Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

CALMAC ID: SCE0451

# 2020 Smart Energy Program Load Impact Evaluation

*Confidential information is redacted and denoted with black highlighting:* [redacted]

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**Prepared for Southern California Edison**

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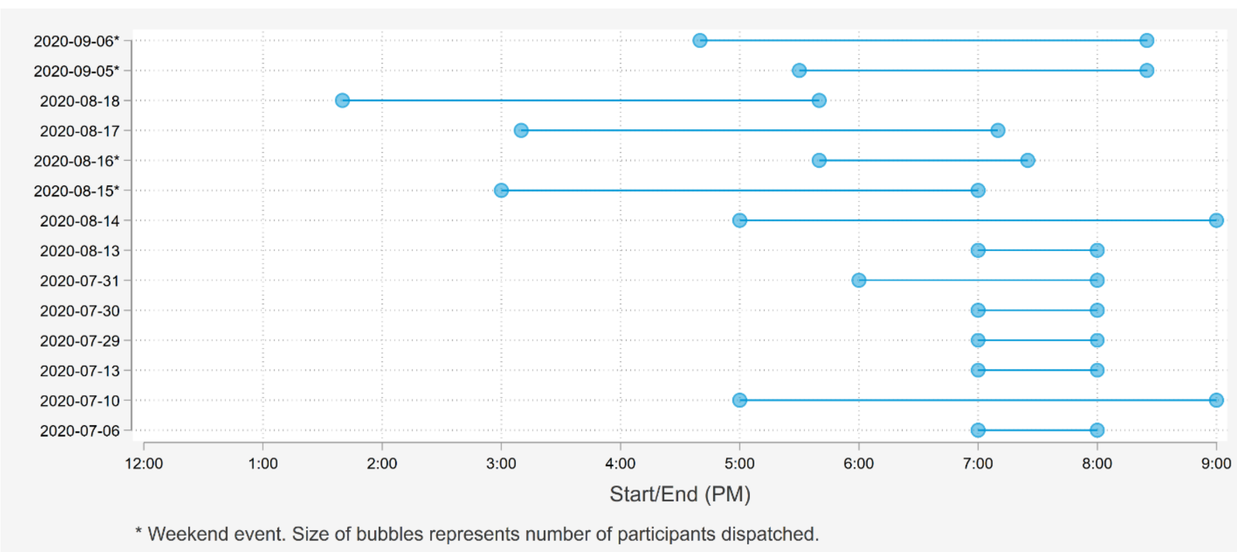
# 1 EXECUTIVE SUMMARY

This report documents the 2020 load impact evaluation of the Southern California Edison's (SCE) Smart Energy Program (SEP). SEP is a residential demand response (DR) program that utilizes Wi-Fi connected smart thermostats to reduce air conditioning load in participating households during peak hours. SCE retained Demand Side Analytics (DSA) to conduct the SEP load impact evaluation for 2020. The primary objectives of this report are to:

- Document the findings of an ex post (after the fact) load impact study for 2020 events
- Provide ex ante (forward looking) estimates of SEP peak demand reduction capability over the next eleven years (2021 to 2031) under various weather conditions.

When SCE initiates SEP events, the two participating DR thermostat providers adjust cooling set points upward by as much as four degrees (F) to limit air conditioning usage and reduce electric demand. SEP events can be called for emergency (reliability), economic purposes or as part of measurement and evaluation. SEP was dispatched on 14 days during PY2020 between July and September. The first eight events of the summer were called for economic purposes and the final six events called in PY2020 were emergency dispatch. There were no measurement and evaluation events during PY2020. Figure 1 lists the 14 event dates along with the start and end time.

**Figure 1: SEP 2020 Event Start and End Times**




SEP enrollments were consistent from 2019 to 2020 in terms of total participant count. However, approximately 15% of the PY2020 participants were not available for dispatch due to contractual issues with one of the thermostat manufacturers.

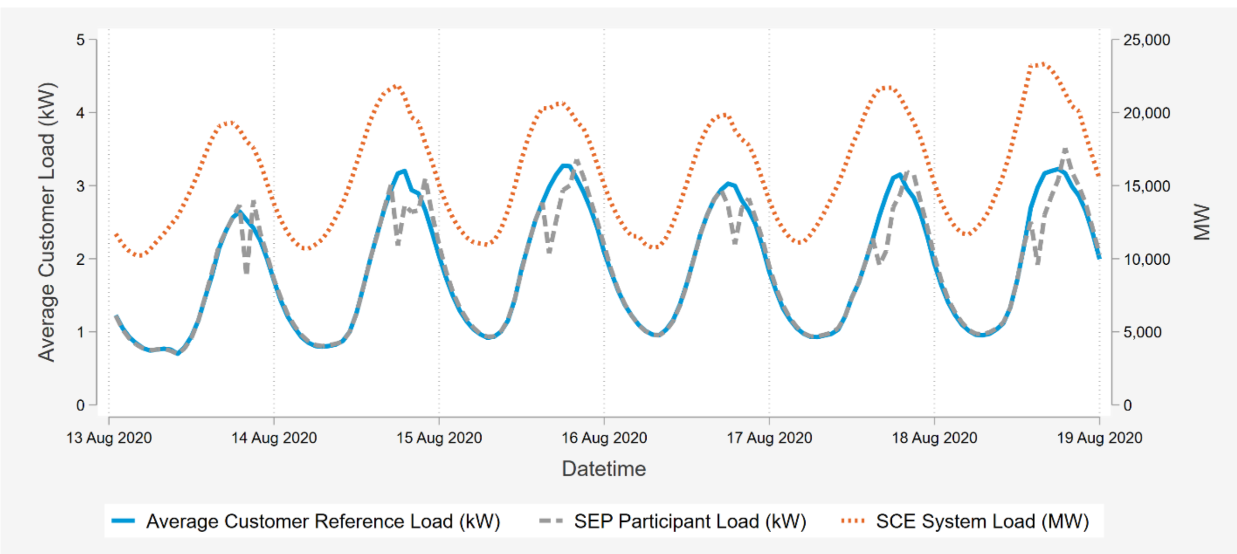
In 2019, SEP was integrated into the California Independent System Operator (CAISO) wholesale energy market where it can be offered as a dispatch resource based on energy prices. As a result of integrating into the CAISO market, 2019 and 2020 events were generally called later in the day compared to previous years when the program was dispatched based on other triggers, such as peak demand forecast. In 2017 and 2018, SEP events were called from 2pm to 6pm. During 2019 and 2020, SEP events have occurred primarily between 4pm and 9pm, which corresponds to the Resource Adequacy (RA) window established by the CAISO.

