REPORT

PY2025 SCE Smart Energy Program Load Impact Evaluation

Confidential information is redacted and denoted with black highlighting:

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1 EXECUTIVE SUMMARY

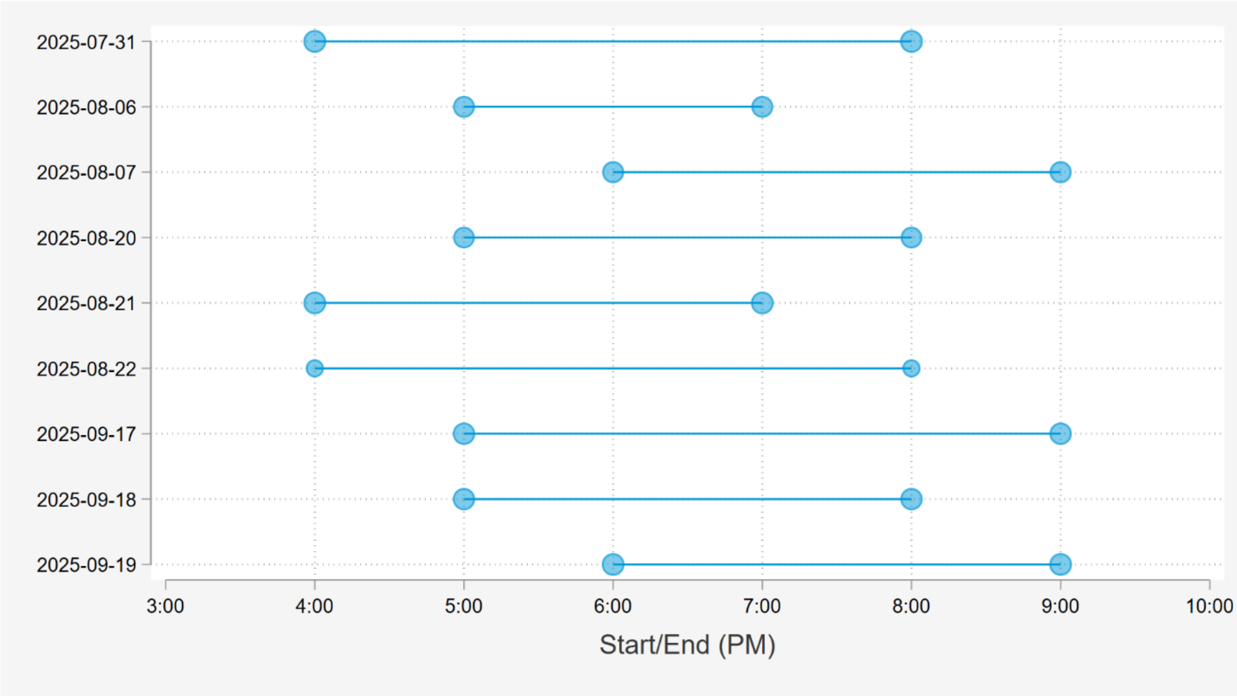
This report documents the evaluation year 2025 load impact evaluation of Southern California Edison's (SCE) Smart Energy Program (SEP). SEP is a demand response (DR) program that utilizes Wi-Fi connected smart thermostats to reduce air conditioning load during peak hours. During the PY2025 evaluation period, participation was limited to residential customers, though the program has since expanded to allow participation from commercial customers. SCE retained Demand Side Analytics (DSA) to conduct the SEP load impact evaluation for PY2025. The primary objectives of this report are to:

- Document the findings of an ex-post (after the fact) load impact study for PY2025 events.
- Provide ex-ante (forward looking) estimates of SEP's demand reduction capability over the next eleven years (2026 to 2036) under various weather conditions[1].

When SCE initiates SEP events, the two participating DR thermostat vendors adjust cooling set points upward by as much as four degrees (F) to limit air conditioning usage and reduce electric demand. SCE can call SEP events for emergency (reliability) reasons, economic purposes, or as part of measurement and evaluation. The evaluation year for 2025 goes from October 2024 to September 2025. Evaluation years end in September to ensure load impacts are available in time for filing the following spring. SCE dispatched SEP on nine days during PY2025 between July and September. All 9 events were called for measurement and evaluation purposes as part of an initiative to test the program's ability to dispatch customers at a granular distribution level. Figure 1 shows the nine events along with the start and end time. All times in this report are displayed in Pacific Daylight time.

[1] Pursuant to the Load Impact Protocol Process Guide (version 6.1, released by the Energy Division on March 5, 2026), large loads (e.g. data centers, EV fleet charging station load) should be reported as a distinct load type within ex-ante and ex-post table generators. Because the formal definition of "large loads" is still under development, this study does not incorporate large-load effects in either the ex post load impact estimates or the ex ante forecasts.

Figure 1: SEP PY2025 Event Start and End Times (Pacific Daylight)



SEP enrollments continued to grow through the summer of 2025, growing by more than 7,000 participants from the end of the prior season. This growth in enrollment was in line with the ex-ante enrollment forecast from the previous year's analysis. SEP has continued a trend of substantial year over year growth for several consecutive years.

1.1 SUMMARY OF EX-POST LOAD IMPACTS

There were nine distinct SEP events in PY2025 between July and September 2025. SEP events may be dispatched at the B-bank substation level[2], Sub-Load Aggregation Point (SubLAP) or called for the entire SCE territory. In PY2025 all events were called for measurement and evaluation purposes as part of an initiative to test the program's ability to dispatch customers at a granular distribution level. During each event, only a subset of all enrolled customers, about 10%, were dispatched. Customers were randomly grouped together at the B-bank substation level to determine which customers were dispatched on each event day. The events called in 2025 were longer on average than previous years in an effort to test the program's ability to provide sustained event impacts across longer events.

DSA utilized a randomized control group, utilizing SEP participants that were not dispatched for a given event as controls for that event, with a simple difference-in-differences analysis to estimate the impacts of each event across the full dispatched group and a variety of segments. Table 1 shows the event details and average hourly impacts for all PY2025 events and the "Average Event Day" profile.

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[2] D.23-12-005, pg.68

DSA defines an "Average Event Day" for PY2025 as the weighted average of the two events that began at 4pm and ended at 8pm (four-hour duration). Savings estimates presented in Table 1 show the average hourly impacts. It is important to note that events with longer durations will tend to have lower average hourly impacts because of the typical tapering trend of smart thermostat program impacts, thus lowering the event's average hourly impact with each additional hour of dispatch.

The hottest event took place on 8/21/2025, which was also the date of the CAISO peak hour from 6PM-7PM. The three-hour event on that day had an average per customer hourly reduction of 0.92 kW and an average aggregate hourly savings of 8.3 MW during the full event hours across the 9,082 customers that were dispatched. If all enrolled customers (87,765) had been dispatched that day, assuming similar impacts to the dispatched customers, the program would have delivered 80.4 MW on average across the three event hours.

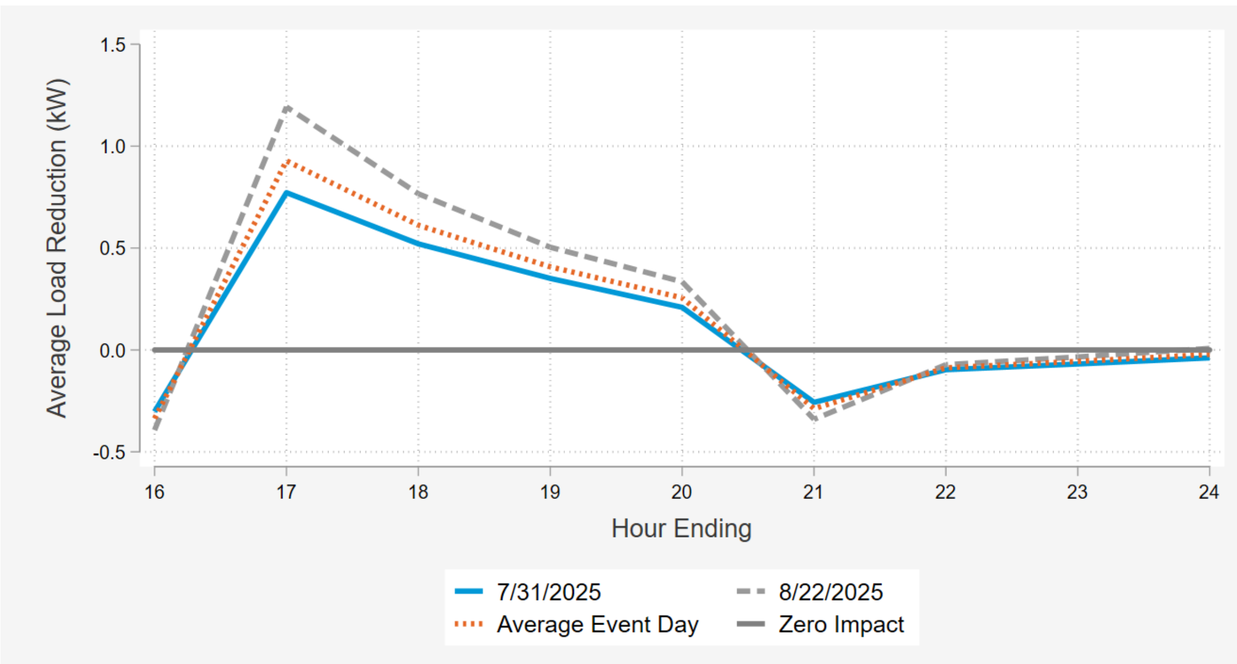
The SCE system peak day occurred on 8/22/2025, which was also an event day. During that four-hour event, the average per-customer hourly reduction was 0.70 kW and there was an average aggregate hourly savings of 3.8 MW across the 5,409 participants dispatched for the event. If all enrolled customers had been dispatched that day, assuming similar impacts to the dispatched customers, the program would have delivered 61.4 MW on average across the four event hours.

Table 1: 2025 Ex-post Event Impacts

Event Date	Start Time	End Time	Participants	Average Event Temp	Daily Max Temp	Average Full Hour Impact (kW Reduction)	Average Aggregate Full Hour Impact (MW Reduction)	Average Aggregate Impacts if All Enrolled Customers were Dispatched (MW Reduction)
7/31/2025	4:00 PM	8:00 PM	9,155	83.0	84.8	0.46	4.2	40.7
8/6/2025	5:00 PM	7:00 PM	8,366	89.2	90.5	0.86	7.2	75.3
8/7/2025	6:00 PM	9:00 PM	8,496	93.7	99.8	0.70	5.9	61.0
8/20/2025	5:00 PM	8:00 PM	8,163	87.9	89.4	0.58	4.7	50.7
8/21/2025	4:00 PM	7:00 PM	9,082	95.1	97.9	0.92	8.3	80.4
8/22/2025	4:00 PM	8:00 PM	5,409	86.8	90.1	0.70	3.8	61.4
9/17/2025	5:00 PM	9:00 PM	8,837	80.2	89.5	0.21	1.9	18.7
9/18/2025	5:00 PM	8:00 PM	8,751	77.3	80.4	0.44	3.8	38.4
9/19/2025	6:00 PM	9:00 PM	9,101	76.8	81.1	0.40	3.6	34.9
Average Event Day	4:00 PM	8:00 PM	7,764	84.4	86.7	0.55	4.3	48.4

Figure 2 shows program load impacts from the "Average Event Day" along with its contributing dates. The event window temperature during the "Average Event Day" was 84.4 °F over the four event hours. Weather conditions of the two dates that make up the "Average Event Day" were very different from one another, with the event day on July 31st being on the cooler side and the event on August 22nd being one of the hottest event days of the year. While outdoor temperature affects SEP load impacts, the most important predictor of hourly load impact is event hour, or whether a given hour is the first, second, etc. hour of dispatch. The first hour of the "Average Event Day" provides a reduction of approximately 0.93 kW per household, while the second hour had a reduction of 0.61 kW per household, declining from there in hours three and four. One of the SEP vendors deployed pre-cooling on each of the event days included in the "Average Event Day", as well as on all other event days. The pre-cooling of homes leads to larger load impacts during the event at the expense of load increases in the hour leading up to each non-emergency event. Customers on dynamic rates are not pre-cooled if the hour before the event start falls in their peak pricing period.

Figure 2: Hourly Load Reductions for 2025 Average Event Day



1.2 SUMMARY OF EX-ANTE LOAD IMPACTS

SCE and CAISO can call SEP reliability events anytime during the year. SEP economic events are restricted to non-holiday weekdays from 11am to 9pm. In the ex-ante impacts, SEP events are assumed to span the Resource Adequacy (RA) window. The definition of the RA window varies by month, beginning at 4pm and lasting until 9pm in June-October, while beginning at 5pm and lasting until 10pm in all other months of the year. The varying RA window is meant to represent the time of day which is most likely to require dispatchable resources throughout each month of the year. We forecast decaying impacts in each hour of the five hours of the RA window just as is typically demonstrated in the ex-post evaluation. Figure 3 illustrates this trend for monthly system worst days using SCE and CAISO 1-in-2 weather conditions. Although SEP is available year-round, it is a weather sensitive program with little or no impact when air conditioning is not being used. Using 1-in-2 weather for monthly system worst days, we estimate non-zero SEP capability in March through November for both SCE and CAISO weather conditions. CAISO 1-in-2 conditions show a significant dip capability between April and May. This is due to lower forecasted temperatures for the May system worst day than the April system worst day in the CAISO 1-in-2 weather scenario.

Figure 3: Average Customer Ex-Ante Impacts on 2026 Monthly System Worst Days: 1-in-2 Conditions

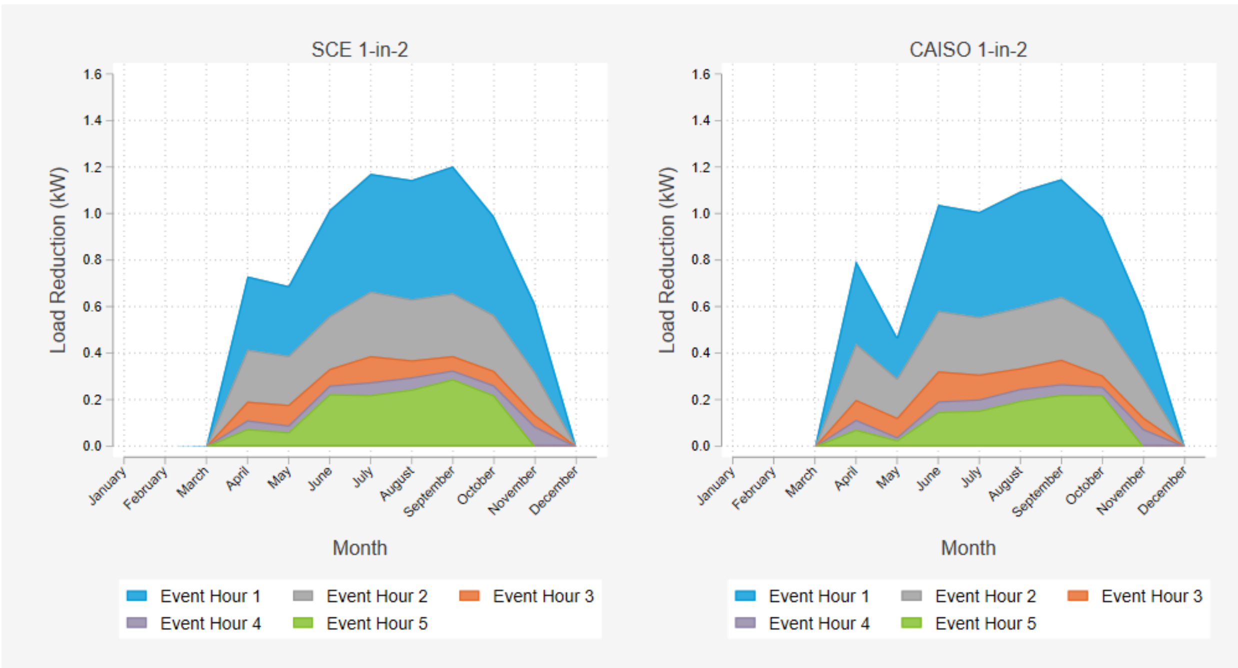


Figure 4 shows the same set of results for 1-in-10 weather conditions, which are hotter than 1-in-2 conditions. The SCE 1-in-10 condition impacts have two peaks over the summer months, July and September. This is due to higher forecasted temperatures in those months. The participant weighted maximum daily temperature for an August worst day in SCE 1-in-10 conditions is 99.3 °F, while July and September are 104.3 and 104.5 °F respectively.

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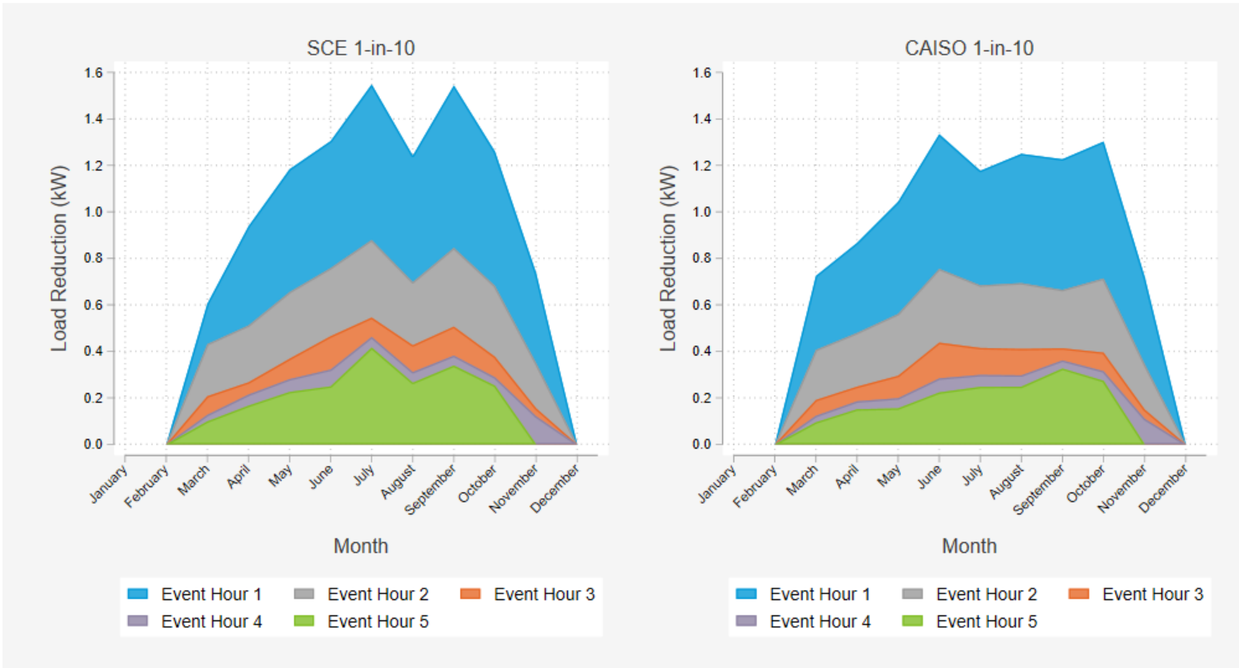
Figure 4: Average Customer Ex-Ante Impacts on 2026 Monthly System Worst Days: 1-in-10 Conditions



The estimated average load impact per customer on a September system worst day using SCE 1-in-10 weather is 1.54 kW during the first hour of dispatch with an expected temperature of 104.2°F in that hour. That impact estimate is down 0.05 kW from the PY2024 ex-ante forecast. For comparison, the weighted average event temperature for a September system worst day using CAISO 1-in-10 weather is 96.0°F in the first event hour and the estimated load impact is 1.23 kW.

Table 2 shows the SEP aggregate ex-ante load impacts for a September Monthly Worst Day in 2026. SCE's current enrollment forecast projects enrollment to reach 89,337 customers by that time. The estimated load impact of SEP in 2026 ranges from 102.6 MW to 138.0 MW during hour ending 17. Estimated impacts decline across the RA window and range from 19.8 MW to 30.3 MW in hour ending 21. Average impacts for the five-hour RA window range from 47.4 MW to 64.6 MW.

Table 2: SEP Aggregate Ex-Ante Impacts (MW) During RA Window: 2026 September Monthly Worst Day

Hour Ending	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
17	107.5	102.6	138.0	109.6
18	58.7	57.4	75.6	59.4
19	34.7	33.2	45.3	36.9
20	29.1	23.9	34.1	32.3
21	25.8	19.8	30.3	29.2
RA Window	**51.2**	**47.4**	**64.6**	**53.5**

SCE forecasts that SEP enrollments will reach 113,816 households by August 2036. Actual enrollment in PY2025 increased from the end of PY2024 and was essentially in line with expectation from the prior year's enrollment forecast. Using the SCE enrollment forecast and the ex-ante average customer impacts, we estimate an average aggregate load impact across the five RA window hours of 65.2 MW for SCE 1-in-2 weather conditions on a September monthly worst day and 82.4 MW for SCE 1-in-10 conditions on a September monthly worst day in 2036. Using CAISO peaking conditions, we estimate an average aggregate impact of 60.4 MW for 1-in-2 conditions and 68.2 MW for 1-in-10 conditions on a September monthly worst day in 2036.

1.3 KEY FINDINGS AND RECOMMENDATIONS

Based on the PY2025 ex-post and ex-ante evaluations, DSA highlights the following considerations for program design and future load impact evaluations.

- SEP operations in PY2025 focused heavily on testing the program's ability to target and deliver load impacts at the distribution level. This was accomplished by randomly grouping together customers at the B-Bank group level and dispatching subsets of the territory in a series of test events. The ex-post evaluation shows that the targeted dispatch of specific groups of customers worked as intended and per-customer impacts remained consistent with previous evaluations. SEP showed it can provide targeted value to the distribution grid in the same way it provides capacity value in CAISO.

- SEP enrollment increased by approximately 7,000 customers from the end of PY2024 to the end of PY2025. This growth trend is similar to the growth seen in the previous year. Continued marketing efforts played a large part in the healthy enrollments this year as well as previous years. The increase is in line with predictions made by the SEP program team in PY2024. Precise enrollment projections increase the accuracy of aggregate ex-ante forecasts as the enrollment forecasts play a large role in predicting future program capabilities.

- The most important predictor of SEP load impact is not time of day or weather, but the position of an hour within an event. Impacts are largest during the first event hour and decline sharply in each subsequent hour. Consequently, shorter events show larger average load impacts than longer events. Over the past several years, the SEP program has tended to call shorter events leading to higher average full hour impacts. PY2025, however, saw mostly longer events of 3 or 4 hours in length. While shorter events are likely preferred by customers, calling only longer duration events is very helpful for estimating ex-ante impacts. In PY2025 ex-ante, 2022-2025 event impacts were used for predicting future program impacts. Over that duration all but one of the four hour events used in ex-ante modeling was called in PY2025. If these testing events had not been called then the accuracy of ex-ante impacts would have likely suffered due to a lack of data. The lack of data on how program participants perform over five hour events, though, means that predicting program performance over a hypothetical five hour event requires using performance from other event hours to predict hour five of control. DSA recommends a continued focus on calling longer events and, if possible, during hotter outdoor temperatures to ensure that ex-ante predictions of program impacts are as accurate as possible.

