, 2020, the CBP dispatch window changed to 3 PM – 9 PM to better align with the resource acquisition (RA) window (4 PM – 9 PM). SCE CBP events are determined by CAISO market awards and may be called Monday through Friday, excluding holidays, year-round, with a maximum of five events and 30 hours per month.

Residential CBP is now open to aggregators as a full program using a 5-in-10 baseline, but SCE has not yet received nominations.

**Program Changes**

In 2022, SCE submitted DR Application A22-05-004. SCE expects a CPUC decision on the proposed changes by later 2023. The proposed changes to be effective in 2024 include the following:

* Discontinue the Day Of program and products.
* Switch to a summer-only program (May through October).
* Change the CBP dispatch window to 4 PM to 9 PM, aligning with the RA window.
* Require aggregators to commit to bidding into an entire season, allowing for month-to-month adjustments on capacity nominations.
* Adjust the 15-day limit to a 75-day limit for bid entry.
* Increase the maximum number of events allowed per month from five to six events, with the same number of available hours (30 hours per month).
* Discontinue the Day Ahead summer program after 2024.

New CBP Elect DA program:

* In 2025, SCE is going to introduce a new CBP Elect Day Ahead program featuring three distinct price triggers: $200, $400 and $600. SCE may call an event whenever the day-ahead market price equals or exceeds any of these specified price triggers.

**SCE Program Nominations**

Table 5‑1 shows the total number of accounts and nominated capacity enrolled in SCE’s CBP programs in each month. In PY2023, only one customer enrolled in the Non-Residential DA program with an average nomination of XXX MW during summer months. The Non-Residential DO program enrolled XXX MW through 13 customers for non-summer months (November – April) and XXX MW (42 customers) for the summer months (May – October). Table 5‑2 and the accompanying figure show the size and industry distribution of the non-residential enrollees. Nearly all customers came from the retail sector, consistent with the PY2022 program. Notably, SCE’s PY2023 CBP program enrolled about half the number of accounts and nominations included in the average PY2022 summer month.

Table 5‑1 SCE Monthly Nominations

| Month | Non-Residential DA | | Non-Residential DO | |
| --- | --- | --- | --- | --- |
| Enrolled  Accounts | Nominated Capacity (MW) | Enrolled  Accounts | Nominated Capacity (MW) |
| November | - | - | 13 | XXX |
| December | - | - | 13 | XXX |
| January | - | - | 13 | XXX |
| February | - | - | 13 | XXX |
| March | - | - | 13 | XXX |
| April | - | - | 13 | XXX |
| Avg. Non-Summer | **-** | **-** | **13** | XXX |
| May | 1 | XXX | 43 | XXX |
| June | 1 | XXX | 40 | XXX |
| July | 1 | XXX | 42 | XXX |
| August | 1 | XXX | 42 | XXX |
| September | 1 | XXX | 41 | XXX |
| October | 1 | XXX | 43 | XXX |
| Avg. Summer | **1** | XXX | **42** | XXX |

*Table 5‑2 SCE Non-Residential Enrollment*

| Industry Type | Size Group | | | Total |
| --- | --- | --- | --- | --- |
| Small | Medium | Large |
| 1. Agriculture, Mining & Construction | - | - | - | **-** |
| 2. Manufacturing | - | - | - | **-** |
| 3. Wholesale, Transport, Other Utilities | - | - | - | **-** |
| 4. Retail Stores | - | 27 | 12 | **39** |
| 5. Offices, Hotels, Finance, Services | - | - | 4 | **7** |
| 6. Schools | - | - | 1 | **1** |
| 7. Institutional/ Government | - | - | 1 | **1** |
| 8. Other/Unknown | - | - | - | **-** |
| Total | **-** | **27** | **18** | **45** |

A purple pie chart with white lines

Description automatically generated

aAEG binned customers by the size of their maximum hourly consumption on non-event days into small (<20 kW), medium (≥20 kW and <200 kW), and large (≥200 kW) groups.

**SCE Key Findings**

The PY2023 LI analysis has the following key findings for SCE’s CBP:

* There was a notable decline in Non-residential CBP participation across both DA and DO programs particularly during summer season. This decline can be attributed in part, to SCE having a few major contributor aggregators, which enrolled only minimal numbers of customers in 2023.
* The Non-Residential DA only included one customer who delivered small, negative impacts (XXX MW) during the average PY2023 summer event (a XXX delivery performance). This customer delivered XXX of their dispatched capacity during the average July event, but their underperformance during the August event (XXX of dispatched capacity) led to an overall negative impact for the PY2023 summer season. Upon examining the statistical significance, it was concluded that this impact was not significant, suggesting it is indifferent from zero.
* The estimated impacts for the Non-residential DO program depended heavily on the performance of one school customer that had substantially larger load than the other customers in the program.
* During the summer season, the Non-residential DO experienced a decline in enrollment with 42 customers enrolled in the average month. However, the delivery performance remained at XXX , which is higher than 2020 and 2021.
  + HE18 (5 PM – 6 PM) was the most dispatched event hour in summer PY2023, and customers delivered the highest impacts during this hour of the average event day.
* Non-Residential DO’s non-summer season remained a small collective resource but improved overall delivery performance from previous years. Non-Residential DA did not have active non-summer participation.
* HE20 (7 PM – 8 PM) is the most dispatched event hour and with the highest impact on average event day, in 2023 for the non-summer season.[[55]](#footnote-56)
* SCE updated the ex-ante enrollment forecast to be consistent with the submitted DR Application A22-05-004, which includes the following assumptions:
* Updated according to 2023 DO nominations,
* 2024 through 2033: zero enrollment in non-summer months and the DO program
* 2024: assume 100% of DO participants will move to the DA program, and
* 2025: closing out the original CBP program; assume increase in enrollment due to the new CBP Elect DA program with 3 price triggers; $200, $400, and $600.
* 2023 impacts are confidential.

**SCE Ex-Post Analysis**

This section describes the PY2023 events, summarizes the ex-post impacts estimated for PY2023 dispatched events, and compares the ex-post to the PY2022 ex-ante forecast for 2023.

**Dispatched Events**

We present a summary of the PY2023 events for SCE’s CBP Non-residential DA and DO programs. SCE’s CBP program is offered year-round, and the PY2023 evaluation period covers November 2022 through October 2023. We report impacts separately for the non-summer months (November-April) and summer months (May-October).

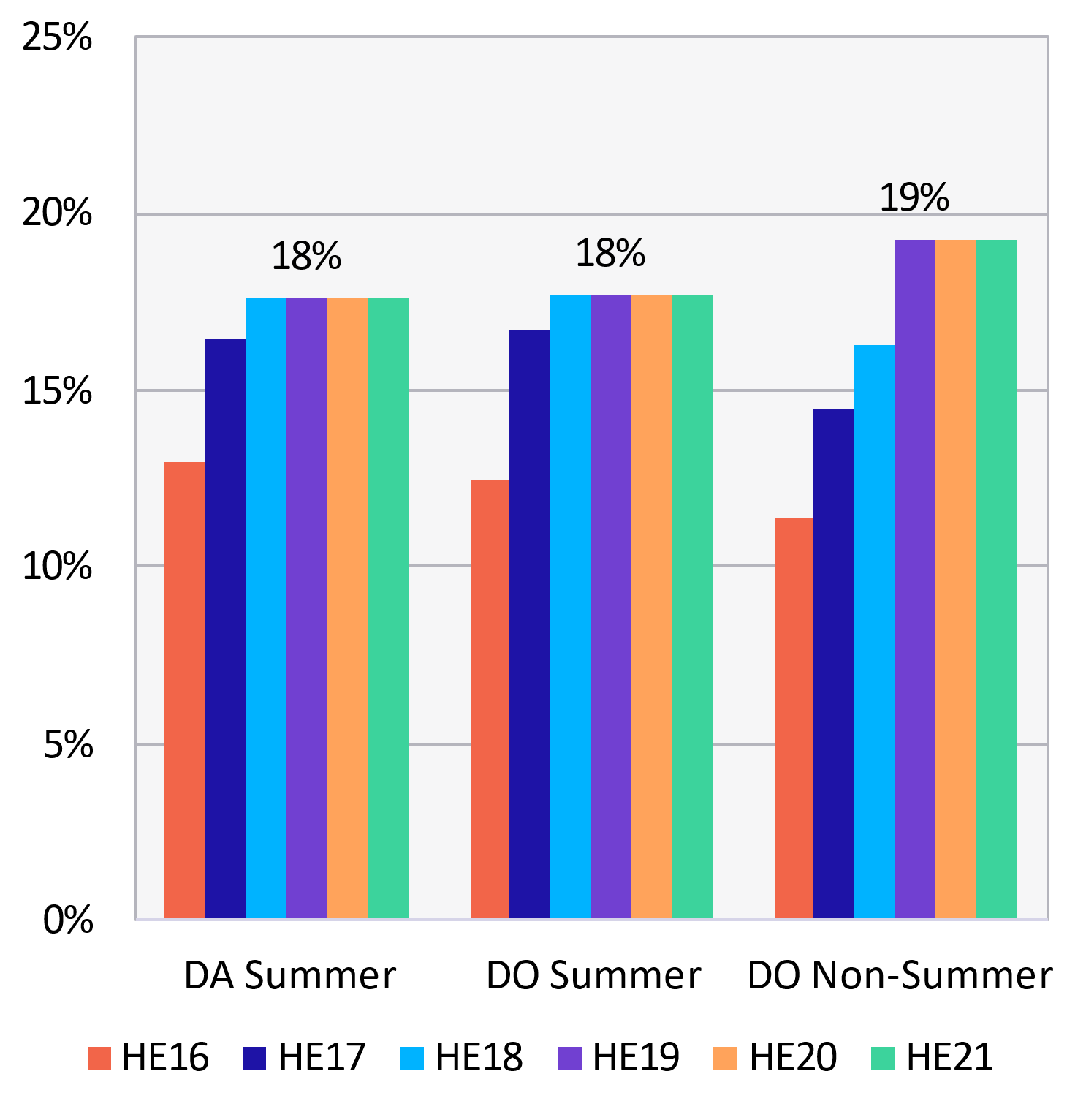
Similar to previous years, SCE dispatched a combination of partial- and system-level events. *Table 5‑3* shows the total dispatched event days and hours by month, season, and program. The DA participants experienced six event days and 33 event hours over the program year, while DO participants experienced 40 event days and 214 event hours.

As in previous years, events are dispatched at various times and durations within the 3 PM to 9 PM dispatch window. Figure 5‑1 shows the distribution of each program and season’s dispatched hours across events, weighted by dispatched customers. The most dispatched hours in PY2023 were HE20 (non-summer) and HE18 (summer).

We include details of the non-summer and summer events in Table 5‑3.

*Table 5‑3 SCE Event Summary[[56]](#footnote-57)*

Figure 5‑1 SCE Event Hour Distribution



| Month | Non-Res DA | | Non-Res DO | |
| --- | --- | --- | --- | --- |
| Total  Event Days | Total  Event Hours | Total  Event Days | Total  Event Hours |
| November | - | - | 6 | 35 |
| December | - | - | 5 | 30 |
| January | - | - | 5 | 30 |
| February | - | - | 4 | 24 |
| March | - | - | 6 | 27 |
| April | - | - | 5 | 15 |
| Non-Summer | - | - | 31 | 161 |
| May | - | - | - | - |
| June | - | - | - | - |
| July | 2 | 12 | 3 | 18 |
| August | 1 | 6 | 4 | 24 |
| September | - | - | - | - |
| October | 3 | 15 | 2 | 11 |
| Summer | 6 | 33 | 9 | 53 |

**Load Impact Summary**

*Table 5‑4* summarizes PY2023 impacts for the average event day, by program and season, for the most dispatched hour (HE20 for non-summer months and HE18 for summer months). Specifically, it shows:

*Table 5‑4* includes the average event day:

* The average number of accounts dispatched across events.
* The total dispatched capacity, load impact, and delivery performance for the average event day.
* The reference load (e.g., the estimated counterfactual load had the customer not been dispatched) and load impact per-customer for the average event day.

SCE’s summer enrollees delivered XXX MW out of XXX MW dispatched on average across event days during HE18, an average delivery performance of XXX During the non-summer months, customers delivered XXX (XXX MW) of the dispatched XXX MW.

*Table 5‑4 SCE Impacts Summary, Average Event Day PY2023*

| Season &  Program | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Non-Summer DA | - | - | - | - | - | - | - |
| Non-Summer DO | 12 | XXX | XXX | XXX | XXX | XXX | XXX |
| Total Non-Summer | **12** | XXX | XXX | XXX | XXX | XXX | XXX |
| Summer DA | 1 | XXX | XXX | XXX | XXX | XXX | XXX |
| Summer DO | 42 | XXX | XXX | XXX | XXX | XXX | XXX |
| Total Summer | **43** | XXX | XXX | XXX | XXX | XXX | XXX |

*Table 5‑5* and *Table 5‑6* show the number of accounts and capacity nominated for each month, the amount dispatched across all event days and event hours and for the most-dispatched hour, and the estimated ex-post impacts for SCE’s two CBP programs.

The Non-Residential DA only included one customer who delivered small, negative impacts (XXX MW) during the average PY2023 summer event (a XXX delivery performance). However, this customer delivered XXX of their dispatched capacity during the average July events (12 event hours across two separate events). Their underperformance during the August event XXX of dispatched capacity) led to an overall negative impact for the PY2023 summer season. Upon examining the statistical significance, it was concluded that this impact was not significant, suggesting it is indifferent from zero.

Non-Residential DO customers delivered an average of XXX MW during the average PY2023 summer event, amounting to a XXX delivery performance overall. Delivered capacity during October events (XXX of the 1.2 MW dispatched) outperformed that in other summer months. Notably, these results depended heavily on the performance of one school customer that had substantially larger load than the other customers in the program.

For the non-summer season, Non-residential DO delivered XXX MW, a XXX delivery performance. While seemingly low, this is an improvement over previous years and represents the highest delivery performance since 2020. January events had the highest delivery performance of the other non-summer months (87%).

*Table 5‑5 SCE Non-Residential DA Monthly Summary*

| Month | Nominations | | Dispatched | | HE\* Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered | Adj. % Delivered |
| May | 1 | XXX | - | - | - | - | - | - | - |
| June | 1 | XXX | - | - | - | - | - | - | - |
| July | 1 | XXX | 1 | XXX | 1 | XXX | XXX | XXX | XXX |
| August | 1 | XXX | 1 | XXX | 1 | XXX | XXX | XXX | XXX |
| September | 1 | XXX | - | - | - | - | - | - | - |
| October | 1 | XXX | 1 | XXX | 1 | XXX | XXX | XXX | XXX |
| Avg. Summer | **1** | XXX | **1** | XXX | **1** | XXX | XXX | XXX | XXX |

*Table 5‑6 SCE Non-Residential DO Monthly Summary*

| Month | Nominations | | Dispatched | | HE\* Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered | Adj. % Delivered |
| November | 13 | XXX | - | - | - | - | - | - | - |
| December | 13 | XXX | - | - | - | - | - | - | - |
| January | 13 | XXX | 13 | XXX | 13 | XXX | XXX | XXX | XXX |
| February | 13 | XXX | 13 | XXX | 13 | XXX | XXX | XXX | XXX |
| March | 13 | XXX | 11 | XXX | 11 | XXX | XXX | XXX | XXX |
| April | 13 | XXX | 13 | XXX | 13 | XXX | XXX | XXX | XXX |
| Avg. Non-Summer | **12** | XXX | **12** | XXX | **12** | XXX | XXX | XXX | XXX |
| May | 43 | XXX | - | - | - | - | - | - | - |
| June | 40 | XXX | - | - | - | - | - | - | - |
| July | 42 | XXX | 42 | XXX | 42 | XXX | XXX | XXX | XXX |
| August | 42 | XXX | 42 | XXX | 42 | XXX | XXX | XXX | XXX |
| September | 41 | XXX | - | - | - | - | - | - | - |
| October | 43 | XXX | 43 | XXX | 43 | XXX | XXX | XXX | XXX |
| Avg. Summer | **42** | XXX | **42** | XXX | **42** | XXX | XXX | XXX | XXX |

***Hourly Load Impacts***

*Figure 5‑2*, *Figure 5‑3*, and *Figure 5‑4* show hourly profiles for the average Non-Residential DA customer in the summer months and Non-Residential DO customer in the non-summer and summer months, respectively.[[57]](#footnote-58) Each shows the estimated reference load (i.e., what the customer would have consumed had an event not been called), the actual observed load, and the estimated load impacts for the average event day. The highlighted hours indicate that at least one group of customers was dispatched during that hour. The vertical dotted lines show the most dispatched hour (HE20 for non-summer months and HE18 for summer months).

*Figure 5‑2* *SCE Day-Ahead 1-6 Hour: Hourly Per-Customer Impact, Summer Average Event*

*Figure 5‑3 SCE Day-Of 1-6 Hour: Hourly Per-Customer Impact, Non-Summer Average Event*

*Figure 5‑4 SCE Day-Of 1-6 Hour: Hourly Per-Customer Impact, Summer Average Event*

***Load Impacts by Industry, LCA, and Sub-LAP***

*Table 5‑7* through *Table 5‑12* show the impacts for an average event day by industry, LCA, and Sub-LAP for each program and separately for non-summer and summer months.[[58]](#footnote-59)

*Table 5‑7 SCE CBP Impacts by Industry and Program, Non-Summer*

|  | Industry | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref.  Load | Impact |
| Retail Stores | 11 | XXX | XXX | XXX | XXX | XXX | 58 |
| Schools | 1 | XXX | XXX | XXX | XXX | XXX | 55 |
| **Total Day Of** | **12** | XXX | XXX | XXX | XXX | XXX | **70** |
| Total Non-Summer CBP | | **12** | XXX | XXX | XXX | XXX | XXX | **70** |

*Table 5‑8 SCE CBP Impacts by Industry and Program, Summer*

|  | Industry | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref.  Load | Impact |
| Day Ahead | Agriculture, Mining & Construction | 0 | - | - | - | - | - | 72 |
| Wholesale, Transport, other utilities | 0 | - | - | - | - | - | 92 |
| Retail Stores | 0 | - | - | - | - | - | 84 |
| Offices, Hotels, Finance, Services | 0 | - | - | - | - | - | 88 |
| Institutional/Government | 1 | XXX | XXX | XXX | XXX | XXX | 95 |
| **Total Day Ahead** | **1** | XXX | XXX | XXX | XXX | XXX | **84** |
| Day Of | Manufacturing | 0 | - | - | - | - | - | 93 |
| Retail Stores | 37 | 4.4 | 0.5 | 116.6 | 14.1 | 12% | 86 |
| Offices, Hotels, Finance, Services | 4 | XXX | XXX | XXX | XXX | XXX | 85 |
| Schools | 1 | XXX | XXX | XXX | XXX | XXX | 72 |
| **Total Day Of** | **42** | XXX | XXX | XXX | XXX | XXX | **85** |
| Total Summer CBP | | **43** | XXX | XXX | XXX | XXX | XXX | **90** |

*Table 5‑9 SCE CBP Impacts by LCA and Program, Non-Summer*

|  | Local Capacity Area | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref.  Load | Impact |
| Day Of | LA Basin | 8 | XXX | XXX | XXX | XXX | XXX | 59 |
| Ventura/Big Creek | 5 | XXX | XXX | XXX | XXX | XXX | 55 |
| **Total Day Of** | **12** | XXX | XXX | XXX | XXX | XXX | **57** |
| Total Non-Summer CBP | | **12** | XXX | XXX | XXX | XXX | XXX | **57** |

*Table 5‑10 SCE CBP Impacts by LCA and Program, Summer*

|  | Industry | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref.  Load | Impact |
| Day Ahead | LA Basin | 1 | XXX | XXX | XXX | XXX | XXX | 95 |
| **Total Day Ahead** | **1** | XXX | XXX | XXX | XXX | XXX | **95** |
| Day Of | LA Basin | 37 | 4.8 | 0.6 | 127.8 | 16.6 | 13% | 87 |
| Ventura/Big Creek | 5 | XXX | XXX | XXX | XXX | XXX | 77 |
| **Total Day Of** | **42** | XXX | XXX | XXX | XXX | XXX | **85** |
| Total Summer CBP | | **43** | XXX | XXX | XXX | XXX | XXX | **90** |

*Table 5‑11 SCE CBP Impacts by Sub-LAP and Program, Non-Summer*

|  | Sub-LAP | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref.  Load | Impact |
| Day Of | SCEC | 2 | XXX | XXX | XXX | XXX | XXX | 71 |
| SCEW | 6 | XXX | XXX | XXX | XXX | XXX | 70 |
| SCNW | 5 | XXX | XXX | XXX | XXX | XXX | 71 |
| **Total Day Of** | **12** | XXX | XXX | XXX | XXX | XXX | **70** |
| Total Non-Summer CBP | | **5** | XXX | XXX | XXX | XXX | XXX | **55** |

*Table 5‑12 SCE CBP Impacts by Sub-LAP and Program, Summer*

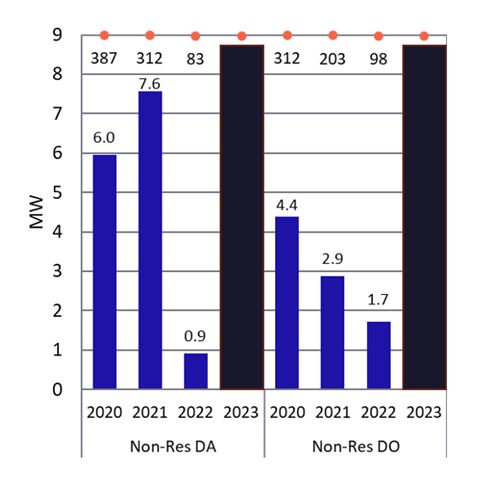
|  | Sub-LAP | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Impact | Ref. Load | Impact | Ref. Load |
| Day Ahead | SCEC | 1 | XXX | XXX | XXX | XXX | XXX | 91 |
| **Total Day Ahead** | 1 | XXX | XXX | XXX | XXX | XXX | **84** |
| Day Of | SCEC | 19 | XXX | XXX | XXX | XXX | XXX | 92 |
| SCEW | 18 | XXX | XXX | XXX | XXX | XXX | 79 |
| SCNW | 5 | XXX | XXX | XXX | XXX | XXX | 80 |
| **Total Day Of** | 42 | XXX | XXX | XXX | XXX | XXX | **85** |
| Total Summer CBP | | 43 | XXX | XXX | XXX | XXX | XXX | 90 |

**Comparison of Ex-Post Impacts**

This section discusses how the PY2023 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast.