## 1.1 SUMMARY OF EX POST LOAD IMPACTS

There were 14 distinct SEP events dispatched in 2020. SEP events are dispatched by Sub-Load Aggregation Point (sub-LAP) and are often, but not always called for the entire territory. While sub-LAPs can be dispatched at different hours on the same day, all 2020 events were called at the same time of day for the participating sub-LAPs.

The unusually high temperatures experienced throughout California in 2020 resulted in heavy reliance on demand response programs like SEP. SEP was dispatched on six consecutive days in August from August 13 to August 18. On August 14 and August 15, the state experienced rolling outages, and August 18th was the System Peak for summer 2020. Figure 2 shows the SEP per-customer reference load and observed load along with SCE system load for this critical six day period. SEP delivered consistent load impacts day after day during this heat wave and helped mitigate the need for additional rolling outages.

**Figure 2: August Heat Wave Consecutive Events**




Demand Side Analytics utilized a matched control group with regression analysis to estimate the impacts of each event across the full participant group and a variety of segments. Table 1 shows the event details and average hourly impacts for all 2020 events and two "Average Event Day" profiles.

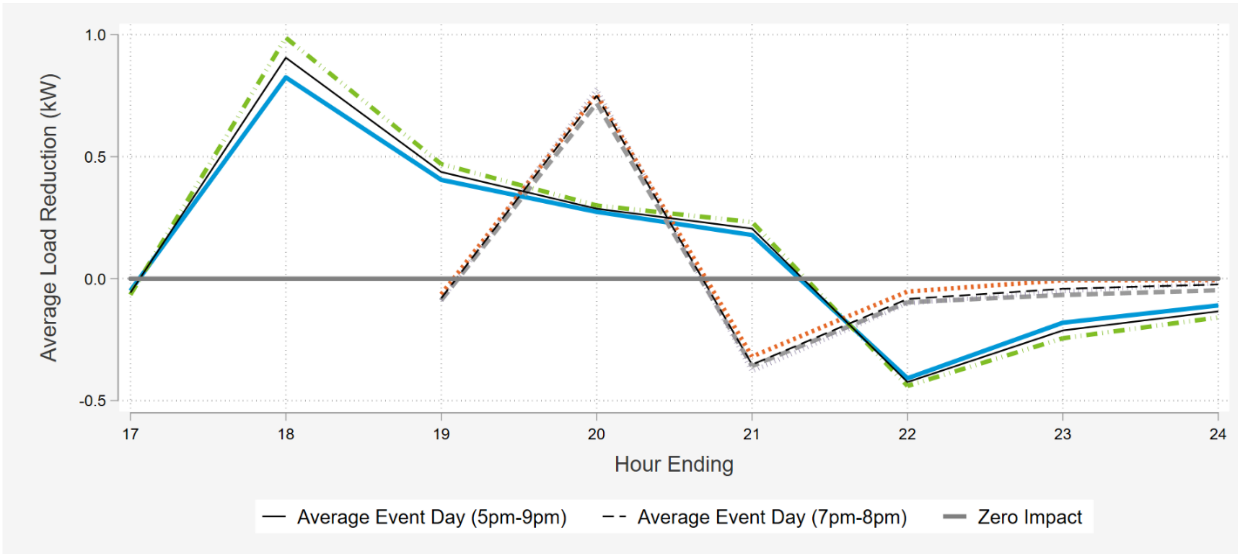
**Table 1: Territory Wide Event Impacts**

| Event Date | Dispatch Region | Participants | Average Event Temp | Daily Max Temp | Average Full Hour Impact (kW Reduction) | Average Aggregate Full Hour Impact (MW Reduction) |
|---|---|---|---|---|---|---|
| 7/6/2020 (7pm-8pm) | Territory Wide | 51,842 | 86.0 | 89.9 | 0.76 | 39.1 |
| 7/10/2020 (5pm-9pm) | Territory Wide | 51,776 | 88.4 | 92.6 | 0.42 | 21.8 |
| 7/13/2020 (7pm-8pm) | SCEC, SCHD, SCLD, SCNW, SCEW | 46,529 | 81.5 | 87.2 | 0.67 | 31.4 |
| 7/29/2020 (7pm-8pm) | SCEC, SCHD, SCLD, SCNW, SCEW | 46,178 | 82.2 | 86.9 | 0.55 | 25.6 |
| 7/30/2020 (7pm-8pm) | Territory Wide | 51,383 | 89.7 | 92.0 | 0.72 | 36.9 |
| 7/31/2020 (6pm-8pm) | Territory Wide | 51,371 | 92.2 | 95.6 | 0.64 | 33.1 |
| 8/13/2020 (7pm-8pm) | Territory Wide | 51,079 | 90.2 | 94.4 | 0.78 | 39.7 |
| 8/14/2020 (5pm-9pm) | Territory Wide | 51,071 | 94.6 | 98.6 | 0.50 | 25.4 |
| 8/15/2020 (3pm-7pm) | SCEC, SCEN, SCEW, SCHD, SCNW | 50,939 | 96.8 | 97.9 | 0.53 | 27.2 |
| *8/16/2020 (5:40pm-7:25pm) | SCEC, SCEN, SCEW, SCHD, SCNW | 50,939 | 88.2 | 95.6 | 0.80 | 40.7 |
| *8/17/2020 (3:10pm-7:10pm) | Territory Wide | 51,002 | 94.7 | 95.7 | 0.48 | 24.3 |
| *8/18/2020 (1:40pm-5:40pm) | Territory Wide | 50,977 | 100.0 | 101.6 | 0.66 | 33.5 |
| *9/5/2020 (5:30pm-8:25pm) | Territory Wide | 50,809 | 104.7 | 107.8 | 0.77 | 39.3 |
| *9/6/2020 (4:40pm-8:25pm) | Territory Wide | 50,809 | 102.9 | 108.6 | 0.70 | 35.5 |
| Average Event Day (7pm-8pm) | Territory Wide | 51,437 | 88.6 | 92.0 | 0.75 | 38.6 |
| Average Event Day (5pm-9pm) | Territory Wide | 51,426 | 91.5 | 95.6 | 0.46 | 23.6 |

*Hourly impacts correspond to full event hours. Partial hours are excluded.