- Pre-cooling was successfully implemented by the larger thermostat vendor for all events in PY2025. Pre-cooling customer's homes in the hour before an event allows for larger impacts during control hours and when successfully utilized can increase program performance.

- In PY2025 homes with two thermostats showed approximately 23% larger load reductions during events than homes with a single thermostat. Those with three or more thermostats had impacts about 15% higher than those with two program thermostats. These incremental increases in the estimated program impacts based on the number of thermostats enrolled are similar to those seen in previous years. Currently customer bill credits do not consider the number of thermostats controlled.

  - ✓ SCE may want to consider larger bill credits for homes with multiple program thermostats. This number may be scaled with the number of thermostats that the customer brings to the program.

- The PY2025 ex-ante forecasts of impacts are generally lower than the PY2024 per-participant impacts for the same ex-ante weather conditions. We attribute this change to two key factors:

  - ✓ Events in PY2025 were longer than in previous years meaning that we were able to fit separate ex-ante models for event hour 3 and event hours 4 and 5. Because smart thermostat event impacts decay in each event hour, impacts estimated for event hour 4 will usually be lower than event hour 3. The impact model for hour 4 is still used to estimate impacts for event hour 5 as there have not been any 5 hour SEP events in the last 5 years. Treating impacts in the final 2 hours of forecasted events in PY2024 as if they were like hour 3 likely overstated program capabilities in those hours.

  - ✓ Events in PY2025 were called for a much wider range of event conditions providing more information on how the program performs at extreme high and low temperatures than in previous years. Ex-ante forecasting conditions, especially in the hottest summer months or the coolest shoulder season months, are typically outside of the range of event conditions observed in ex-post, meaning that forecasted impacts must be extrapolated out of sample from the existing data. Observing additional ex-post data for both cool and hot events provides more certainty in out of sample estimates. The relationship between weather and event impacts was estimated to be slightly less steep, meaning that impacts are less weather sensitive, in the PY2025 analysis.

2 PROGRAM DESCRIPTION

SCE's Smart Energy Program is a technology-enabled program in which residential customers with a qualified smart thermostat are provided a monthly bill credit in exchange for allowing their smart thermostat provider to temporarily adjust their temperature set point or limit their air conditioning runtime. Prior to and during the evaluation period, participation was limited to residential customers, however, the program has since expanded to allow commercial customer enrollment. During SEP events, thermostat providers can adjust cooling set points upward by as much as four degrees (F) or impose a cycling strategy to limit air conditioning usage during peak hours. Participants receive a courtesy notification through their smart thermostat service provider prior to event dispatch but are not expected to take any action in response to the event signal.

Limiting air conditioning usage lowers electric demand at participating sites (i.e., homes or businesses). SCE can call multiple events on a single day, but the total number of hours triggered cannot exceed six hours in a given day. The six-hour limit can only be used for emergency purposes.[3] Economic events are limited to no more than four hours in a day. Dual enrollment in Critical Peak Pricing (CPP) dispatchable pricing tariffs or most other Demand Response programs, such as the Summer Discount Plan (SDP) program, is prohibited. Dual participation in some ELRP subgroups is allowed for SEP customers.

SCE provides eligible new SEP participants with a one-time $75 bill credit for enrolling and a daily bill credit of $0.4098 per day provided annually during the summer from June 1 through September 30 for remaining in the program. The daily credit for participation was updated beginning in 2026, replacing the prior credit of $0.3275 per day. SCE can call events year-round, though customers only receive bill credits for June through September participation. SEP events can be dispatched, or triggered, for multiple reasons.

A. CAISO emergency conditions
B. At the discretion of SCE's grid control center for load relief in SCE service territory
C. In response to high wholesale energy prices (e.g., economic dispatch)
D. For program measurement and evaluation or system contingencies.

SEP economic dispatch (trigger C) is limited to the first 40 hours of dispatch per year. Once 40 hours of SEP events have been triggered in a calendar year for any of the dispatch reasons noted above (A – D), SCE will not trigger any SEP events under trigger C. Additionally, Trigger C can only be activated on non-holiday weekdays from 11am to 9pm. SEP dispatch for triggers A, B, and D can be activated at any time, including weekends and holidays. No more than 180 hours of SEP events can be called in a calendar year for all dispatch triggers combined.

[3] D.21-12-015, Attachment 1, pg.6

In PY2025, SEP events were dispatched on a total of nine days between July 2025 and September 2025. Each event was called for program measurement and evaluation purposes as part of an initiative to test the program's ability to dispatch customers at a granular distribution level. During each event, only a subset of all enrolled customers, about 10%, were dispatched. Customers were randomly grouped together at the B-bank substation level to determine which customers were dispatched on each event day. Table 3 lists the event dates and dispatch reason. The SCE system peak day for 2025 is highlighted in green.

Table 3: PY2025 SEP Event Days and Dispatch Reason

Date	Dispatch Trigger	Partial SubLAPs Dispatched
7/31/2025	Program Measurement and Evaluation	SCEC, SCEN, SCEW
8/6/2025	Program Measurement and Evaluation	SCEC, SCEN, SCEW, SCNW
8/7/2025	Program Measurement and Evaluation	SCEC, SCEN, SCNW, SCHD
8/20/2025	Program Measurement and Evaluation	SCEC, SCEN, SCEW, SCLD
8/21/2025	Program Measurement and Evaluation	SCEC, SCEN, SCEW
8/22/2025	Program Measurement and Evaluation	SCEC, SCHD, SCEW
9/17/2025	Program Measurement and Evaluation	SCEC, SCHD, SCEW, SCNW
9/18/2025	Program Measurement and Evaluation	SCEC, SCHD, SCEW, SCEN
9/19/2025	Program Measurement and Evaluation	SCEC, SCEW

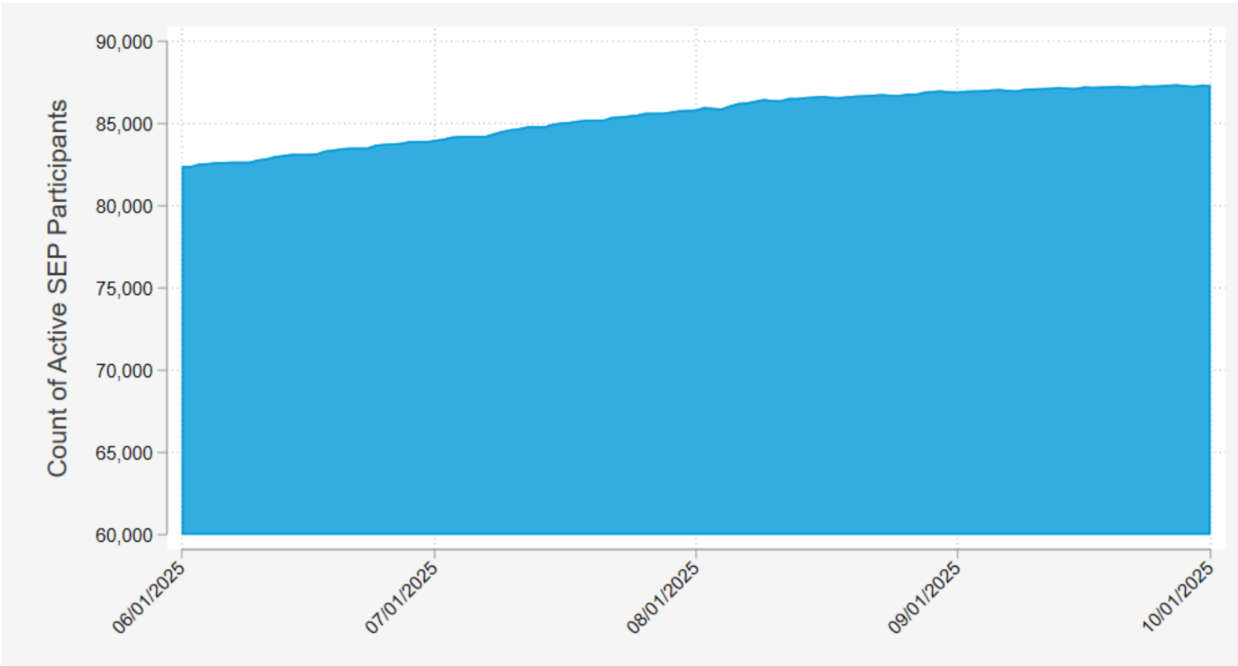
There were 87,765 active participants in SEP as of the last event date of the season on 9/19/2025. This is a substantial increase over the end of summer count from 2024 (80,528). The growth between the two years can be attributed to effective marketing efforts between SCE and participating thermostat manufacturers.

Figure 5 shows the number of enrolled households over the summer 2025 DR season. Historically, enrollments have been highest during the summer months when bill credits are available, and SCE's marketing efforts are most active. There was steady and continued growth in enrollment over the summer that outpaced attrition. In past years, attrition in enrollment was typically associated with move outs, disconnected or offline thermostats, or customers disenrolling because of heat waves that included many DR events. When a customer's comfort is impacted multiple days in quick succession, they are much more likely to leave the program.

The 2025 summer event season was different than prior years for a couple of reasons. First, the summer was cooler than many prior years, meaning that the impacts to participant comfort was smaller overall, resulting in lower attrition rates. Second, because each event was called for measurement and evaluation purposes, only a subset of customers was dispatched for each event. Each program participant was only dispatched for a maximum of one event, despite the program calling a total of nine events. Less frequent dispatch is helpful for minimizing customer dissatisfaction and attrition.

SEP also conducts compliance reviews and may remove customers whose thermostat is offline, consistently opting out of events or not meeting the minimum energy usage requirement. In past years, these compliance reviews have made up a substantial amount of the customers leaving the program.

Figure 5: Summer 2025 Enrollment Trend



Total program enrollment as of the final event date in PY2025 was 87,765. Table 4 shows the distribution of customers across various segmentation variables of interest.

- The LCA variable indicates the Local Capacity Area. About 82% of SEP participants are located in the LA Basin LCA.
- SEP participants enrolled in the low income rates (CARE or FERA programs) are indicated by the 'Low Income' segment.
- Approximately 38% of SEP participants have net energy metering (NEM) of rooftop solar arrays. The NEM percentage is up by 2% compared to PY2024, when only 36% of SEP customers had net energy metering.
- The 'Size' variable is based on customer's 2025 average net load on non-event weekdays during the Resource Adequacy window of 4pm to 9pm. Participants were binned based on whether they were above or below the median RA window average demand, which is 1.30 kW, considerably lower than PY2024 (2.11 kW) as a result of the cooler summer temperatures in 2025.
- The SubLAP variable segments participants by sub-load aggregation point.
- The 'Tariff' variable indicates whether the participant was on a flat volumetric rate (e.g. Domestic Service Plan) or a time-varying rate during summer 2025. Dynamic rate customers make up 68% of the SEP customer base in PY2025. SCE defaults customers to a dynamic rate in most parts of its service territory so they now make up the majority of the population. We consider tiered rates based on consumption flat because they do not vary by time of day.
- The 'Thermostats' variable indicates the number of smart thermostats a participant enrolls in SEP. Approximately 85% of participants have just a single smart thermostat enrolled in the program.
- [redacted]

- Zone is another geographic segmentation variable. The 'Remainder of System' segment are outside of the area impacted by the 2013 decommissioning of the San Onofre Nuclear Generating Station. SEP enrollments in the South Orange County and South of Lugo regions have increased since 2018, while the number of active participants in the Remainder of System region have decreased.

Table 4: Summary of SEP Enrollment by Customer Segment

Segmentation Variable	Segment Description	Participants	Percentage
All Customers		87,765	100%
LCA	Big Creek/Ventura	13,220	15%
	LA Basin	71,736	82%
	Outside LA Basin	2,809	3%
Low Income	CARE	22,459	26%
	Non-CARE	65,306	74%
NEM	NEM Customer	33,466	38%
	Non-NEM Customer	54,299	62%
Size	Above Median (1.3 kW)	44,507	51%
	Below Median (1.3 kW)	43,258	49%
SubLAP	SCEC	39,167	45%
	SCEN	10,460	12%
	SCEW	32,569	37%
	SCHD	2,752	3%
	SCLD	57	0%
	SCNW	2,760	3%
Tariff	Dynamic	59,493	68%
	Flat	28,272	32%
Thermostats	1 Thermostat	74,416	85%
	2 Thermostats	11,833	13%
	3+ Thermostats	1,516	2%
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Zone	Remainder of System	44,455	51%
	South Orange County	13,301	15%
	South of Lugo	30,009	34%

Table 5 shows the percentage of each customer segment variable that was dispatched as a part of each event date. The All Customers section shows that for almost all events about 10% of enrolled customers were dispatched with the only exception being August 22nd. An overlapping Public Safety Power Shutoff (PSPS) event, which is a localized outage implemented due to high fire risk and extreme weather, led the program to omit those areas from SEP dispatch to avoid overburdening affected customers. For most segments there is a similar trend to the All Customer group's dispatch percentages on each day, typically between 5% and 15% of customers were dispatched within each subsegment. Some smaller segments like the SCHD and SCLD SubLAPs, which are only made up of a small number of B-Banks, are typically either not dispatched or a large majority of the enrolled customers are dispatched depending on whether their few B-Banks were randomly assigned to treatment on that event date or not.

Table 5: Customer Segment Dispatch Percentage by Event Date in PY2025

Segmentation Variable	Segment Description	Event Date								
		7/31/2025	8/6/2025	8/7/2025	8/20/2025	8/21/2025	8/22/2025	9/17/2025	9/18/2025	9/19/2025
	All Customers	10.7%	9.7%	9.8%	9.4%	10.5%	6.2%	10.1%	10.0%	10.4%
LCA	Big Creek/Ventura	2.9%	17.3%	10.1%	7.6%	5.1%	0.0%	3.0%	19.6%	0.0%
	LA Basin	12.5%	8.7%	10.1%	10.0%	11.9%	7.2%	8.7%	8.4%	12.7%
	Outside LA Basin	0.0%	0.0%	2.1%	2.1%	0.0%	10.8%	78.7%	7.0%	0.0%
Low Income	CARE	9.6%	9.1%	10.5%	8.5%	13.5%	5.6%	11.3%	12.1%	6.4%
	Non-CARE	11.0%	9.9%	9.6%	9.7%	9.4%	6.5%	9.7%	9.3%	11.8%
NEM	NEM Customer	9.5%	10.0%	12.1%	8.8%	12.1%	5.9%	10.3%	10.5%	8.5%
	Non-NEM Customer	11.4%	9.5%	8.5%	9.8%	9.5%	6.4%	10.0%	9.7%	11.6%
Size	Above Median (1.3 kW)	9.7%	10.0%	10.5%	8.5%	11.4%	6.0%	10.5%	10.5%	8.9%
	Below Median (1.3 kW)	11.6%	9.3%	9.1%	10.3%	9.5%	6.5%	9.8%	9.6%	11.9%
SubLAP	SCEC	11.3%	11.0%	18.5%	5.8%	16.2%	5.8%	10.6%	12.2%	3.0%
	SCEN	3.7%	6.9%	5.4%	9.6%	6.4%	0.0%	0.0%	24.7%	0.0%
	SCEW	14.0%	5.8%	0.0%	15.1%	6.7%	8.9%	6.5%	3.8%	24.4%
	SCHD	0.0%	0.0%	2.1%	0.0%	0.0%	11.1%	80.3%	7.1%	0.0%
	SCLD	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	SCNW	0.0%	57.7%	28.1%	0.0%	0.0%	0.0%	14.4%	0.0%	0.0%
Tariff	Dynamic	10.5%	9.7%	10.0%	9.9%	10.2%	6.5%	9.9%	9.6%	10.9%
	Flat	11.0%	9.6%	9.4%	8.3%	11.1%	5.7%	10.6%	10.9%	9.3%
Thermostats	1 Thermostat	10.6%	9.9%	9.2%	9.7%	10.3%	6.3%	10.2%	10.3%	10.6%
	2 Thermostats	10.9%	8.5%	13.9%	7.7%	11.6%	5.9%	9.5%	8.8%	9.2%
	3+ Thermostats	12.7%	10.2%	10.8%	8.4%	9.0%	6.4%	12.5%	7.9%	10.0%
[redacted]										
Zone	Remainder of System	8.5%	14.0%	5.9%	5.5%	13.1%	5.1%	14.4%	12.6%	7.6%
	South Orange County	23.0%	0.0%	0.0%	3.8%	6.3%	4.0%	3.8%	6.7%	30.7%
	South of Lugo	8.3%	7.6%	20.0%	17.7%	8.5%	8.9%	6.6%	7.7%	5.6%

The SEP participant population is located across SCE service territory and experiences a wide range of weather conditions. At the conclusion of the PY2025 event season, there were active participants in nine of the sixteen California Energy Commission climate zones. For both the ex-post and ex-ante analysis we map each participant to one of 23 SCE-maintained weather stations. Table 6 presents the number of SEP participants mapped to each weather station along with the three year average number of cooling degree days (CDD) and heating degree days (HDD) using the period October 1, 2022 to September 30, 2025.

CDD and HDD were each calculated using a base of 60°F. We calculate CDD separately for each day using the difference of average daily temperature and 60, but the value is capped at zero. As an example, an 80-degree day has a CDD of 20, which is the difference of 80°F and 60°F. A cooler day, at 45°F, would have a CDD of zero, because the value is capped at zero, and an HDD60 value of 15. Higher values of CDD indicate greater needs for cooling, while higher values of HDD indicate greater needs for heating.

$$CDD60 = \max\,(0, average\ daily\ temperature - 60)$$

$$HDD60 = \max(0{,}60 - average\ daily\ temperature)$$

The daily CDD and HDD values are summed across the three-year period, then divided by three to give an average yearly value. SEP has relatively few participants in areas with mild summer weather that requires limited air conditioning.

Table 6: SEP Enrollments by Weather Station with Yearly Average CDD60 and HDD60

Weather Station	SEP Enrollments	CDD60	HDD60
173	20,307	1,727	500
121	15,471	2,354	1,223
122	11,726	2,732	775
112	5,233	1,944	563
172	4,708	1,407	569
51	4,508	3,142	1,468
111	4,097	2,136	751
171	3,950	1,510	548
132	3,422	2,118	1,104
181	3,388	5,623	324
161	2,231	958	578
123	2,193	1,122	1,130
194	2,125	2,959	1,882
193	1,825	3,072	1,835
113	626	833	929
131	513	954	3,836
191	390	4,167	1,571
195	382	3,167	1,838
151	356	711	968
192	144	3,777	1,505
141	71	2,685	2,626
182	57	5,706	471
101	42	474	5,381

3 EVALUATION METHODOLOGY

3.1 EX-POST METHODS

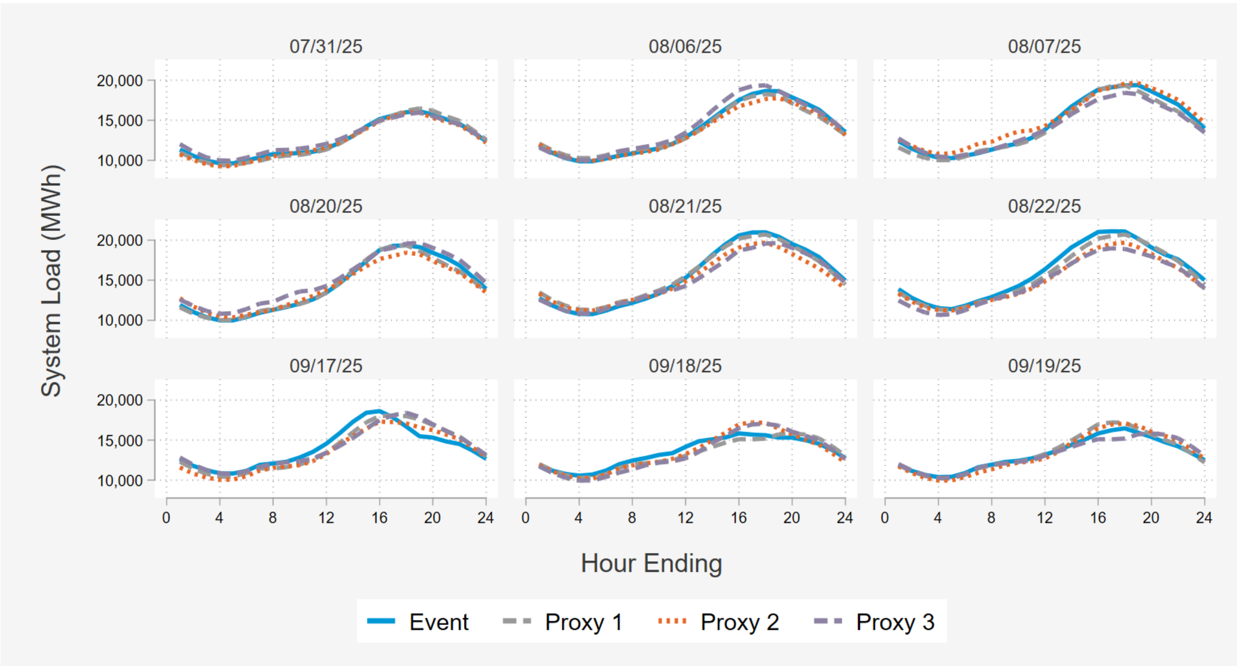
Overview of Evaluation Method Selected

DSA utilized a randomized control group and a simple difference-in-difference analysis for the 2025 SEP load impact evaluation. Each event in 2025 only dispatched a small subset of the program population. Participants were grouped at the B-bank substation level and randomly assigned to 10 different groups to be dispatched on each event day. The 9 randomized groups that were not dispatched for a given event create the control group for the analysis. The impact analysis incorporates a simple difference-in-differences model where the small differences between the participant and randomized control group on proxy days are netted out of the differences observed on event days. We estimate ex-post load impacts across all customers as well as at a segment level for a variety of categories including SubLAP, size, tariff rate, and more.