Figure 5‑5 shows SCE’s average summer nominations for PY2020 through PY2023, and *Table 5‑13* shows the same for summer and non-summer.

Figure 5‑5 SCE Summer Nominations



Despite consistently low enrollment in the non-summer season, Non-Residential DO customers continued to improve their performance relative to dispatched capacity. Notably, the enrolled Non-residential DO customers, while slightly smaller in size, delivered double the load reductions and increased delivery performance XXX compared to 2022.

Conversely, the summer season experienced a decline in both the number of enrolled accounts and delivered capacity, likely due to SCE’s low enrollment in 2023. However, the Non-residential DO program successfully recruited larger customers, helping it maintain an outstanding delivery performance, even with over a 50% decrease in enrollment compared to 2022.

*Table 5‑13 SCE: Current v. Previous Ex-Post, Average Event Day*

| Season | Program | Year | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Non-Summer | **Non-Res  DA** | 2020 | 3 | XXX | XXX | XXX | XXX | XXX | XXX | 78 |
| 2021 | 6 | XXX | XXX | XXX | XXX | XXX | XXX | 61 |
| 2022 | - | - | - | - | - | - | - | - |
| **2023** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Non-Res DO** | 2020 | 5 | XXX | XXX | XXX | XXX | XXX | XXX | 62 |
| 2021 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 62 |
| 2022 | 7 | XXX | XXX | XXX | XXX | XXX | XXX | 70 |
| **2023** | **12** | XXX | XXX | XXX | XXX | XXX | XXX | **57** |
| Summer | **Non-Res  DA** | 2020 | 387 | 6.0 | 3.9 | 65% | 35.1 | 3.9 | 11% | 80 |
| 2021 | 312 | 7.6 | 4.0 | 53% | 81.1 | 12.8 | 16% | 82 |
| 2022 | 83 | 0.9 | 1.1 | 117% | 78.8 | 12.8 | 16% | 84 |
| **2023** | **1** | XXX | XXX | XXX | XXX | XXX | XXX | **95** |
| **Non-Res DO** | 2020 | 312 | XXX | XXX | XXX | XXX | XXX | XXX | 78 |
| 2021 | 203 | 2.9 | 2.0 | 70% | 95.7 | 10.0 | 10% | 79 |
| 2022 | 98 | XXX | XXX | XXX | XXX | XXX | XXX | 85 |
| **2023** | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 85 |

*Table 5‑14* shows the PY2023 ex-post impacts compared to PY2022 ex-ante impacts for a 2023 January (non-summer) or August (summer) peak day. Note that the ex-ante impacts forecast performance for a system-level dispatch. AEG identified the following key findings:

* In the non-summer season of 2023, the performance exceeded the forecast from 2022, with a slightly lower number of participants.
* In PY2023, the summer months experienced a drop in overall enrollment. However, the Non-Residential DO program successfully recruited better-performing customers and so the aggregate impact exceeded the 2022 forecast with a much lower number of participants.

*Table 5‑14 SCE Current Ex-Post (Average Event Day) v. Prior Ex-Ante (SCE 1-in-2, Peak Day, 2023)*

| Season | Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Non-Summer | **Non-Res DA** | PY2022 Ex-Ante | - | - | - | - | - | - | - |
| **Current Ex-Post** | - | - | - | - | - | - | - |
| **Non-Res DO** | PY2022 Ex-Ante | 15 | XXX | XXX | XXX | XXX | XXX | 62 |
| **Current Ex-Post** | **12** | XXX | XXX | XXX | XXX | XXX | **57** |
| Summer | **Non-Res DA** | PY2022 Ex-Ante | 150 | 11.3 | 0.9 | 75.6 | 5.7 | 8% | 89 |
| **Current Ex-Post** | **1** | XXX | XXX | XXX | XXX | XXX | **95** |
| **Non-Res DO** | PY2022 Ex-Ante | 150 | XXX | XXX | XXX | XXX | XXX | 89 |
| **Current Ex-Post** | **42** | XXX | XXX | XXX | XXX | XXX | **85** |

**SCE Ex-Ante Analysis**

**Enrollment and Load Impact Summary**

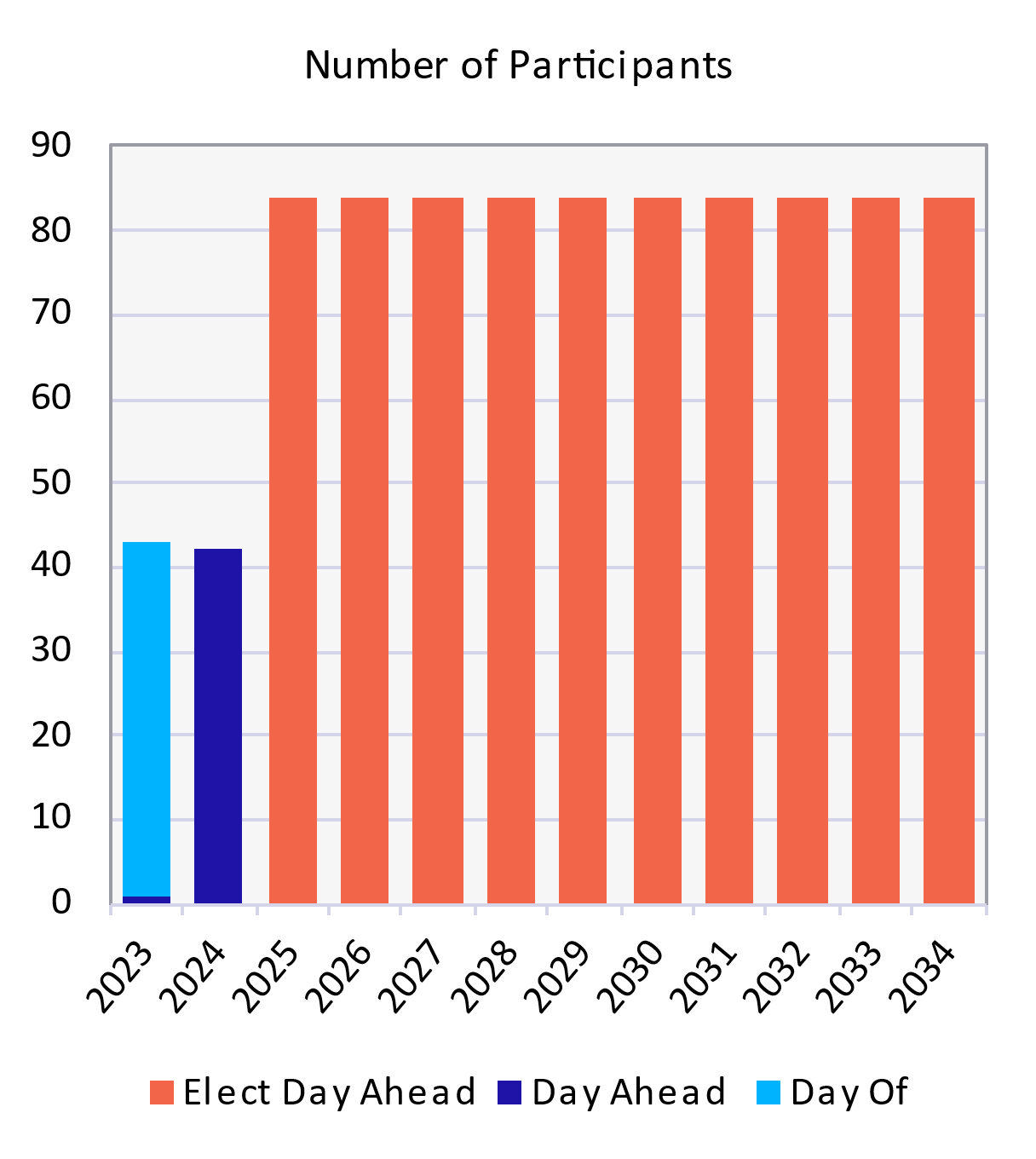
SCE’s 11-year forecast aligns with the submitted DR Application A22-05-004, updated according to average PY2023 enrollment. *Figure 5‑6* (August peak day, summer season) shows SCE’s Non-residential Day-Ahead and Day-Of enrollment and load impact forecast under the SCE 1-in-2 weather scenario.[[59]](#footnote-60) The figure includes the PY2023 “back-cast,” which consists of weather-adjusted ex-post estimates of the current program year. As SCE CBP will discontinue the non-summer month programs, AEG can only provide the 2023 "back-cast" for the non-summer months. According to the weather-adjusted ex-post estimates, 13 customers were able to achieve a load impact of XXX MW.

Consistent with the DR Application A22-05-004 are the following assumptions:

* In PY2024, SCE’s CBP will close out the Day-Of program and the non-summer season.
* In PY2024, SCE’s CBP Day-Ahead program will continue for one more year, with the summer season only.
* In PY2025, SCE’s current CBP will close out; the new CBP Elect Day-Ahead will start.

SCE hasn’t seen any residential enrollment since the program was introduced, so residential participation is assumed to be zero throughout the forecast period.

*Figure 5‑6 SCE CBP Enrollment and Load Impact Forecast (SCE 1-in-2, August Peak Day)*



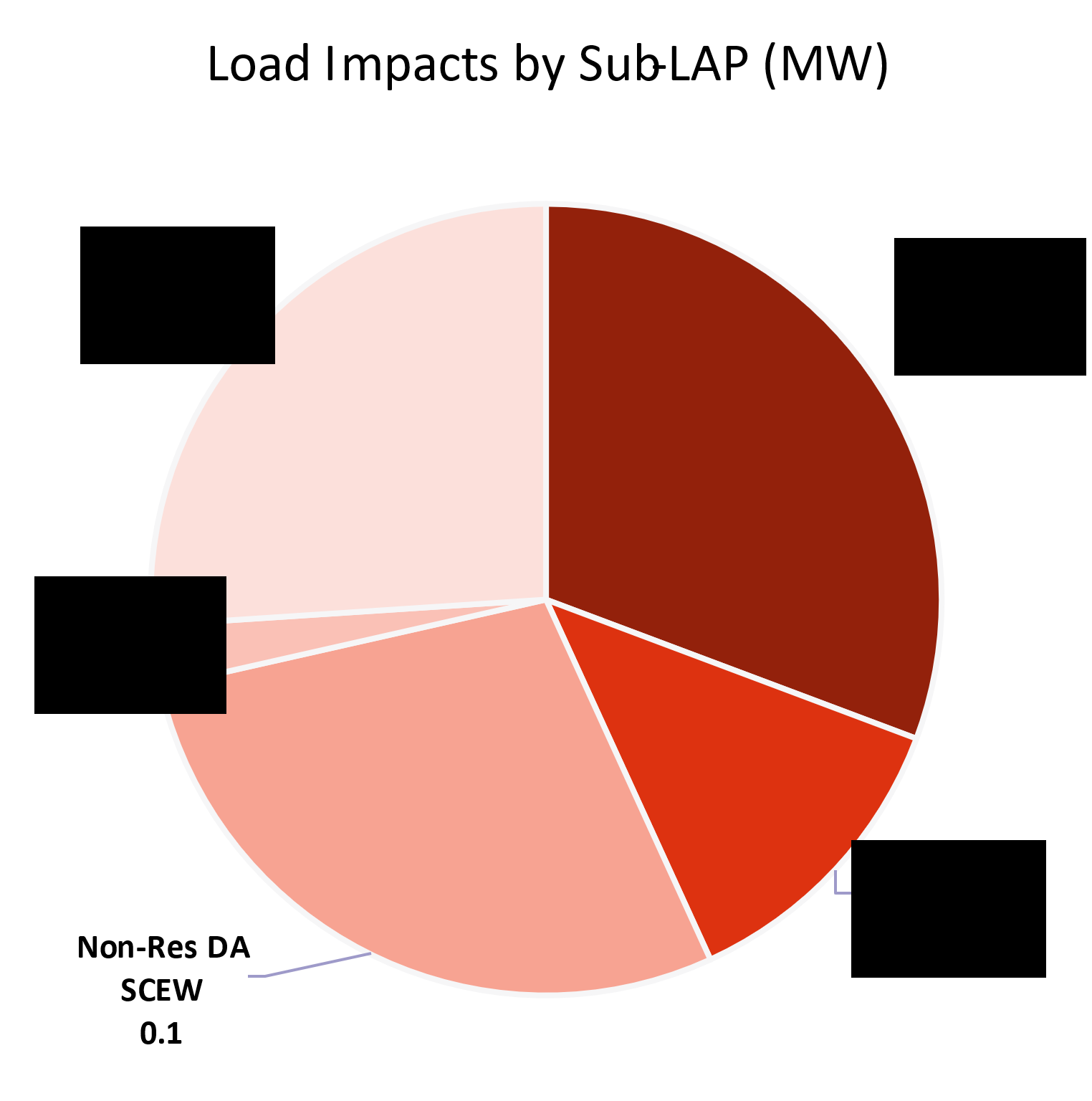
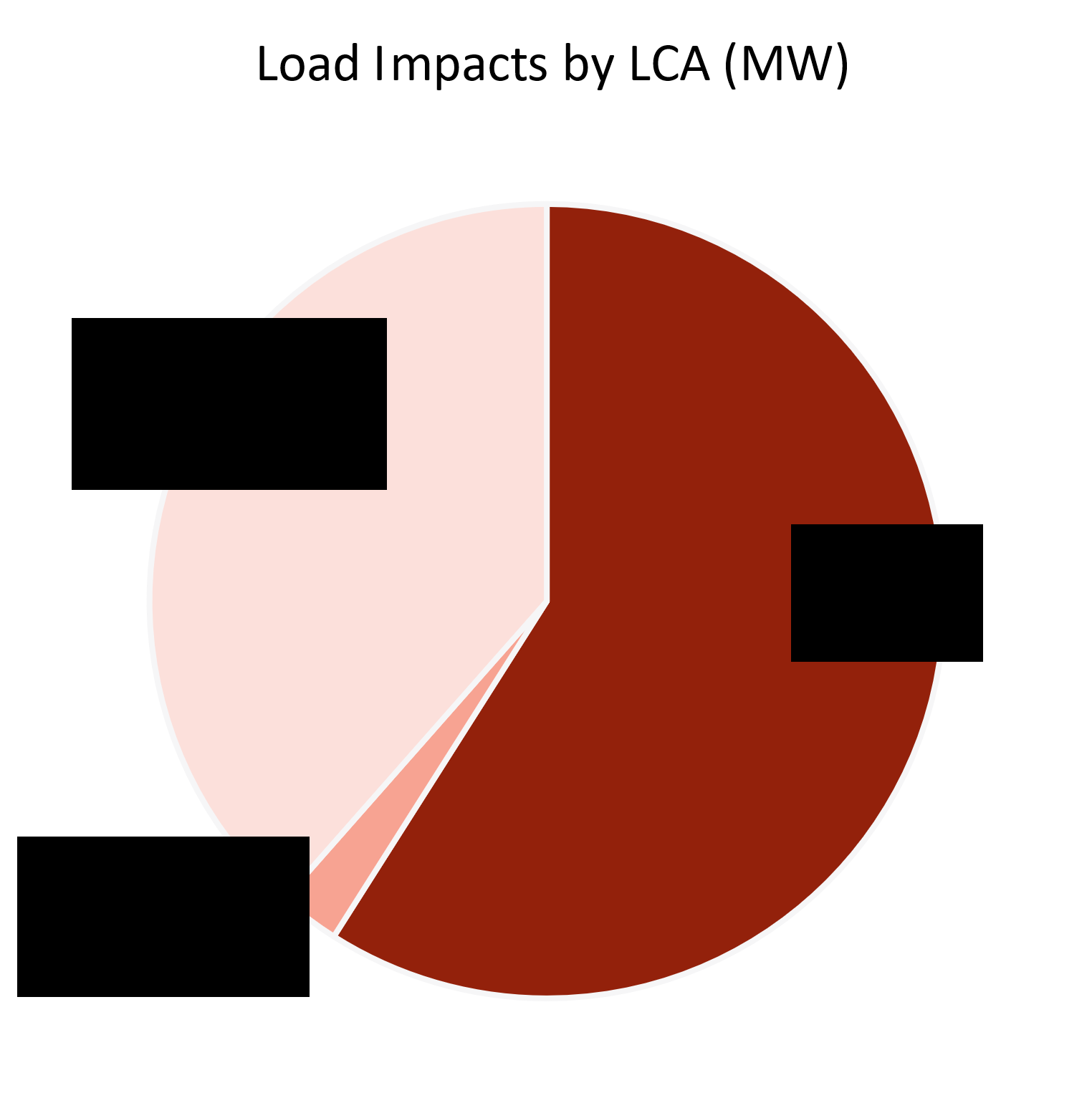
*Table 5‑15* summarizes the average RA window load impact forecasts for the Non-residential DA and DO products on an August peak day (summer) in 2024 and 2025. The table includes the per-customer, aggregate, and corresponding percent impacts under the utility and CAISO 1-in-2 and 1-in-10 weather scenarios. We assume constant per-customer average impacts across weather scenarios and forecast years. Any variations in the percentage of impacts are attributed to the reference load's response to each specific weather scenario.