DSA defines Average Event Days as the weighted average of the applicable territory wide events with the standard event windows of either 5pm to 9pm (four hour duration) or 7pm to 8pm (one hour duration). For the four hour average event, only two events met the criteria to be included. For the one hour event, three events met the necessary criteria. The averages and their contributing dates are shown in Figure 3. The SEP impacts are fairly consistent across events. By far the most important predictor of load impact is event hour, or whether a given hour is the first, second, third, or fourth hour of dispatch. The first hour of the average events provide a reduction of approximately 0.75 kW. Each subsequent hour tapers off, but the average four hour event maintains positive reductions in all four event hours. Savings estimates presented in Table 1 show the average hourly impacts. It is important to note that events with longer event windows are expected to have lower hourly impacts because of this tapering trend, thus lowering the average event impact with each additional hour of dispatch.

**Figure 3: Hourly Load Reductions for Territory Wide Average Events**




The system peak day in 2020 was August 18th. The four hour event on that day had an average per customer hourly reduction of 0.66 kW and an average aggregate hourly savings of 33.5 MW. However, the event on this day started at 1:40 pm. Interval data for residential customers is recorded on an hourly basis. The data constraint requires special handling of partial hour events, and for this particular event, only three full event hours were used. The first full event hour (2pm to 3pm) missed the first twenty minutes of the event, dampening the hourly effect of the event.

The Average Event Day with the four hour duration had an aggregate hourly reduction of 23.6 MW and the one hour duration Average Event Day had an aggregate hourly savings of 38.6 MW.

## 1.2 SUMMARY OF EX ANTE LOAD IMPACTS

Historically ex ante load impact evaluations assume the same average customer impact for each year of the forecast. Due to COVID, there are adjustments to the methodology that modify this pattern. For 2020, we included a COVID term in the ex ante modeling and assume a declining effect of COVID over the forecast horizon. As a result, the average customer impacts for SEP increase slightly each year from 2021 to 2031. See Section 3.2 for more detail. The charts that follow are for 2021.

SEP reliability events can be called 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 RA window, beginning at 4pm and lasting until 9pm. This event profile prevents any post-event snapback from occurring during the RA window. However, the estimated load reduction capability of SEP during the later hours of the RA window is lower than the initial event hours. Figure 4 illustrates this trend for monthly system peak days using SCE and CAISO 1-in-2 weather conditions. The impacts during hour 20 are only slightly larger than the impacts in hour 21 and shown in purple in Figure 4. Although SEP can be dispatched 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 peak days, we estimate SEP impacts in March through November for both SCE and CAISO weather conditions.

**Figure 4: Average Customer Ex Ante Impacts on 2021 Monthly System Peak Days: 1-in-2 Conditions**

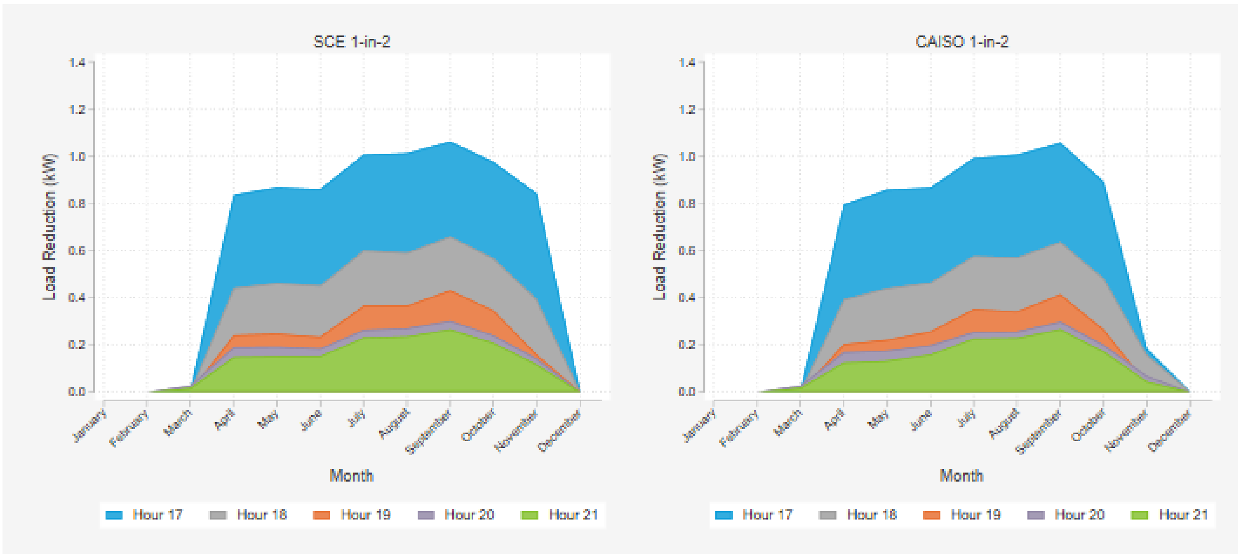
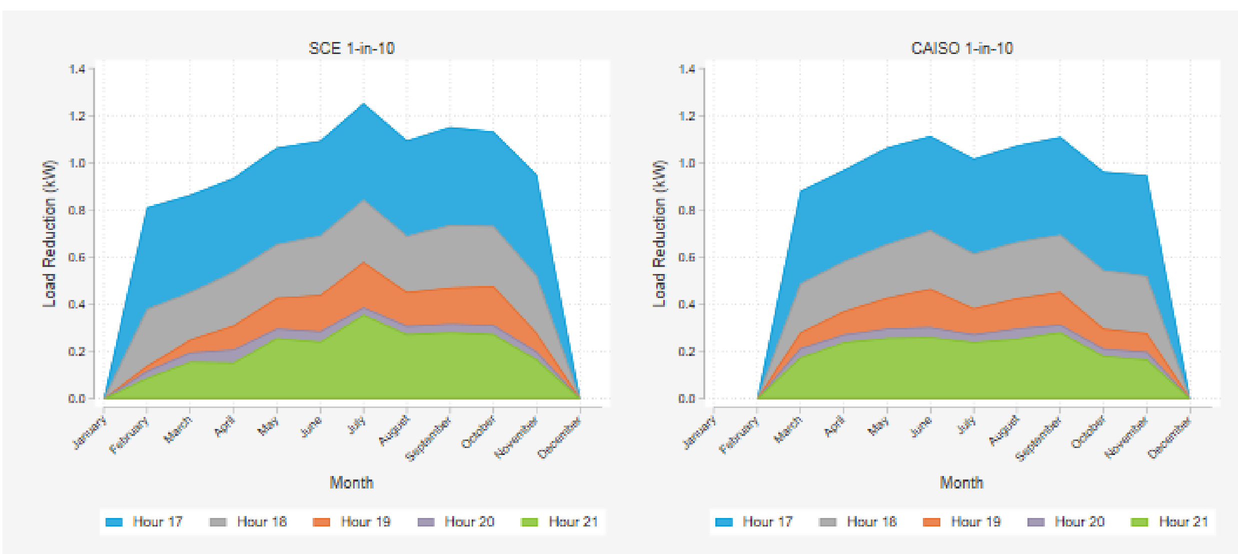