Proxy Day Selection

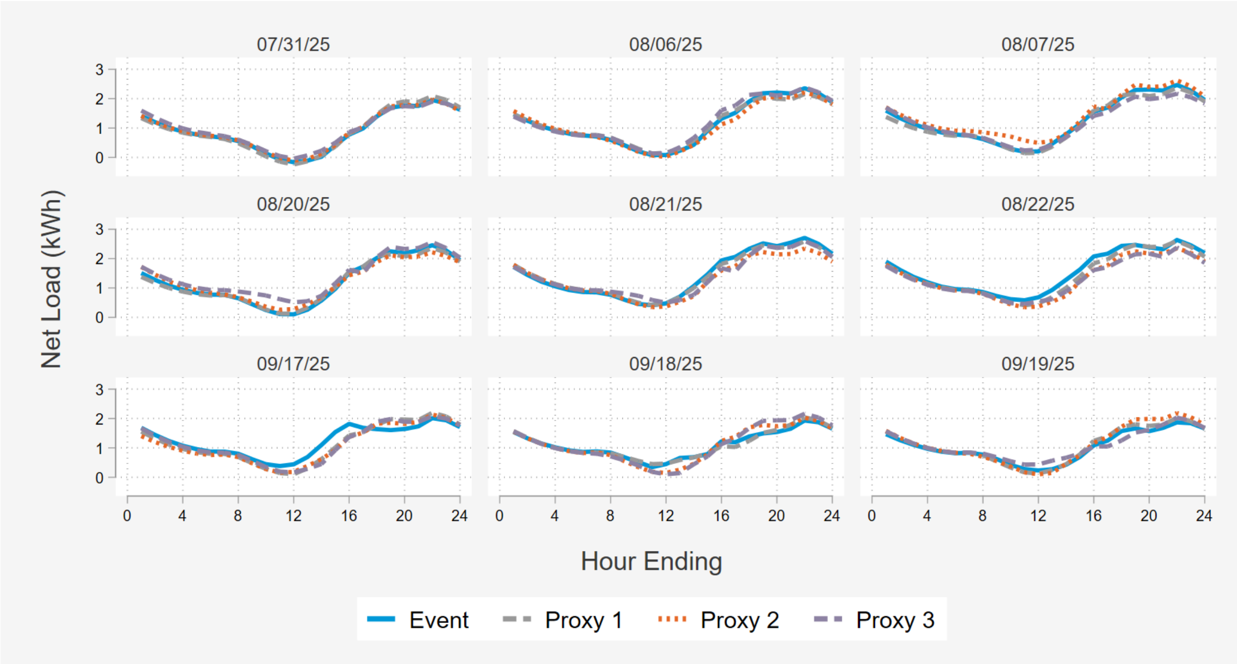
DSA used Euclidean distance matching on system loads to select a set of proxy days for each SEP event. We choose proxy days from a set of days with similar characteristics to each event day in PY2025. All PY2025 events occurred from July to September. All these events also happened on a non-holiday weekday, which means that they were able to be matched with any non-event non-holiday weekdays from summer 2025. For every event date, we select the three most similar SCE system load days based on their available matches. A proxy day can be chosen multiple times for different events, but an event day cannot be used as a proxy day for another event. Figure 6 shows each event date with its three selected matches. Days that are generally warm but not extreme tend to have very similar and predictable load shapes to each other, so proxy day matches in 2025 were generally good. The only exceptions to that are the September event days which all had unique load shapes due to cool and cloudy weather conditions. The chosen proxy days still provide a reasonable approximation of the event day load shape and the randomized control group should provide a good control for the unique event day conditions.

Figure 6: Event and Proxy Day System Load



While we use SCE system load to select the proxy days, the control customers come from a randomized group of non-dispatched SEP participants for each event day. Because customers are randomly assigned to the treated group, we would expect their loads to, on average, be similar to that of the treated customers on non-event days. Figure 7 shows the selected proxy days and event days, as seen in Figure 6, but for the average control customer pool for each event day. The proxy day loads line up well with the event day loads during event hours for most event days. The hottest and coolest event days, August 22nd and each of the events in September, show some differences between the event and proxy days due to the unique conditions of those events, but, due to the random nature of treatment for each event, we would expect to see similar patterns for the treated participants if there had been no treatment.

Figure 7: Event Day and Proxy Day Loads for Average Control Customer



Control Group Creation

Prior evaluations have relied on the use of a matched control group to create a counterfactual for each event. Because most SEP events in the past dispatched all customers, a matched control group was the only possible choice for creating a control group. In PY2025 however, a randomized subset of program participants was dispatched on each event day. Because of this, the randomly non-dispatched participants can be used to form the control group on each event day. The randomization of the groups ensures that each control group provides an unbiased counterfactual for what the dispatched customers' loads would have looked like if there had been no treatment on each event day.

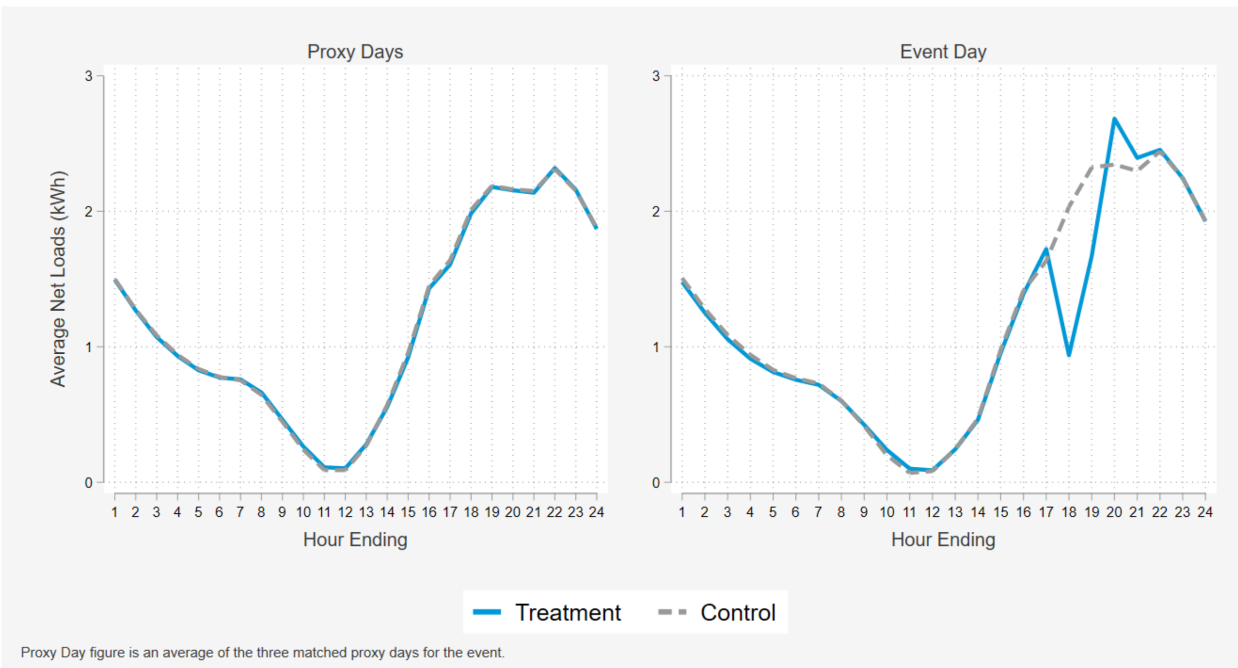
On each event day in PY2025, 6-10% of the customers enrolled in the program were dispatched leaving the remainder of participants to potentially be used as controls. The subset of customers that was dispatched for each event rotated throughout the summer, meaning that the customers available to be included in the control group for each event also rotated throughout the summer. This means that the control group utilized for each event day must be different depending on which customers were dispatched on that event day.

To construct the control group for each event day, DSA first removed the dispatched customers from the pool of potential controls. Second, in some cases, we removed control customers in areas of the territory where no participants were dispatched for a given event. Because customers were dispatched at the B-Bank level, with each event targeting a random subset of B-Banks, each geographic area of SCE territory was not guaranteed to include dispatched customers. In this case, including customers that experienced totally different weather patterns decreased the accuracy of initial modeling results so customers from non-dispatched geographies were not included in the control groups for certain events.

DSA identified the potential control group customers that should be excluded for events by excluding customers when there were no dispatched customers within their induvial A-Bank designation. This secondary process was done for both the September 18th and 19th events to get a more similar control group for analysis.

Generally, use of a randomized control group should ensure that there are, on average, no differences between the treated customers and the control customers on days when no treatment occurs. Figure 8 shows the average observed net loads of the treatment and control groups utilized in the event analysis for the August 6th event. Ideally, we would expect the control group customers to have exactly identical loads on the proxy days to the treatment customers and then only see differences on the event day when treatment is happening. For this event analysis, that is exactly what is observed. The loads on the proxy days and prior to the event are almost exactly identical between the two groups and the impact from the event can clearly be seen in the drop in loads for the treatment customers in hour ending 18.

Figure 8: Average Hourly Usage on Proxy Days and the Event Day for Treatment and Control Customers in the August 6th Event Analysis



Ex-post Model

DSA used a difference-in-differences modeling approach to estimate the hourly load impacts for each SEP event. Once a matched control group was established, impacts were estimated by comparing the usage of participants in the treatment group to that of the control group, both on the event day and on the matched proxy days preceding the event. In instances where the treated and control groups closely aligned on non-event days, simple difference-in-differences modeling makes minimal adjustments to the counterfactual on the event day. However, when substantial differences in the treated and control

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customers existed on proxy days, netting these out from the event day differences facilitated precise impact estimation.

In previous ex-post evaluations, DSA also utilized as difference-in-differences modeling approach to estimate program impacts, but, in the PY2025 analysis, chose to utilize a simple difference-in-differences analysis rather than a regression based one. In practice, each approach will produce similar results, but conceptually, the simple difference-in-differences approach is much easier to calculate and understand. Equation 1 describes the basic calculation that is used to estimate impacts from each event using this approach.

Equation 1: Simple Difference-in-Differences Equation

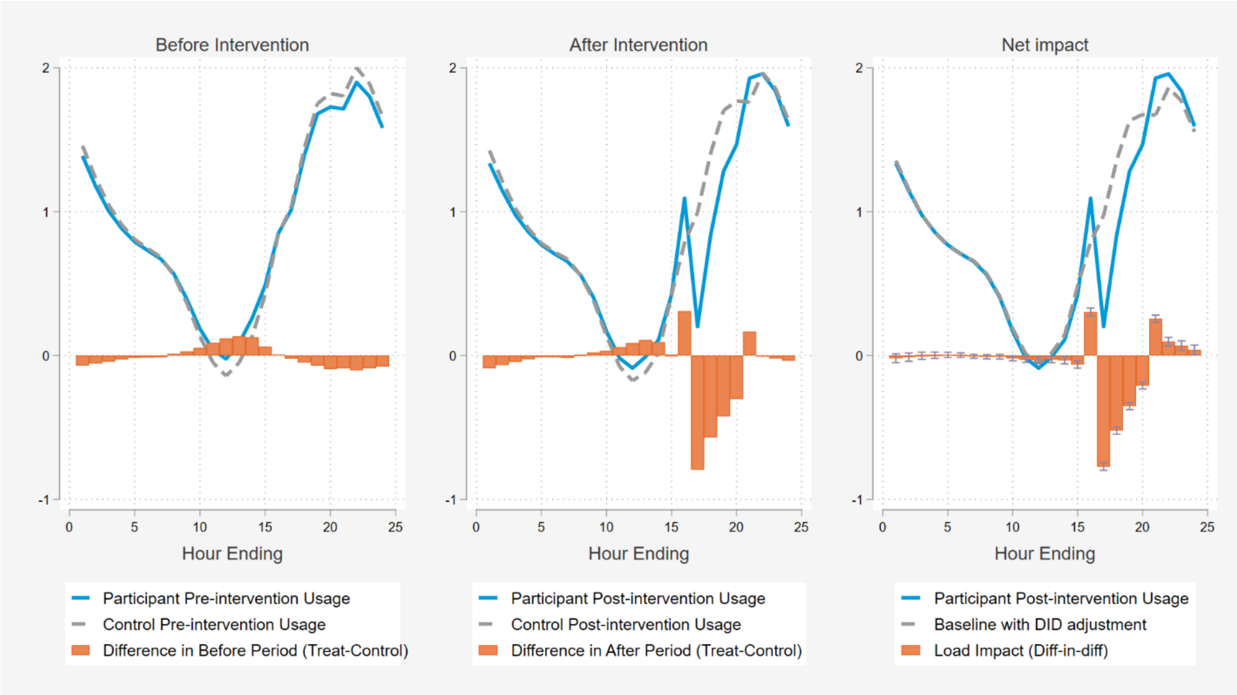
$$\left(\boldsymbol{Participant\ kWh_{event\ ih}} - \boldsymbol{Participant\ kWh_{proxy\ day\ ih}}\right) - \left(\boldsymbol{Control\ kWh_{event\ ih}} - \boldsymbol{Control\ kWh_{proxy\ day\ ih}}\right)$$

where:

1. The first difference is the proxy day/event change in usage for treatment customers during hour h for event i.
2. The second difference is the proxy day/event change in usage for non-dispatched customers in the control group during hour h for event i
3. Taking the difference of the two yields the hourly load impact, net of any changes observed for control group customers over the same time during hour h for event i.

Figure 9 shows an example of how the differences in consumption on non-event days were netted out from the event day from July 31st. The first pane in each shows the pre-event differences, the second pane shows the differences on the event day, and the third pane represents the net impact estimate obtained by subtracting the pre-event differences from the control's event day loads.

Figure 9: Example Difference-in-Difference Adjustment from Analysis of July 31st Event Day



3.2 EX-ANTE METHODS

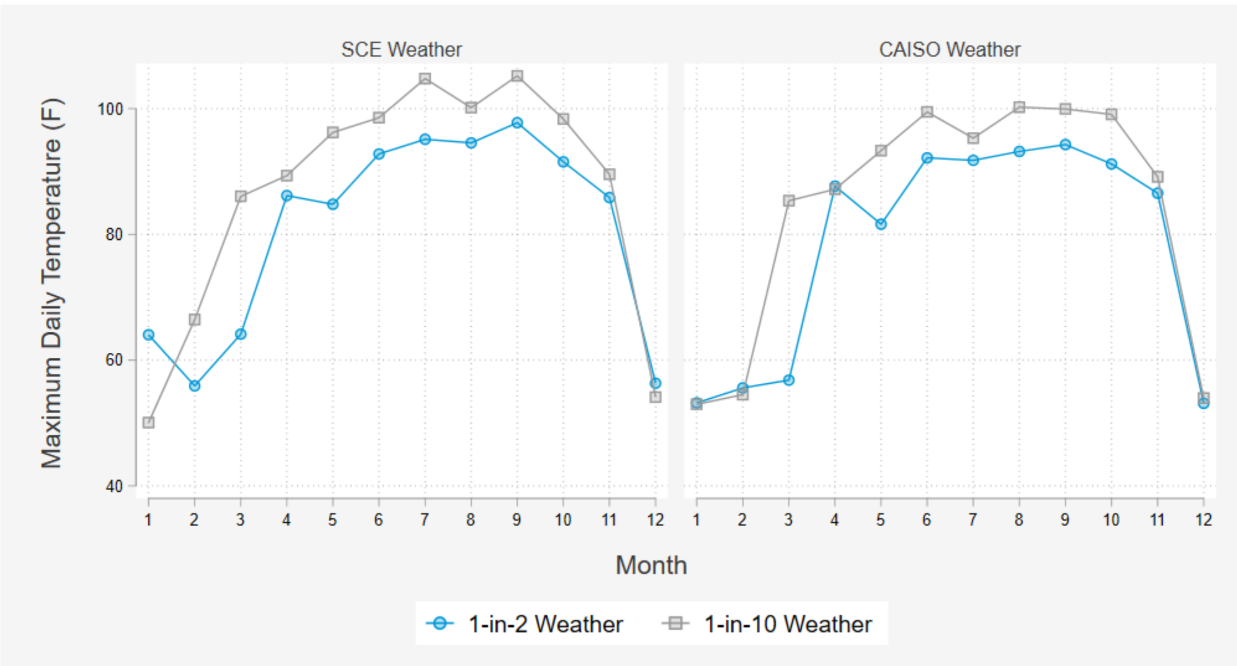
A key objective of DR evaluations is to quantify the expected load relief a program can deliver under different planning conditions. The weather conditions used for ex-ante load impact estimates are generally extreme to reflect conditions when the grid is constrained due to high demand. For SEP, we produce a forecast of load impacts for multiple sets of weather conditions.

- 1-in-2 weather reflects the expected peaking conditions for a normal year.
- 1-in-10 weather reflects peaking conditions that would be observed in an extreme year.
- Monthly system worst day for each month of the year. The ex-ante forecast also includes 'Typical Event Day' conditions, which are assumed to occur in August.
- SCE forecast and a CAISO forecast. Both forecasts have 1-in-2 and 1-in-10 weather for all weather stations.

Figure 10 compares the maximum daily temperature for the monthly system worst days using the 1-in-2 and 1-in-10 weather for the SCE and CAISO forecasts. We weight the forecasts across weather stations using the number of active SEP participants at the conclusion of PY2025 shown in Table 6. We hold these weights constant over the forecast horizon. There are notable differences in the SCE and CAISO forecasts. For example, the SCE forecast predicts a weighted average temperature 5°F higher than the CAISO forecast for a monthly system worst day in September on a 1-in-10 weather year. For a weather sensitive program like SEP, this means the ex-ante load reduction capability of SEP is greater using the SCE forecast for a September system worst day.

The PY2025 ex-ante weather forecasts project a higher monthly maximum temperature for April than May in the 1-in-2 weather scenarios. This is due to the fact that these forecasts are done using historic data and, in the current dataset, April is the more extreme month.

Figure 10: Monthly System Worst Day Comparison by Forecast

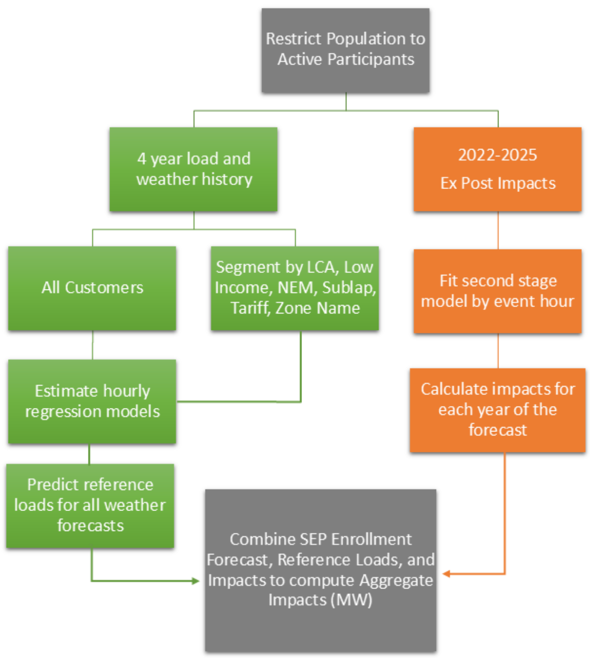


During PY2025, SEP dispatched events at different times of day and the duration of events was either three or four full hours. Ex-ante estimation requires a single event profile to be selected. The ex-ante event profile was selected to mirror the CAISO RA window, which begins at 4pm and ends at 9pm for all summer months covering June-October. The RA window for each of the other months from November-May is from 5pm to 10pm. There were no events in 2025 that fully matched this profile, with all of the events being 4 hours or less. The larger dispatch windows from PY2025 ex-post will be very helpful in estimating the program impacts in later hours of the RA window. For example, in prior years, there was not enough event information on the fourth or fifth hour of an SEP event to fit a sperate model and those hours had to be treated as if they were an event hour 3 when forecasting. In the PY2025 ex-ante analysis, this same approach will still be needed for event hour 5 (i.e. it will be treated as if it were an event hour 4) because there have not been any 5 hour SEP events in the last 4 years. In practice, the predicted impacts of the fifth hour will differ from those of the fourth hour due to differences in expected outdoor temperature and are likely to be of lesser magnitude than the ones predicted by the ex-ante model.

Overview of Evaluation Method Selected

Figure 11 outlines the SEP ex-ante estimation methodology. On the left (green), it shows the steps to model reference loads (what average customer loads would be without SEP), and on the right (orange), it lists the steps to estimate SEP load impacts. The ex-ante segmentation is similar to the ex-post segmentation but excludes the "size," "thermostats," and "vendor" segments. Active participant shares are calculated by LCA, Low Income (CARE/FERA Status), NEM, SubLAP, Tariff, and Zone Name, with the assumption that these ratios remain constant as enrollment grows. Events from 2022–2025—weighted more heavily for recent events—are used to estimate the second-stage model (see Ex-ante Impacts Model Section). Finally, reference loads, average per-customer impacts, and the enrollment forecast are combined to produce the aggregate savings.

Figure 11: Ex-ante Estimation Process Diagram



Ex-ante Reference Load Model

DSA selected the reference load model by analyzing model fit statistics at the "All Customers" level. Upon determining the final model, we applied the model specification to the subcategories of the LCA, Low Income (CARE Status), NEM, SubLAP, Tariff, and Zone Name categories. The specific modeling steps taken were:

- Merge hourly load data and hourly weather data for all active SEP participants from January 2022 through September 2025.
- Drop any SEP event days.
- Drop dates when customers experienced outages.

- Restrict the data set to non-holiday weekdays.
- Structure all data in Pacific Prevailing Time. This produces reference load estimates for March and November that reflect a mix of daylight savings and standard time. This is appropriate because monthly averages include a mix of the two conventions, and the worst day could fall before or after the time change.
- Estimate the regression model shown in Equation 2.

Equation 2: Reference Load Regression Model Specification

$$Net\ kW_i = \beta_0 + \beta_1 * CDH65 + \beta_2 * bins\_60 + \beta_3 * bins\_65 + \beta_4 * bins\_70 + \beta_5 * bins\_75 + \beta_{6-10} * DayOfWeek + \varepsilon_i$$

Table 7 defines each of the terms listed in Equation 2. The model terms and base temperatures for degree day and degree hour terms were selected based on model fit statistics (adjusted R-squared, root mean square error) and the statistical significance of model parameters (standard error and t-statistic).

Table 7: Reference Load Regression Model Specification

Model Term	Description
Net kW_i	Average net electrical demand in kW during interval i
β_0	The model intercept
CDH65	Cooling degree hours base 65°F
β_1	Regression coefficient for the CDH65 term
bins_60, bins_65, bins_70, bins_75	Quantile smoothing spline which allows for different temperature slopes at different temperature ranges
β_2-β_5	Regression coefficients for the spline terms
DayOfWeek	Indicator variables for each of the 5 weekdays
β_6- β_{10}	Regression coefficients for five weekday variables
ε_i	Error term

Next, we use the regression coefficients estimated for each model run to predict average hourly demand for electricity for the set of ex-ante weather conditions. We computed weighted average weather conditions for each of the segments using the number of active SEP participants mapped to each constituent weather station. Figure 12 shows the 2026 predicted reference loads for all customers in black, with the LCA, Low Income (CARE Status), NEM, Tariff, and Zone Name categories on a September system worst day using SCE 1-in-2 weather. Due to the number of subcategories, the intent of Figure 12 is to highlight the variability in reference load rather than provide detailed insight on specific groups. Notably, the NEM customers show a prominent "duck curve" which differentiates these customers from some of the other subcategories.