*Table 5‑15 SCE Non-Residential: RA Window Ex-Ante Impacts, 2024*

| Year | Program | # of Accts | Per Customer Impact (kW) | Aggregate Impact (MW) | Percent Impact (%) | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Utility Peak | | CAISO Peak | |
| 1-in-2 | 1-in-10 | 1-in-2 | 1-in-10 |
| 2024 | Day Ahead | 42 | XXX | XXX | XXX | XXX | XXX | XXX |
| 2025 | Elect Day Ahead | 84 | XXX | XXX | XXX | XXX | XXX | XXX |

*Figure 5‑7* illustrates the average RA window load impact distribution by LCA and Sub-LAP for Non-residential Day-Ahead and Day-Of on an August peak day in 2024. The results shown are for 1-in-2 weather conditions for the utility peak. In 2025, the distribution by LCA and Sub-LAP will align with that of 2024. However, the aggregate impact MW will double in amount, reflecting the doubling in the customer count.

*Figure 5‑7 SCE: RA Window Load Impacts by LCA and Sub-LAP (SCE 1-in-2, August Peak Day, 2024)*



**Forecast Assumptions**

This section discusses the assumptions used to develop the Non-residential Day-Ahead and Day-Of forecasts. Both forecasts incorporate the following:

* **Enrollment Outlook** – consistent with the submitted DR Application A22-05-004:
* Updated according to PY2023’s Day-Of nominations.
* From 2024 through 2033, there will be zero enrollment in non-summer months and the Day-Of program.
* In 2024, assume 100% of PY2023 Day-Of summer participants will move to the Day-Ahead summer program.
* In 2025, discontinue the current CBP program, introduce the new CBP Elect Day-Ahead program, and assume more enrollment than PY2023.
* **Updated assumptions based on PY2023 performance** – AEG assumes the per-customer load impacts on reporting hour (5:00 PM-6:00 PM for summer) as the maximum impact during the RA window.
* **Impact Degradation Rate** – AEG developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the 5-hour RA window. The approach used to develop these assumptions is discussed in Section 3 [Impact Degradation Across the RA Window](#ImpactDeg). For SCE, we used PY2023 data to update the impact degradation rate. *Table 5‑16* shows the estimated shape of the impacts as a percent of the maximum load impact for each program and season.
* Both **per**-**customer impact** and **impact degradation** are dependent on the impact from PY2023 Day-Of program summer participants for the following reasons:
* In PY2023, there was only one Day-Ahead participant, which is insufficient to accurately represent the program in future years.
* CBP Day-Ahead will remain for just one more summer; it is reasonable to assume there will be minimal changes in participation compared to PY2023.
* In the new CBP Elect Day-Ahead program, AEG assumes that customers will look like those observed in 2023. The target customer group will remain relatively stable, with existing program participants maintaining their interest in the program.

*Table 5‑16 SCE CBP: RA Window Shape of Impacts*

| Summer | Program |  | | Percent of Maximum Impact | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 5:00 PM-6:00 PM | 6:00 PM-7:00 PM | | 7:00 PM-8:00 PM | 8:00 PM-9:00 PM | 9:00 PM-10:00 PM | Overall RA |
| Day Ahead/Elect Day Ahead | 100% | 78% | | 55% | 45% | 42% | 64% |

*Figure 5‑8* show SCE’s Non-residential Day-Ahead per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2024 and 2025 for the SCE 1-in-2 weather condition—the hours highlighted in blue show the RA window (4:00 PM to 9:00 PM). Since 2024 will be the last year of the current Day-Ahead summer program and the introduction of the new CBP Elect Day-Ahead in 2025, uncertainties arise. In this forecast, AEG assumes that the per-customer impact will remain the same for the next 11 years, matching the 2023 Day-Of participation.

*Figure 5‑8 SCE Non-Residential Day Ahead: Hourly Per-Customer Load (SCE 1-in-2, August Peak Day, 2024 & 2025)*

**Comparison of Ex-Ante Impacts**

This section discusses how the PY2023 ex-ante load impacts compare to:

* PY2023 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios, and
* PY2022 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

*Table 5‑17 SCE: Current Ex-Ante (SCE 1-in-2, 2023 Peak Day, Maximum Impact) v. Current Ex-Post (Average Event, Reporting Hour)Table 5‑17* compares **the current ex-post estimates with the current ex-ante estimates**. The current ex-post estimates show average load impacts for PY2023 dispatched events, while the current ex-ante estimates show how the program would have performed in a 1-in-2 weather year for a system-level event. Note that the ex-ante estimates in this comparison are for a 2023 August peak day on the maximum impact hour (4:00 PM-5:00 PM), which is most comparable to the ex-post average event day reporting hours: 7:00 PM-8:00 PM (non-summer) and 5:00 PM-6:00 PM (summer). Again, there was no Day-Ahead non-summer enrollment. In the Day-Of non-summer month "back cast," which assumes a system-level event, the increase in the per-customer reference load is attributed to customers who were enrolled but not dispatched during the ex-post reporting hour.

*Table 5‑17 SCE: Current Ex-Ante (SCE 1-in-2, 2023 Peak Day, Maximum Impact) v. Current Ex-Post (Average Event, Reporting Hour)*

| Season | Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref. Load | Impact |
| Non-Summer | **Day Ahead** | **Current**  **Ex-Ante** | - | - | - | - | - | - | - |
| Current  Ex-Post | - | - | - | - | - | - | - |
| **Day Of** | **Current**  **Ex-Ante** | **13** | XXX | XXX | XXX | XXX | XXX | **65** |
| Current  Ex-Post | 12 | XXX | XXX | XXX | XXX | XXX | 57 |
| Summer | **Day Ahead** | **Current**  **Ex-Ante** | **1** | XXX | XXX | XXX | XXX | XXX | **101** |
| Current  Ex-Post | 1 | XXX | XXX | XXX | XXX | XXX | 95 |
| **Day Of** | **Current**  **Ex-Ante** | **42** | XXX | XXX | XXX | XXX | XXX | **91** |
| Current  Ex-Post | 42 | XXX | XXX | XXX | XXX | XXX | 85 |

*Table 5‑18* compares **the previous ex-ante forecast to the current ex-ante forecast for 2024 and 2025**. This comparison demonstrates how the program forecast was updated since last year. These changes are the following:

* Moving forward, SCE's CBP will transition to a summer-only program. This comparison only considers the summer months.
* The summer forecast was updated based on PY2023 Day-Of program nominations and performance. It is assumed that in 2024, the remaining year of the Day-Ahead program, current Day-Of customers will move to Day-Ahead. In 2025, the new Elect Day Ahead will start, the target customer group will remain relatively steady, the customers currently on the program will retain their interest in the program, and it is also expected to attract more customers.
* Based on the 2023 forecast, In PY2024, SCE’s CBP will experience a drop in customer enrollments but saw increased per-customer load impacts. The overall decrease in customer enrollment resulted in lower aggregate load impacts.
* Based on the 2023 forecast, enrollment in SCE's CBP is expected to begin increasing again in PY2025 with more large customers expected to join.

*Table 5‑18 SCE: Current v. Prior Ex-Ante (SCE 1-in-2, Peak Day, 2024 & 2025), RA Window*

| Year | Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref. Load | Impact |
| 2024 | **Day Ahead** | **PY2023 Forecast** | **42** | XXX | XXX | XXX | XXX | XXX | **88** |
| PY2022 Forecast | 225 | 17.0 | 1.3 | 75.6 | 5.7 | 8% | 89 |
| 2025 | **Elect Day Ahead** | **PY2023 Forecast** | **84** | XXX | XXX | XXX | XXX | XXX | **88** |
| PY2022 Forecast | 848 | 64.1 | 4.9 | 75.6 | 5.7 | 8% | 89 |

**SCE Ex-Post Impacts by Event Day**

*Table 5‑19* to *Table 5‑21* show the average event-hour impacts for SCE’s two CBP programs by season, including:

* The average number of accounts dispatched for the event.
* The total dispatched capacity, load impact, and delivery performance.
* The reference load (e.g., the estimated counterfactual load had the customer not been dispatched) and load impact per-customer.
* The average event window temperature.

*Table 5‑19* *SCE Day Ahead 1-6 Hour: Summer Impacts by Event[[60]](#footnote-61)*

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Summer | **16** | **1** | XXX | XXX | XXX | XXX | XXX | XXX | **95** | **No** |
| Jul 17, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 95 | No |
| Jul 18, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 94 | No |
| Jul 20, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 97 | No |
| Jul 21, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 92 | No |
| Jul 24, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 97 | No |
| Aug 1, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 90 | No |
| Aug 2, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 91 | No |
| Aug 7, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 91 | No |
| Aug 14, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 93 | No |
| Aug 15, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 97 | No |
| Oct 5, 2023 | 18 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 91 | Yes |
| Oct 6, 2023 | 17 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 93 | No |
| Oct 16, 2023 | 17 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 88 | No |
| Oct 17, 2023 | 17 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 85 | No |
| Oct 18, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | XXX | 92 | Yes |

*Table 5‑20 SCE Day Of 1-6 Hour: Non-Summer Impacts by Event[[61]](#footnote-62)*

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg.  Non-Summer | **20** | **12** | XXX | XXX | XXX | XXX | XXX | XXX | **57** | **Yes** |
| Nov 7, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 60 | Yes |
| Nov 8, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 56 | Yes |
| Nov 9, 2022 | 17 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | XXX | 58 | Yes |
| Nov 10, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 61 | Yes |
| Nov 14, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 61 | Yes |
| Nov 15, 2022 | 16 - 21 | 5 | XXX | XXX | XXX | XXX | XXX | XXX | 64 | Yes |
| Dec 1, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 57 | Yes |
| Dec 2, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 58 | No |
| Dec 5, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 59 | Yes |
| Dec 6, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 57 | Yes |
| Dec 7, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 56 | Yes |
| Jan 3, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 57 | Yes |
| Jan 4, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 59 | Yes |
| Jan 5, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 58 | Yes |
| Jan 6, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 58 | Yes |
| Jan 9, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 58 | Yes |
| Feb 1, 2023 | 16 - 21 | 11 | XXX | XXX | XXX | XXX | XXX | XXX | 60 | Yes |
| Feb 2, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 61 | Yes |
| Feb 24, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 53 | Yes |
| Feb 27, 2023 | 16 - 21 | 11 | XXX | XXX | XXX | XXX | XXX | XXX | 52 | Yes |
| 17 - 21 | 2 | XXX | XXX | XXX | XXX | XXX | XXX | 53 | No |
| Mar 1, 2023 | 18 - 21 | 11 | XXX | XXX | XXX | XXX | XXX | XXX | 50 | Yes |
| Mar 2, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 55 | Yes |
| Mar 3, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 56 | Yes |
| Mar 6, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 55 | Yes |
| Mar 7, 2023 | 18 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 55 | No |
| Mar 8, 2023 | 18 - 21 | 2 | XXX | XXX | XXX | XXX | XXX | XXX | 61 | Yes |
| Apr 5, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 60 | Yes |
| Apr 6, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 65 | Yes |
| Apr 10, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 62 | Yes |
| Apr 21, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 75 | **Yes** |
| Apr 26, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | XXX | 64 | Yes |

*Table 5‑21 SCE Day Of 1-6 Hour: Summer Impacts by Event*

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Summer | **18** | **42** | XXX | XXX | XXX | XXX | XXX | XXX | **85** | **Yes** |
| Jul 17, 2023 | 16 - 21 | 37 | 0.7 | 0.6 | 76% | 127.6 | 15.0 | 12% | 86 | Yes |
| Jul 17, 2023 | 17 - 21 | 5 | XXX | XXX | XXX | XXX | XXX | XXX | 74 | Yes |
| Jul 18, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 85 | Yes |
| Jul 20, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 88 | Yes |
| Jul 21, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 83 | Yes |
| Jul 24, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 85 | Yes |
| Aug 1, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 84 | Yes |
| Aug 2, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 84 | Yes |
| Aug 7, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 82 | Yes |
| Aug 14, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 82 | Yes |
| Aug 15, 2023 | 16 - 21 | 42 | XXX | XXX | XXX | XXX | XXX | XXX | 85 | Yes |
| Oct 5, 2023 | 18 - 21 | 43 | XXX | XXX | XXX | XXX | XXX | XXX | 84 | Yes |
| Oct 6, 2023 | 17 - 21 | 43 | XXX | XXX | XXX | XXX | XXX | XXX | 86 | Yes |
| Oct 16, 2023 | 17 - 21 | 43 | XXX | XXX | XXX | XXX | XXX | XXX | 80 | Yes |
| Oct 17, 2023 | 16 - 21 | 18 | XXX | XXX | XXX | XXX | XXX | XXX | 72 | Yes |
| Oct 17, 2023 | 17 - 21 | 25 | XXX | XXX | XXX | XXX | XXX | XXX | 81 | Yes |
| Oct 18, 2023 | 16 - 21 | 43 | XXX | XXX | XXX | XXX | XXX | XXX | 79 | Yes |

**Additional Event Day Impacts for TA/TI and Auto DR Participants**

The Automated Demand Response (AutoDR) program provides customers with incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electricity controls and management strategies.

*Table 5‑22* and *Table 5‑23* show the per-customer and aggregate ex-post impacts by PY2023 event day for the AutoDR participants in the Day-Ahead and Day-Of programs, respectively.

*Table 5‑22 SCE AutoDR and TA/TI Participant Impacts: Day Ahead 1-6 Hour*

| Event Day | Event Hours | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Reference  Load | Impact | Reference Load | Impact |
| Avg. Event | **18** | **40** | XXX | XXX | XXX | XXX | XXX | **7%** |
| Jul 17, 2023 | 17 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 5% |
| Jul 18, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Jul 20, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Jul 21, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Jul 24, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Aug 1, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Aug 2, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Aug 7, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Aug 14, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Aug 15, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Oct 5, 2023 | 18 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 7% |
| Oct 6, 2023 | 17 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Oct 16, 2023 | 17 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Oct 17, 2023 | 17 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 6% |
| Oct 18, 2023 | 16 - 21 | 40 | XXX | XXX | XXX | XXX | XXX | 7% |

*Table 5‑23 SCE AutoDR and TA/TI Participant Impacts: Day Of 1-6 Hour[[62]](#footnote-63)*

| Event Day | Event Hours | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Reference  Load | Impact | Reference Load | Impact |
| Avg. Event | **20** | **12** | XXX | XXX | XXX | XXX | XXX | **57** |
| Nov 7, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 60 |
| Nov 8, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 56 |
| Nov 9, 2022 | 17 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 58 |
| Nov 10, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 61 |
| Nov 14, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 61 |
| Nov 15, 2022 | 16 - 21 | 5 | XXX | XXX | XXX | XXX | XXX | 64 |
| Dec 1, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 57 |
| Dec 2, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 58 |
| Dec 5, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 59 |
| Dec 6, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 57 |
| Dec 7, 2022 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 56 |
| Jan 3, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 57 |
| Jan 4, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 59 |
| Jan 5, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 58 |
| Jan 6, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 58 |
| Jan 9, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 58 |
| Feb 1, 2023 | 16 - 21 | 11 | XXX | XXX | XXX | XXX | XXX | 60 |
| Feb 2, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 61 |
| Feb 24, 2023 | 16 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 53 |
| Feb 27, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 52 |
| Mar 1, 2023 | 18 - 21 | 11 | XXX | XXX | XXX | XXX | XXX | 50 |
| Mar 2, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 55 |
| Mar 3, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 56 |
| Mar 6, 2023 | 17 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 55 |
| Mar 7, 2023 | 18 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 55 |
| Mar 8, 2023 | 18 - 21 | 2 | XXX | XXX | XXX | XXX | XXX | 61 |
| Apr 5, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 60 |
| Apr 6, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 65 |
| Apr 10, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 62 |
| Apr 21, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 75 |
| Apr 26, 2023 | 19 - 21 | 13 | XXX | XXX | XXX | XXX | XXX | 64 |

**Additional Event Day Impacts by Geographical Area**

*Table 5‑24* through *Table 5‑26* show the event day impacts for two additional geographical areas in SCE’s service territory: South of Lugo and Southern Orange County.

*Table 5‑24 South of Lugo Event Day Impacts: Day Ahead 1-6 Hour[[63]](#footnote-64)*

| Event Day | Event Hours | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Reference  Load | Impact | Reference Load | Impact |
| Jul 17, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 95 |
| Jul 18, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 94 |
| Jul 20, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 97 |
| Jul 21, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 92 |
| Jul 24, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 97 |
| Aug 1, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 90 |
| Aug 2, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 91 |
| Aug 7, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 91 |
| Aug 14, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 93 |
| Aug 15, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 97 |
| Oct 5, 2023 | 18 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 91 |
| Oct 6, 2023 | 17 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 93 |
| Oct 16, 2023 | 17 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 88 |
| Oct 17, 2023 | 17 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 85 |
| Oct 18, 2023 | 16 - 21 | 1 | XXX | XXX | XXX | XXX | XXX | 92 |

*Table 5‑25 South of Lugo Event Day Impacts: Day Of 1-6 Hour*

| Event Day | Event Hours | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Reference  Load | Impact | Reference Load | Impact |
| Jul 17, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 95 |
| Jul 18, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 93 |
| Jul 20, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 96 |
| Jul 21, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 92 |
| Jul 24, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 96 |
| Aug 1, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 90 |
| Aug 2, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 90 |
| Aug 7, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 91 |
| Aug 14, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 92 |
| Aug 15, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 96 |
| Oct 5, 2023 | 18 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 91 |
| Oct 6, 2023 | 17 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 93 |
| Oct 16, 2023 | 17 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 87 |
| Oct 17, 2023 | 17 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 85 |
| Oct 18, 2023 | 16 - 21 | 9 | XXX | XXX | XXX | XXX | XXX | 92 |

*Table 5‑26 Southern Orange County Event Day Impacts: Day Of 1-6 Hour*

| Event Day | Event Hours | # of Accts | Aggregate Impact  (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Reference  Load | Impact | Reference Load | Impact |
| Apr 21, 2023 | 19 - 21 | 3 | XXX | XXX | XXX | XXX | XXX | 79 |
| Apr 26, 2023 | 19 - 21 | 3 | XXX | XXX | XXX | XXX | XXX | 66 |
| Jul 17, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 77 |
| Jul 18, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 79 |
| Jul 20, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 79 |
| Jul 21, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 75 |
| Jul 24, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 77 |
| Aug 1, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 80 |
| Aug 2, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 79 |
| Aug 7, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 75 |
| Aug 14, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 76 |
| Aug 15, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 80 |
| Oct 5, 2023 | 18 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 82 |
| Oct 6, 2023 | 17 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 80 |
| Oct 16, 2023 | 17 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 77 |
| Oct 17, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 72 |
| Oct 18, 2023 | 16 - 21 | 8 | XXX | XXX | XXX | XXX | XXX | 71 |

**Additional Summary of Dispatched Events**

*Table 5‑27* below shows the number of Sub-LAPs, the event hours, and the number of accounts dispatched on each event day. For reference, Table 5‑1 presents the total monthly enrollment for both SCE programs, which would be comparable to dispatched counts for a system-level event.