Figure 5 shows the same set of results for 1-in-10 weather conditions, which are more extreme than 1-in-2 conditions.

**Figure 5: Average Customer Ex Ante Impacts on 2021 Monthly System Peak Days: 1-in-10 Conditions**




The weighted average maximum daily temperature on a July system peak day using SCE 1-in-10 weather is 104.2°F and the 2021 estimated average load impact is 1.25 kW during the first hour of dispatch. For comparison, the weighted average maximum daily temperature for a July system peak day using CAISO 1-in-10 weather is 93.7°F and the estimated load impact is 1.02 kW during the first hour of dispatch.

- **For SCE 1-in-10 weather conditions**: SEP is projected to have load impact capability in all calendar months except January and December.
- **For CAISO 1-in-10 weather conditions**: SEP is projected to have load impact capability on all monthly system peak days except January, February, and December.

Table 2 shows the SEP aggregate ex ante load impacts for an August Monthly Peak Day in 2021. The estimated load impact of SEP in 2021 ranges from 59.8 MW to 65.1 MW during hour ending 17. Estimated impacts decline across the RA window and range from 13.6 MW to 16.2 MW in hour ending 21. Average impacts for the five hour RA window range from 28.6 MW to 33.5 MW.

**Table 2: SEP Aggregate Ex Ante Impacts (MW) During RA Window: 2021 August Monthly Peak Day**

| Hour Ending | SCE 1-in-2 | CAISO 1-in-2 | SCE 1-in-10 | CAISO 1-in-10 |
|---|---|---|---|---|
| 17 | 60.2 | 59.8 | 65.1 | 63.9 |
| 18 | 35.1 | 34.0 | 41.1 | 39.5 |
| 19 | 21.7 | 20.3 | 26.9 | 25.3 |
| 20 | 16.1 | 15.2 | 18.4 | 17.7 |
| 21 | 14.0 | 13.6 | 16.2 | 15.2 |
| **RA Window** | **29.4** | **28.6** | **33.5** | **32.3** |

SCE forecasts that SEP enrollments will approach 155,000 households by 2031. 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 80.5 MW for SCE 1-in-2 weather conditions on an August system peak day and 91.2 MW for SCE 1-in-10 conditions on an August system peak day in 2031. Using CAISO peaking conditions, we estimate an aggregate impact of 78.3 MW for 1-in-2 conditions and 88.0 MW for 1-in-10 conditions on an August system peak day.

## 1.3 RECOMMENDATIONS

Based on the findings of the PY2020 load impact evaluation, Demand Side Analytics makes the following program and evaluation recommendations for SEP.

- Contract issues with one of the participating thermostat manufacturers led to approximately 15% of participating households being unavailable for dispatch during summer 2020 DR events. SCE was not able to determine which households were available for dispatch so enrolled accounts continued to receive bill credits. This led to lower average customer ex post impacts compared to prior years. In the ex ante analysis, we assume that all enrolled customers will be available for dispatch. It will be important for SCE to monitor contract terms and conditions with all participating vendors and thermostat manufacturers to ensure the lack of availability observed in 2020 doesn't happen in the future.

- The extreme weather conditions of summer 2020 highlighted the value of weather-sensitive programs like SEP as a grid resource. SEP load impacts increase with temperature so its capability is greatest during emergency conditions like the ones observed in California during the August and September heat waves.
  - ✓ Typically system peaking conditions are expected to occur on weekdays, but during the August and September heat waves of 2020, the California grid was highly constrained on four weekend days. SEP was called for emergency dispatch on all four of these critical weekend days. In the 2020 ex post evaluation, DSA observed no significant differences in performance between weekday and weekend events.
  - ✓ All four weekend events were called at extreme temperatures when SEP load impacts are the largest. In order to better understand the weekday versus weekend performance of SEP, it would be beneficial to call some weekend measurement and evaluation events at milder temperatures in 2021.
- 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.
- [redacted]
- Rollout of default TOU pricing for residential customers is underway in SCE territory. As shown in Table 4, nearly 28% of SEP participants faced time-varying pricing during PY2020. It will be important to continue to monitor the effect of TOU on SEP participant reference loads and load impacts.
- The COVID-19 pandemic affected all aspects of life in 2020. In the ex ante modeling of reference loads and impacts, we included a COVID indicator variable to capture the differences between summer 2020 and prior years. At a high level, we estimated slightly higher reference loads under COVID and slightly lower load impacts holding other conditions constant. In the ex ante projections, the COVID effect is gradually withdrawn from 2021 to 2031.
  - ✓ For the 2021 ex ante evaluation, it will be important to decide what to set the COVID term equal to for 2021 loads and event impacts. The COVID glide path provided by SCE sets the index to 50% for 2021, but this assumption should be revisited based on the extent to which changes in energy consumption and energy patterns observed in 2020 persist.
- In PY2020, five of the 14 events were dispatched mid-hour. The irregular start and end times resulted in evaluation challenges and reporting modifications that reduced impacts. Partial event hours, either at the start or end of an event, result in diluted impacts. All irregular events were dispatched for reliability purposes, suggesting the potential sudden need for dispatch.