Figure 12: 2026 Reference Load by Segment: September System Worst Day, SCE 1-in-2 Weather

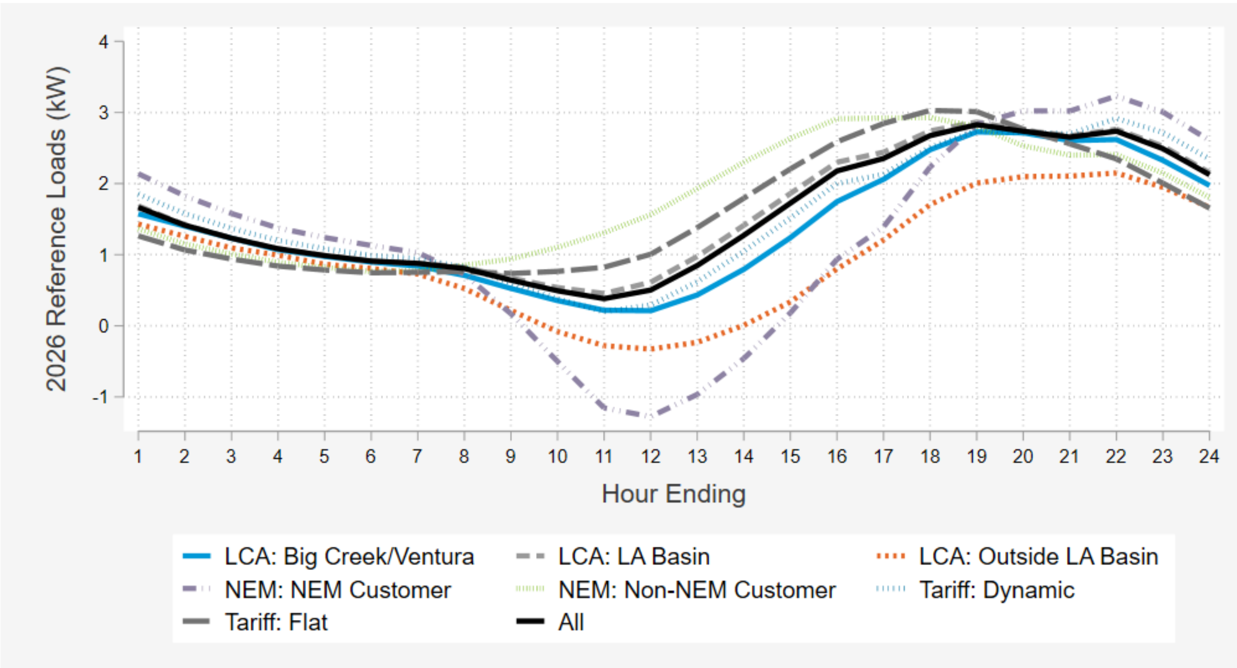


Figure 13 shows the modeled 2026 reference loads for each of the six SubLAPs on a September system worst day using SCE 1-in-2 weather. The Low Desert experiences the hottest conditions of all the SubLAPs and has the highest per-customer peaks but is overall a very small portion of the SEP population.

Figure 13: 2026 Reference Load by SubLAP: September System Worst Day, SCE 1-in-2 Weather

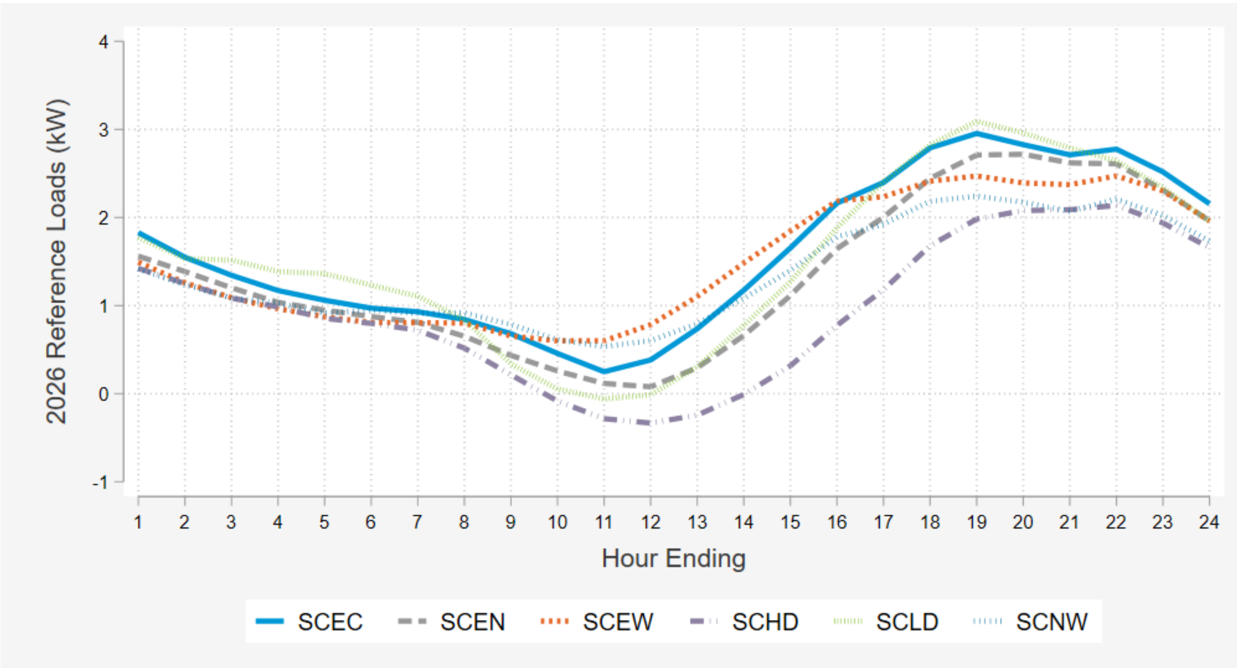
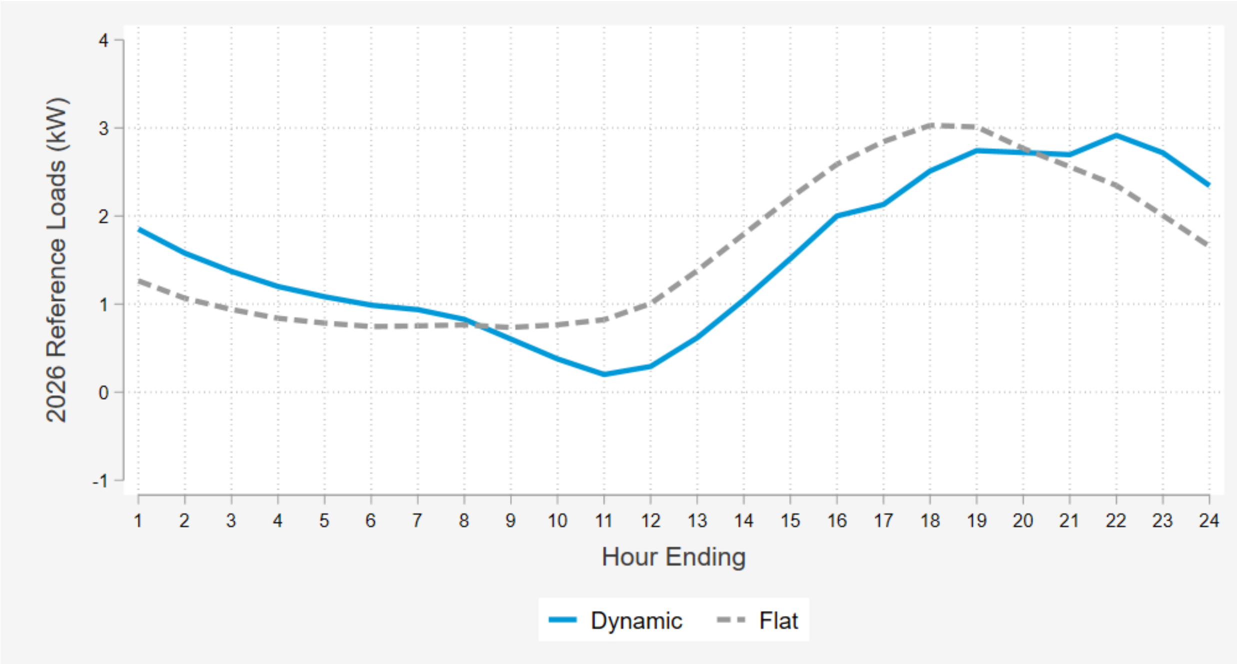


Figure 14 shows the modeled 2026 reference loads for both tariff rate groups on a September system worst day using SCE 1-in-2 weather. Dynamic rate customers now make up most customers in SEP. They tend to live in cooler climate zones and have lower loads in the middle of the day, typically due to solar generation, to take advantage of their rate structure. Flat rate customers tend to live in the hotter climate zones and have much higher loads in the middle of the day. Their load shapes typically peak right in the middle of the RA window (4pm-9pm).

Figure 14: 2026 Reference Load by Tariff Category: September System Worst Day, SCE 1-in-2 Weather



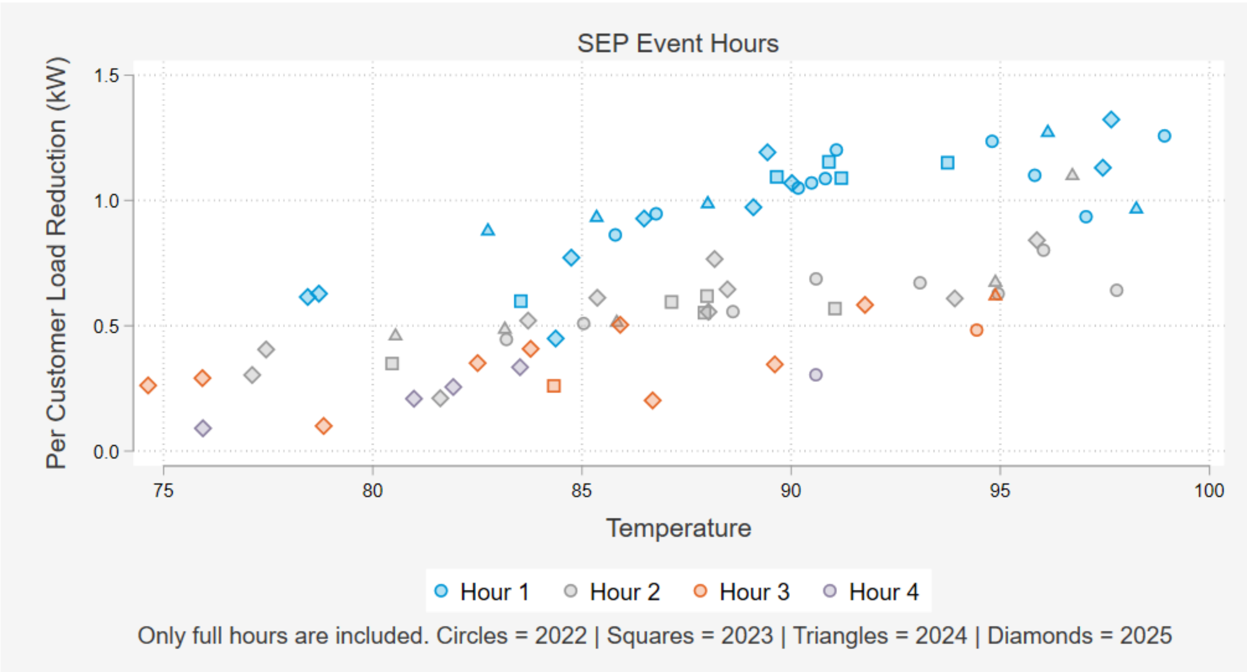
EX-ANTE IMPACTS MODEL

To estimate SEP per customer load reductions under varying conditions, DSA fit a second stage model using the PY2022, PY2023, PY2024, and PY2025 ex-post impacts as the dependent variable and dry bulb temperature as the independent variable and an indicator variable for each of the four observed SEP event hours as well as the three hours of post-event snapback. The model also includes an interaction term for temperature and event hour which lets the relationship between temperature and event impacts vary with each hour of the event and hour of snapback. We do not model the effects of pre-cooling in hour ending 16 for ex-ante. We do use event impacts from events that included pre-cooling in our impact modelling though. Pre-cooling is included in almost all SEP events and if impacts from events with pre-cooling were not included in the model, then there would not be enough data to reliably fit the model.

A key caveat to the event impacts included in the model concerns partial event hours. When event hours do not start or end on the hour, the impact estimates are diluted by the portions of the hour that were not controlled. In PY2025 there were no such events but there have been in previous years. In these cases, we omit the partial hours. For events where we drop the first partial hour, we treat the following full hour as the normal second hour of the event. These modifications allow us to use as much of an event as possible without deflating hourly impacts with unperturbed pre-event periods or post-event snapback.

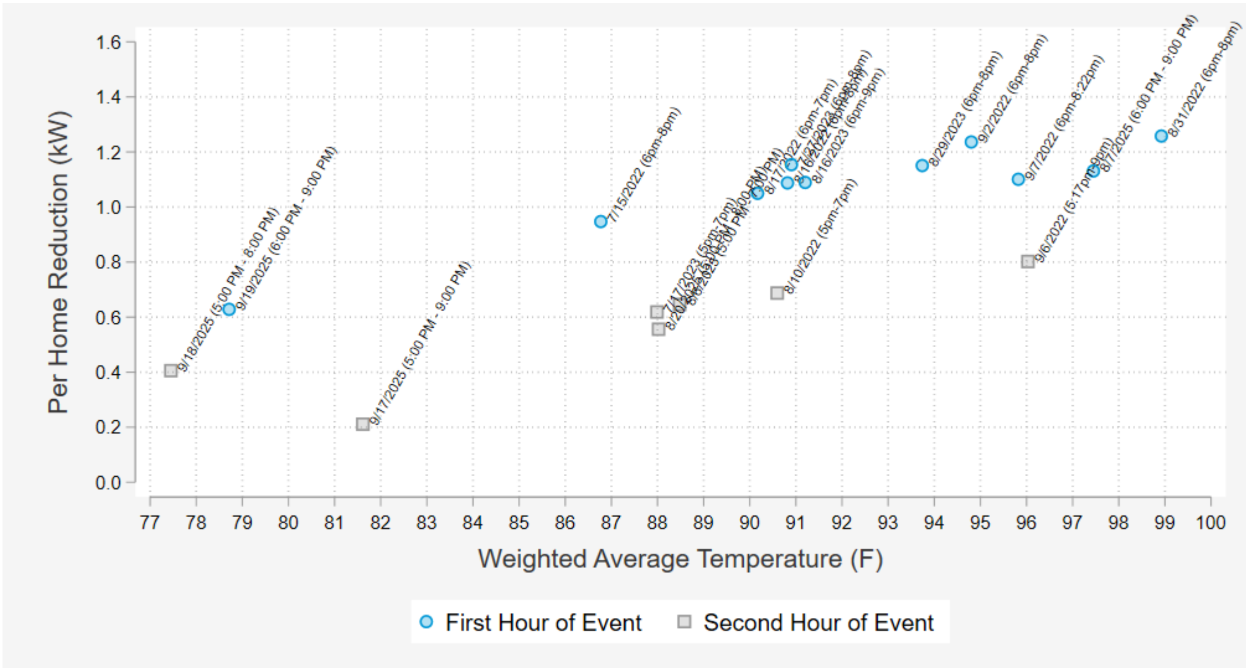
Figure 15 shows the PY2022- PY2025 hourly impacts by event hour. Each color represents a different event hour, with blue representing hour 1 of the events and consistently showing the largest impacts regardless of temperature. Because events vary in length, there are more hour 1 impacts than hour 3 or hour 4 impacts. Impacts are largest in the first hour of an event and diminish with each subsequent hour.

Figure 15: Per Customer SEP Load Reductions by Event Hour



The decision to model impacts as a function of event hour rather than hour of the day was informed by the results of the ex-post analysis. Figure 16 illustrates the issue using the ex-post results from the PY2022 - PY2025 full hour events during hour ending 19 (6pm to 7pm). There were 27 events active from 6pm to 7pm during the four summers. However, for some of these events, the event hour was a partial event hour and those are not included in the below figure. Figure 16 shows that the same hour of day provides a consistently larger impact when it is the first hour of an event, regardless of temperature.

Figure 16: Hour Ending 19 Event Impacts vs. Temperature, by Event Hour



The average kW impact per participant household across the eleven days where hour ending 19 was the first event hour was 1.08 kW with an average event hour temperature of 91.8°F. The average kW impact per participant household across the seven days where hour ending 19 was the second event hour was just 0.56 kW with an average event hour temperature of 87.2°F. This example illustrates why the position of an hour within an event is a far more important predictor of load impact than time of day. Declining load shed is indicative of the thermostat setback strategy. However, once homes warm up to the new set point, air conditioners gradually come back on and the kW impact decays. Some program administrators implement tactics to mitigate the decay of impacts across the event. Three such approaches are:

1. Stagger the dispatch time so that participants come in and out of the event at different times. This approach reduces the aggregate impact in the first hour but produces impacts that are more consistent across event hours.
2. A cascading offset. Instead of implementing a four-degree (F) setback at the beginning of the event, raise the offset one degree per hour over the course of the event.
3. Implement a cycling strategy rather than a setpoint change. This change would cause SEP load impacts to look more like the Summer Discount Plan (SDP) program.

4 EX-POST RESULTS

The ex-post results document the measured impacts for each SEP event called during PY2025. The variation in event start times, durations, and observed weather conditions from the distribution level event tests provides useful information on the key drivers of SEP load impacts.

4.1 OVERALL RESULTS

SCE called 9 SEP events in PY2025 from July through September 2025. In PY2025 all events were called for measurement and evaluation purposes as part of an initiative to test the program's ability to dispatch customers at a granular distribution level. During each event, only a subset of all enrolled customers, about 10%, were dispatched. Customers were randomly grouped together at the B-bank substation level to determine which customers were dispatched on each event day. The events called in 2025 were longer on average than previous years in an effort to test the program's ability to provide sustained event impacts across longer events. Table 8 shows average hourly impacts by event date. We also show an Average Event Day segment row based on the 4PM – 8PM event window for PY2025 as this was the longest event window, four hours, that had more than one event called. This average encompasses two events in PY2025. DSA used a customer-weighted average across the two events that shared the applicable dispatch profile.

While each event set out to dispatch about 10% of the enrolled customers, the event on August 22nd only dispatched 5,409 customers, about 6%. On this event day, some of the B-Banks that were designated to be dispatched experienced a PSPS event at the same time as the planned SEP event. Those B-Banks were subsequently excluded from the SEP event to ensure that they were not overburdening the customers.

The last three columns report average per customer kW reductions, average aggregate MW reductions from the actually dispatched number of customers, and average aggregate impacts calculated as if all enrolled customers had participated. These values are calculated by taking the average of the hourly impacts for each event. The final column multiplies the per customer kW values by 87,765, which was the end of season program enrollment. Thes values assume that all the non-dispatched customers would have, on average, delivered similar results to the dispatched customers during each event.

The largest per customer reduction occurred on August 21st, 2025, with 0.92 kW reduced per customer. This was a three hour event, which also had the warmest event conditions of any event in PY2025. The smallest per customer reductions occurred on September 17th. On that day, temperatures declined quickly in the afternoon around the same time that a large amount of cloud cover rolled through the SCE territory. This combination led to lower AC loads and therefore event impacts than would have been anticipated given the relatively high temperatures earlier in the day.

Table 8: 2025 SEP Event Impacts

Event Date	Start Time	End Time	Dispatch Region	Participants	Average Event Temp	Daily Max Temp	Average Full Hour Impact (kW Reduction)	Average Aggregate Full Hour Impact (MW Reduction)	Average Aggregate Impacts if All Enrolled Customers were Dispatched (MW)
7/31/2025	4:00 PM	8:00 PM	SCEC, SCEN, SCEW	9,155	83.0	84.8	0.46	4.2	40.7
8/6/2025	5:00 PM	7:00 PM	SCEC, SCEN, SCEW, SCNW	8,366	89.2	90.5	0.86	7.2	75.3
8/7/2025	6:00 PM	9:00 PM	SCEC, SCEN, SCHD, SCNW	8,496	93.7	99.8	0.70	5.9	61.0
8/20/2025	5:00 PM	8:00 PM	SCEC, SCEN, SCEW, SCLD	8,163	87.9	89.4	0.58	4.7	50.7
8/21/2025	4:00 PM	7:00 PM	SCEC, SCEN, SCEW	9,082	95.1	97.9	0.92	8.3	80.4
8/22/2025	4:00 PM	8:00 PM	SCEC, SCEW, SCHD	5,409	86.8	90.1	0.70	3.8	61.4
9/17/2025	5:00 PM	9:00 PM	SCEC, SCEW, SCHD, SCNW	8,837	80.2	89.5	0.21	1.9	18.7
9/18/2025	5:00 PM	8:00 PM	SCEC, SCEN, SCEW, SCHD	8,751	77.3	80.4	0.44	3.8	38.4
9/19/2025	6:00 PM	9:00 PM	SCEC, SCEW	9,101	76.8	81.1	0.40	3.6	34.9
Average Event Day	4:00 PM	8:00 PM	-	7,764	84.4	86.7	0.55	4.3	48.4

Figure 17 shows ex-post load impacts for the Average Event Day window. Figure 18 provides aggregate load impacts. The 4pm to 8pm window includes impact estimates from two event days in PY2025. The following figures provide detail on average number of participants, temperature, average event impact and percent impact. These figures come directly from the Microsoft Excel ex-post load impact table generators that accompany this report. The table generators provide estimated reference load, observed load, impact, and temperature by the hour, with an included visual display of the load curves and statistical significance of the impact. The average impact value provided under the 'Event Day Information' heading aligns with the average hourly impacts shown in Table 8.

There is a notable snapback effect beginning in the hour after each SEP event and tapering off for the remainder of the event day. These snapback effects are significant – approximately 0.29 kW per customer during the hour immediately following dispatch – and may be an important consideration for event planning as SEP enrollment continues to grow. Hour ending 16 shows that, on most of the event days, there was evidence of pre-cooling in the loads leading up the first event hour. This leads to an increase in loads of about 0.34 kW on the average event day.