*Table 5‑27 SCE Dispatched Events*

| Date | Day of Week | # of  Sub-LAPs | Event Hours  (HE) | # Accounts | |
| --- | --- | --- | --- | --- | --- |
| Day Ahead | Day Of |
| Nov 7, 2022 | Monday | 3 | 16-21 | - | 13 |
| Nov 8, 2022 | Tuesday | 3 | 16-21 | - | 13 |
| Nov 9, 2022 | Wednesday | 2 | 17-21 | - | 8 |
| Nov 10, 2022 | Thursday | 3 | 16-21 | - | 13 |
| Nov 14, 2022 | Monday | 3 | 16-21 | - | 13 |
| Nov 15, 2022 | Tuesday | 1 | 16-21 | - | 5 |
| Dec 1, 2022 | Thursday | 3 | 16-21 | - | 13 |
| Dec 2, 2022 | Friday | 3 | 16-21 | - | 13 |
| Dec 5, 2022 | Monday | 3 | 16-21 | - | 13 |
| Dec 6, 2022 | Tuesday | 3 | 16-21 | - | 13 |
| Dec 7, 2022 | Wednesday | 3 | 16-21 | - | 13 |
| Jan 3, 2023 | Tuesday | 3 | 16-21 | - | 13 |
| Jan 4, 2023 | Wednesday | 3 | 16-21 | - | 13 |
| Jan 5, 2023 | Thursday | 3 | 16-21 | - | 13 |
| Jan 6, 2023 | Friday | 3 | 16-21 | - | 13 |
| Jan 9, 2023 | Monday | 3 | 16-21 | - | 13 |
| Feb 1, 2023 | Wednesday | 2 | 16-21 | - | 11 |
| Feb 2, 2023 | Thursday | 3 | 16-21 | - | 13 |
| Feb 24, 2023 | Friday | 3 | 16-21 | - | 13 |
| Feb 27, 2023 | Monday | 3 | 16-21, 17-21 | - | 13 |
| Mar 1, 2023 | Wednesday | 2 | 18-21 | - | 11 |
| Mar 2, 2023 | Thursday | 3 | 17-21 | - | 13 |
| Mar 3, 2023 | Friday | 3 | 17-21 | - | 13 |
| Mar 6, 2023 | Monday | 3 | 17-21 | - | 13 |
| Mar 7, 2023 | Tuesday | 3 | 18-21 | - | 13 |
| Mar 8, 2023 | Wednesday | 1 | 18-21 | - | 2 |
| Apr 5, 2023 | Wednesday | 3 | 19-21 | - | 13 |
| Apr 6, 2023 | Thursday | 3 | 19-21 | - | 13 |
| Apr 10, 2023 | Monday | 3 | 19-21 | - | 13 |
| Apr 21, 2023 | Friday | 3 | 19-21 | - | 13 |
| Apr 26, 2023 | Wednesday | 3 | 19-21 | - | 13 |
| Jul 17, 2023 | Monday | 3 | 16-21, 17-21 | 1 | 42 |
| Jul 18, 2023 | Tuesday | 3 | 16-21 | 1 | 42 |
| Jul 20, 2023 | Thursday | 3 | 16-21 | 1 | 42 |
| Jul 21, 2023 | Friday | 3 | 16-21 | 1 | 42 |
| Jul 24, 2023 | Monday | 3 | 16-21 | 1 | 42 |
| Aug 1, 2023 | Tuesday | 3 | 16-21 | 1 | 42 |
| Aug 2, 2023 | Wednesday | 3 | 16-21 | 1 | 42 |
| Aug 7, 2023 | Monday | 3 | 16-21 | 1 | 42 |
| Aug 14, 2023 | Monday | 3 | 16-21 | 1 | 42 |
| Aug 15, 2023 | Tuesday | 3 | 16-21 | 1 | 42 |
| Oct 5, 2023 | Thursday | 3 | 18-21 | 1 | 43 |
| Oct 6, 2023 | Friday | 3 | 17-21 | 1 | 43 |
| Oct 16, 2023 | Monday | 3 | 17-21 | 1 | 43 |
| Oct 17, 2023 | Tuesday | 3 | 16-21, 17-21 | 1 | 43 |
| Oct 18, 2023 | Wednesday | 3 | 16-21 | 1 | 43 |

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San Diego Gas & Electric

This section presents San Diego Gas & Electric’s (SDG&E) PY2023 Capacity Bidding Program (CBP) descriptions and expected program changes, participation, ex-post load impact estimates, ex-ante load impact estimates, and key findings.

**SDG&E Program Description**

SDG&E currently offered six CBP products fall under either a Non-residential Day Ahead (DA) or a Non-residential Day Of (DO) program, as shown in *Table 6‑1*.

* **Day Ahead Program**: SDG&E may call an event:
* whenever the day-ahead market price is equal to or greater than the product price trigger listed in the table below or as utility system conditions warrant. The day-ahead market price is defined as California Independent System Operator (CAISO) DLAP or applicable pnode SDGE-APND day-ahead market locational marginal price (DAM LMP).
* **Day Of Program**: SDG&E may call an event:
* whenever the forecasted real-time price is equal to or greater than the product price trigger 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).
* Program may also be called 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.

In PY2022, SDG&E added two Elect products, each with three price trigger options, to its previously existing Prescribed products. The Prescribe products did not receive any nominations in PY2023.

SDG&E CBP events may be dispatched on:

* Monday through Friday (excluding holidays),
* May through October,
* 2- to 4-hour durations,
* Maximum of 1 event per event day,
* Maximum of 24 cumulative hours per month, and
* Maximum of 6 event days per month with up to 3 consecutive event days per month.

SDG&E no longer allows customers to be enrolled in CBP if they are already enrolled in another demand response program. The exception includes customers who dually enrolled before October 1, 2018.

*Table 6‑1 SDG&E Product Types*

|  |  |  |  |
| --- | --- | --- | --- |
| Program | Product | Operating Hours | Price Trigger |
| Non-Res DA | Presc DA 11-7 Hour | 11 AM–7 PM | $80/MWh |
| Presc DA 1-9 Hour | 1 PM–9 PM | $80/MWh |
| Elect DA 1-9 Hour | 1 PM–9 PM | $200/MWh, $400/MWh, $600/MWh |
| Non-Res DO | Presc DO 11-7 Hour | 11 AM–7 PM | $95/MWh |
| Presc DO 1-9 Hour | 1 PM–9 PM | $110/MWh |
| Elect DO 1-9 Hour | 1 PM–9 PM | $200/MWh, $400/MWh, $600/MWh |

**Program Changes**

* SDG&E is currently implementing a Residential CBP pilot, limiting the number of residential enrollments due to system limitations.
* The Residential CBP evaluation for PY2023 is not included in this report.
* On December 14, 2023, Decision (D.) 23-12-005 ordered SDG&E to eliminate its Capacity Bidding Program Prescribed product option (Day Ahead and Day Of 11am-7pm and Day Ahead 1pm-9pm) within 60 days of the date of issuance of this decision. Therefore, in 2024 SDG&E will offered only the following products: Elect DA 1-9 hour ($200/MWh, $400/MWh, $600/MWh) and Elect DO 1-9 hour ($200/MWh, $400/MWh, $600/MWh)

**SDG&E Program Nominations**

*Table 6‑2* shows the program-level monthly nominations for SDG&E’s CBP programs. On average across the months, the Non-residential DA program enrolled 2.7 MW in nominations through 90 customers, while Non-residential DO enrolled 1.8 MW through 54 customers. *Figure 6‑1* shows the monthly capacity nominations by product. Under the Non-residential DA program, the slight majority of nominations fell under the Elect $600 product. Conversely, nearly all DO nominations fell under the Elect $400 product. However, no events were called for DO Elect $600 participants in 2023.

*Table 6‑2 SDG&E Monthly Nominations*

| Month | Non-Residential DA | | Non-Residential DO | |
| --- | --- | --- | --- | --- |
| Enrolled  Accounts | Nominated Capacity (MW) | Enrolled  Accounts | Nominated Capacity (MW) |
| May | 48 | 2.1 | 44 | 1.7 |
| June | 56 | 2.3 | 52 | 1.6 |
| July | 97 | 2.8 | 57 | 1.9 |
| August | 104 | 3.0 | 56 | 1.9 |
| September | 118 | 3.1 | 57 | 1.9 |
| October | 119 | 2.9 | 57 | 1.9 |
| Avg. Summer | **90** | **2.7** | **54** | **1.8** |

*Figure 6‑1 SDG&E Monthly Nominations by Product*

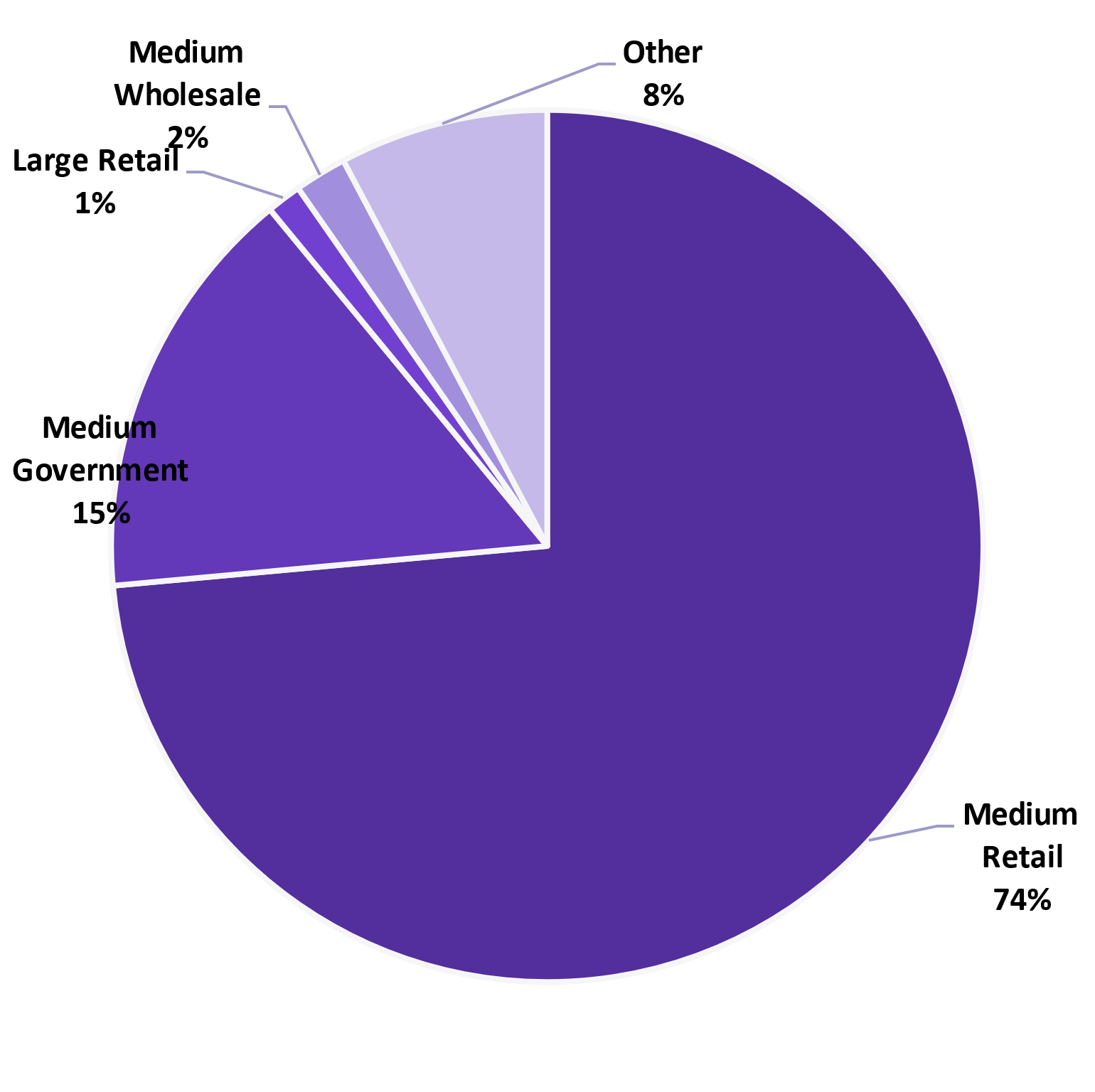
A screenshot of a graph

Description automatically generated

*Table 6‑3* and the accompanying figure show the size and industry distribution of non-residential enrollment in CBP. Most enrollments came from the retail (75%) industry. This aligns with PY2022 program enrollments, where 86% of customers came from the retail industry. Nearly all customers belonged to the medium size group, consuming between 20 kW and 200 kW at their hour of maximum demand.

*Table 6‑3 SDG&E Non-Residential Enrollment*

| Industry Type | Size Groupa | | | Total |
| --- | --- | --- | --- | --- |
| Small | Medium | Large |
| 1. Agriculture, Mining & Construction | - | - | - | - |
| 2. Manufacturing | - | 1 | 1 | 2 |
| 3. Wholesale, Transport, Other Utilities | - | 3 | 1 | 4 |
| 4. Retail Stores | - | 114 | 2 | 116 |
| 5. Offices, Hotels, Finance, Services | - | 3 | - | 3 |
| 6. Schools | - | - | 1 | 1 |
| 7. Institutional/ Government | 4 | 24 | 1 | 29 |
| 8. Other/Unknown | - | - | - | - |
| Total | **4** | **145** | **6** | **155** |



aAEG binned customers by the size of their maximum hourly consumption on non-event days into small (<20 kW), medium (≥20 kW and <200 kW), and large (≥200 kW) groups.

**SDG&E Key Findings**

The PY2023 evaluation identified the following key findings for SDG&E’s CBP:

* SDG&E Elect products entered their second year in PY2023. These include the Elect DA 1-9 Hour and Elect DO 1-9 Hour options, each with three price trigger options ($200/MWh, $400/MWh, and $600/MWh).
* SDG&E still offers their previously existing products as Prescribed options, with the following price triggers: $90/MWh (Prescribed DA 11-7 Hour and 1-9 Hour), $115/MWh (Prescribed DO 11-7 Hour), and $125/MWh (Prescribed DO 1-9 Hour).
* The Elect DO ($600) product only included five customers and average nominations of 0.1 MW across summer months. However, these customers were not dispatched as no events were called for this product.
* The Non-Residential DA customers delivered 42% of dispatched capacity during the average PY2023 event. The improvement in delivery performance over the average PY2022 season (XXX in 2022 from three customers) can be largely attributed to customers’ performance in July, when customers delivered an average of 91% of the dispatched capacity, though performance in August (22% delivered of the 3.0 MW dispatched) still surpassed the average delivery seen in the 2022 summer.
* Non-residential DO participants delivered 1.7 MW in PY2023, a 95% delivery performance. This marks a substantial improvement in the delivery performance of this program from PY2022 (65% delivery performance), especially considering that nearly all nominations were dispatched in each month. Customers performed similarly well in both July and August with delivery performances of 101% and 91%, respectively.
* HE20 (7 PM – 8 PM) was the most dispatched event hour in PY2023. Across events, 3.8 MW and 135 participants were dispatched during the average HE20 even hour.
* SDG&E dispatched events on five days in PY2023. For comparison, under the Prescribed product option, SDG&E historically dispatched around 20-30 events per program year under the $90-$125/MWh price triggers. In PY2023, more aggregators opted for the $400/MWh and $600/MWh price triggers, reducing the resources that qualify for dispatches.
* SDG&E updated the enrollment forecast based on the PY2023 nominations, increasing the growth rate to 3% between the 2024 and 2027 forecast years to account for the CBP program improvements proposed by SDG&E. SDG&E assumed the programs would not see any growth after 2027.

**SDG&E Ex-Post Analysis**

This section describes the PY2023 events, summarizes the ex-post impacts estimated for PY2023 dispatched events, and compares the ex-post to the PY2022 ex-ante forecast for 2023.

**Dispatched Events**

*Table 6‑4* shows the event hours and the number of accounts dispatched on each event day by product offering. SDG&E’s service territory falls under one Sub-LAP, making all SDG&E dispatched events system-level events to the extent that within a product, all customers will be dispatched together. However, the Elect price triggers mean that not all Elect products will be dispatched for each event.

As shown, the Non-residential DA 1-9 Hour ($400) customers participated in five events (14 event hours total) and Elect DA 1-9 Hour ($600) customers participated in two events (8 event hours total). The Non-residential DO 1-9 Hour ($400) customers participated in five events (14 event hours).

The average event day is calculated by including all events called in PY2023, regardless of the event hours dispatched. We report impacts for the average event day on the most dispatched hour, HE20.

*Table 6‑4 SDG&E Dispatched Events*

| Date | Day of Week | Event Hours (HE) | # Accounts | | | |
| --- | --- | --- | --- | --- | --- | --- |
| Elect DA  1-9 Hour ($400) | Elect DA  1-9 Hour ($600) | Elect DO  1-9 Hour ($400) |
| Avg. Event | **-** | **20** | **70** | **34** | **51** |
| Jul 27, 2023 | Thursday | 20-21 | 70 | 0 | 51 |
| Jul 28, 2023 | Friday | 20-21 | 70 | 0 | 51 |
| Aug 15, 2023 | Tuesday | 18-19, 18-20, 19-21 | 70 | 34 | 51 |
| Aug 16, 2023 | Wednesday | 18-21 | 70 | 34 | 51 |
| Aug 28, 2023 | Monday | 19-20 | 70 | 0 | 51 |

* In 2023, SDG&E experienced its system peak day on August 28th, at Hour Ending 18, SDG&E triggered its Non-residential DO $400 event.

**Load Impact Summary**

*Table 6‑5* summarizes PY2023 impacts for the average event day, by program, for the most dispatched hour (HE20). Specifically, it shows:

* The average number of accounts dispatched across events.
* The total dispatched capacity, load impact, and delivery performance for the average event day.
* The reference load (e.g., the estimated counterfactual load had the customer not been dispatched) and load impact per customer for the average event day.

SDG&E’s CBP programs delivered 2.6 MW out of 4.7 MW dispatched on average across event days during HE20, an average delivery performance of 56%.

*Table 6‑5 SDG&E Impacts Summary, Average Event Day PY2023*

| Program &  Product | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Non-Res DA  (Elect [$400]) | 70 | 1.4 | 0.8 | 57% | 94.8 | 11.0 | 12% |
| Non-Res DA  (Elect [$600]) | 34 | 1.6 | 0.2 | 10% | 112.5 | 4.5 | 4% |
| Total Non-Res DA | 84 | 2.0 | 0.8 | 42% | 97.7 | 10.0 | 9% |
| Non-Res DO  (Elect [$400]) | 51 | 1.8 | 1.7 | 95% | 188.3 | 33.6 | 18% |
| Total CBP | **155** | **4.7** | **2.6** | **56%** | **129.5** | **17.0** | **13%** |

*Table 6‑6* and *Table 6‑7* show the number of accounts and capacity nominated for each month, the amount dispatched across all event days and event hours and for the most-dispatched hour, and the estimated ex-post impacts for SDG&E’s two CBP programs. In 2023, Non-residential DA and DO dispatched five events during July and August.

The Non-Residential DA customers delivered 0.8 MW of the 1.2 MW dispatched capacity during the average PY2023 event, a delivery performance of 42%. The improvement in delivery performance over the average PY2022 season (XXX in 2022) can be largely attributed to customers’ performance in July, when customers delivered an average of 91% of the dispatched capacity (1.3 MW) across the two events. Customers’ performance in August (22% delivered of the 3.0 MW dispatched) still surpassed the average delivery seen in the 2022 summer and aligns well with 2021 delivery performance. Notably, all of the August nominations were dispatched during the average event, whereas only half were dispatched in July.

Non-residential DO participants delivered 1.7 MW in PY2023, a 95% delivery performance. This marks a substantial improvement in the delivery performance of this program from PY2022 (65% delivery performance), especially considering that nearly all nominations were dispatched in each month. Customers performed similarly well in both July and August with delivery performances of 101% and 91%, respectively.