However, to the extent that SCE has control over timing, events should start and end on the hour to obtain the most accurate impact estimates.

# 2 PROGRAM DESCRIPTION

SCE's Smart Energy Program (SEP) 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. During SEP events, thermostat providers can adjust cooling set points upward by as much as four degrees (F) to limit air conditioning usage during peak hours. Limiting air conditioning usage lowers electric demand in participating households. Multiple events can be called on a single day, but the number of hours of control cannot exceed four hours in a given day. Dual enrollment in Critical Peak Pricing (CPP) dispatchable pricing tariffs or the Summer Discount Plan (SDP) program is prohibited.

SEP has evolved considerably in recent years from its predecessor program, Save Power Day (SPD). SEP now relies exclusively on direct load control of central air conditioning systems through Wi-Fi connected smart thermostats. Participants are sent 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.

SCE provides new SEP participants with a one-time $75 bill credit for enrolling and a daily bill credit of $0.3275 per day provided annually during the summer from June 1 through September 30 for remaining in the program. Events can be called 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) may only be dispatched within 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.

SEP events were called on a total of 14 days during 2020. Table 3 lists the event dates and dispatch reason. The first eight events were economic dispatch. August temperatures began to rise and SCE territory experienced unusually hot temperatures. Beginning on August 15, all events were Reliability dispatched events in response to the extreme heat conditions. SEP events can be dispatched by Sub-Load Aggregation Points (sub-LAPs), and four of the events were dispatched to five of the six sub-LAPs. The August 18, 2020 event is shaded in Table 3 because it was the system peak day for 2020.

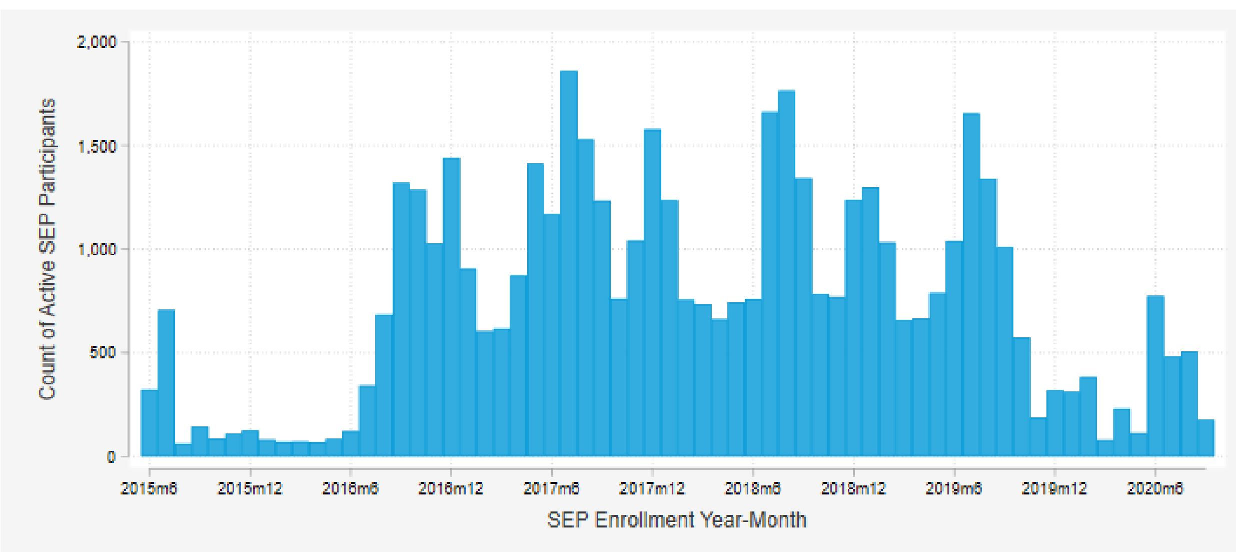
**Table 3: 2019 SEP Event Days and Dispatch Reason**

| Date | Dispatch Trigger | Sub-LAPs Dispatched |
|---|---|---|
| 7/6/2020 | Economic | Territory Wide |
| 7/10/2020 | Economic | Territory Wide |
| 7/13/2020 | Economic | SCEC, SCHD, SCLD, SCNW, SCEW |
| 7/29/2020 | Economic | SCEC, SCHD, SCLD, SCNW, SCEW |
| 7/30/2020 | Economic | Territory Wide |
| 7/31/2020 | Economic | Territory Wide |
| 8/13/2020 | Economic | Territory Wide |
| 8/14/2020 | Economic | Territory Wide |
| 8/15/2020 | Reliability | SCEC, SCEN, SCEW, SCHD, SCNW |
| 8/16/2020 | Reliability | SCEC, SCEN, SCEW, SCHD, SCNW |
| 8/17/2020 | Reliability | Territory Wide |
| 8/18/2020 | Reliability | Territory Wide |
| 9/5/2020 | Reliability | Territory Wide |
| 9/6/2020 | Reliability | Territory Wide |

There were approximately 52,000 active participants in SEP during the summer 2020 event season. Despite various causes of turnover such as the 2019 migration of a subset of residential customers to Community Choice Aggregators, the total participant count is similar to the counts from the 2018 (51,000 customers) and 2019 (52,000 customers) event seasons.

Figure 6 shows the distribution of enrollment month households that were active in SEP at the conclusion of the PY2020 event season. Historically, enrollments have been highest during the summer months when bill credits are available and program marketing efforts are most active.

**Figure 6: Distribution of Enrollment Month among Active SEP Participants**



There was also churn among the SEP participant population during the PY2020 event season. Approximately 1,900 households that were active during the first PY2020 event on July 6, 2020 left the program prior to the last event on September 6, 2020. Conversely, approximately 1,100 households were active during the final PY2020 event that had not enrolled on July 6, 2020 when the first SEP event was called.

At the conclusion of PY2020, there were approximately 51,000 active participants in SEP. Table 4 shows the distribution of participants still active at the end of the PY2020 season across various segmentation variables of interest.

- 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 2020. Tiered rates based on consumption are considered flat because they do not vary by time of day.

- The 'Size' variable is based on customer's 2020 average net load on weekdays during the Resource Adequacy window of 4pm to 9pm. Participants were binned based on whether they were above or below 1.82 kW.