Figure 17: SEP Ex-post Load Impact per Participant for Average 2025 Event (4pm-8pm) (kW)

Southern California Edison
2025 Ex Post Load Impacts - SEP Program

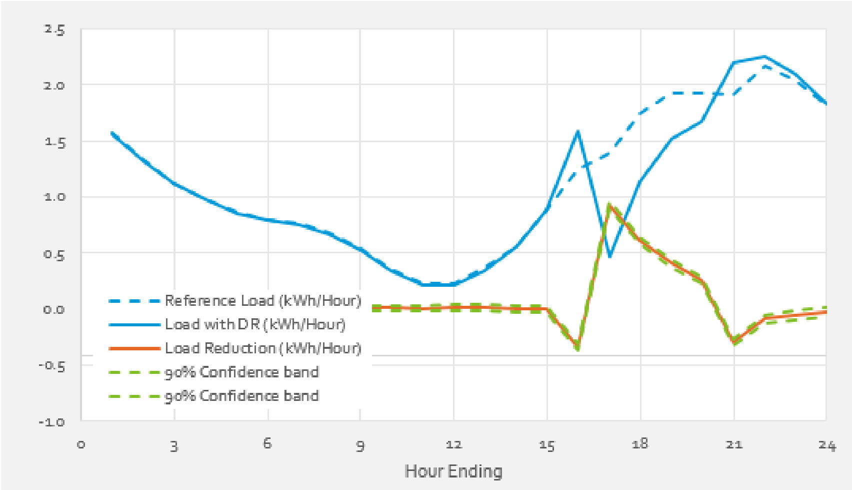
Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	Average Event Day (4:00 PM - 8:00 PM)
Hour Ending View	HE (Prevailing Time)

Public

Table 2: Event day information

Total sites	7,764
Daily Max Temp	86.7
Average Impact - kW	0.55
Average Impact - %	31.5%
Full Hours Only - Average Impact - kW	0.55
Full Hours Only - Average Impact - %	31.5%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.57	1.56	0.02	1%	73.65
2	1.33	1.32	0.02	1%	72.30
3	1.13	1.13	0.00	0%	71.36
4	0.99	0.98	0.01	1%	70.43
5	0.87	0.86	0.01	2%	69.73
6	0.80	0.79	0.01	1%	69.20
7	0.76	0.75	0.01	2%	68.43
8	0.68	0.67	0.01	2%	68.25
9	0.54	0.52	0.02	3%	70.16
10	0.36	0.35	0.01	4%	73.36
11	0.23	0.22	0.01	4%	76.27
12	0.23	0.21	0.02	8%	79.31
13	0.37	0.35	0.02	6%	82.27
14	0.56	0.55	0.00	0%	84.85
15	0.88	0.88	0.01	1%	86.24
16	1.25	1.59	-0.34	-27%	86.65
17	1.40	0.47	0.93	66%	86.49
18	1.74	1.13	0.61	35%	85.37
19	1.93	1.52	0.41	21%	83.77
20	1.92	1.67	0.26	13%	81.93
21	1.91	2.20	-0.29	-15%	78.75
22	2.17	2.26	-0.09	-4%	76.38
23	2.05	2.10	-0.06	-3%	75.07
24	1.81	1.83	-0.02	-1%	73.91

By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	1.75	1.20	0.55	31.5%	84.4
Daily	1.15	1.08	0.07	5.8%	76.8

Figure 18: Aggregate SEP Ex-post Load Impact for Average 2025 Event (4pm-8pm) (MW)

Southern California Edison

2025 Ex Post Load Impacts - SEP Program

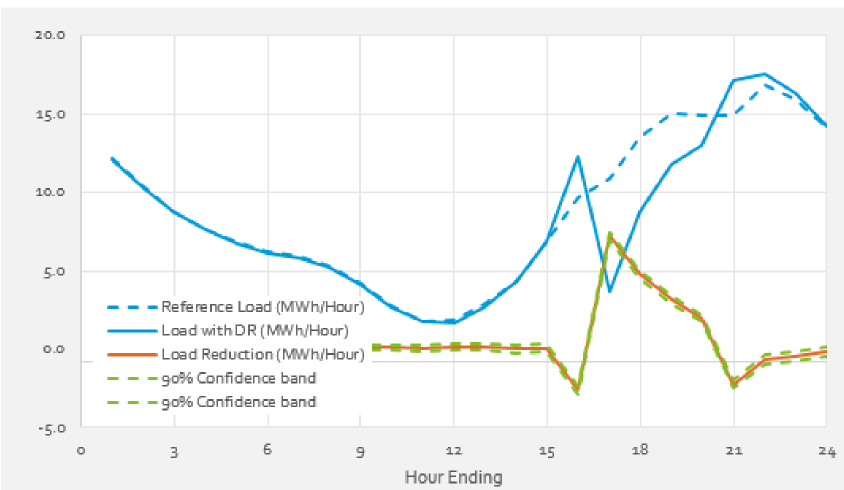
Table 1: Menu options

Type of Result	Aggregate
Category	All
Segment	All Customers
Date	Average Event Day (4:00 PM - 8:00 PM)
Hour Ending View	HE (Prevailing Time)

Public

Table 2: Event day information

Total sites	7,764
Daily Max Temp	86.7
Average Impact - MW	4.28
Average Impact - %	31.5%
Full Hours Only - Average Impact - MW	4.28
Full Hours Only - Average Impact - %	31.5%



Hour Ending	Reference Load (MWh/Hour)	Load with DR (MWh/Hour)	Load Reduction (MWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	12.22	12.08	0.14	1%	73.65
2	10.36	10.24	0.12	1%	72.30
3	8.76	8.75	0.01	0%	71.36
4	7.66	7.59	0.06	1%	70.43
5	6.78	6.68	0.10	2%	69.73
6	6.22	6.15	0.07	1%	69.20
7	5.93	5.83	0.10	2%	68.43
8	5.29	5.19	0.11	2%	68.25
9	4.18	4.06	0.12	3%	70.16
10	2.81	2.70	0.11	4%	73.36
11	1.81	1.73	0.07	4%	76.27
12	1.82	1.67	0.15	8%	79.31
13	2.89	2.71	0.18	6%	82.27
14	4.31	4.29	0.01	0%	84.85
15	6.86	6.80	0.06	1%	86.24
16	9.70	12.31	-2.61	-27%	86.65
17	10.85	3.65	7.21	66%	86.49
18	13.53	8.78	4.75	35%	85.37
19	14.96	11.79	3.17	21%	83.77
20	14.93	12.94	1.99	13%	81.93
21	14.86	17.09	-2.23	-15%	78.75
22	16.87	17.55	-0.68	-4%	76.38
23	15.89	16.33	-0.43	-3%	75.07
24	14.08	14.24	-0.17	-1%	73.91
By Period:	Reference Load (MWh/Hour)	Load with DR (MWh/Hour)	Energy Savings (MWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	13.57	9.29	4.28	31.5%	84.4
Daily	8.90	8.38	0.52	5.8%	76.8

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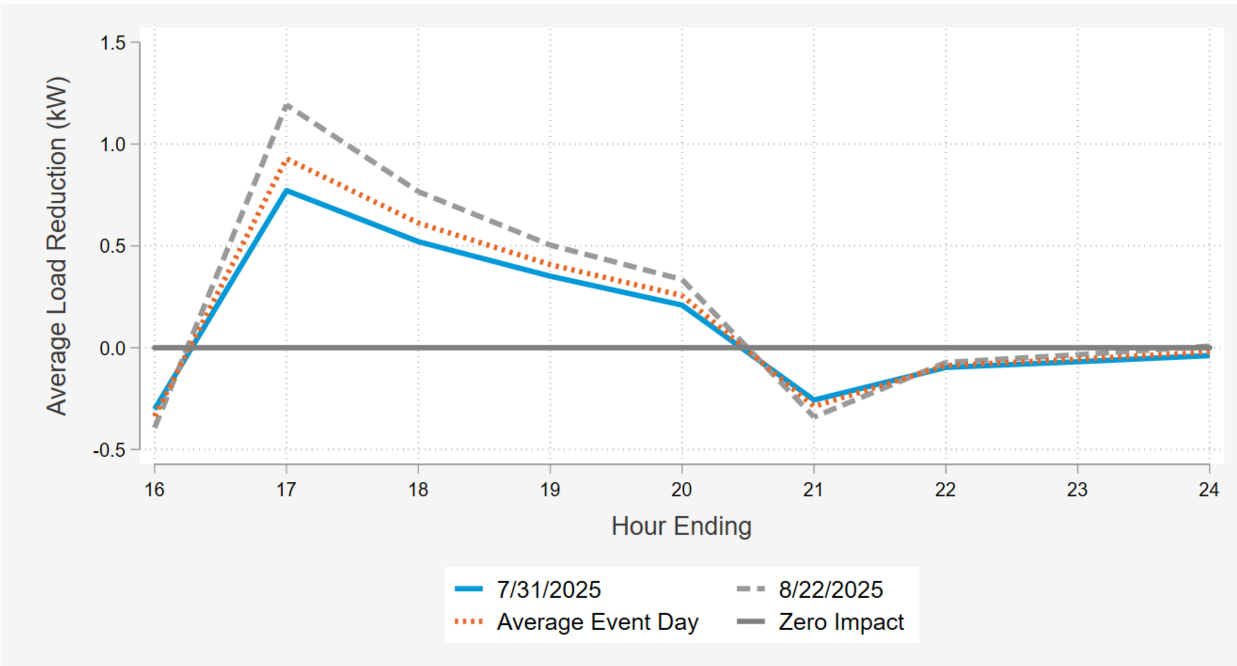
Figure 19 shows the average load impacts, by hour, for the 2025 average event window. Positive numbers indicate reductions in demand (kW) and negative values indicate an increase in demand. Impacts are largest during the first of hour of dispatch and decline in each subsequent event hour. Prior to the event impacts, there is clear evidence of pre-cooling, from one of the vendors, which leads to an increase of about 0.34 kW per customer. Following each event, we see a "snapback" period where demand exceeds the reference load by 0.29 kW in the hour immediately following dispatch. For the remainder of the evening, this snapback diminishes as impacts return to zero.

Figure 19: Hourly Load Reductions for Average Event Day



4.2 PERFORMANCE ON SCE AND CAISO SYSTEM PEAK DAY

Figure 20 shows the ex-post per customer impacts on the SCE system peak day, August 22nd, 2025. The first hour of the event, hour ending 17, had an average impact of 1.19 kW. Impacts then decayed in each subsequent event hour to an average impact of 0.33 kW in hour ending 20. This event dispatched the lowest number of customers of any event in PY2025. On this event day, some of the B-Banks that were designated to be dispatched experienced a PSPS event at the same time as the planned SEP event. Those B-Banks were subsequently excluded from the SEP event to ensure that they were not overburdening the customers.

Figure 20: SCE System Peak Day, August 22nd, 2025 Per Customer Results

Southern California Edison
2025 Ex Post Load Impacts - SEP Program

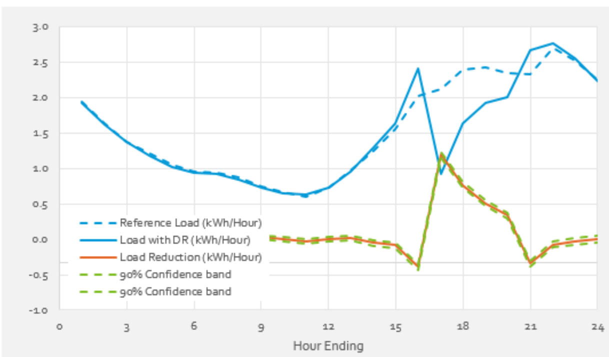
Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	8/22/2025 (4:00 PM - 8:00 PM)
Hour Ending View	HE (Prevailing Time)

Public

Table 2: Event day information

Total sites	5,409
Daily Max Temp	90.1
Average Impact - kW	0.70
Average Impact - %	30.1%
Full Hours Only - Average Impact - kW	0.70
Full Hours Only - Average Impact - %	30.1%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.94	1.93	0.02	1%	76.63
2	1.64	1.62	0.02	1%	75.71
3	1.38	1.38	0.00	0%	75.07
4	1.21	1.18	0.03	2%	74.61
5	1.06	1.01	0.04	4%	74.07
6	0.96	0.93	0.03	3%	73.47
7	0.94	0.92	0.03	3%	73.13
8	0.87	0.85	0.02	3%	72.91
9	0.75	0.73	0.03	4%	74.94
10	0.66	0.65	0.01	1%	78.33
11	0.61	0.63	-0.02	-4%	81.63
12	0.73	0.73	0.00	0%	84.59
13	0.97	0.96	0.01	1%	87.18
14	1.25	1.30	-0.05	-4%	89.22
15	1.56	1.64	-0.08	-5%	90.13
16	2.03	2.42	-0.39	-19%	89.81
17	2.12	0.92	1.19	56%	89.43
18	2.40	1.63	0.77	32%	88.17
19	2.43	1.92	0.50	21%	85.92
20	2.34	2.01	0.33	14%	83.52
21	2.32	2.66	-0.34	-15%	80.21
22	2.70	2.77	-0.07	-3%	78.52
23	2.52	2.55	-0.03	-1%	77.67
24	2.25	2.24	0.01	0%	77.06

By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.32	1.62	0.70	30.1%	86.8
Daily	1.57	1.48	0.09	5.4%	80.5

Figure 21 shows the ex-post per customer impacts on the CAISO system peak day, August 21st, 2025. The first hour of the event, hour ending 17, had an average impact of 1.32 kW. Impacts then decayed in each subsequent event hour to an average impact of 0.58 kW in hour ending 19. Despite the fact that the following day ended up being the SCE peak day from 2025, August 21st was the day with the warmest participant weighted conditions of any event in 2025. The customers that were dispatched on August 21st experienced a maximum daily temperature of 97.9 °F and an average event temperature of 95.1 °F across all three event hours. These hot weather conditions led to the largest impact of any event in PY2025.

Figure 21: CAISO System Peak Day, August 21st, 2025 Per Customer Results

Southern California Edison
2025 Ex Post Load Impacts - SEP Program

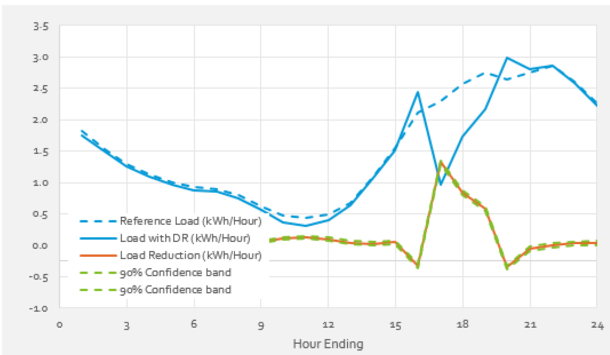
Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	8/21/2025 (4:00 PM - 7:00 PM)
Hour Ending View	HE (Prevailing Time)

Public

Table 2: Event day information

Total sites	9,082
Daily Max Temp	97.9
Average Impact - kW	0.92
Average Impact - %	36.1%
Full Hours Only - Average Impact - kW	0.92
Full Hours Only - Average Impact - %	36.1%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.82	1.75	0.07	4%	76.58
2	1.53	1.49	0.04	3%	75.00
3	1.30	1.25	0.04	3%	73.78
4	1.13	1.09	0.04	3%	72.64
5	1.00	0.96	0.04	4%	71.66
6	0.93	0.87	0.05	6%	70.92
7	0.90	0.86	0.04	4%	70.51
8	0.79	0.75	0.04	6%	70.12
9	0.61	0.56	0.05	9%	72.90
10	0.48	0.37	0.11	23%	77.15
11	0.44	0.31	0.13	29%	82.82
12	0.50	0.41	0.09	19%	88.34
13	0.68	0.64	0.04	6%	92.53
14	1.09	1.07	0.02	2%	95.53
15	1.55	1.50	0.05	3%	97.40
16	2.10	2.44	-0.33	-16%	97.92
17	2.29	0.97	1.32	58%	97.65
18	2.57	1.73	0.84	33%	95.87
19	2.75	2.17	0.58	21%	91.76
20	2.64	2.99	-0.35	-13%	87.92
21	2.74	2.80	-0.05	-2%	84.26
22	2.86	2.86	-0.01	0%	81.80
23	2.60	2.58	0.03	1%	80.02
24	2.25	2.21	0.04	2%	78.81
By Period:	**Reference Load (kWh/Hour)**	**Load with DR (kWh/Hour)**	**Energy Savings (kWh/Hour)**	**% Change**	**Average Temperature (°F)**
Average Event Hour	2.54	1.62	0.92	36.1%	95.1
Daily	1.56	1.44	0.12	7.8%	82.7

4.3 RESULTS BY CATEGORY

DSA estimated the SEP impacts for each event for a variety of segments of interest. However, due to the randomized event dispatch approach in PY2025, every segment was not dispatched on each event day. Table 5 in Section 2 details the percentage of each segment of interest that was dispatched on each event day. Due to the fact that some areas of the territory were not called on each event day, availability of results by segment may differ from event to event. For most categories, like NEM status or tariff, a similar number of customers was dispatched each day, while some geographic categories were only dispatched on a limited number of days, like the High Desert SubLAP. The category results presented in this section focus on the average event, which is made of the average impacts from the events on July 31st and August 22nd, which shared a 4-8 PM event window. For a wider range of event day and segmented results please see the Microsoft Excel ex-post load impact table generators that accompany this report.

Figure 22 shows the average event day impacts by SubLAP. The "All Customers" group is represented by a black line, and the zero impact line is drawn in gray. The "All" category represents a participant weighted average of each segment category and is therefore shown approximately in the middle of the SubLAPs. Impacts are highest in hour 1 for each SubLAP and decrease in each subsequent hour. Hour ending 16 shows increases in load associated with pre-cooling prior to the events. "Snapback" effects can be seen in hour ending 21-24. "Snapback" effects are largest in hour ending 21 and slowly decay overtime just like event impacts during event hours. Note that the Low Desert and Northwest SubLAPs impacts are not present on the average event day. Neither of these relatively small SubLAPs had any of their B-Banks dispatched on either of the event days that made up the average event day.

Figure 22: Average Customer Impact on Average Event Day, by SubLAP

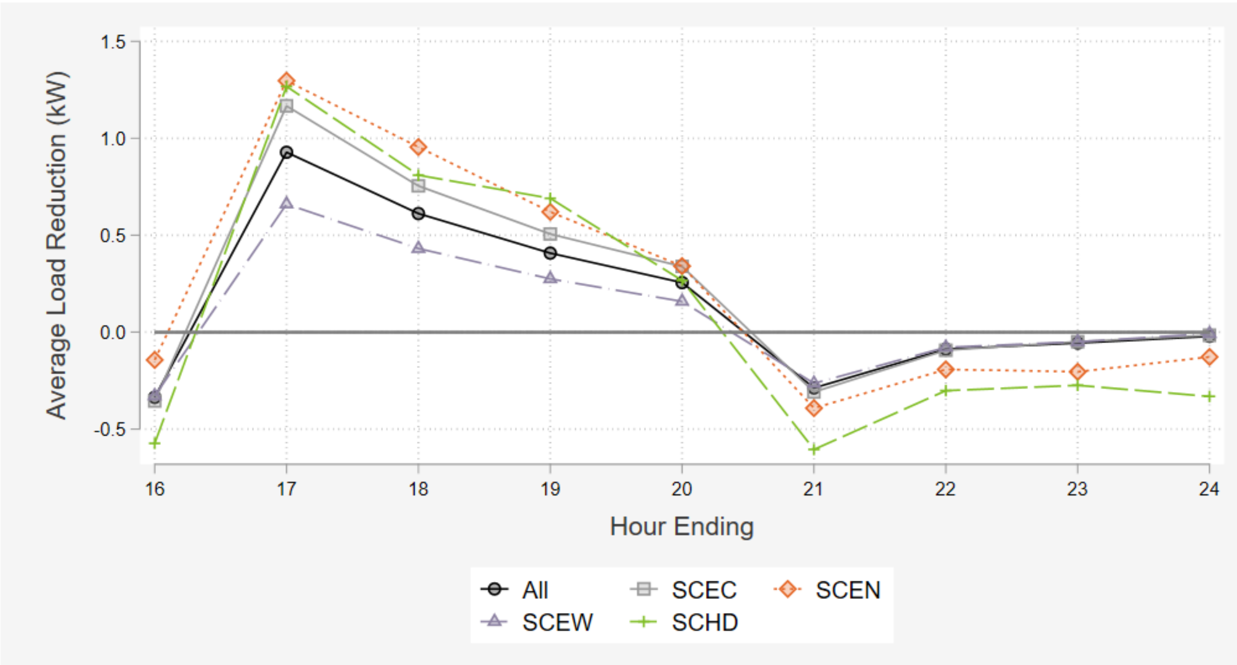
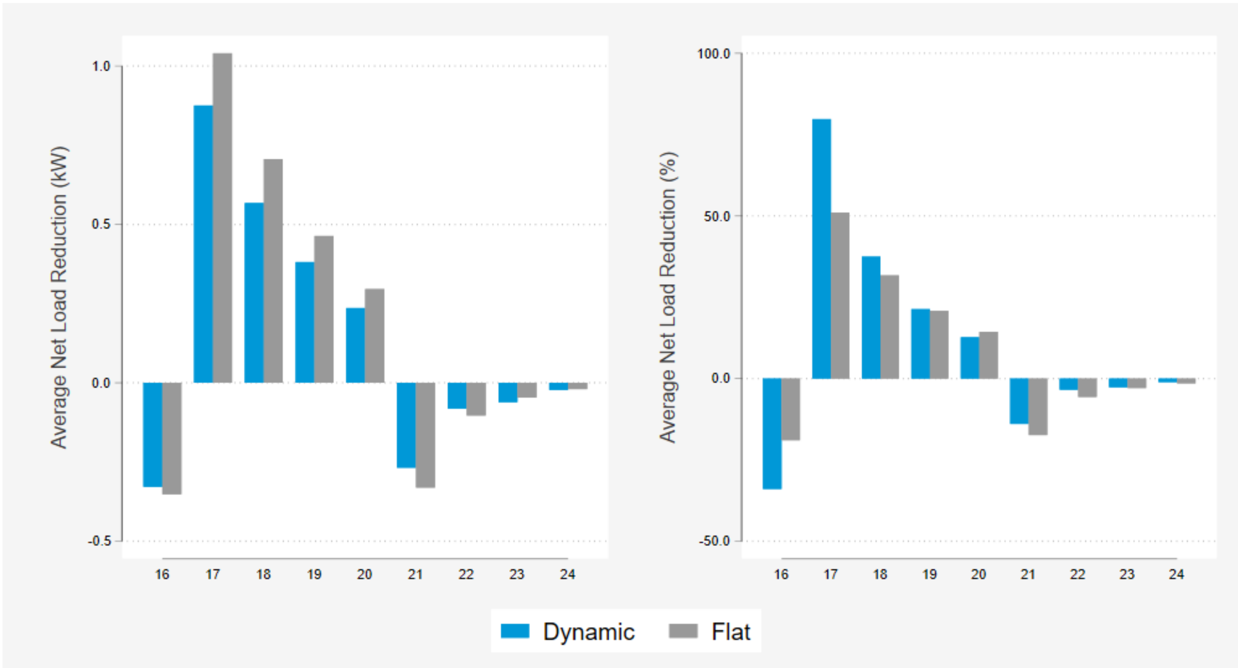


Figure 23 shows the average reductions for SEP participants who face flat and dynamic time-of-use (TOU) rates. The left side of Figure 23 shows net load reductions in kW by hour and the right side shows net load percent savings by hour. Participants on dynamic rates show higher percent reductions in event hour one to those on flat rates, but on average basis the flat rate customers provide slightly higher net load reductions. In 2025 only 32% of all SEP participants were on flat rates. Those with flat rates tend to live in warmer areas and have higher loads in the RA window, which means there is more load to be curtailed with those customers. On the average event day, flat rate customers experienced weather that was almost 3 °F warmer than those on Dynamic rates. Hour ending 16 shows the effects of pre-cooling for both flat and dynamic rate customers. Typically, dynamic rate customers are not pre-cooled when the hour before the event falls within their peak pricing window, but because hour ending 16 is outside most dynamic rate customer's peak period, they were pre-cooled alongside the flat rate customers. Pre-cooling increases energy usage when initiated, so dynamic rate customers are intentionally not pre-cooled when the hour before the event falls within their peak pricing window to avoid increasing their energy costs.