*Table 6‑6 SDG&E Non-Residential DA Monthly Summary*

| Month | Nominations | | Dispatched | | HE20 Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered | Adj. % Delivered |
| May | 48 | 2.1 | - | - | - | - | - | - | - |
| June | 56 | 2.3 | - | - | - | - | - | - | - |
| July | 97 | 2.8 | 70 | 1.3 | 70 | 1.3 | 1.2 | 91% | 91% |
| August | 104 | 3.0 | 104 | 3.0 | 104 | 3.0 | 0.7 | 22% | 22% |
| September | 118 | 3.1 | - | - | - | - | - | - | - |
| October | 119 | 2.9 | - | - | - | - | - | - | - |
| Overall | **90** | **2.7** | **84** | **1.2** | **84** | **1.2** | **0.8** | **42%** | **42%** |

*Table 6‑7 SDG&E Non-Residential DO Monthly Summary*

| Month | Nominations | | Dispatched | | HE20 Dispatched | | Ex-Post Analysis | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| # Accts | Capacity (MW) | # Accts | Capacity (MW) | # Accts | Capacity (MW) | Impact (MW) | % Delivered | Adj. % Delivered |
| May | 44 | 1.7 | - | - | - | - | - | - | - |
| June | 52 | 1.6 | - | - | - | - | - | - | - |
| July | 57 | 1.9 | 51 | 1.8 | 51 | 1.8 | 1.8 | 101% | 101% |
| August | 56 | 1.9 | 51 | 1.8 | 51 | 1.8 | 1.6 | 91% | 91% |
| September | 57 | 1.9 | - | - | - | - | - | - | - |
| October | 57 | 1.9 | - | - | - | - | - | - | - |
| Overall | **54** | **1.8** | **51** | **1.8** | **51** | **1.8** | **1.7** | **95%** | **95%** |

***Hourly Load Impacts***

*Figure 6‑2* and *Figure 6‑3* show hourly profiles for the average Non-Residential DA and DO customer, respectively.[[64]](#footnote-65) Each shows the estimated reference load (i.e., what the customer would have consumed had an event not been called), the actual observed load, and the estimated load impacts for the average event day. The highlighted hours indicate that at least one group of customers was dispatched during that hour. The vertical dotted lines show the most dispatched hour (HE20).

*Figure 6‑2 SDG&E All Day-Ahead: Hourly Per-Customer Impact, Summer Average Event*

A graph with lines and dots

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*Figure 6‑3 SDG&E All Day-Of: Hourly Per-Customer Impact, Summer Average Event*

A screen shot of a graph

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***Load Impacts by Industry Type***

*Table 6‑8* shows the impacts for an average event day by industry group.[[65]](#footnote-66)

*Table 6‑8 SDG&E Impacts by Industry[[66]](#footnote-67)*

|  | Industry | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref. Load | Impact |
| DA | Manufacturing | XXX | XXX | XXX | XXX | XXX | XXX | 69 |
| Wholesale, Transport, other utilities | XXX | XXX | XXX | XXX | XXX | XXX | 77 |
| Retail Stores | 66 | 6.4 | 0.7 | 96.8 | 10.3 | 11% | 73 |
| Offices, Hotels, Finance, Services | XXX | XXX | XXX | XXX | XXX | XXX | 70 |
| Schools | XXX | XXX | XXX | XXX | XXX | XXX | 69 |
| Institutional/Government | XXX | XXX | XXX | XXX | XXX | XXX | 75 |
| **Total DA** | **84** | **8.2** | **0.8** | **97.7** | **10.0** | **10%** | **73** |
| DO | Retail stores | 49 | 9.2 | 1.7 | 188.5 | 34.1 | 18% | 73 |
| Offices, Hotels, Finance, Services | XXX | XXX | XXX | XXX | XXX | XXX | 77 |
| Institutional/Government | XXX | XXX | XXX | XXX | XXX | XXX | 69 |
| **Total DO** | 51 | 8.5 | 1.7 | 167.1 | 33.6 | 20% | 73 |
| Total CBP | | **155** | **20.1** | **2.6** | **129.5** | **17.0** | **13%** | **75** |

**Comparison of Ex-Post Impacts**

This section discusses how the PY2023 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast. Figure 6‑4 and *Table* 6*‑9* show SDG&E’s average program nominations for PY2020 through PY2023 for its two Non-Residential CBP programs.

Figure 6‑4 SDG&E Annual Nominations



Non-Residential DA program notably grew in both participation and dispatched capacity in PY2023 following the low enrollment in both 2021 and 2022. While these customers appeared smaller in size (based on their estimated reference load), they contributed to substantial improvements in the delivery performance from the 2022 season (when only three large customers participated) and even the 2021 season.

The Non-residential DO program similarly improved its performance in PY2023 compared to previous years through fewer, slightly larger customers.

*Table* 6*‑9 SDG&E: Current v. Previous Ex-Post, Average Summer Event Day*

| Program | Year | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Non-Res DA | 2020 | 23 | 0.6 | 0.4 | 71% | 121.3 | 18.0 | 15% | 78 |
| 2021 | 46 | 1.1 | 0.3 | 25% | 110.9 | 5.8 | 5% | 75 |
| 2022 | XXX | XXX | XXX | XXX | XXX | XXX | XXX | 83 |
| **2023** | **84** | **2.0** | **0.8** | **42%** | **97.7** | **10.0** | **10%** | **73** |
| Non-Res DO | 2020 | 158 | 2.9 | 2.2 | 74% | 115.4 | 13.8 | 12% | 77 |
| 2021 | 133 | 3.4 | 1.0 | 30% | 103.0 | 7.8 | 8% | 76 |
| 2022 | 63 | 2.1 | 1.4 | 65% | 167.1 | 22.0 | 13% | 85 |
| **2023** | **51** | **1.8** | **1.7** | **95%** | **188.3** | **33.6** | **20%** | **73** |

*Table* 6*‑10* shows the PY2023 ex-post impacts compared to PY2022 ex-ante impacts on an aggregate and per-customer basis for the average, e.g., typical, event day.

Note that the ex-ante impacts forecast performance for a system-level dispatch. With the implementation of Elect products in PY2022, SDG&E’s dispatched events are no longer always system-level events, since the Elect products' pricing triggers differ. This adds some nuance to the comparison of ex-post to ex-ante. That said, both DA and DO programs over-performed compared to the 2022 forecast in terms of delivered aggregate impacts, but each for slightly different reasons. The Non-Residential DA program recruited about 50% more customers than forecasted, but the per-customer reference load shows that they were smaller customers who generated similar per-customer impacts as forecasted. Conversely, the Non-Residential DO program recruited about half the customers as expected, but these were larger customers who generated more than twice the impact forecasted for ex-ante.

*Table* 6*‑10 SDG&E Current Ex-Post (Average Summer Event Day) v. Prior Ex-Ante (SDG&E 1-in-2, Typical Event Day, 2023)*

| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Non-Res DA | PY2022 Ex-Ante | 51 | 6.6 | 0.5 | 130.0 | 9.7 | 7% | 82 |
| **Current Ex-Post** | **84** | **8.2** | **0.8** | **97.7** | **10.0** | **10%** | **73** |
| Non-Res DO | PY2022 Ex-Ante | 97 | 10.7 | 1.3 | 110.5 | 13.9 | 13% | 81 |
| **Current Ex-Post** | **51** | **9.6** | **1.7** | **188.3** | **33.6** | **18%** | **73** |

**SDG&E Ex-Ante Analysis**

**Enrollment and Load Impact Summary**

Starting in 2022, SDG&E added two Elect products with three price trigger options: $200/MWh, $400/MWh, or $600/MWh. SDG&E will continue to offer their existing products, referring to them as Prescribed products. Both Non-residential DA and DO programs will have three products: (1) Prescribed 11-7 Hour, (2) Prescribed 1-9 Hour, and (3) Elect 1-9 Hour.

Note that SDG&E is currently implementing a Residential CBP pilot, limiting the number of residential enrollments due to system limitations. The Residential CBP pilot evaluation is not included in this evaluation report.

SDG&E updated the enrollment forecast to align with PY2023 nominations after the addition of the two CBP Elect products. For a 2024 August peak day, SDG&E forecasts 0.8 MW and 1.7 MW load impacts the Non-residential DA and DO[[67]](#footnote-68) programs, respectively. *Table* 6*‑10* shows the PY2023 ex-post impacts compared to PY2022 ex-ante impacts on an aggregate and per-customer basis for the average, e.g., typical, event day.

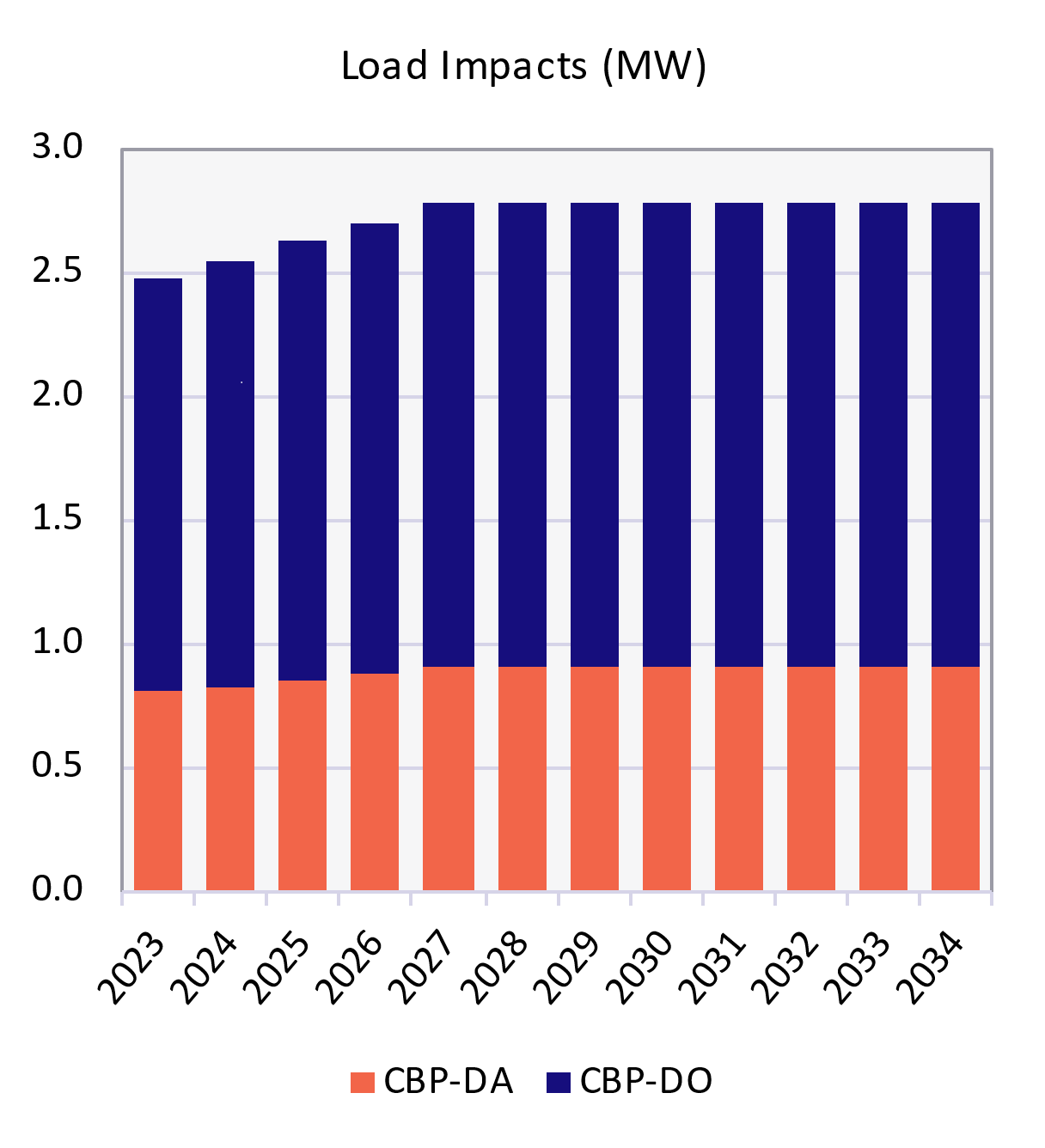
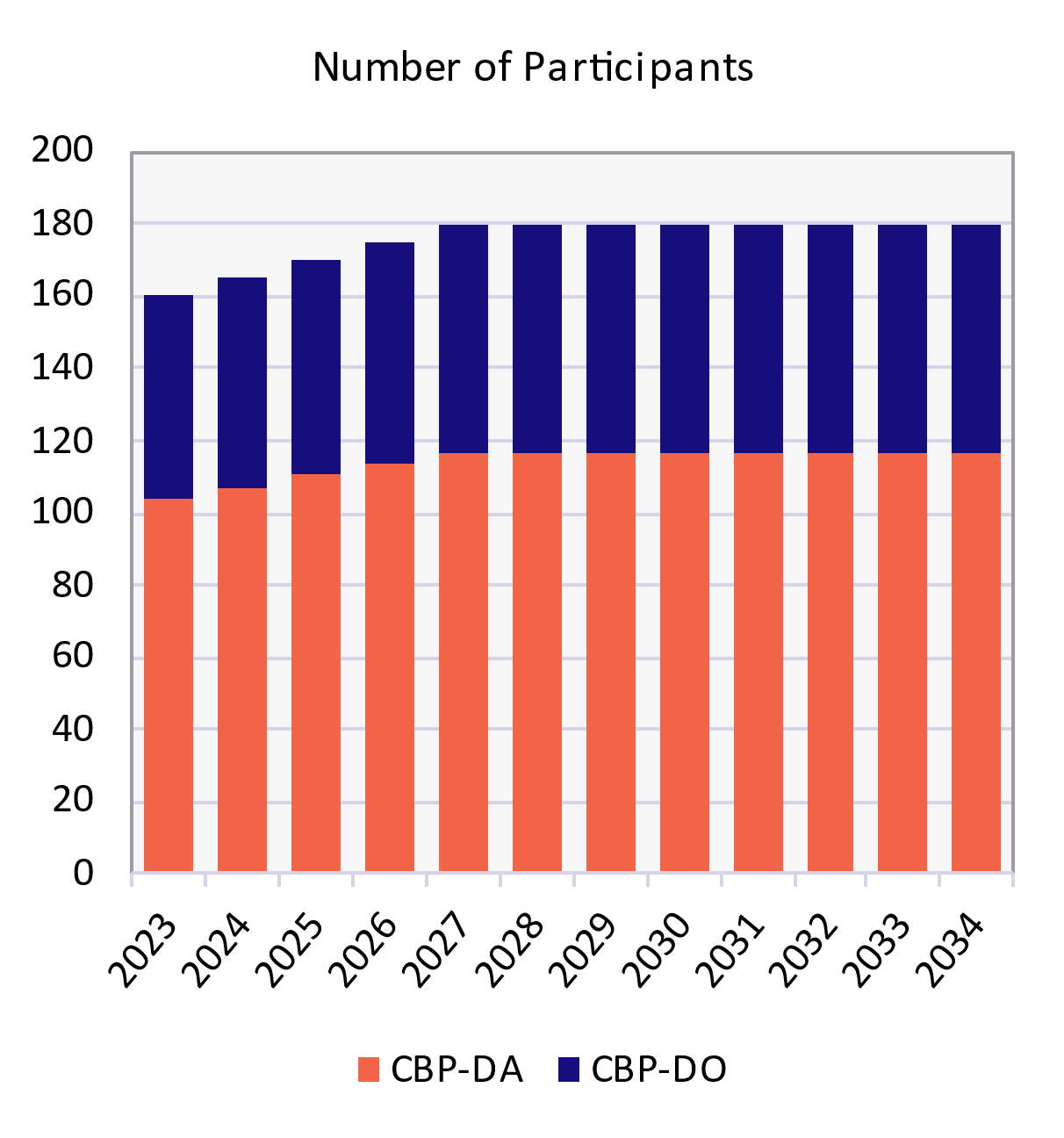
Note that the ex-ante impacts forecast performance for a system-level dispatch. With the implementation of Elect products in PY2022, SDG&E’s dispatched events are no longer always system-level events, since the Elect products' pricing triggers differ. This adds some nuance to the comparison of ex-post to ex-ante. That said, both DA and DO programs over-performed compared to the 2022 forecast in terms of delivered aggregate impacts, but each for slightly different reasons. The Non-Residential DA program recruited about 50% more customers than forecasted, but the per-customer reference load shows that they were smaller customers who generated similar per-customer impacts as forecasted. Conversely, the Non-Residential DO program recruited about half the customers as expected, but these were larger customers who generated more than twice the impact forecasted for ex-ante.

*Table* 6*‑10 SDG&E Current Ex-Post (Average Summer Event Day) v. Prior Ex-Ante (SDG&E 1-in-2, Typical Event Day, 2023)*

| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref.  Load | Impact | Ref.  Load | Impact |
| Non-Res DA | PY2022 Ex-Ante | 51 | 6.6 | 0.5 | 130.0 | 9.7 | 7% | 82 |
| **Current Ex-Post** | **84** | **8.2** | **0.8** | **97.7** | **10.0** | **10%** | **73** |
| Non-Res DO | PY2022 Ex-Ante | 97 | 10.7 | 1.3 | 110.5 | 13.9 | 13% | 81 |
| **Current Ex-Post** | **51** | **9.6** | **1.7** | **188.3** | **33.6** | **18%** | **73** |

*Figure 6‑5* shows SDG&E’s Non-residential CBP enrollment and load impact forecast for an August peak day under the SDG&E 1-in-2 weather scenario.

*Figure 6‑5 SDG&E CBP Enrollment and Load Impact Forecast (SDG&E 1-in-2, August Peak Day)*



*Table 6‑11* summarizes the average RA window load impact forecasts for the Non-residential DA and DO programs on an August peak day in 2024. The table includes the per-customer, aggregate, and corresponding percent impacts under the utility and CAISO 1-in-2 and 1-in-10 weather scenarios. We assume constant per-customer average impacts across the weather scenarios and across months within a program year. The varying percent impacts are due to the reference load’s response to each weather scenario.

*Table 6‑11 SDG&E Non-Residential: RA Window Ex-Ante Impacts, 2024*

| Program | # of Accts | Per Customer Impact (kW) | Aggregate Impact (MW) | Percent Impact  (%) | | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Utility Peak | | CAISO Peak | |
| 1-in-2 | 1-in-10 | 1-in-2 | 1-in-10 |
| Non-Res Day Ahead | 107 | 7.7 | 0.8 | 9.5% | 9.4% | 9.6% | 9.4% |
| Non-Res Day Of | 58 | 29.8 | 1.7 | 21.0% | 20.7% | 21.1% | 20.8% |

**Forecast Assumptions**

This section discusses the assumptions used to develop the Non-residential DA and DO forecasts. Both forecasts use a combination of the following:

Table 6‑12 SDG&E Delivery Performance

|  |  |  |
| --- | --- | --- |
| Year | Non-Res  DA | Non-Res  DO |
| 2020 | 71% | 74% |
| 2021 | 25% | 30% |
| 2022 | XXX | 65% |
| 2023 | 42% | 95% |
| Average | **35%** | **66%** |

**Delivery Performance** – We calculated program-level delivery performance based on PY2020 through PY2022 performance to produce modest estimates, given the inconsistent delivery performance over the last three years. Table 6‑12 shows the delivery performance assumed for each program, 35% and 66% for Non-Residential DA and DO, respectively. We applied the product-level delivery performances to capacity nominations to estimate maximum ex-ante load impacts.

**Enrollment Growth** – We updated the enrollment forecast based on PY2023 nominations and assumed a 3% growth per year from 2024-2027 due to the CBP program improvements proposed by SDG&E and no additional growth from 2027-2034.