- Approximately 22% of SEP participants have net energy metering (NEM) of rooftop solar arrays. The NEM percentage is up from 17% in 2019. All load impact analysis is conducted using net load so to the extent a home with solar becomes a larger net exporter because of reduced air conditioning demand, SEP is credited with those impacts. As noted in the discussion of participant matching in Section 3.1, NEM participants are matched with NEM non-participants for analysis.

- [redacted]

- SEP participants also enrolled in the CARE or FERA programs are indicated by the 'Income Qualified' segment

- The LCA variable indicates the load capacity area. Almost 85% of SEP participants are located in the LA Basin LCA.

- Region 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 in 2013. 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.

- The Sub-LAP variable segments participants by sub-load aggregation point.

**Table 4: Summary of SEP Enrollment by Customer Segment**

| Segmentation Variable | Segment Description | Participants | Percent |
|---|---|---|---|
| | All Customers | 50,809 | 100.0% |
| LCA | Big Creek/Ventura | 6,040 | 11.9% |
| | LA Basin | 43,403 | 85.4% |
| | Outside | 1,366 | 2.7% |
| Low Income | CARE | 7,337 | 14.4% |
| | Non-CARE | 43,472 | 85.6% |
| NEM | NEM Customer | 11,217 | 22.1% |
| | Non-NEM Customer | 39,592 | 77.9% |
| Sub-LAP | SCEC | 20,538 | 40.4% |
| | SCEN | 5,137 | 10.1% |
| | SCEW | 22,867 | 45.0% |
| | SCHD | 1,318 | 2.6% |
| | SCLD | 48 | 0.1% |
| | SCNW | 901 | 1.8% |
| Tariff | Dynamic | 14,080 | 27.7% |
| | Flat | 36,729 | 72.3% |
| Zone | Remainder of System | 21,789 | 42.9% |
| | South Orange County | 10,615 | 20.9% |
| | South of Lugo | 18,405 | 36.2% |
| [redacted] | [redacted] | [redacted] | [redacted] |
| | [redacted] | [redacted] | [redacted] |
| | [redacted] | [redacted] | [redacted] |
| | [redacted] | [redacted] | [redacted] |
| | [redacted] | [redacted] | [redacted] |
| Size | Less than 1.82 kW during RA window | 25,591 | 50.4% |
| | Greater than 1.82 kW during RA window | 25,218 | 49.6% |

The SEP participant population is located across SCE service territory and experiences a wide range of weather conditions. At the conclusion of the PY2020 event season, there were active participants in nine of the sixteen California climate zones. For both the ex post and ex ante analysis each participant was mapped to one of 23 weather stations. Table 5 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 November 1, 2017 to October 31, 2020.

CDD and HDD were each calculated using a base of 60°F. CDD is separately calculated 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

50°F, would have a CDD of 0, because the value is capped at zero. The 50°F day would have an HDD60 value of 10.

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

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

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

**Table 5: SEP Enrollments by Weather Station with Yearly Average CDD60 and HDD60**

| Weather Station | SEP Enrollments | CDD60 | HDD60 |
|---|---|---|---|
| 173 | 14,782 | 3,131 | 431 |
| 121 | 7,221 | 3,432 | 1,393 |
| 122 | 7,090 | 5,447 | 512 |
| 172 | 3,775 | 2,434 | 581 |
| 112 | 2,695 | 3,337 | 654 |
| 111 | 2,679 | 3,481 | 780 |
| 132 | 2,620 | 3,398 | 1,156 |
| 171 | 2,391 | 2,767 | 562 |
| 51 | 1,469 | 4,291 | 1,750 |
| 181 | 1,392 | 7,792 | 452 |
| 161 | 1,159 | 1,786 | 579 |
| 194 | 949 | 3,855 | 2,264 |
| 193 | 823 | 4,438 | 1,987 |
| 123 | 488 | 2,108 | 1,187 |
| 151 | 434 | 1,429 | 958 |
| 131 | 328 | 1,486 | 4,511 |
| 191 | 267 | 5,578 | 1,950 |
| 195 | 173 | 4,231 | 2,159 |
| 113 | 125 | 1,712 | 940 |
| 192 | 71 | 5,210 | 1,752 |
| 101 | 65 | 587 | 7,884 |
| 182 | 47 | 7,680 | 623 |
| 141 | 32 | 3,035 | 3,687 |