Figure 23: Average and Percent Impacts on Average Event Day, by Tariff and Hour Ending



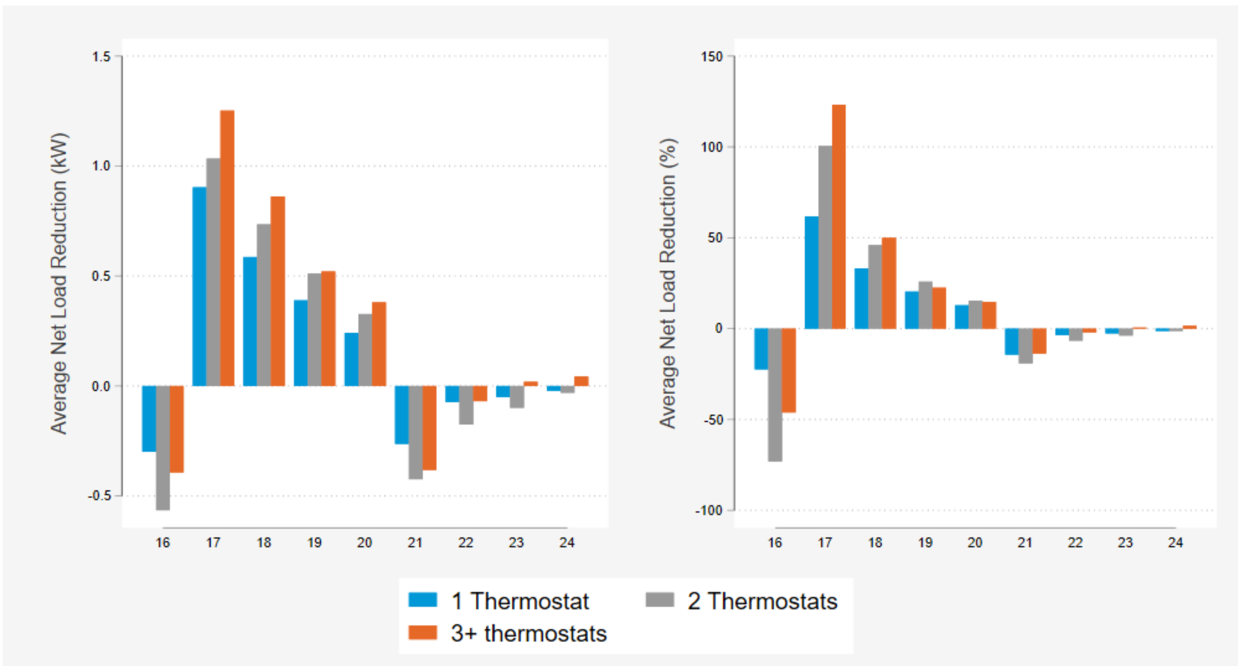
[redacted]

Figure 24: [redacted]

[redacted]

Figure 25 shows the ex-post results by count of thermostats per customer. The average kW reduction increases by approximately 23% for homes with two thermostats in comparison with 1 thermostat homes along with an additional 16% increase when moving from two to 3+ thermostats. In percent impacts, homes with 3+ thermostats provide the highest impact at 123% in event hour 1. These customers move from net importers to net exporters in the first hour of the average event day. The higher prevalence of solar customers in the 3+ thermostat group means that net reference loads tend to be lower in the hours of the day when solar production is highest, which is why, despite having generally more load within the household, their net reference loads are actually the lowest of the three groups in the first hour of the average event day. Only 2% of participants have 3+ thermostats so the estimates for those customers also tend to be less precise than the larger groups.

Figure 25: Average Ex-post Average Event Day Impact, by Thermostat Count and Hour Ending



4.4 COMPARISON TO PRIOR YEAR

SEP dispatched more events and for a longer duration on average in PY2025 in comparison to previous years. All events in Summer 2025 were dispatched as part of an initiative to test the program's ability to dispatch customers at a granular distribution level. The test events, were meant to test the program's ability to deliver targeted load relief at the distribution level, while also testing the program's ability to deliver overall load impacts under different weather conditions, event start times, and event lengths Weather during the event days in Summer 2025 was generally similar to the prior year, with the average event hour temperature on the average event day in PY2025 being 84.4 °F versus 84.3 °F the prior year. One caveat in making any comparisons in event temperatures between PY2025 and any of the previous years is that for each event in 2025 only around 10% of customers were dispatched while in previous years, the vast majority of events were called territory wide. This means that any given event in 2025 could be made up of customers that are more concentrated in certain geographic areas that are warmer or cooler than the territory average.

While the more extreme weather events in summer 2025 will be helpful for accurate predictions of the more extreme ex-ante weather conditions, the mild days from summer 2025 can help to give more information for predicting impacts during relatively mild events. This underscores the importance of using multiple years of data to predict future event impacts. The wide range of temperatures experienced in 2025, and the larger number of events will provide greater insight into ex-ante forecasting conditions and in tandem with impacts from other years should improve the accuracy of ex-ante projections. For example, SCE 1-in-10 conditions for a September monthly system worst day is expected to peak at 98.4 °F during event hours. In 2025, the highest temperature experienced during an event hour in September was 84.4 °F. When making an ex-ante prediction for that September monthly system worst day, ideally, we would have data that covers temperatures even more extreme than 1-in-10 conditions which allows us to more easily make an accurate prediction.

The overall SEP population continued to grow through 2025 summer season. Customer counts do fluctuate over the course of the season as customer attrition and enrollments happen continuously. The SEP participant population was larger in PY2025 by about 7,200 customers, when comparing the end of season enrollment in 2024 to end of season enrollment in 2025.

In past years, like PY2022, extreme weeks where multiple events were called consecutively tended to lead to large amounts of customers dropping out of the program quickly. In 2025, however due to the distribution level event testing, no enrolled customers experienced more than one event throughout the Summer. From an evaluation standpoint this is ideal, as there were still a full nine events dispatched by the program during the season, which provides a great deal more insight into program performance than years with fewer events, while also minimizing participant attrition due to event burden.

Table 9 shows the characteristics of the average event day windows from PY2022 through PY 2025. Reference loads and impacts in PY2025 were the lowest of the four years, mostly attributable to differing event windows. The reference loads being lower than years past is likely due to a combination of the earlier start time of the average event window in 2025, as well as the lower temperatures on those days both during the events and in the earlier hours leading up to the events. Earlier in the day there is more solar production thus lowering net loads and leading to a lower estimated reference load when those early afternoon hours are included in the average. The lower average load impacts are likely due to the four hour event window in 2025 in comparison to the two hour window in all prior years. Impacts from smart thermostat events decay in each hour meaning that longer event windows average in event hours that have experienced more decay than shorter event windows. The load impacts from just the first two hours of the 2025 average event were similar to prior years with an average of 0.77 kW.

Enrollment changes between the four years though, means that aggregate impacts differ substantially, with 2025 being the smallest as only around 10% of customers were dispatched for the event. If all enrolled SEP customers had been dispatched, the average 2025 event would have had the largest aggregate impacts of the last four years.

Table 9: Comparison of Historical and Current Average Event Ex-post Load Impact Estimates

Measure	2022 (6-8 PM)	2023 (6-8 PM)	2024 (6-8 PM)	2025 (4-8 PM)
Avg. Reference Load (kW)	2.67	2.37	2.17	1.75
Avg. Load Impact (kW)	0.86	0.73	0.71	0.55
% Load Impact	32.40%	30.88%	32.6%	31.5%
Avg. Event Temperature	92.0	87.8	84.3	84.4
Heat Buildup (Avg. F, 12 AM to 5 PM)	79.3	79.0	77.4	75.8
Dispatched Customers	56,668	69,286	78,771	7,764

4.5 COMPARISON TO 2024 EX-ANTE

A key question for program administrators, regulators, and system planners is whether the ex-post performance of demand response programs was consistent with the projected capability in the PY2024 ex-ante analysis for the 2025 delivery year. There are two elements to consider when reviewing the accuracy of the PY2024 ex-ante projections.

1. Did the actual number of enrollments match the projected number of enrollments in SCE's PY2024 enrollment forecast? The number of enrolled accounts is a key component of the aggregate capability of the program in MW.
2. Did the program deliver ex-post impacts on a per-customer basis consistent with the ex-ante projections for comparable weather conditions?

On an aggregate basis, PY2025 SEP ex-post impacts were lower than the MW projections from the PY2024 ex-ante analysis, due to events in PY2025 only dispatching a subset of customers during each event. If the program had dispatched all enrolled customers during each event in PY2025, aggregate impacts would have likely been in line with projections from the PY2024 ex-ante analysis as forecasted enrollments from PY2024 were similar to the actual overall program enrollment in PY2025. The SEP program forecast of enrollments for September 2025 underestimated the actual enrollment numbers by less than 100 customers. Strong per customer performance across many events in summer 2025 meant that SEP was able to outperform the 2024 ex-ante per customer impact projections during several event days.

In Table 10, Table 11, and Table 12, we compare the ex-post results from select PY2025 events to the PY2024 ex-ante results for monthly system worst day conditions at comparable weather conditions. In each comparison, hour 1 for the ex-ante forecasts is 4-5pm while each ex-post event started at 4, 5, or 6pm, so hour 1 corresponds to 4-5, 5-6, or 6-7pm depending on the event day.

Table 10 compares the July 31st SEP event impacts to projected impacts from PY2024 for a July Monthly System Worst Day at SCE 1-in-2 weather conditions. Ex-post weighted average event temperature conditions were well below the SCE 1-in-2 conditions. This means that we would expect the impacts of the event to be below that of the ex-ante projections, and that is exactly what we observe. The event percent impact decay from one hour to the next was lower than projected, meaning that, during this event, later event hours showed higher impacts than would have been expected.

Table 10: July 31, 2025 Ex-post Impacts vs. Comparable PY2024 Ex-ante Conditions

7/31/2025 (4:00-8:00 PM)		Per-Customer Impact (kW)			
Results	Event Hour Average Temp (F)	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-2 July Monthly Worst Day (PY2024 Ex-Ante Predictions for 2025)	91.6	1.20	0.66	0.41	0.35
Ex-Post	83.0	0.77	0.52	0.35	0.21

Table 11 presents a similar comparison for August 21st, 2025. This event day was very hot, and we compare this event with the August worst day during SCE 1-in-10 conditions. The event average temperature was higher than the projection by 0.5 degrees. Due to this temperature difference, we would expect actual impacts to be slightly higher than the ex-ante projections and that is the case which is exactly what we observe. Per customer impacts were higher in hour one by 0.05 kW; the difference in hour 2 and 3 were even higher. This tight alignment between projected impacts and actual event performance is exactly the goal of ex-ante projections.

Table 11: August 21, 2025 Ex-post Impacts vs. Comparable PY2024 Ex-ante Conditions

8/21/2025 (4:00-7:00 PM)		Per-Customer Impact (kW)		
Results	Event Hour Average Temp (F)	Hour 1	Hour 2	Hour 3
SCE 1-in-10 August Monthly Worst Day (PY2024 Ex-Ante Predictions for 2025)	94.6	1.27	0.69	0.45
Ex-Post	95.1	1.32	0.84	0.58

Table 12 presents a comparison for the September 19th, 2025, SEP event, with the PY2024 November monthly worst day under SCE 1-in-2 conditions. This event, called as part of the distribution level testing initiative, was meant to test the program's capabilities when dispatched under cooler weather conditions, which can be seen in the average event hour temperatures on that day of 76.8 degrees. The conditions of this event were not even close to the planning conditions used for September which is why we instead compare it to November monthly worst day conditions which are much more similar. Despite the lower temperatures in the ex-post event, hour 1 impacts were actually higher than the ex-ante projections. Hour 2 impacts were lower, but hour 3 impacts were higher for the ex-post event in comparison to ex-ante projections. Test events like this one are very useful in demonstrating program capabilities for a program that relies on cooling loads to provide grid value.

Table 12: September 19, 2025 Ex-post Impact vs. Comparable PY2024 Ex-ante Conditions

9/19/2025 (6:00-9:00 PM)		Per-Customer Impact (kW)		
Results	Event Hour Average Temp (F)	Hour 1	Hour 2	Hour 3
SCE 1-in-2 November Monthly Worst Day (PY2024 Ex-Ante Predictions for 2025)	81.9	0.58	0.43	0.16
Ex-Post	76.8	0.63	0.30	0.26

5 EX-ANTE RESULTS

The ex-ante results for SEP project increasing aggregate MW impacts over the eleven year forecast horizon based on the growth projections in SCE's enrollment forecast. Because the program is expected to rely largely on direct load control of residential air conditioning, SEP impacts are inherently weather dependent. The projected impacts are largest during the summer months, more modest during the shoulder months, and non-existent during the winter heating season. For 2026 RA compliance year and moving forward, the RA window is from 4pm-9pm in June-October and 5pm-10pm in all other months of the year.[4]

5.1 ENROLLMENT FORECAST

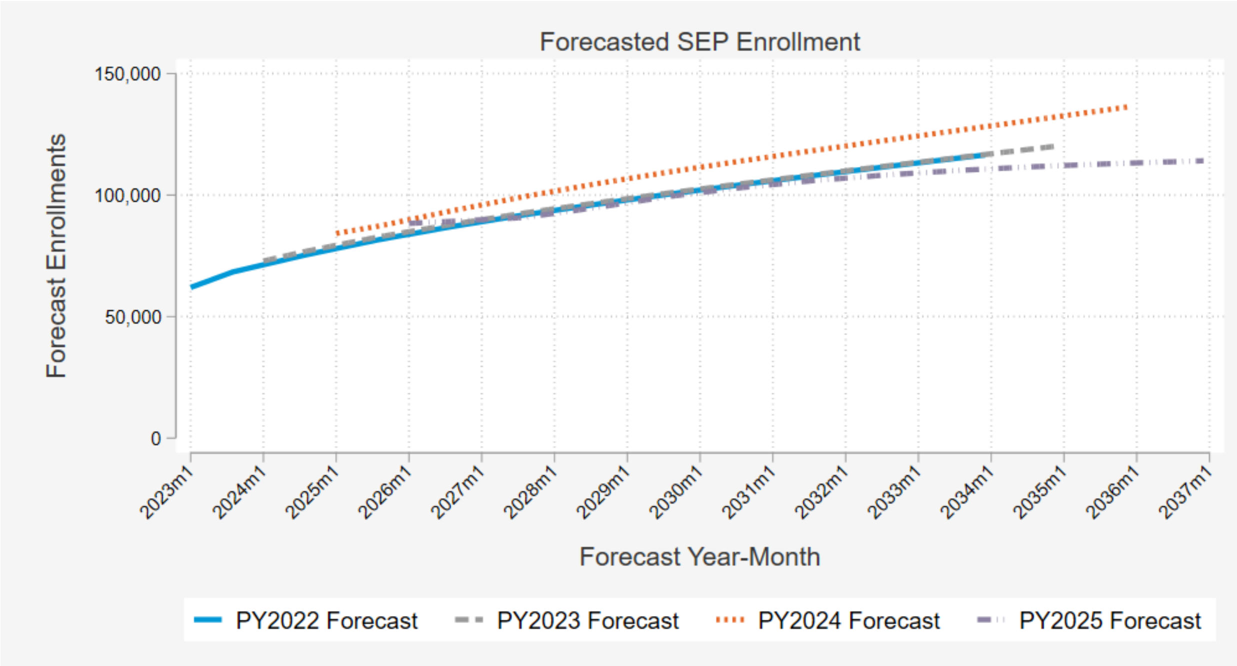
SCE provided an eleven-year forecast of SEP enrollments 2026-2036 representing the expected number of participants as of August of each calendar year. To place the forecast on an even monthly basis, DSA imputed the estimated enrollments in each month of the forecast.

Figure 26 compares this new forecast with the forecast from the PY2022-PY2024 SEP evaluations. The PY2025 forecast shows a lower rate of growth in comparison to PY2024, due to higher than expected compliance removal rates over the past season. Participants in the program whose thermostats are not installed or connected to wi-fi, and customers that choose to opt out of too many events are removed from SEP.

SCE expects the total number of enrollments to grow over the next decade from the current level of approximately 87,800 to nearly 114,000 enrollments by 2036. Forecasted growth is expected due to sustained marketing efforts as well as direct collaboration with the program thermostat vendors to explore opportunities to eliminate enrollment barriers (e.g., removing the up-front account information requirements) and improve backend data-matching to increase approval rates and reduce manual review workload.

[4] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K237/571237404.PDF (Page 121)

Figure 26: Comparison of PY2022-PY2025 SEP Enrollment Forecasts



5.2 OVERALL RESULTS

Figure 27 shows the average ex-ante load impacts per SEP participant for each hour of a September system worst day in 2026 using the SCE 1-in-2 weather forecast. Figure 28 shows the 2025 per-participant impact estimates using SCE 1-in-10 weather for a September system worst day. In Figure 27 and Figure 28, the five hours of the RA window are shaded light green. Hours ending 17 through 21 correspond to the RA window in September of 4pm to 9pm. These two event profiles have a very similar percent load reduction (21.6% vs. 21.5%), which is consistent with most months between 1-in-2 and 1-in-10 weather.

These figures come from the companion Microsoft Excel reporting table generators that accompany this evaluation report. Via a series of pick lists, the ex-ante table generators allow users to view specific sets of results. Per customer (kW) and aggregate (MW) impacts are available for each forecast year 2026-2036 and for the different weather forecasts described in Section 3.2. Users can also view the ex-ante results for a subcategory within LCA, Low Income (CARE Status), NEM, SubLAP, Tariff, and Zone Name. The table generators utilize an "hour ending" time convention. The results presented for hour ending 19 correspond to the average reference load, DR impact, and weather for the hour from 6pm to 7pm Pacific Prevailing Time. Additionally, the table can be toggled between Pacific Prevailing Time (as shown in the figures) or UTC-8 time, which shifts the ending hour by one, if applicable.

Figure 27: SEP Average Load Impact (kW) per Customer in 2026: September Monthly Worst Event Day, SCE 1-in-2 Weather

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PY2025 Ex Ante - SEP

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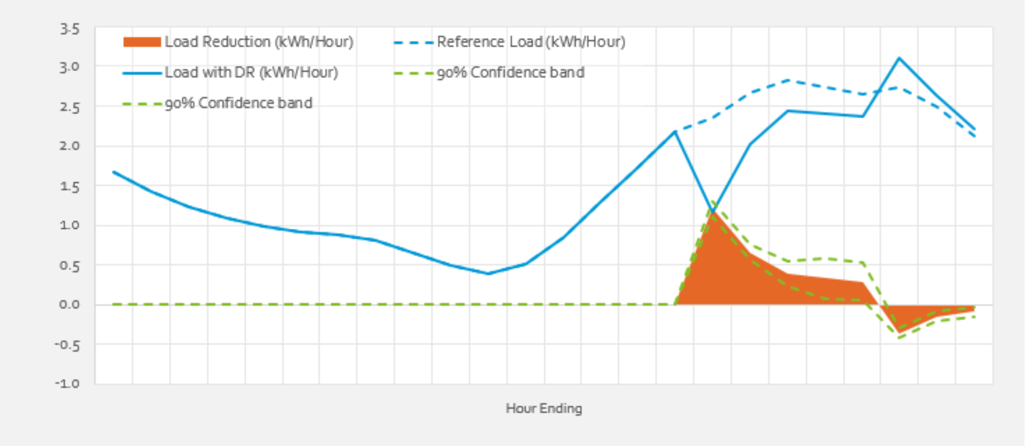
Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-2
Day Type	September Monthly Worst Day
Forecast Year	2026
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	89,337
Event window temperature (F)	91.8
Event window load reduction (kWh/Hour)	0.57
% Load reduction (Event window)	21.6%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.67	1.67	0.00	0.0%	76.77
2	1.41	1.41	0.00	0.0%	75.38
3	1.23	1.23	0.00	0.0%	74.34
4	1.08	1.08	0.00	0.0%	73.10
5	0.99	0.99	0.00	0.0%	72.42
6	0.91	0.91	0.00	0.0%	71.47
7	0.88	0.88	0.00	0.0%	71.46
8	0.81	0.81	0.00	0.0%	72.37
9	0.64	0.64	0.00	0.0%	74.81
10	0.49	0.49	0.00	0.0%	80.24
11	0.38	0.38	0.00	0.0%	86.62
12	0.50	0.50	0.00	0.0%	91.43
13	0.85	0.85	0.00	0.0%	94.81
14	1.27	1.27	0.00	0.0%	96.76
15	1.73	1.73	0.00	0.0%	97.44
16	2.18	2.18	0.00	0.0%	96.65
17	2.35	1.15	1.20	51.1%	95.18
18	2.68	2.02	0.66	24.6%	93.74
19	2.83	2.44	0.39	13.7%	92.31
20	2.74	2.41	0.33	11.9%	90.26
21	2.65	2.37	0.29	10.9%	87.35
22	2.74	3.10	-0.36	-13.2%	84.53
23	2.49	2.64	-0.15	-6.0%	82.54
24	2.13	2.22	-0.09	-4.3%	80.47

By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.65	2.08	0.57	21.6%	91.77
Daily	1.57	1.47	0.09	6.0%	83.85

Figure 28: SEP Average Load Impact (kW) per Customer in 2026: September Monthly Worst Event Day, SCE 1-in-10 Weather