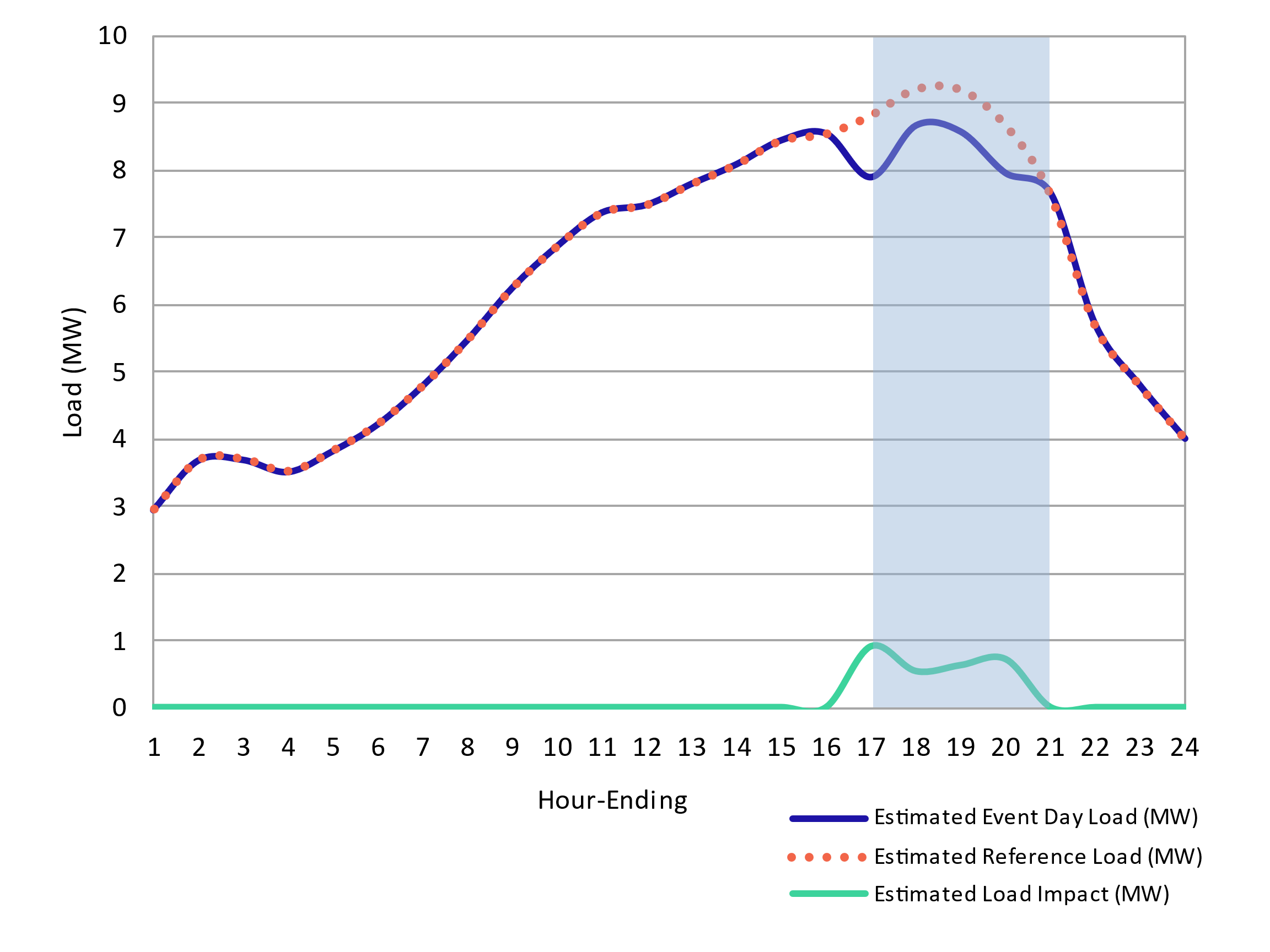
**Impact Degradation Rate** – we developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the 5-hour RA window. The approach used to develop these assumptions is discussed in Section 3 [Impact Degradation Across the RA Window](#ImpactDeg). For SDG&E, we used PY2023 data to update the Impact Degradation Rate, as moving forward, the program is expected to resemble what was observed in PY2023, the second year after it had been introduced. *Table 6‑13* shows the estimated shape of the impacts as a percent of the maximum load impact for each program and product. Note that SDG&E does not anticipate any enrollment under prescribed products for future years. The table only includes the Non-residential DA and DO products.

*Table 6‑13 SDG&E CBP: RA Window Shape of Impacts*

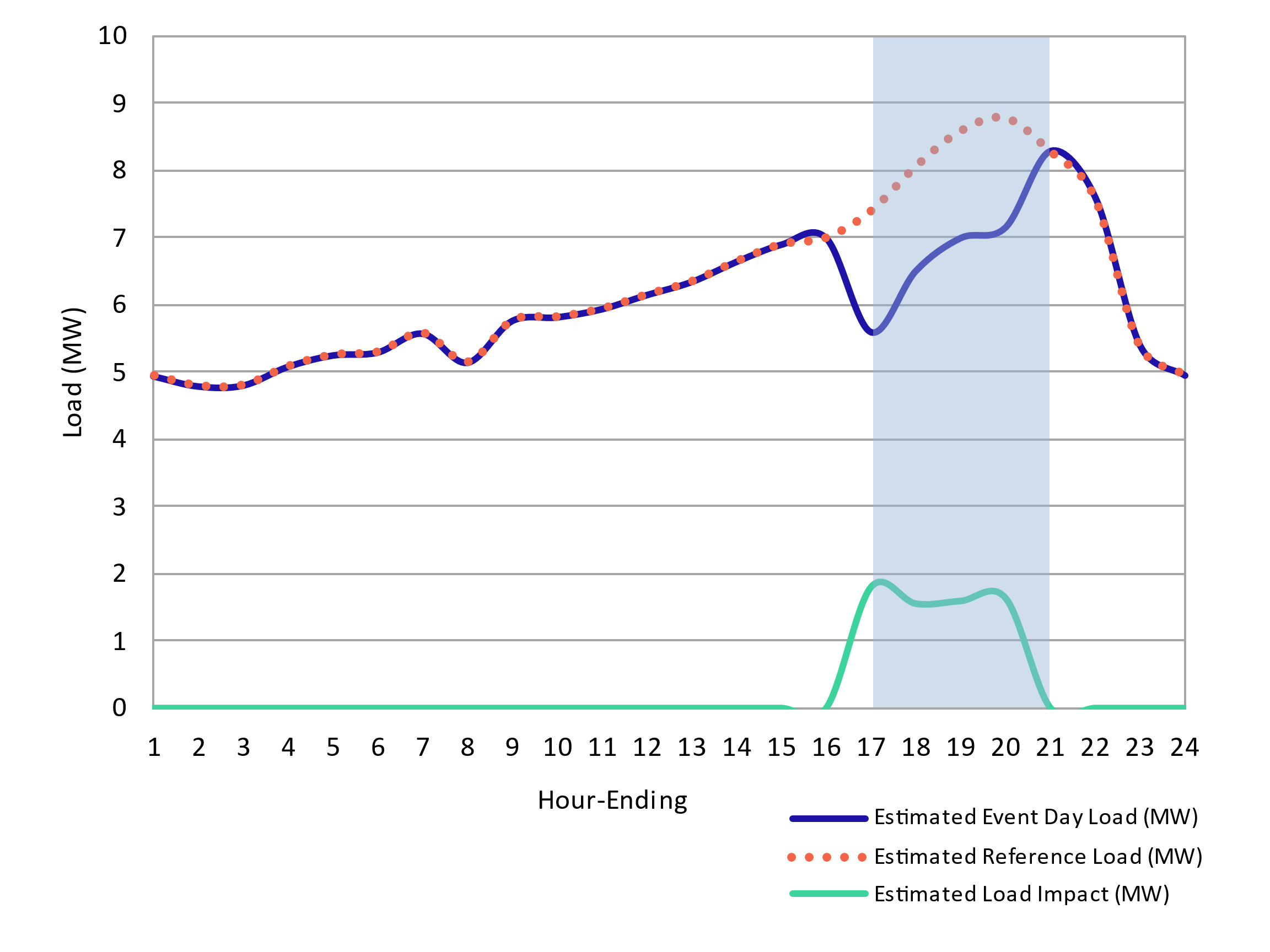
| Program |  | | Percent of Maximum Impact | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 5:00 PM-6:00 PM | 6:00 PM-7:00 PM | | 7:00 PM-8:00 PM | 8:00 PM-9:00 PM | 9:00 PM-10:00 PM | Overall RA |
| DA 1-9 Hour | 100% | 71% | | 42% | 49% | 56% | 64% |
| DO 1-9 Hour | 100% | 87% | | 75% | 77% | 79% | 84% |

*Figure 6‑6* and *Figure 6‑7* show the SDG&E’s Non-residential DA and DO per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2024 for the SCE 1-in-2 weather condition. The hours highlighted in blue show the RA window, 4 PM to 9 PM.

*Figure 6‑6 SDG&E Non-Residential Day Ahead: Hourly Per-Customer Load (SDG&E 1-in-2, August Peak Day, 2024)*



*Figure 6‑7 SDG&E Non-Residential Day Of: Hourly Per-Customer Load (SDG&E 1-in-2, August Peak Day, 2024)*



**Comparison of Ex-Ante Impacts**

This section discusses how the PY2023 ex-ante load impacts compare to:

* PY2023 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios and
* PY2022 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

*Table 6‑14* compares **the current ex-post estimates with the current ex-ante estimates**. The current ex-post estimates show average load impacts for PY2023 dispatched events, while the current ex-ante estimates show how the program would have performed in a 1-in-2 weather year for a system-level event. Note that the ex-ante estimates in this comparison are for a 2023 Typical event day on the maximum impact hour (HE17), which is most comparable to the ex-post average event day reporting hour HE20. Compared to 2022’s forecast, the ex-post results for 2023 show lower participation but relatively larger customers for both Day Ahead and Day Of products.

*Table 6‑14 SDG&E: Current Ex-Ante (SDG&E 1-in-2, 2023 Typical Event Day, Maximum Impact) v. Current Ex-Post (Average Summer Event, HE19)*

| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref. Load | Impact |
| Day Ahead | **Current Ex-Ante** | **104** | **8.6** | **1.3** | **82.4** | **12.1** | **14.7%** | **87** |
| Current Ex-Post | 84 | 8.2 | 0.8 | 97.7 | 10.0 | 10.2% | 73 |
| Day Of | **Current Ex-Ante** | **56** | **7.2** | **2.0** | **127.9** | **35.7** | **27.9%** | **87** |
| Current Ex-Post | 51 | 9.6 | 1.7 | 188.3 | 33.6 | 17.8% | 73 |

*Table 6‑15* compares **the previous ex-ante forecast to the current ex-ante forecast, both for the year 2024**. This comparison demonstrates how the program forecast has been updated since last year. These changes are the following:

* The ex-ante forecast was updated based on PY2023 nominations.
* Per-customer performance was also updated based on PY2023 performance.

As SDG&E enter the second year of the new Elect Program, we are observing improved performance in both Day Ahead and Day Of products, as reflected in the 2023 forecast. Compared to last year’s forecast, 2023 anticipates an increase in both enrollment and aggregate impact.

*Table 6‑15 SDG&E: Current v. Prior Ex-Ante (SDG&E 1-in-2, August Peak Day, 2024), RA Window*

| Program | Estimate | # of Accts | Aggregate Impact (MW) | | Per-Customer Impact  (kW) | | % Impact | Temp (˚F) |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Ref. Load | Impact | Ref. Load | Impact |
| Day Ahead | **PY2023 Forecast** | **107** | **8.7** | **0.8** | **81.4** | **7.7** | **9%** | **83** |
| PY2022 Forecast | 52 | 6.8 | 0.5 | 130.0 | 9.7 | 7% | 83 |
| Day  Of | **PY2023 Forecast** | **58** | **8.2** | **1.7** | **142.3** | **29.8** | **21%** | **83** |
| PY2022 Forecast | 99 | 10.9 | 1.4 | 110.5 | 13.9 | 13% | 82 |

**SDG&E Ex-Post Event Day Load Impacts**

*Table 6‑16*, *Table 6‑17*, and *Table 6‑18* show the average event-hour impacts for the two DA products ($400 and $600) and the DO ($400) products dispatched in PY2023. Each table includes:

* The average number of accounts dispatched for the event.
* The total dispatched capacity, load impact, and delivery performance.
* The reference load (e.g., the estimated counterfactual load had the customer not been dispatched) and load impact per customer.
* The average event window temperature.

*Table 6‑16 SDG&E Elect Day Ahead 1 PM to 9 PM Product ($400/MWh Trigger): Impacts by Event*

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Event | **20** | **70** | **1.4** | **0.8** | **57%** | **94.8** | **11.0** | **12%** | **73** | **Yes** |
| Jul 27, 2023 | 20-21 | 70 | 1.3 | 0.9 | 66% | 85.6 | 12.3 | 14% | 74 | Yes |
| Jul 28, 2023 | 20-21 | 70 | 1.3 | 0.9 | 66% | 87.2 | 12.3 | 14% | 72 | Yes |
| Aug 15, 2023 | 18-20 | 70 | 1.4 | 0.7 | 51% | 93.3 | 10.2 | 11% | 69 | Yes |
| Aug 16, 2023 | 18-21 | 70 | 1.4 | 0.8 | 57% | 95.0 | 11.5 | 12% | 71 | Yes |
| Aug 28, 2023 | 19-20 | 70 | 1.4 | 0.9 | 62% | 98.7 | 12.4 | 13% | 80 | Yes |

*Table 6‑17 SDG&E Elect Day Ahead 1 PM to 9 PM Product ($600/MWh Trigger): Impacts by Event*

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Event | **20** | **34** | **1.6** | **0.2** | **10%** | **112.5** | **4.5** | **4%** | **69** | **Yes** |
| Aug 15, 2023 | 18-19 | 34 | 1.6 | 0.3 | 18% | 114.1 | 8.2 | 7% | 68 | Yes |
| Aug 16, 2023 | 18-21 | 34 | 1.6 | 0.4 | 23% | 114.5 | 10.3 | 9% | 70 | Yes |

*Table 6‑18 SDG&E Elect Day Of 1 PM to 9 PM Product ($400/MWh Trigger): Impacts by Event*

| Event Day | Event Hours | # Accts | Aggregate (MW) | | | Per-Customer (kW) | | | Temp (F) | Sig |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Dispatched Capacity | Load Impact | % Delivered | Reference Load | Load Impact | % Impact |
| Avg. Event | **20** | **51** | **1.8** | **1.7** | **95%** | **188.3** | **33.6** | **18%** | **73** | **Yes** |
| Jul 27, 2023 | 20-21 | 51 | 1.8 | 1.7 | 92% | 179.6 | 32.4 | 18% | 73 | Yes |
| Jul 28, 2023 | 20-21 | 51 | 1.8 | 1.7 | 92% | 180.1 | 32.4 | 18% | 71 | Yes |
| Aug 15, 2023 | 19-21 | 51 | 1.8 | 1.6 | 90% | 184.8 | 31.8 | 17% | 68 | Yes |
| Aug 16, 2023 | 18-21 | 51 | 1.8 | 1.7 | 97% | 190.7 | 34.2 | 18% | 70 | Yes |
| Aug 28, 2023 | 19-20 | 51 | 1.8 | 1.8 | 100% | 194.6 | 35.4 | 18% | 80 | Yes |

**Additional Event Day Impacts for TA/TI and Auto DR Participants**

SDG&E did not have any TA/TI or AutoDR participants in PY2023.

Appendices

PG&E CBP Ex-Post Table Generator

PG&E CBP Ex-Ante Table Generator

SCE CBP Ex-Post Table Generator

SCE CBP Ex-Ante Table Generator

SDG&E CBP Ex-Post Table Generator

SDG&E CBP Ex-Ante Table Generator

# A

Model validity

We selected and validated regression models during our optimization process. The regression models are designed to:

* Accurately predict the actual participant load on event days (addressed by in-sample testing), and
* Accurately predict the reference load or participant usage on event days in the absence of an event (addressed by out-of-sample testing).

As described in Section 2, we selected each participant/segment’s best model through a three-part optimization process, consisting of the following steps: (1) In-sample and out-of-sample testing; (2) assessing model validity; and (3) model fine-tuning.

Figure A - 1 Optimization Process

This section presents metrics related to our optimization process, specifically:

* Selection of event-like days used for out-of-sample testing
* Metrics from in-sample and out-of-sample tests from the final models of the ex-post analysis, and
* Comparison load graphs.

Selecting Event-Like Days

To select similar non-event days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. We calculated a Euclidean distance metric defined as the square root of the sum of the squared differences between the matching variables to determine how close event day temperature is to a potential event-like day. Any number of relevant variables could be included in the Euclidean distance. The equation below shows an example of a Euclidean distance metric, and Table A - 1 summarizes the variables included in the ED metric used by IOU and customer class.

Table A - 1 ED Metrics by Program

|  |  |
| --- | --- |
| IOU/Customer Class | Metric Variables |
| PG&E Residential | Temp16, Temp17, Temp18, Temp19, Mean(Temp1-Temp3), Mean(Temp22-Temp24) |
| PG&E Non-Residential | Temp16, Temp17, Temp18, Temp19 |
| SCE Non-Residential | Maximum Temp, Mean(Temp15-Temp18), Mean(Temp22-Temp24), Temp16, Temp21; segmented by season |
| SDG&E Non-Residential | Mean(Temp1-Temp3), Mean(Temp13-Temp15), Temp15, Temp18, Temp19 |

In Figure A - 2 to Figure A - 6, we compare the distributions of the average and maximum daily temperatures of event days and event-like days for each IOU and customer class. The event-like day selection was made at this granularity, i.e., each IOU and customer class combination has the same event and event-like dates. PG&E, SCE, and SDG&E all have a selection of event-like days with comparable average and maximum temperature distributions to PY2023 events.