# 3 EVALUATION METHODOLOGY

## 3.1 EX POST METHODS

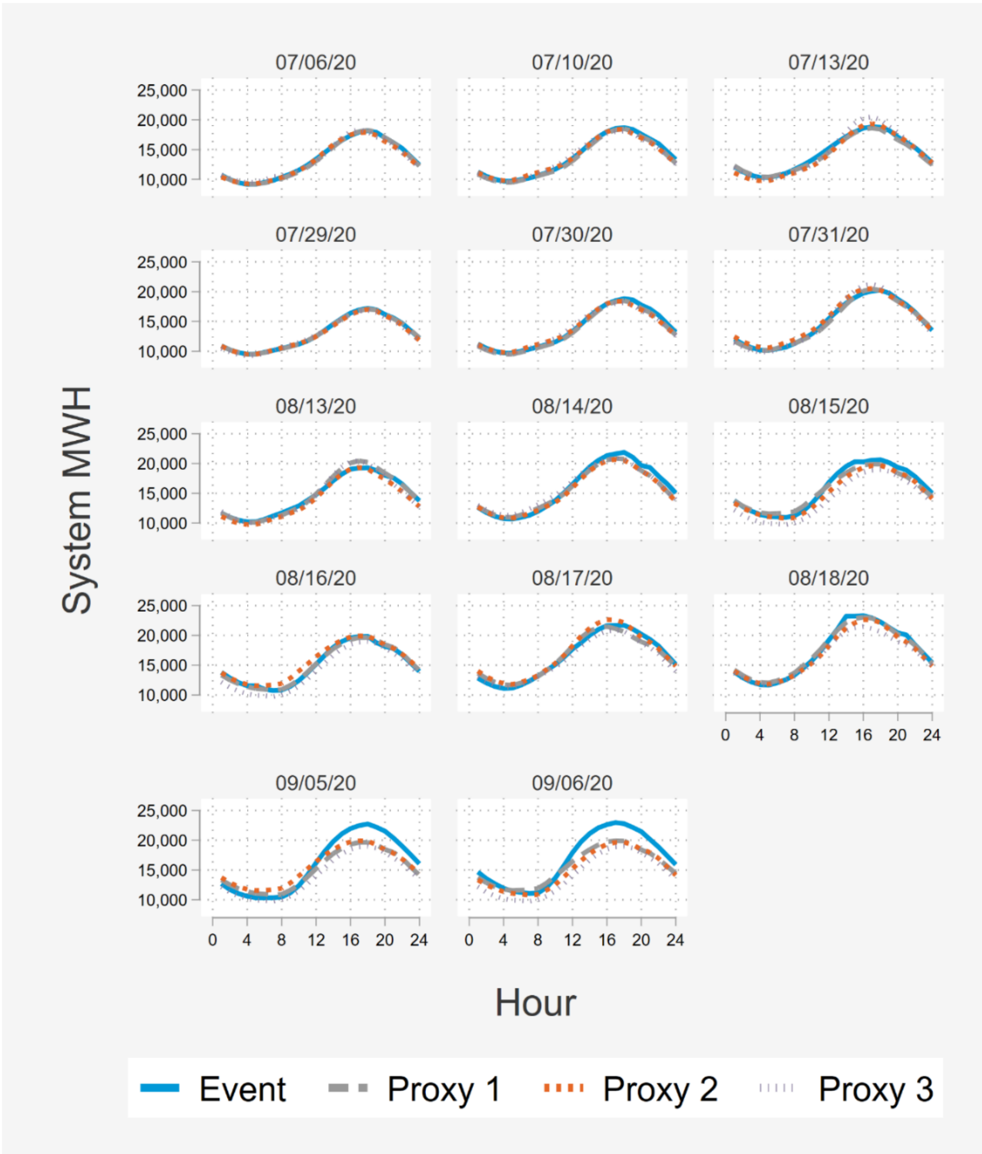
### Overview of Evaluation Method Selected

DSA utilized a matched control group and panel regression analysis for the 2020 SEP program evaluation. The matched control group customers were pulled from a stratified random sample, which ensures that large and/or unique participants are still likely to find an appropriate match. The control group is selected using non-event day load patterns, geographic location, and other customer characteristics (e.g., net metering status) to develop propensity scores within each stratum. For each participant, the nearest neighbor based on propensity scores is identified. The matched control group was selected through the use of proxy days and propensity score matching and the regression analysis incorporated a simple difference in difference model. The small differences between the participant and matched control group on proxy days were netted off of the differences observed on event days. The program was evaluated across all customers as well as at a segment level for a variety of categories including sub-LAP, size, tariff rate, and more.

### Proxy Day Selection

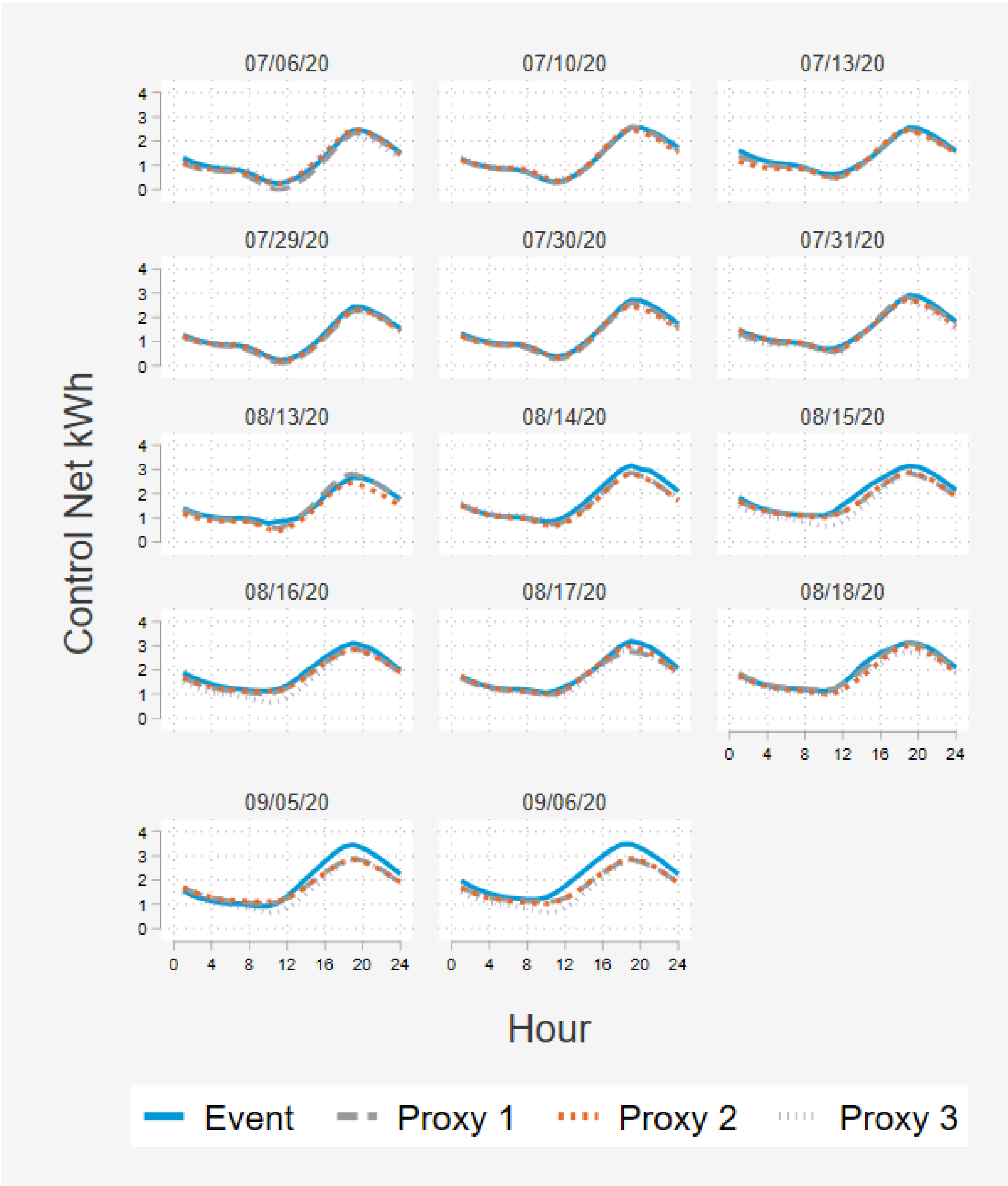
Euclidean distance matching was used to select a set of proxy days for each SEP event. Proxy days are chosen from the set of non-holiday, summer weekdays in 2020. The first 2020 SEP event was in July and the last was in September, so summer is defined here as July through September. The selected matches are chosen based on SCE system load. For every event date, the three most similar SCE system load days are chosen. 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 7 shows each event date with its three selected matches. September 5$^{th}$ and 6$^{th}$ are visibly poorer matches than the other days. These are weekend events which occurred on extremely hot days. Because weekend events are matched to weekend proxies, there are fewer days for these events to match with, resulting in imperfect proxies. However, regression modeling nets out any differences visible below.