Southern California Edison

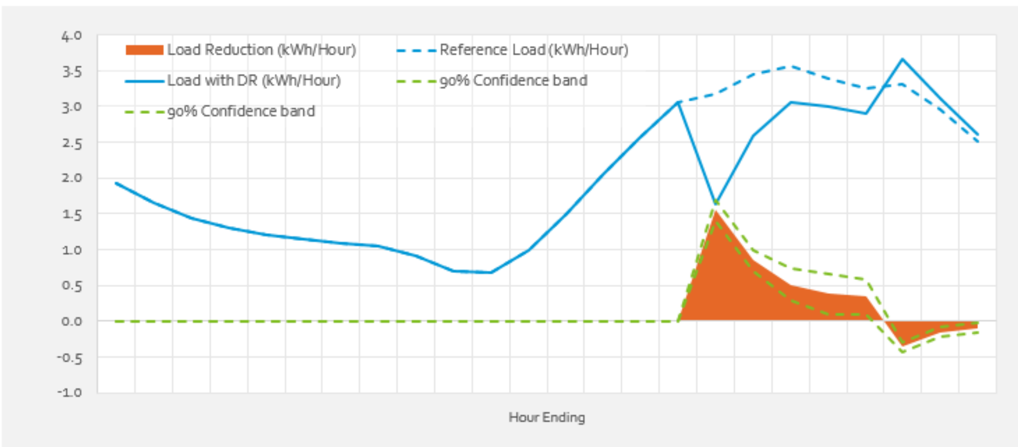
PY2025 Ex Ante - SEP

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-10
Day Type	September Monthly Worst Day
Forecast Year	2026
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	89,337
Event window temperature (F)	98.4
Event window load reduction (kWh/Hour)	0.72
% Load reduction (Event window)	21.5%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.92	1.92	0.00	0.0%	81.89
2	1.64	1.64	0.00	0.0%	80.50
3	1.45	1.45	0.00	0.0%	79.45
4	1.30	1.30	0.00	0.0%	78.69
5	1.20	1.20	0.00	0.0%	78.30
6	1.14	1.14	0.00	0.0%	78.26
7	1.09	1.09	0.00	0.0%	77.83
8	1.04	1.04	0.00	0.0%	78.94
9	0.91	0.91	0.00	0.0%	82.83
10	0.69	0.69	0.00	0.0%	88.11
11	0.68	0.68	0.00	0.0%	93.81
12	0.98	0.98	0.00	0.0%	98.08
13	1.49	1.49	0.00	0.0%	101.21
14	2.04	2.04	0.00	0.0%	103.25
15	2.56	2.56	0.00	0.0%	104.25
16	3.05	3.05	0.00	0.0%	104.46
17	3.18	1.63	1.54	48.6%	104.24
18	3.44	2.60	0.85	24.6%	102.00
19	3.56	3.06	0.51	14.2%	99.05
20	3.38	3.00	0.38	11.3%	94.74
21	3.24	2.90	0.34	10.5%	91.79
22	3.30	3.66	-0.36	-10.9%	89.85
23	2.96	3.12	-0.15	-5.2%	87.99
24	2.51	2.60	-0.09	-3.8%	86.03
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	3.36	2.64	0.72	21.5%	98.36
Daily	2.03	1.91	0.13	6.2%	90.23

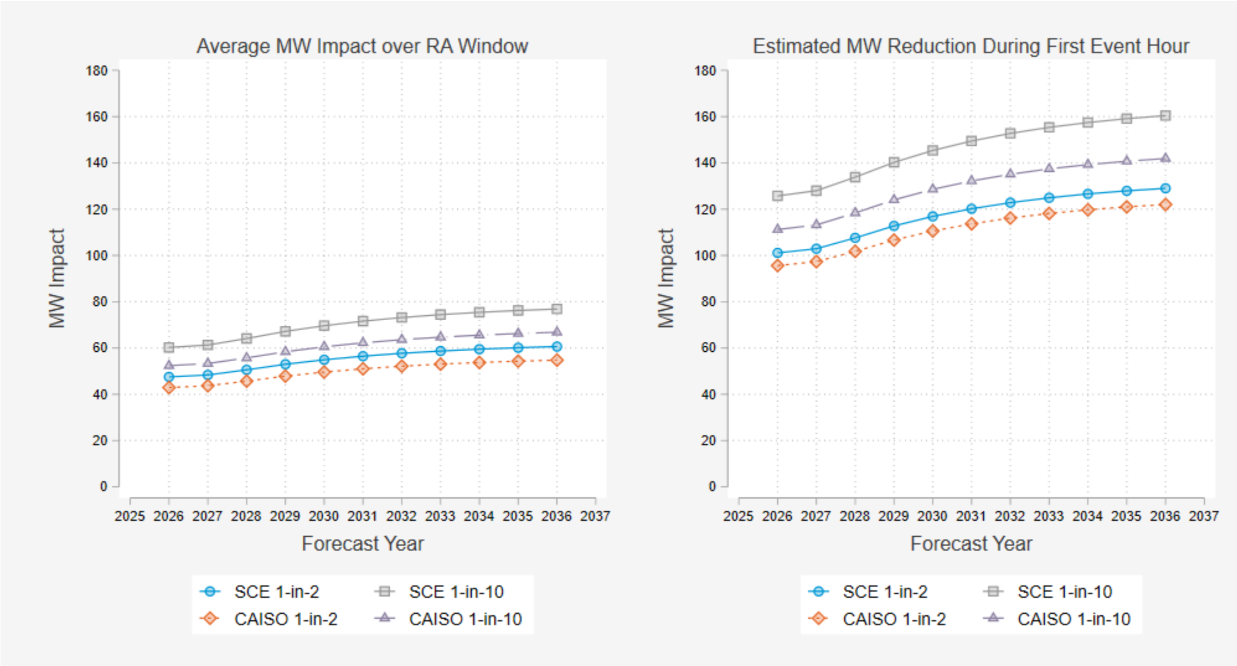
The PY2025 ex-ante forecasts of impacts are slightly lower than the PY2024 per-participant impacts for the same ex-ante weather conditions when averaged across the RA window. We generally attribute this to lower impacts estimated for event hours 3, 4, and 5. Due to the increase number of long events in PY2025, we were able to more reliably fit our second stage model for event hours 3 and 4. Estimates of impacts for those hours, and subsequently event hour 5 as well which uses the same model as hour 4, decreased with the use of this new data. General weather sensitivity of estimated impacts for hour 1 also decreased slightly in this year's analysis, leading to slightly lower estimates of impacts at higher temperatures and slightly higher impact estimates at lower temperatures.

We do not explicitly model the hypothetical ex-ante event as having or not having pre-cooling. This means that impacts in the hour prior to hour 1 of the event are zero. While the ex-ante event profile does not assume pre-cooling, we do not believe pre-cooling is always mutually exclusively with a reliability event. During a heat wave, SCE could pre-cool in advance of a reliability event, strategically estimating event dispatch start times. Inclusion of impacts from events with pre-cooling in the second stage model has an upward influence on the ex-ante impacts but excluding them would drastically limit the amount and recency of data used to model impacts. We believe an SEP event without pre-cooling would have slightly lower expected impacts than an SEP event with pre-cooling, but the study design and available data don't allow us to estimate this difference. Our decision to use events with and without pre-cooling in the second stage model means our ex-ante estimates are likely somewhere in between an event that includes pre-cooling and one that does not.

Aggregate Impacts

The MS Excel reporting tables include the functionality to view aggregate MW impacts for any forecast year under the various day types and sets of weather conditions. Figure 29 consolidates multiple estimates to show the change in the size of the SEP resource over time. The growth over time is a function of the enrollment forecast. The left panel of Figure 29 shows the average SEP MW impact over the five hour RA window on a typical event day. The right panel shows the average SEP MW impact over the first event hour, which is assumed to occur from 4pm to 5pm. The load reduction capability of SEP during the first event hour is significantly larger than the five-hour average. This is due to the reduced impacts over each subsequent hour in the event. The difference between these two views of load reduction capability has important implications for valuation of SEP as a capacity resource.

Figure 29: Aggregate SEP Impacts over Time by Weather Conditions: Typical Event Day



The SCE weather conditions tend to be warmer than CAISO weather conditions on the typical event day. In both the 1-in-2 and 1-in-10 cases, the SCE conditions lead to higher projected event impacts. The highest overall impacts coming from the SCE 1-in-10 conditions. The more extreme weather assumptions lead to higher reference loads, per-participant impacts, and MW capability.

Table 13 shows the aggregate ex-ante load impact estimates in forecast year 2026 by hour and peaking conditions for a typical event day. The estimated load impacts of SEP for a typical event day range from 95.6 MW to 125.8 MW during hour ending 17 depending on which weather scenario is used. Estimated impacts decline across the RA window and range from 16.0 MW to 28.3 MW in hour ending 21.

Table 13: 2026 Typical Event Day Aggregate Impacts (MW) by Hour and Weather Conditions

Hour Ending	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
17	101.1	95.6	125.8	111.2
18	56.1	53.0	71.0	62.4
19	32.9	29.8	43.3	37.4
20	25.7	20.2	32.9	27.6
21	21.8	16.0	28.3	23.2
RA Window	**47.5**	**42.9**	**60.3**	**52.4**

In addition to the typical event day, DSA estimated ex-ante impacts for all monthly system worst days. Table 14 shows the average estimated MW reduction capability of SEP during the RA window for SCE 1-in-2 and SCE 1-in-10 weather. Table 15 presents the same results using CAISO 1-in-2 and CAISO 1-in-10 weather. The SCE 1-in-2 and CAISO 1-in-2 weather year conditions show the largest impacts on

September worst days. The SCE 1-in-10 estimates are largest for the July monthly system worst day. The CAISO 1-in-10 estimates are largest for the June monthly system worst day. The weather conditions used for ex-ante weather predictions were last updated in PY2022, any differences in the expected weather conditions for SEP as a whole from those used in prior evaluations can be attributed to participant location changes over time. The impacts in Table 14 and Table 15 follow the expected temperatures very closely.

Table 14: Aggregate Average Load Impacts (MW) on Monthly System Worst Days 2026-2036: SCE Weather

Weather Year	Month	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1-in-2	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
	April	27.1	27.5	28.5	29.9	31.1	32.0	32.8	33.4	33.9	34.3	34.6
	May	25.0	25.4	26.4	27.6	28.7	29.6	30.3	30.8	31.3	31.6	31.9
	June	42.6	43.3	45.1	47.2	49.1	50.5	51.7	52.6	53.3	53.9	54.4
	July	48.5	49.3	51.5	53.9	55.9	57.6	58.9	59.9	60.7	61.4	61.9
	August	47.9	48.8	51.0	53.5	55.4	57.0	58.2	59.2	60.0	60.7	61.2
	September	51.2	52.2	54.6	57.1	59.2	60.8	62.1	63.2	64.0	64.7	65.2
	October	42.2	43.1	45.1	47.2	48.8	50.2	51.2	52.1	52.7	53.3	53.7
	November	20.6	21.1	22.1	23.1	23.9	24.5	25.0	25.4	25.7	26.0	26.2
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1-in-10	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	26.0	26.5	27.4	28.7	29.9	30.8	31.5	32.2	32.6	33.0	33.3
	April	37.2	37.9	39.2	41.1	42.7	44.1	45.1	46.0	46.6	47.2	47.6
	May	48.2	49.1	51.0	53.4	55.5	57.1	58.5	59.6	60.4	61.1	61.6
	June	55.2	56.1	58.4	61.2	63.6	65.4	66.9	68.1	69.1	69.9	70.5
	July	68.6	69.9	72.9	76.4	79.2	81.5	83.3	84.8	86.0	86.9	87.6
	August	52.5	53.4	55.9	58.6	60.7	62.4	63.8	64.9	65.7	66.4	67.0
	September	64.6	65.9	69.0	72.2	74.8	76.9	78.5	79.8	80.9	81.7	82.4
	October	51.1	52.3	54.7	57.2	59.2	60.8	62.1	63.1	64.0	64.6	65.2
	November	24.4	25.0	26.2	27.4	28.3	29.0	29.6	30.1	30.5	30.8	31.1
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 15: Aggregate Average Load Impacts (MW) on Monthly System Worst Days 2026-2036: CAISO Weather

Weather Year	Month	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
1-in-2	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	April	28.8	29.3	30.4	31.8	33.1	34.1	34.9	35.6	36.1	36.5	36.9
	May	16.9	17.2	17.8	18.7	19.4	20.0	20.5	20.8	21.1	21.4	21.6
	June	40.6	41.3	43.0	45.1	46.8	48.2	49.3	50.2	50.9	51.4	51.9
	July	39.7	40.4	42.1	44.1	45.8	47.1	48.2	49.0	49.7	50.2	50.6
	August	44.1	44.9	46.9	49.2	50.9	52.4	53.5	54.4	55.2	55.8	56.2
	September	47.4	48.3	50.6	52.9	54.8	56.3	57.6	58.5	59.3	59.9	60.4
	October	41.4	42.3	44.3	46.3	47.9	49.2	50.3	51.1	51.8	52.3	52.7
	November	19.1	19.5	20.4	21.4	22.1	22.7	23.2	23.5	23.8	24.1	24.3
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1-in-10	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	27.3	27.8	28.7	30.1	31.3	32.3	33.1	33.7	34.2	34.6	34.9
	April	34.3	34.9	36.1	37.8	39.4	40.6	41.5	42.3	42.9	43.4	43.8
	May	40.0	40.8	42.3	44.3	46.1	47.5	48.6	49.5	50.2	50.7	51.2
	June	54.0	54.9	57.2	59.9	62.2	64.1	65.5	66.7	67.6	68.4	69.0
	July	50.3	51.2	53.4	55.9	58.0	59.7	61.0	62.1	63.0	63.7	64.2
	August	51.7	52.7	55.1	57.7	59.8	61.5	62.8	63.9	64.8	65.5	66.0
	September	53.5	54.5	57.0	59.7	61.9	63.6	64.9	66.0	66.9	67.6	68.2
	October	53.7	54.9	57.4	60.0	62.2	63.8	65.2	66.3	67.1	67.8	68.4
	November	23.8	24.3	25.5	26.6	27.5	28.3	28.8	29.3	29.7	30.0	30.2
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5.3 RESULTS BY CATEGORY

Table 16 presents the aggregate SEP impacts for a typical event day in 2026 under each set of weather conditions by local capacity area averaged across all RA hours. The majority of SEP participants are located in the LA Basin, so this LCA shows the majority of the projected load reduction capacity.

Table 16: Ex-ante Aggregate 2026 Impacts (MW) by LCA: Typical Event Day

LCA	Enrollment	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
Big Creek/Ventura	13,437	7.0	6.8	8.8	8.0
LA Basin	72,912	39.2	34.7	49.9	42.8
Outside LA Basin	2,855	1.4	1.4	1.5	1.5
SEP Total	**89,204**	**47.5**	**42.9**	**60.3**	**52.4**

Approximately 82% of SEP participants are located in the LA Basin LCA, and between 80.9% and 82.8% of the ex-ante MW impacts come from the LA Basin. Average customer impacts in the LA Basin LCA are about the same as Big Creek/Ventura, with Outside LA Basin customers having the lowest. For SCE 1-in-2 weather conditions the Big Creek/Ventura LCA has an average customer impact of 0.52 kW, Outside LA Basin has an average customer impact of 0.49 kW and LA Basin has an average customer impact of 0.54 kW.

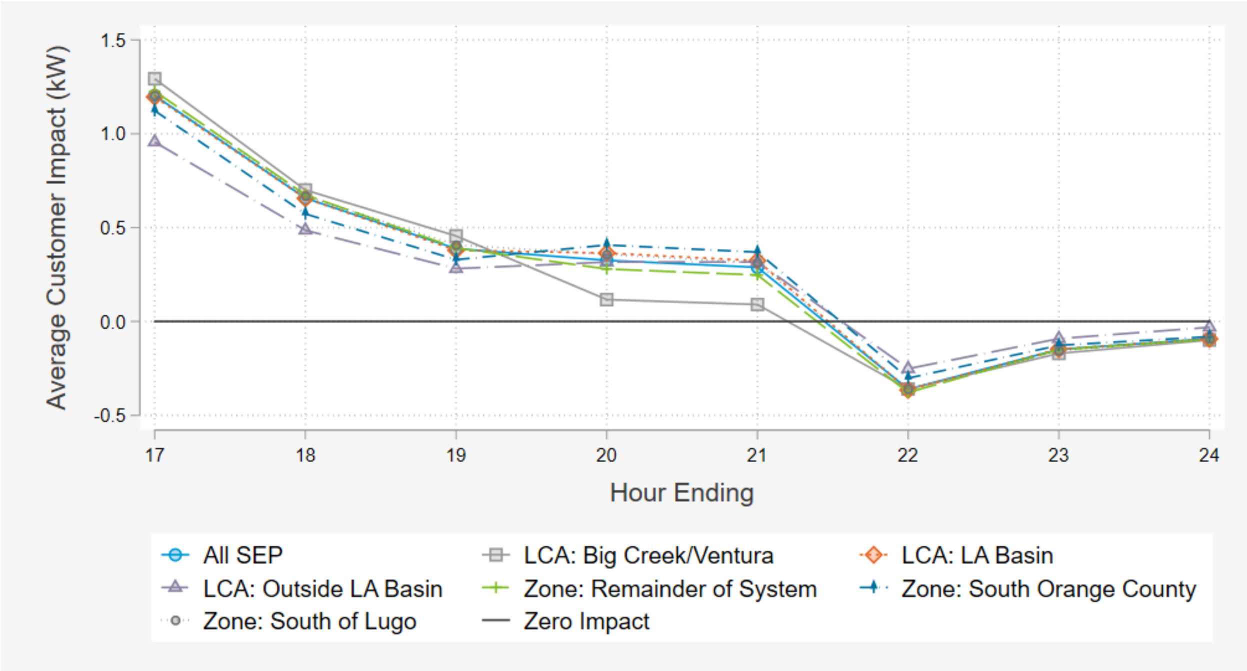
Table 17 provides a similar breakdown of impacts for each region of the SCE system affected by the SONGS closure averaged across all RA hours. For SCE 1-in-2 weather conditions, we expect 35.4% of the SEP load reduction to come from South of Lugo, 12.8% from South Orange County, and 51.8% from the Remainder of the System unaffected by the SONGS closure. While South Orange County has 15.2% of the participants, the average customer impacts are lower, so the region only provides approximately 11.6-12.8% of the total load reduction capability. Remainder of the System has the opposite trend with approximately 50.1% of the customers and 51.4-53.6% of the impacts.

Table 17: Ex-ante Aggregate 2026 Impacts (MW) by SONGs Region: Typical Event Day

Region	Enrollment	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
Remainder of System	45,184	24.6	23.0	31.0	27.5
South Orange County	13,519	6.1	5.0	7.5	6.3
South of Lugo	30,501	16.8	15.0	21.8	18.6
SEP Total	**89,204**	**47.5**	**42.9**	**60.3**	**52.4**

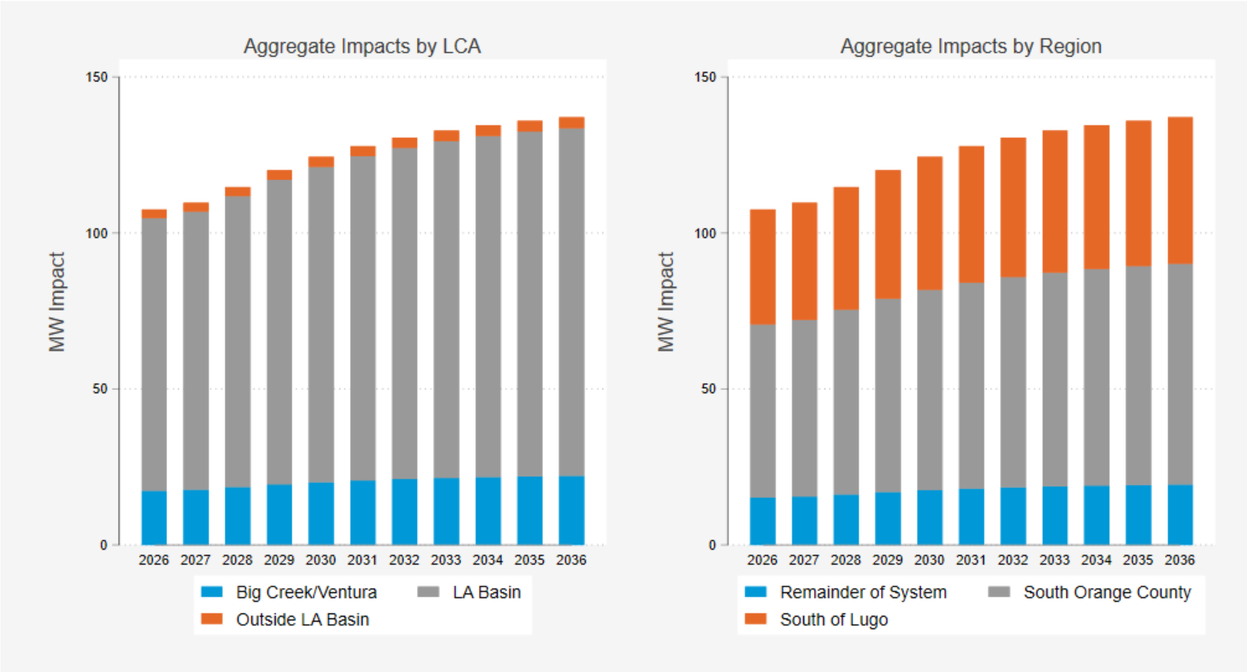
Figure 30 shows the average impact on a September system worst day by segment and hour across the RA window and post-event snapback period using SCE 1-in-2 weather and reveals that that average MW impacts across the RA window mask a significant amount of inter-hour diversity in estimated performance. Figure 30 presents load reductions as a positive impact and load increases as negative values. The largest impact occurs during the first dispatch hour, which is assumed to occur from 4pm to 5pm. Impacts degrade steadily for the remainder of the RA window. The post-event snapback is largest during hour immediately following the conclusion of the event and has largely vanished by midnight.

Figure 30: Average Customer Load Impacts by Segment and Hour: September System Worst Day, SCE 1-in-2 (2026 – 2036)



As shown in Figure 30, the per-participant impact is greatest during the first hour of event dispatch. The forecasted enrollments are the same in each hour. Figure 31 shows the projected aggregate MW impacts for SEP 2026-2036 by LCA and Region using SCE 1-in-2 weather conditions for a September system worst day.

Figure 31: First Event Hour Ex-ante MW Reduction by LCA and Region: September System Worst Day, SCE 1-in-2 Weather



5.4 COMPARISON TO PRIOR YEAR

The PY2025 ex-ante forecasts of impacts are generally lower than the PY2024 per-participant impacts for the same ex-ante weather conditions and more in line with forecasts from PY2023. We attribute this change to two key factors:

- Events in PY2025 were longer than in previous years meaning that we were able to fit separate ex-ante models for event hour 3 and event hours 4 and 5. Because smart thermostat event impacts decay in each event hour, impacts estimated for event hour 4 will usually be lower than event hour 3. The impact model for hour 4 is still used to estimate impacts for event hour 5 as there have not been any 5 hour SEP events in the last 5 years. Treating impacts in the final 2 hours of forecasted events in PY2024 as if they were like hour 3 likely overstated program capabilities in those hours.

- Events in PY2025 were called for a much wider range of event conditions providing more information on how the program performs at extreme high and low temperatures than in previous years. Ex-ante forecasting conditions, especially in the hottest summer months or the coolest shoulder season months, are typically outside of the range of event conditions observed in ex-post, meaning that forecasted impacts must be extrapolated out of sample from the existing data. Getting additional ex-post data for both cool and hot events provides more certainty in out of sample estimates. The relationship between weather and event impacts was estimated to be slightly less steep, meaning that impacts are less weather sensitive, in the PY2025 analysis.

Table 18 compares the average customer impacts on an absolute and percent basis and shows the weighted average temperature (°F) across the SEP population for the 2026 August system worst day using SCE 1-in-2 weather in the PY2024 and PY2025 analysis. Weather conditions have not changed much from year to year. Average per-customer impacts were generally lower in 2025.