Figure A - 2 PG&E Temperatures of Event Days v. Event-Like Days – Non-Residential

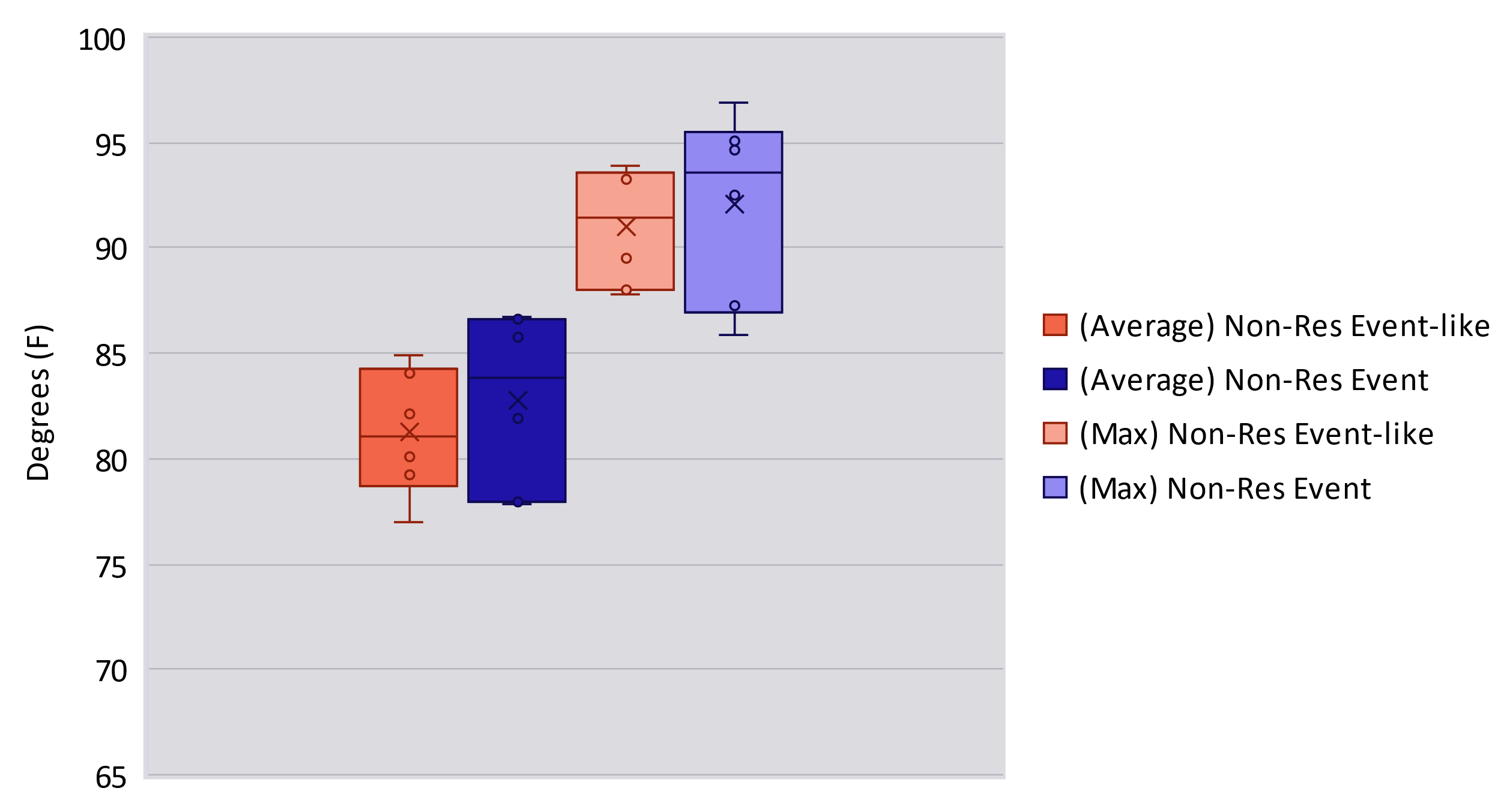


Figure A - 3 PG&E Temperatures of Event Days v. Event-Like Days – Residential

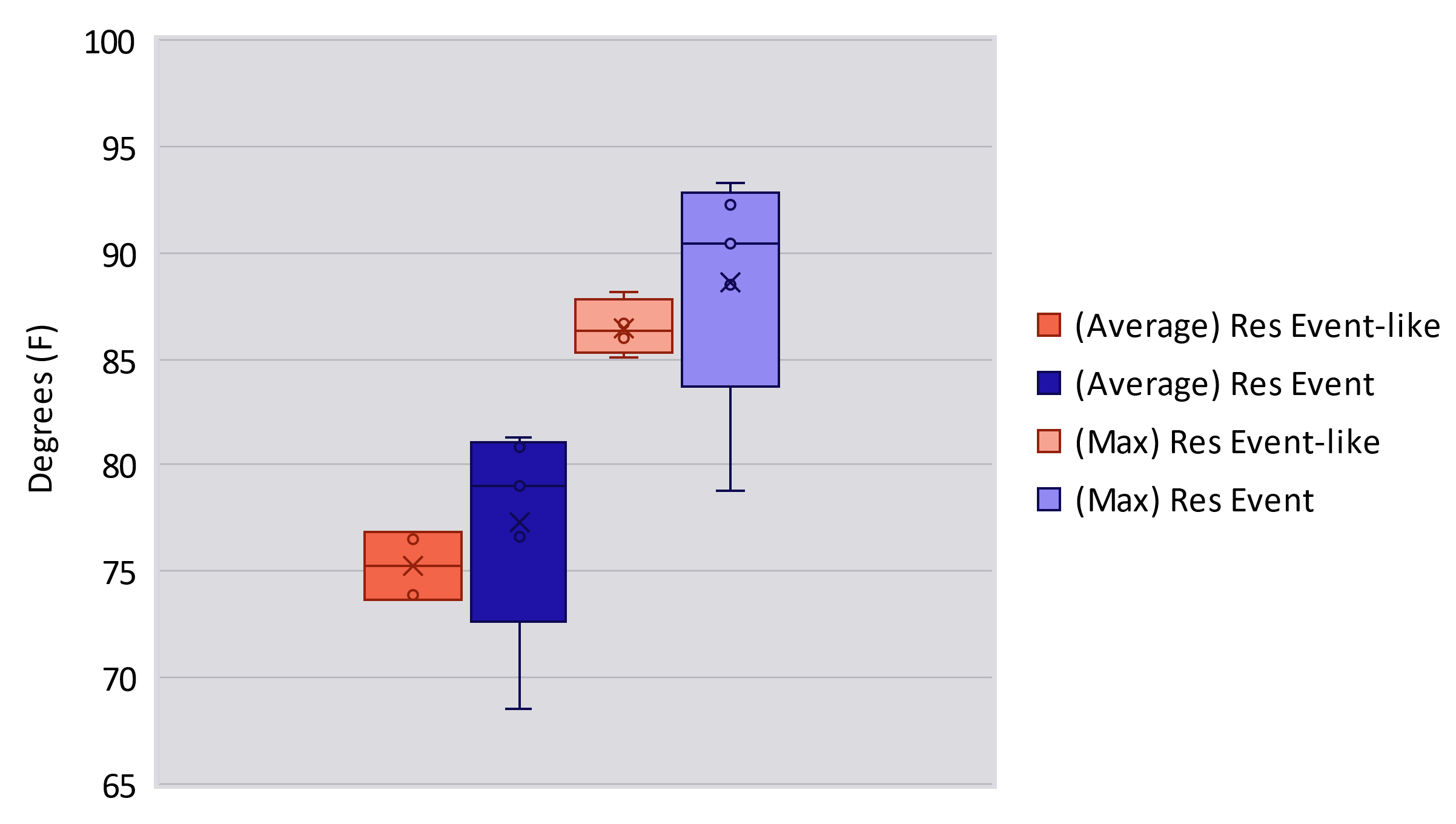


Figure A - 4 SCE Temperatures of Event Days v. Event-Like Days – Summer

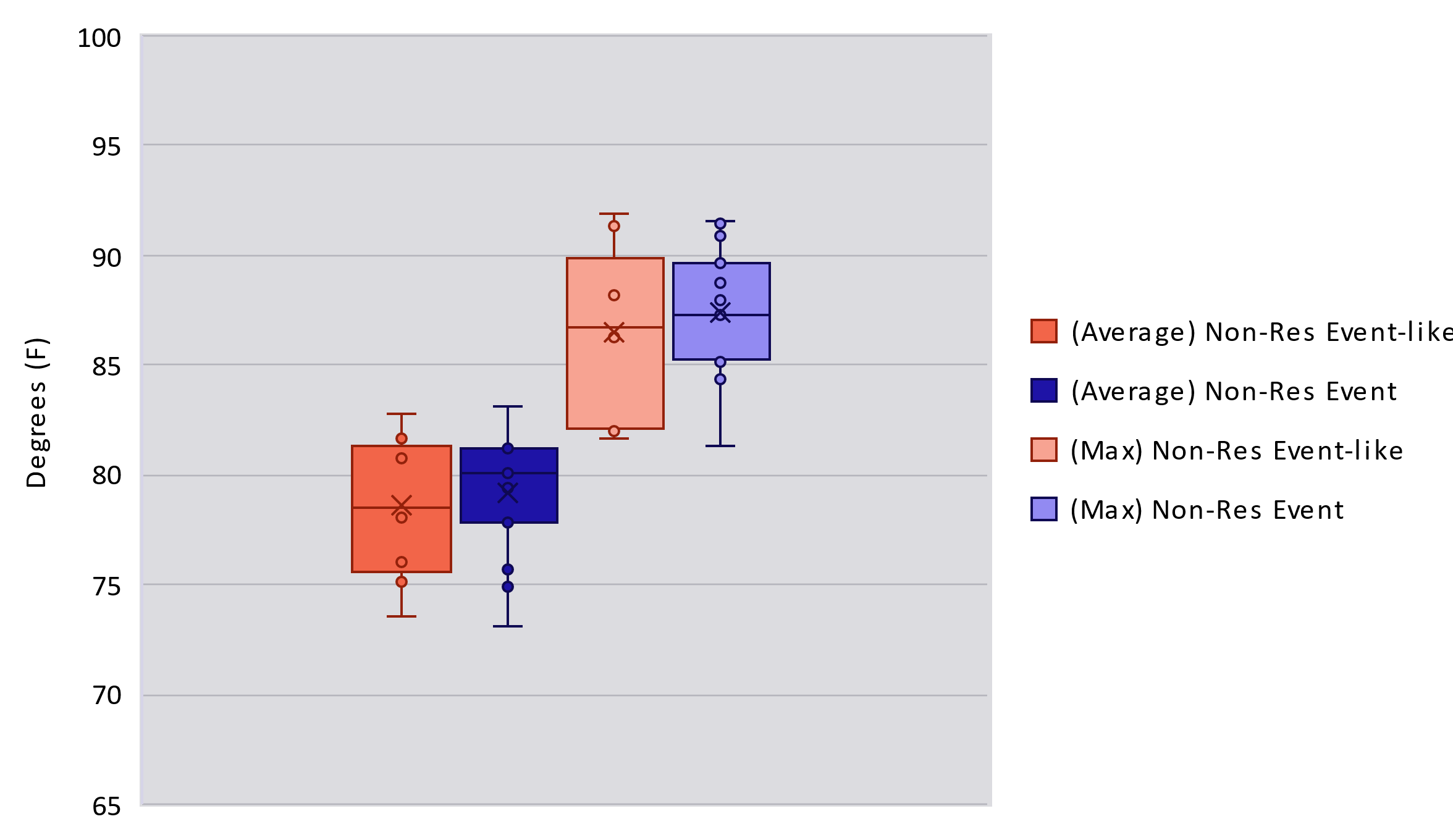


Figure A - 5 SCE Temperatures of Event Days v. Event-Like Days – Non-Summer

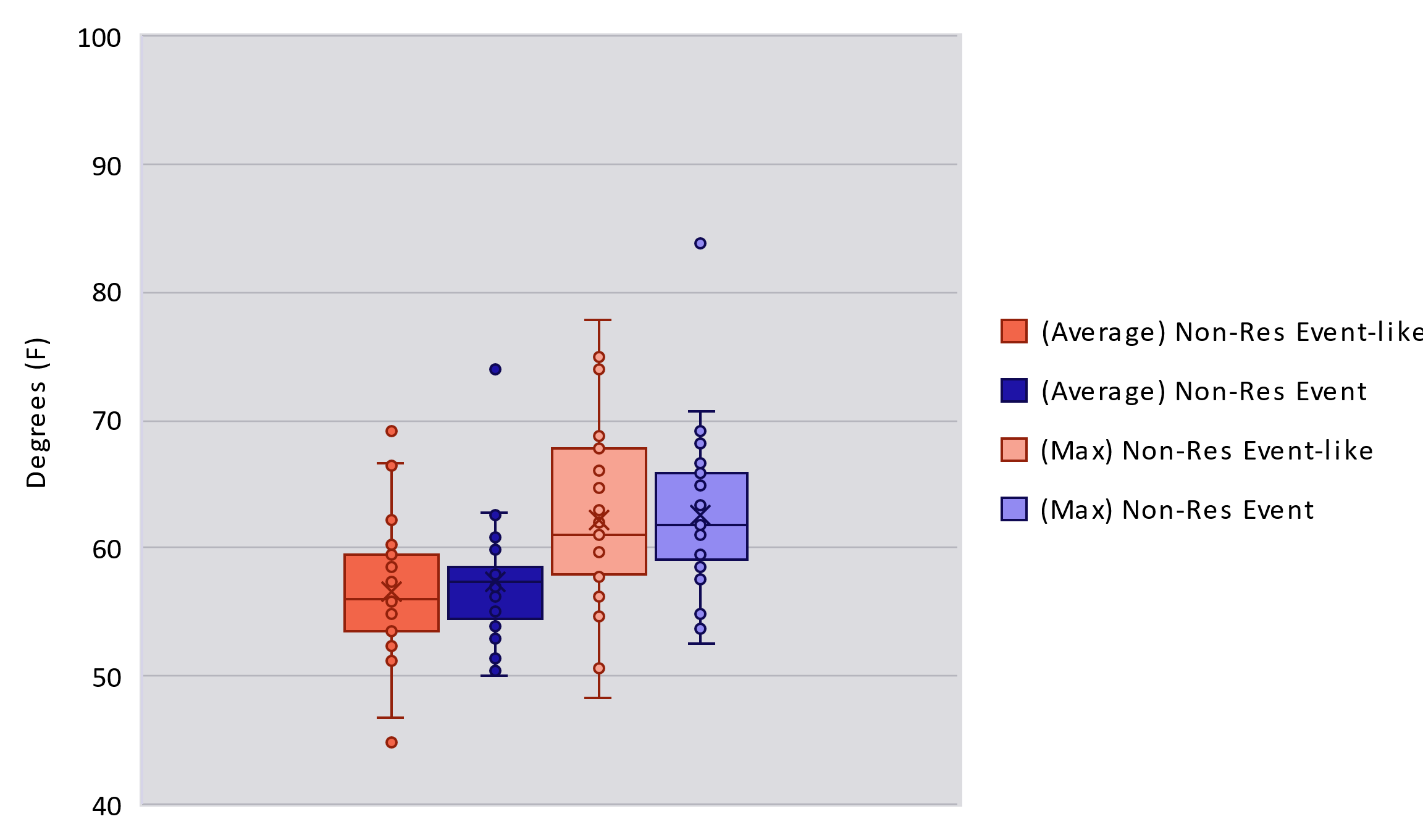
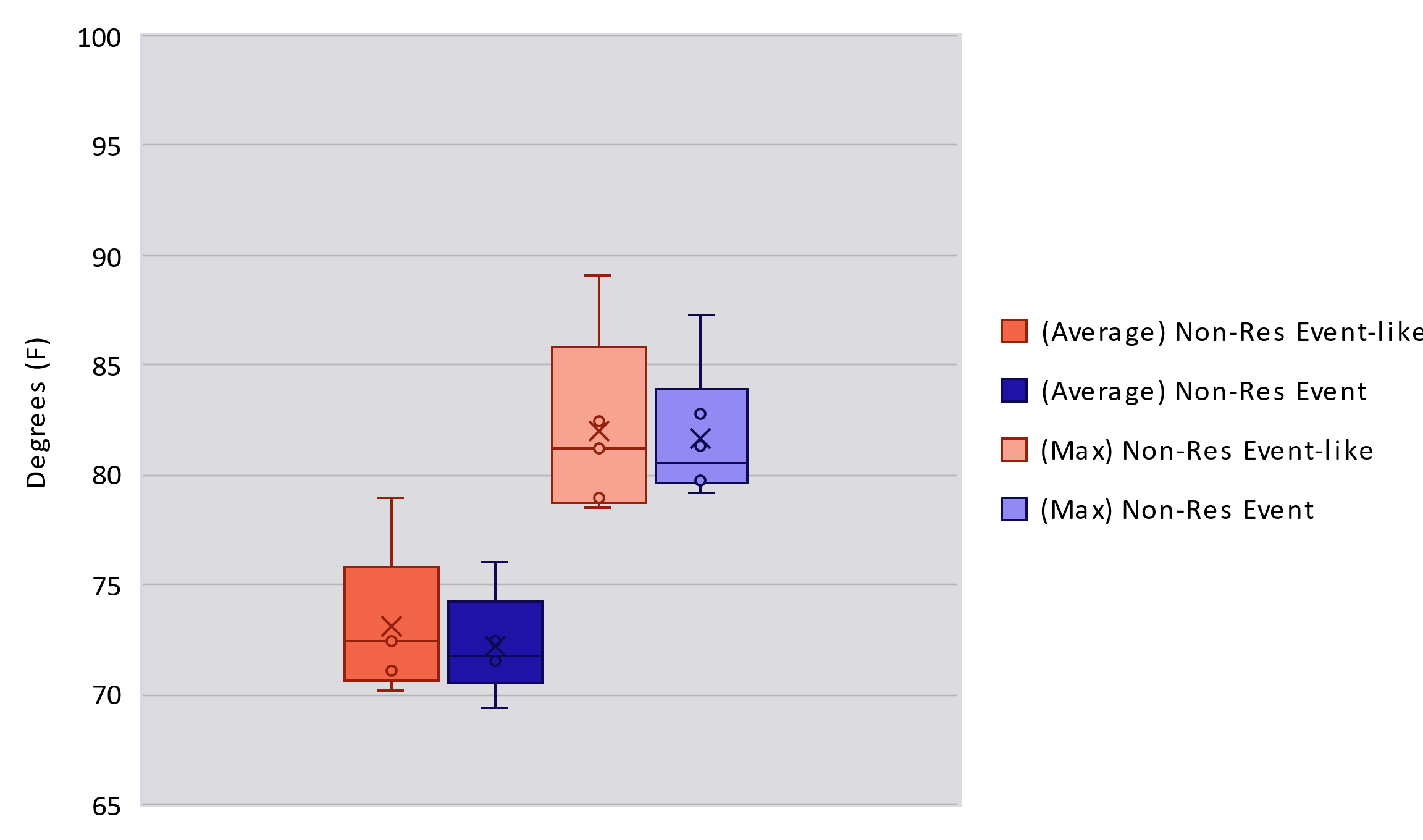


Figure A - 6 SDG&E Temperatures of Event Days v. Event-Like Days



Optimization Process and Results

Next, we present the metrics produced by our optimization process for in-sample and out-of-sample testing. To perform each test, we used the following approach:

* In-sample test. We fitted each candidate model to the entire data set and used the results of these fitted models to predict the usage on CBP event days. The models should be able to accurately predict customers’ actual consumption for these days, having controlled for the impacts of the event hours. We assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE) and mean percent error (MPE), respectively. We refer to these metrics as the in-sample MAPE and MPE.
* Out-of-sample test. We fitted each candidate model to the data set excluding event-like days, and used the results of these fitted models to predict the usage on event-like days. We similarly assessed the accuracy and bias of the event-like day predictions by calculating the MAPE and MPE, which we refer to as the out-of-sample MAPE and MPE.

These two tests resulted in several in-sample and out-of-sample metrics. To determine the best model for each segment in terms of its ability to predict both the reference load and the actual load for each participant with accuracy and limited bias, we combined the two tests into a single metric as follows:

Where,

Once we had a single metric for each candidate model for each participant, we selected the best model for each participant by choosing the model specification with the smallest overall metric. The optimization process metrics are shown in the following tables and figures.

Table A - 2 presents the weighted average MAPE and MPE for each IOU and program’s final set of programs. Most MAPE values are below 5%, indicating high accuracy. MPE values very close to zero, indicating low levels of bias. SCE’s Non-residential DA shows high out-of-sample MAPE (above 8%) and very high in-sample MAPE (above 30%), resulting from very low participant counts with highly variable loads.

Table A - 2 Weighted Average MAPE and MPE by Utility and Program

| IOU | Program | Out-of-Sample | | In-Sample | |
| --- | --- | --- | --- | --- | --- |
| MAPE | MPE | MAPE | MPE |
| PG&E | Non-Residential DA | 1.17% | 0.33% | 0.11% | 0.02% |
| Residential DA | 7.51% | 4.43% | 1.30% | -0.29% |
| SCE | Non-Res DA | 8.02% | -3.51% | 32.98% | -12.76% |
| Non-Res DO | 0.76% | -0.53% | 1.10% | -0.03% |
| SDG&E | Non-Residential DA | 2.08% | 0.31% | 0.69% | -0.01% |
| Non-Residential DO | 1.36% | 0.39% | 0.29% | 0.00% |

Visual inspection can also be a simple but highly effective tool. Figure A - 7 to Figure A - 10 present the average event-like day predicted loads (dotted lines) and actual loads (solid lines) from the in-sample and out-of-sample tests by IOU and program. Due to confidentiality, SCE non-summer loads are not shown below.

During the inspection, we looked for specific aspects of the predicted and reference load shapes to tell us how well the models performed. For example,

* We checked to ensure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate a problem with the reference load, either over- or under-estimating usage in the absence of the event.
* We closely examined the reference load for odd increases or decreases in the load that could indicate an effect not correctly captured in the models. If we found such an increase or decrease, we investigated the cause and attempted to control for the effect in the models.
* We also looked for bias, both visually and mathematically. Bias is the consistent over- or under-prediction of the actual load. We may see temperature-related bias, under-predicting on hot days, and over-predicting on cool days. We have also seen bias that is time-based, over-predicting at the beginning of the year and under-predicting at the end of the year. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

The figures below show predicted loads very close to the actual loads, which visually tells us that, on average, the customer-specific regression models do a good job estimating what customer loads would be like on event-like days therefore, can produce accurate reference loads. SCE’s Non-residential DA, similar to MAPE metrics shown above, show less accurate predictions likely resulting from very low participant counts with highly variable loads.

Figure A - 7 PG&E Actual and Predicted Loads, Non-Residential

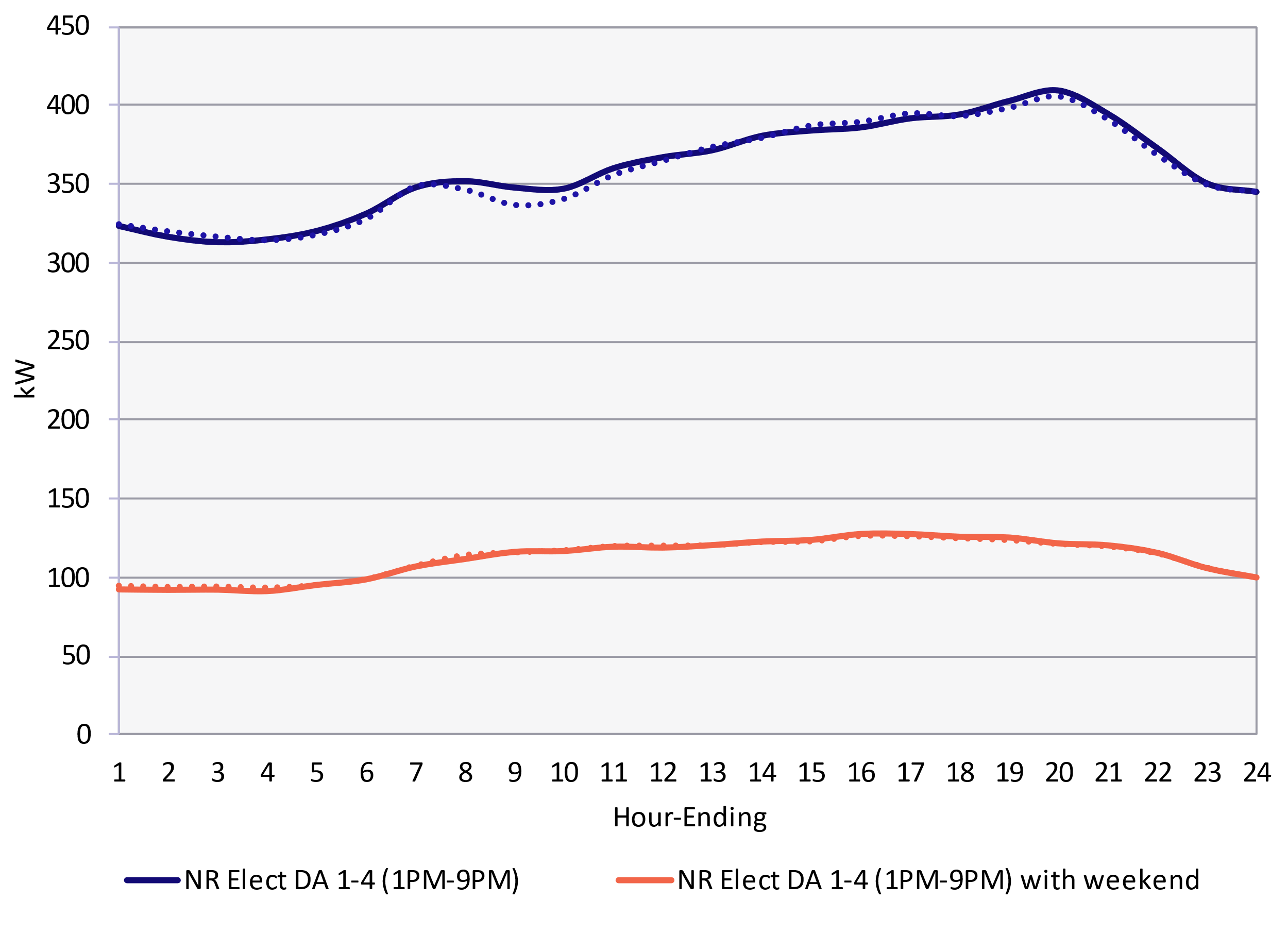
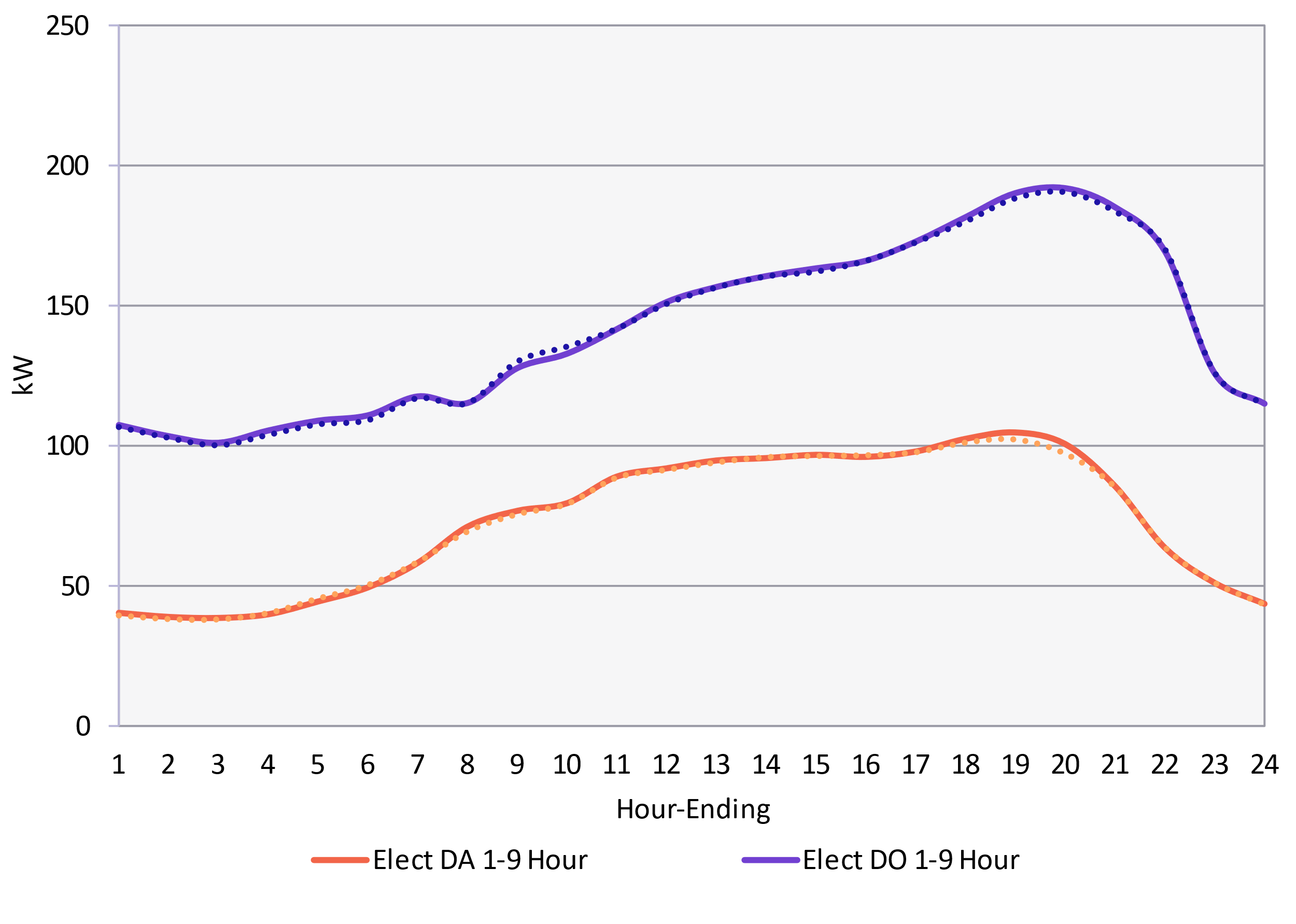


Figure A - 8 PG&E Actual and Predicted Loads, Residential

Figure A - 9 SCE Actual and Predicted Loads



Figure A - 10 SDG&E Actual and Predicted Loads



|  |  |
| --- | --- |
| Applied Energy Group, Inc.  2300 Clayton Road, Suite 1370  Concord, CA 94520 | P: 510.982.3525 |

1. “Program” refers to each IOU’s notification type by customer class. For example, SDG&E’s Non-residential CBP Day-of notification is a program. SCE and SDG&E both have Non-residential Day-Ahead and Non-residential Day-Of programs, while PG&E has the Day-Ahead program for both residential and non-residential customers. [↑](#footnote-ref-2)
2. “Product” refers to different product offerings within each program. For example, the PG&E Day Ahead program has 3 products offerings: Elect, Elect+, and Prescribed. [↑](#footnote-ref-3)
3. Starting in PY2018, DO products are no longer offered by PG&E. [↑](#footnote-ref-4)
4. PG&E refers to these as service agreements. [↑](#footnote-ref-5)
5. “Program” refers to each IOU’s notification type by customer class. For example, SDG&E’s Non-residential CBP Day Of notification is a program. SCE and SDG&E both have Non-residential Day Ahead and Non-residential Day Of programs, while PG&E has the Day Ahead program for both Residential and Non-residential customers. [↑](#footnote-ref-6)
6. “Product” refers to different product offerings within each program. For example, the PG&E Day-Ahead program has three products offerings: Elect, Elect+, and Prescribed. [↑](#footnote-ref-7)
7. Since PY2018, the program has been open to residential customer enrollment. [↑](#footnote-ref-8)
8. PG&E’s partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible. [↑](#footnote-ref-9)
9. Self-aggregated customers receive up to 80% of the available capacity payment; aggregators receive 100% of the capacity payment for the load reduction received. Note that all of PG&E and SCE’s CBP customers participate through an aggregator. [↑](#footnote-ref-10)
10. Self-aggregated customers receive additional energy payments directly. [↑](#footnote-ref-11)
11. PG&E and SDG&E’s energy payments are made to bundled customers. SCE’s energy payment calculation is based upon all types of customers including bundled, DA, and CCA. [↑](#footnote-ref-12)
12. A summer month is defined as months between May through October. [↑](#footnote-ref-13)
13. Delivery performance is the measure of the program performance. It is the ratio of ex-post MW results compared to the dispatched MWs. [↑](#footnote-ref-14)
14. The impact degradation refers to a set of factors that are applied to each hour throughout the Resource Adequacy (RA) window. It assumes that only one hour within the RA window could reach the 100% average customer impact from ex-post. [↑](#footnote-ref-15)
15. Achievement Rate is ratio of market dispatched MWs compared to nominated MWs. [↑](#footnote-ref-16)
16. During both the summer and non-summer season, HE18-21 and HE19-21 consistently have the same number of dispatches. For reporting purposes, HE18 was chosen as the designated reporting hour for the summer season, while HE20 was selected for the non-summer period for both DA and DO programs. This decision was guided by the observed highest impact on average event days during those two hours. [↑](#footnote-ref-17)
17. Non-residential CBP follows three confidentiality scenarios, where any one of them being met would impact being treated as confidential. Firstly, if there's only one aggregator involved for a group of customers. Secondly, if a group of customers comprises fewer than 15 customers. Lastly, within a group of customers, if one customer constitutes 15% or more of the group's load. A group of customers is defined as sharing the same LCA, Sub-LAP, Product, and other criteria, depending on the IOU. [↑](#footnote-ref-18)
18. PY2022 did not have active Residential programs. [↑](#footnote-ref-19)
19. Starting in 2024 For March and April, the RA window shifted to 5 PM to 10 PM, starting in 2025 for May, RA window shifted to 5 PM to 10 PM; 4 PM to 9 PM otherwise. [↑](#footnote-ref-20)
20. We included a PY2022 back cast as part of the ex-ante impact analysis. [↑](#footnote-ref-21)
21. Since PY2018, the program was open to residential customer enrollment. [↑](#footnote-ref-22)
22. PG&E’s partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible. [↑](#footnote-ref-23)
23. Self-aggregated customers receive up to 80% of the available capacity payment; aggregators receive 100% of the capacity payment for the load reduction received. Note that all of PG&E and SCE’s CBP customers participate through an aggregator. [↑](#footnote-ref-24)
24. Self-aggregated customers receive additional energy payments directly. [↑](#footnote-ref-25)
25. PG&E and SDG&E’s energy payments are made to bundled customers. SCE’s energy payment calculation is based upon all types of customers including bundled, DA, and CCA. [↑](#footnote-ref-26)
26. PY2022 did not have active Residential program, but the approach to Residential program analysis is included for reference. [↑](#footnote-ref-27)
27. PY2022 did not have active Residential program, but the approach to Residential program analysis is included for reference. [↑](#footnote-ref-28)
28. We used weather variables in the Euclidean distance metrics calculation to select event-like days and developed a metric specific to each IOU and customer class. We discuss each metric used in the Model Validity Appendix. [↑](#footnote-ref-29)
29. Any unexplained variation will end up in the error term. [↑](#footnote-ref-30)
30. The specified window can be one or more of the following: 4AM – 10 AM; 10 AM – 2 PM; 10 PM – 12 AM. [↑](#footnote-ref-31)
31. PY2022 did not have active Residential program, but the approach to Residential program analysis is included for reference. [↑](#footnote-ref-32)
32. The mean absolute percent error (MAPE) is defined as: [↑](#footnote-ref-33)
33. The mean percent error (MPE) is defined as: [↑](#footnote-ref-34)
34. Any unexplained variation will end up in the error term. [↑](#footnote-ref-35)
35. PY2022 did not have active Residential program, but the approach to Residential program analysis is included for reference. [↑](#footnote-ref-36)
36. HE20 for PG&E and SCE; HE19 for SDG&E. [↑](#footnote-ref-37)
37. Starting in 2024 For March and April, the RA window shifted to 5 PM to 10 PM, starting in 2025 for May, RA window shifted to 5 PM to 10 PM; 4 PM to 9 PM otherwise. [↑](#footnote-ref-38)
38. We include a PY2023 back cast as part of the ex-ante impact analysis. [↑](#footnote-ref-39)
39. IOU-specific adjustments to the assumptions will be discussed in Section 5, alongside the ex-ante results. [↑](#footnote-ref-40)
40. SCE Residential program is open but has not received any nominations. SDG&E is currently running pilots for their Residential DA and DO programs. [↑](#footnote-ref-41)
41. Delivery performance is the measure of the program’s performance. It is the ratio of ex-post MW results compared to the dispatched MWs. [↑](#footnote-ref-42)
42. Achievement Rate is ratio of market dispatched MWs compared to nominated MWs. [↑](#footnote-ref-43)
43. During both the summer and non-summer season, HE18-21 and HE19-21 consistently have the same number of dispatches. For reporting purposes, HE18 was chosen as the designated reporting hour for the summer season, while HE20 was selected for the non-summer period for both DA and DO programs. This decision was guided by the observed highest impact on average event days during those two hours. [↑](#footnote-ref-44)
44. Non-residential CBP follows three confidentiality scenarios, where any one of them being met would impact being treated as confidential. Firstly, if there's only one aggregator involved for a group of customers. Secondly, if a group of customers comprises fewer than 15 customers. Lastly, within a group of customers, if one customer constitutes 15% or more of the group's load. A group of customers is defined as sharing the same LCA, Sub-LAP, Product, and other criteria, depending on the IOU. [↑](#footnote-ref-45)
45. Test events are not triggered by CAISO market awards. However, aggregators and participants experience a similar notification or “experience” as a normal CBP event. Test events are shown in red text. [↑](#footnote-ref-46)
46. To measure the delivery performance at the monthly level, we compare the impact on the most dispatched hours for each month to the average event day reporting hour to determine whether any adjustments need to be applied to the monthly delivery performance. In 2023, the most dispatched hour for each month aligns with the reporting hour selected for the average event day, thus no adjustment is needed. [↑](#footnote-ref-47)
47. We've selected HE20 as the reporting hour for the residential DA. Since events were only called in October, we did not apply adjustments to the delivery performance. [↑](#footnote-ref-48)
48. The data underlying the figures are available in the Excel-based table generators that are included as appendices to this report. [↑](#footnote-ref-49)
49. The results are for an average event day. Note that the total for the program does not always exactly equal the total of the individual segments (industry, LCA, or Sub-LAP). This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments. [↑](#footnote-ref-50)
50. Industry type breakdown doesn’t apply to Residential DA. [↑](#footnote-ref-51)
51. Residential DA capacity nominations are confidential and not shown in the figure. [↑](#footnote-ref-52)
52. Starting in 2024, the (RA) resource Adequacy window shifts to 5:00 – 10:00 PM for May; remains 4:00 – 9:00 PM for the other months. [↑](#footnote-ref-53)
53. Test events are not triggered by CAISO market awards. However, aggregators and participants experience a similar notification or “experience” as a normal CBP event. [↑](#footnote-ref-54)
54. Test events are not triggered by CAISO market awards. However, aggregators and participants experience a similar notification or “experience” as a normal CBP event. [↑](#footnote-ref-55)
55. During both the summer and non-summer season, HE18-21 and HE19-21 consistently have the same number of dispatches. For reporting purposes, HE18 was chosen as the designated reporting hour for the summer season, while HE20 was selected for the non-summer period for both DA and DO programs. This decision was guided by the observed highest impact on average event days during those two hours. [↑](#footnote-ref-56)
56. Maximum of 5 events/month and 30 hours/month for each resource. [↑](#footnote-ref-57)
57. The data underlying the figures are available in the Excel-based table generators that are included as appendices to this report. [↑](#footnote-ref-58)
58. The results are for an average event day. Note that the total for the program does not always exactly equal the total of the individual segments (industry or LCAs). This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments. [↑](#footnote-ref-59)
59. PY2023 is the last year of SCE’s CBP non-summer season, only 2023 “back-cast” is included in the figure. [↑](#footnote-ref-60)
60. The small negative impacts are most likely a modeling artifact resulting from an imperfect quantification of weather effects and/or omitted variable bias. AEG has no evidence to suggest that customers are actually increasing their load in response to events. [↑](#footnote-ref-61)
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63. The small negative impacts are most likely a modeling artifact resulting from an imperfect quantification of weather effects and/or omitted variable bias. AEG has no evidence to suggest that customers are actually increasing their load in response to events.. [↑](#footnote-ref-64)
64. The data underlying the figures are available in the Excel-based table generators that are included as appendices to this report. [↑](#footnote-ref-65)
65. The results are for an average event day. Note that the total for the program does not always exactly equal the total of the individual industry segments. This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments. [↑](#footnote-ref-66)
66. The small negative impacts likely reflect modeling error, either from imperfect quantifications of weather effects and/or omitted variable bias. We have no reason to think that customers increased their load in response to events. [↑](#footnote-ref-67)
67. SDG&E no longer offers the Technical Incentives (TI) program, thus an additional forecast that includes TI enrollment growth is no longer necessary. [↑](#footnote-ref-68)