Table 18: Comparison of PY2024 and PY2025 Average Customer Impacts: 2026 August System Worst Day, SCE 1-in-2 Weather

Hour Ending	2024 (kW)	2025 (kW)	2024 (%)	2025 (%)	2024 (Temp)	2025 (Temp)
17	1.17	1.14	48.7%	50.8%	93.5	93.5
18	0.63	0.63	23.4%	24.4%	92.0	92.0
19	0.40	0.37	14.1%	13.4%	90.5	90.4
20	0.37	0.30	13.5%	11.2%	88.8	88.8
21	0.30	0.24	11.4%	9.5%	85.5	85.5
RA Window Average	**0.57**	**0.54**	**22.2%**	**21.0%**	**90.1**	**90.0**

Table 19 shows the same comparison for SCE 1-in-10 weather. The PY2025 average customer impacts during the RA window are lower than the PY2024 impacts on an absolute and percentage basis. We calculate the percent reductions by dividing the average RA Window kW reduction by the average RA Window Reference Load.

Table 19: Comparison of PY2024 and PY2025 Average Customer Impacts: 2026 August System Worst Day, SCE 1-in-10 Weather

Hour Ending	2024 (kW)	2025 (kW)	2024 (%)	2025 (%)	2024 (Temp)	2025 (Temp)
17	1.27	1.24	45.7%	47.5%	96.0	96.0
18	0.69	0.70	22.6%	23.8%	94.8	94.8
19	0.45	0.43	14.2%	13.8%	93.1	93.1
20	0.39	0.31	13.1%	10.6%	90.2	90.2
21	0.33	0.27	11.6%	9.4%	87.2	87.2
RA Window Average	**0.63**	**0.59**	**21.4%**	**20.4%**	**92.2**	**92.3**

Table 20 and

Table 21 show the same comparison for CAISO 1-in-2 and CAISO 1-in-10 weather conditions on an August system worst day in 2026. Absolute and percentage impacts in PY2024 are higher than those in PY 2025.

Table 20: Comparison of PY2024 and PY2025 Average Customer Impacts: 2026 August System Worst Day, CAISO 1-in-2 Weather

Hour Ending	2024 (kW)	2025 (kW)	2024 (%)	2025 (%)	2024 (Temp)	2025 (Temp)
17	1.12	1.10	51.1%	53.6%	92.2	92.2
18	0.60	0.60	23.8%	25.0%	90.2	90.2
19	0.35	0.34	13.3%	13.1%	88.1	88.0
20	0.30	0.25	12.0%	10.0%	85.7	85.7
21	0.23	0.20	9.7%	8.2%	82.3	82.3
RA Window Average	**0.52**	**0.49**	**22.0%**	**20.8%**	**87.7**	**87.7**

Table 21: Comparison of PY2024 and PY2025 Average Customer Impacts: 2026 August System Worst Day, CAISO 1-in-10 Weather

Hour Ending	2024 (kW)	2025 (kW)	2024(%)	2025 (%)	2024 (Temp)	2025 (Temp)
17	1.28	1.25	47.0%	48.8%	96.2	96.3
18	0.69	0.69	22.8%	24.1%	94.6	94.6
19	0.44	0.41	14.1%	13.5%	92.4	92.5
20	0.37	0.30	12.6%	10.3%	89.2	89.2
21	0.31	0.25	10.9%	8.9%	86.0	86.0
RA Window Average	**0.62**	**0.58**	**21.5%**	**20.5%**	**91.7**	**91.7**

Aggregate Impacts

In addition to the variation in average participant impacts discussed in the prior section, the estimated number of SEP enrollments affects aggregate impact estimates. As discussed in Section 5.1, the PY2025 enrollment forecast is generally lower than what was predicted in PY2024. However, enrollment is expected to still continue to grow over the next eleven years at a steady rate, which means we expect aggregate impacts to grow at the same steady rate over the 11 year forecast horizon.

For a 2026 typical event day, the PY2025 ex-ante impacts assumed 89,204 participants. For comparison, the PY2024 ex-ante impacts assume 93,252 participants – a decrease of 4%. In past years, forecasts were typically much further apart, differing by more than 30% between some years. The differences in the two forecasts increase over time as the growth percentage used in the PY2025 enrollment forecast is smaller than then one used for PY2024.

Table 22 compares the PY2024 and PY2025 aggregate ex-ante load reduction estimates for forecast year 2026 on a typical event day using SCE peaking conditions. The 2025 average estimated performance across the five-hour RA window is lower under both sets of weather conditions. The difference is due to the decreased forecasted enrollment and per-customer impacts in PY2025.

Table 22: Comparison of 2026 Aggregate Typical Event Day Ex-ante Impacts (MW): PY2024 vs. PY2025 with SCE Weather

Hour Ending	SCE 1-in-2		SCE 1-in-10	
	PY2024	PY2025	PY2024	PY2025
17	108.7	101.1	135.4	125.8
18	58.9	56.1	73.9	71.0
19	37.3	32.9	50.3	43.3
20	33.5	25.7	43.9	32.9
21	27.6	21.8	37.6	28.3
RA Window Average	**53.2**	**47.5**	**68.2**	**60.3**

Table 23 presents the same comparison using CAISO peaking conditions. Impacts are once again lower in PY2025 than in the previous forecast.

Table 23: Comparison of 2026 Aggregate Typical Event Day Ex-ante Impacts (MW): PY2024 vs. PY2025 with CAISO Weather

Hour Ending	CAISO 1-in-2		CAISO 1-in-10	
	PY2024	PY2025	PY2024	PY2025
17	102.6	95.6	119.6	111.2
18	55.4	53.0	64.9	62.4
19	32.2	29.8	42.2	37.4
20	26.2	20.2	36.5	27.6
21	20.2	16.0	30.6	23.2
RA Window Average	**47.3**	**42.9**	**58.8**	**52.4**

5.5 EX-POST TO EX-ANTE COMPARISON

Weather conditions during the average PY2025 event day were cooler than SCE 1-in-2 ex-ante weather conditions for the typical event day. Figure 32 comes directly from the MS Excel ex-post reporting template and shows the average SEP 4pm to 8pm event from PY2025. Figure 33 shows the average customer ex-ante impacts for SCE 1-in-2 weather conditions for the typical event day. It should be noted in the comparisons of the following figures that, the average event in 2025 was in the timeframe 4pm-8pm and ex-ante is predicted in the window 4pm-9pm.

Figure 32: PY2025 Ex-Post Average Event Day 4pm-8pm

Southern California Edison
2025 Ex Post Load Impacts - SEP Program

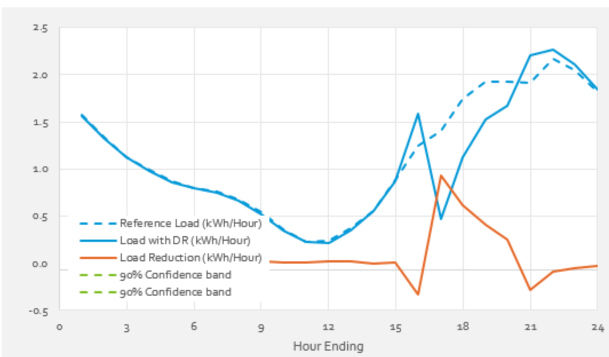
Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	Average Event Day (4:00 PM - 8:00 PM)
Hour Ending View	HE (Prevailing Time)

Public

Table 2: Event day information

Total sites	7,764
Daily Max Temp	86.7
Average Impact - kW	0.55
Average Impact - %	31.5%
Full Hours Only - Average Impact - kW	0.55
Full Hours Only - Average Impact - %	31.5%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.57	1.56	0.02	1%	73.65
2	1.33	1.32	0.02	1%	72.30
3	1.13	1.13	0.00	0%	71.36
4	0.99	0.98	0.01	1%	70.43
5	0.87	0.86	0.01	2%	69.73
6	0.80	0.79	0.01	1%	69.20
7	0.76	0.75	0.01	2%	68.43
8	0.68	0.67	0.01	2%	68.25
9	0.54	0.52	0.02	3%	70.16
10	0.36	0.35	0.01	4%	73.36
11	0.23	0.22	0.01	4%	76.27
12	0.23	0.21	0.02	8%	79.31
13	0.37	0.35	0.02	6%	82.27
14	0.56	0.55	0.00	0%	84.85
15	0.88	0.88	0.01	1%	86.24
16	1.25	1.59	-0.34	-27%	86.65
17	1.40	0.47	0.93	66%	86.49
18	1.74	1.13	0.61	35%	85.37
19	1.93	1.52	0.41	21%	83.77
20	1.92	1.67	0.26	13%	81.93
21	1.91	2.20	-0.29	-15%	78.75
22	2.17	2.26	-0.09	-4%	76.38
23	2.05	2.10	-0.06	-3%	75.07
24	1.81	1.83	-0.02	-1%	73.91
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	1.75	1.20	0.55	31.5%	84.4
Daily	1.15	1.08	0.07	5.8%	76.8

The "Average Impact - kW" characteristic in Figure 33 is lower than the ex-post impacts, because the "Average Event Day" in 2025 was only a four-hour window, but it is not lower by a significant margin. If you compare the averages of the first four hours of both figures, impacts are 0.60 kW from ex-ante and 0.55 kW for ex-post. This higher impacts for the ex-ante predictions are due to the higher expected temperatures for the typical event day when compared with the average 2025 event.

Figure 33: Ex-Ante Typical Event Day under SCE 1-in-2 Conditions: 4pm to 9pm

Southern California Edison

PY2025 Ex Ante - SEP

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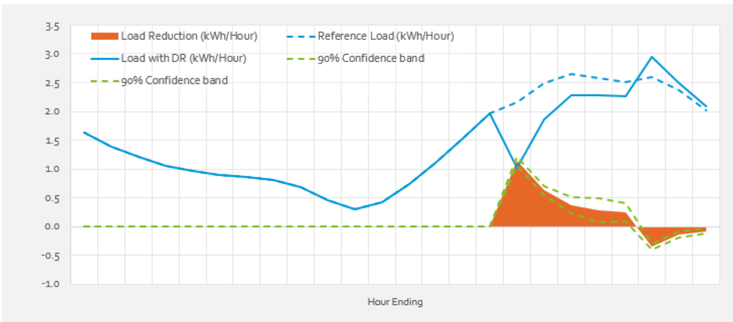
Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-2
Day Type	Typical Event Day
Forecast Year	2026
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	89,204
Event window temperature (F)	89.8
Event window load reduction (kWh/Hour)	0.53
% Load reduction (Event window)	21.6%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.63	1.63	0.00	0.0%	75.98
2	1.39	1.39	0.00	0.0%	74.69
3	1.20	1.20	0.00	0.0%	73.56
4	1.06	1.06	0.00	0.0%	72.48
5	0.96	0.96	0.00	0.0%	71.71
6	0.89	0.89	0.00	0.0%	71.01
7	0.86	0.86	0.00	0.0%	70.88
8	0.80	0.80	0.00	0.0%	72.07
9	0.68	0.68	0.00	0.0%	75.32
10	0.46	0.46	0.00	0.0%	80.10
11	0.31	0.31	0.00	0.0%	84.94
12	0.42	0.42	0.00	0.0%	88.79
13	0.73	0.73	0.00	0.0%	91.55
14	1.11	1.11	0.00	0.0%	93.47
15	1.52	1.52	0.00	0.0%	94.49
16	1.96	1.96	0.00	0.0%	94.27
17	2.15	1.02	1.13	52.7%	93.27
18	2.49	1.86	0.63	25.3%	91.81
19	2.65	2.28	0.37	13.9%	90.46
20	2.57	2.29	0.29	11.2%	88.43
21	2.50	2.26	0.24	9.8%	85.26
22	2.59	2.94	-0.35	-13.4%	82.19
23	2.36	2.50	-0.14	-5.9%	79.90
24	2.01	2.09	-0.08	-3.9%	78.02
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.47	1.94	0.53	21.6%	89.85
Daily	1.47	1.38	0.09	5.9%	82.28

CAISO 1-in-2 peaking conditions are more mild than SCE 1-in-2 peaking conditions for a typical event day. Figure 34 shows the ex-ante estimates for an average SEP customer on a typical event day in 2026 under CAISO 1-in-2 peaking conditions. The weighted average event window temperature is 87.1 °F and the average impact across the five-hour RA window is 0.48 kW.

Figure 34: Ex-Ante Typical Event Day under CAISO 1-in-2 Conditions: 4pm to 9pm

Southern California Edison

PY2025 Ex Ante - SEP

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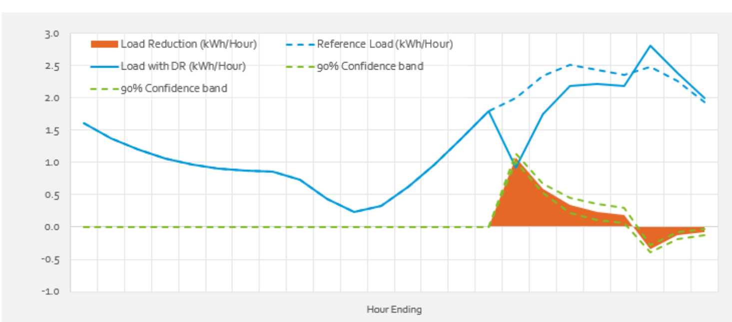
Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	CAISO
Weather Year	1-in-2
Day Type	Typical Event Day
Forecast Year	2026
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	89,204
Event window temperature (F)	87.1
Event window load reduction (kWh/Hour)	0.48
% Load reduction (Event window)	20.7%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.60	1.60	0.00	0.0%	75.31
2	1.38	1.38	0.00	0.0%	74.29
3	1.20	1.20	0.00	0.0%	73.37
4	1.07	1.07	0.00	0.0%	72.57
5	0.97	0.97	0.00	0.0%	71.97
6	0.90	0.90	0.00	0.0%	71.39
7	0.87	0.87	0.00	0.0%	71.26
8	0.85	0.85	0.00	0.0%	72.96
9	0.73	0.73	0.00	0.0%	76.22
10	0.43	0.43	0.00	0.0%	80.22
11	0.23	0.23	0.00	0.0%	84.19
12	0.32	0.32	0.00	0.0%	87.48
13	0.61	0.61	0.00	0.0%	89.78
14	0.97	0.97	0.00	0.0%	91.23
15	1.36	1.36	0.00	0.0%	92.11
16	1.79	1.79	0.00	0.0%	92.23
17	1.99	0.92	1.07	53.8%	91.64
18	2.34	1.74	0.59	25.4%	90.07
19	2.52	2.18	0.33	13.3%	87.78
20	2.43	2.21	0.23	9.3%	84.59
21	2.36	2.18	0.18	7.6%	81.36
22	2.47	2.81	-0.34	-13.6%	79.05
23	2.25	2.39	-0.13	-5.8%	77.42
24	1.92	2.00	-0.07	-3.8%	76.15
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.33	1.85	0.48	20.7%	87.09
Daily	1.40	1.32	0.08	5.6%	81.03

Figure 35 shows ex-ante impacts for the average customer under SCE 1-in-10 conditions, which assume a weighted average event window temperature of 96.4 °F. The predicted load impact across the five-hour RA window is 0.68 kW and the estimated load impact during the first two hours of dispatch is 1.10 kW. The average post-event load increase estimates are 0.35 kW, 0.14 kW, and 0.08 kW during hours ending 22, 23, and 24.

Figure 35: Ex-ante Typical Event Day under SCE 1-in-10 Conditions: 4pm to 9pm

Southern California Edison

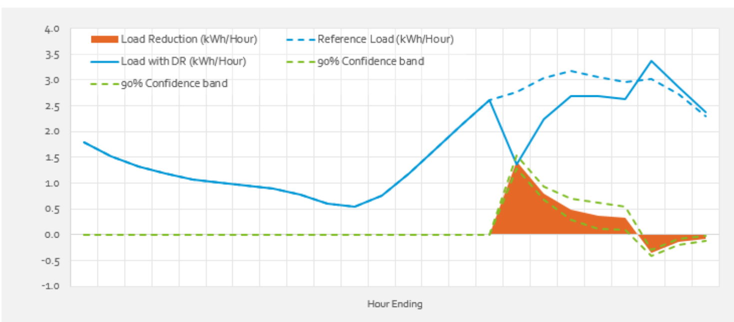
PY2025 Ex Ante - SEP

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-10
Day Type	Typical Event Day
Forecast Year	2026
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	89,204
Event window temperature (F)	96.4
Event window load reduction (kWh/Hour)	0.68
% Load reduction (Event window)	22.5%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.79	1.79	0.00	0.0%	79.32
2	1.52	1.52	0.00	0.0%	77.78
3	1.32	1.32	0.00	0.0%	76.52
4	1.18	1.18	0.00	0.0%	75.57
5	1.07	1.07	0.00	0.0%	74.76
6	1.00	1.00	0.00	0.0%	74.16
7	0.95	0.95	0.00	0.0%	73.61
8	0.88	0.88	0.00	0.0%	74.68
9	0.77	0.77	0.00	0.0%	78.60
10	0.59	0.59	0.00	0.0%	84.18
11	0.54	0.54	0.00	0.0%	89.78
12	0.76	0.76	0.00	0.0%	94.04
13	1.19	1.19	0.00	0.0%	97.02
14	1.66	1.66	0.00	0.0%	99.09
15	2.13	2.13	0.00	0.0%	100.60
16	2.60	2.60	0.00	0.0%	101.02
17	2.76	1.35	1.41	51.1%	100.59
18	3.04	2.24	0.80	26.2%	99.45
19	3.17	2.69	0.49	15.3%	97.46
20	3.06	2.69	0.37	12.0%	94.05
21	2.95	2.63	0.32	10.8%	90.64
22	3.01	3.36	-0.35	-11.6%	87.41
23	2.71	2.86	-0.14	-5.2%	84.48
24	2.30	2.38	-0.08	-3.5%	82.42
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	3.00	2.32	0.68	22.5%	96.44
Daily	1.79	1.67	0.12	6.5%	86.97

Aggregate ex-ante impacts for 2026 are larger than the PY2025 ex-post impacts because of the projected increase in enrollment. The average number of households dispatched during the average PY2025 event from 4pm to 8pm was 7,764 due to the distribution level test events. The enrollment forecast for a 1-in-2 August peak day in 2026 is much higher at 89,204. Table 24 compares the aggregate impacts for the most common PY2025 event profile to the April monthly worst day ex-ante estimates for 2026 as those weather conditions match the average event day profile most closely. Because the PY2025 events were shorter than the ex-ante events, we show the average impact during the first hour of dispatch.

Table 24: Comparison of PY2025 Ex-post Impacts to 2026 Ex-Ante April Worst Day Impacts

Event Date	Max Daily Temp (F)	Hour 1 Temp (F)	Participants	Hour 1 kW	Hour 1 MW
PY2025 Average Event Day	86.7	86.5	7,764	0.93	7.2
2026 April Worst Day SCE 1-in-2	85.9	84.1	88,724	0.73	64.8
2026 April Worst Day SCE 1-in-10	89.0	88.9	88,724	0.94	83.2
2026 April Worst Day CAISO 1-in-2	87.2	85.0	88,724	0.80	70.7
2026 April Worst Day CAISO 1-in-10	87.0	86.8	88,724	0.87	76.9

6 DISCUSSION

Based on the PY2025 ex-post and ex-ante evaluations, DSA highlights the following considerations for program design and future load impact evaluations.

- SEP operations in PY2025 focused heavily on testing the program's ability to target and deliver load impacts at the distribution level. This was accomplished by randomly grouping together customers at the B-Bank group level and dispatching subsets of the territory in a series of test events. The ex-post evaluation shows that the targeted dispatch of specific groups of customers worked as intended and per-customer impacts remained consistent with previous evaluations. SEP showed it can provide targeted value to the distribution grid in the same way it provides capacity value in CAISO.

- SEP enrollment increased by approximately 7,000 customers from the end of PY2024 to the end of PY2025. This growth trend is similar to the growth seen in the previous year. Continued marketing efforts played a large part in the healthy enrollments this year as well as previous years. The increase is in line with predictions made by the SEP program team in PY2024. Precise enrollment projections increase the accuracy of aggregate ex-ante forecasts as the enrollment forecasts play a large role in predicting future program capabilities.

- The most important predictor of SEP load impact is not time of day or weather, but the position of an hour within an event. Impacts are largest during the first event hour and decline sharply in each subsequent hour. Consequently, shorter events show larger average load impacts than longer events. Over the past several years, the SEP program has tended to call shorter events leading to higher average full hour impacts. PY2025, however, saw mostly longer events of 3 or 4 hours in length. While shorter events are likely preferred by customers, calling only longer duration events is very helpful for estimating ex-ante impacts. In PY2025 ex-ante, 2022-2025 event impacts were used for predicting future program impacts. Over that duration all but one of the four hour events used in ex-ante modeling was called in PY2025. If these testing events had not been called then the accuracy of ex-ante impacts would have likely suffered due to a lack of data. The lack of data on how program participants perform over five hour events, though, means that predicting program performance over a hypothetical five hour event requires using performance from other event hours to predict hour five of control. DSA recommends a continued focus on calling longer events and, if possible, during hotter outdoor temperatures to ensure that ex-ante predictions of program impacts are as accurate as possible.

- Pre-cooling was successfully implemented by the larger thermostat vendor for all events in PY2025. Pre-cooling customer's homes in the hour before an event allows for larger impacts during control hours and when successfully utilized can increase program performance.

- In PY2025 homes with two thermostats showed approximately 23% larger load reductions during events than homes with a single thermostat. Those with three or more thermostats had impacts about 15% higher than those with two program thermostats. These incremental increases in the estimated program impacts based on the number of thermostats enrolled are similar to those seen in previous years. Currently customer bill credits do not consider the number of thermostats controlled.

  - ✓ SCE may want to consider larger bill credits for homes with multiple program thermostats. This number may be scaled with the number of thermostats that the customer brings to the program.

- The PY2025 ex-ante forecasts of impacts are generally lower than the PY2024 per-participant impacts for the same ex-ante weather conditions. We attribute this change to two key factors:

  - ✓ Events in PY2025 were longer than in previous years meaning that we were able to fit separate ex-ante models for event hour 3 and event hours 4 and 5. Because smart thermostat event impacts decay in each event hour, impacts estimated for event hour 4 will usually be lower than event hour 3. The impact model for hour 4 is still used to estimate impacts for event hour 5 as there have not been any 5 hour SEP events in the last 5 years. Treating impacts in the final 2 hours of forecasted events in PY2024 as if they were like hour 3 likely overstated program capabilities in those hours.

  - ✓ Events in PY2025 were called for a much wider range of event conditions providing more information on how the program performs at extreme high and low temperatures than in previous years. Ex-ante forecasting conditions, especially in the hottest summer months or the coolest shoulder season months, are typically outside of the range of event conditions observed in ex-post, meaning that forecasted impacts must be extrapolated out of sample from the existing data. Observing additional ex-post data for both cool and hot events provides more certainty in out of sample estimates. The relationship between weather and event impacts was estimated to be slightly less steep, meaning that impacts are less weather sensitive, in the PY2025 analysis.