**Figure 7: Event and Proxy Day System Load**




While the SCE system load is used to select the proxy days, the control customers come from a small sample of customers within the SCE system. These customers, or the "pool" of potential control customers, should be representative of the system, but must also cover the range characteristics of the participant customers. Figure 8 shows the selected proxy days and event days, as seen in Figure 7, but for the average customer in the control pool. The proxy days are visibly well aligned with the event day loads for the pool of non-participant homes from which the matched control group was ultimately selected.

**Figure 8: Event Day and Proxy Day Loads for Matching Pool**

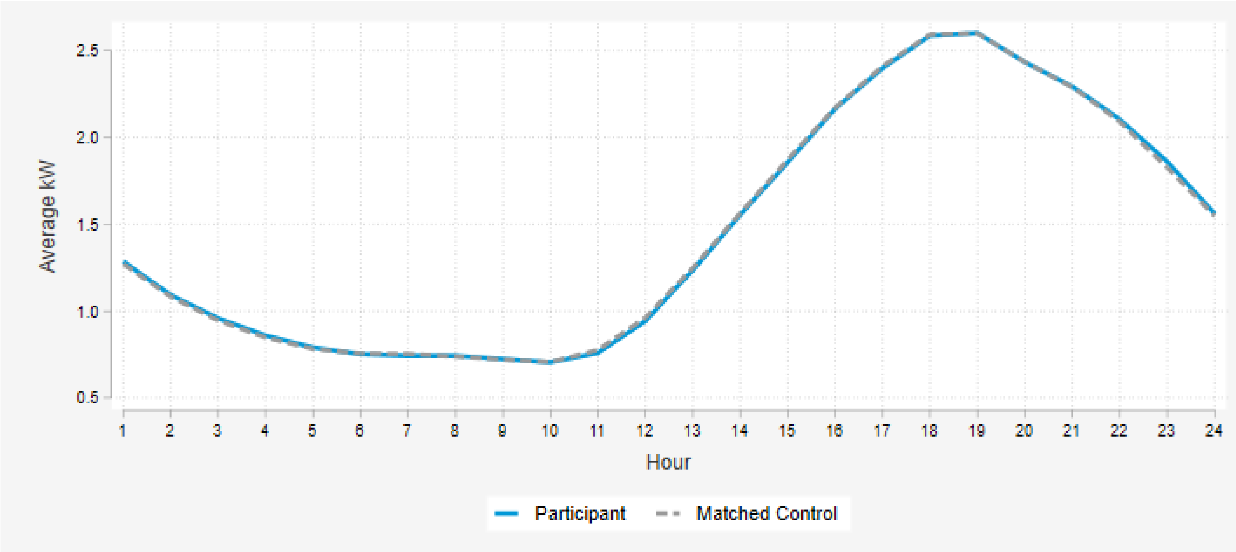


## Participant Matching

Using the SEP participant and non-participant load data on the full set of proxy days, matches are selected for each participant with propensity score matching. Title 26 customers and those who participate in other demand response programs are excluded from the eligible control pool. Propensity score matching (PSM) is a method that uses probit modeling to predict the propensity score, which is the likelihood of a customer participating in SEP. We first categorize households based on presence of net metering, climate zone, and CDD bin. Net metering indicates the household has rooftop solar. Climate zone is discussed in Section 2. The CDD bin classifies customers by weather sensitivity into 10 bins based on the slope coefficient when daily kWh regressed on CDD. Within each of these segmentations, all applicable participant and control homes are grouped and then undergo PSM for a set of matching model specifications. The best PSM model is selected based on lowest bias and best fit using out of sample testing on proxy days not used to develop the matches. For this analysis, the chosen model included variables for kWh during 4pm to 9pm RA window, eight three-hour bins of kWh to capture usage during the entire day, and a load shape variable to describe load distribution throughout the day.

Matches are selected with replacement, ensuring every participant is matched to the best possible non-participant. If there are no controls within a specified range of a given participant, that participant will not have a matched control. For the summer 2020 analysis, 1,049 participants don't get matched: this is about 2% of participants. Possible causes for a customer to not find a match include missing data, lack of sufficient interval data to span events and proxy days, or usage vales that are not comparable to the pool of potential control matches. Matches are assigned pseudo characteristics, where each match takes on the characteristics of its participant household. For matches that are selected multiple times, the load will be represented multiple times in the regression analysis, but the characteristics will vary based on each unique participant. Figure 9 compares the average hourly kW by treatment and control group on all proxy days. There is a subtle deviation between the curves, but the resource adequacy window is well matched. The hourly difference-in-differences regression analysis is used to estimate load impacts and capture any remaining statistical difference between the treatment and control groups.

**Figure 9: Average Hourly kW on Proxy Days**




## Ex Post Model

Demand Side Analytics used a difference-in-difference (DiD) panel regression model to estimate the hourly load impacts for SEP. With minor differences between the treatment and matched control group, the DiD approach will net out any unobserved differences from the two groups and the resulting coefficient will indicate the event impact. To capture the best results for each event, DSA individually regressed each event with its three proxy days. Every hour is separately regressed to avoid any heteroscedastic errors. Hourly impacts are then appended to form full event impacts, which are detailed in Section 4. The model specification is provided in Equation 1 and components are described in Table 6.

**Equation 1: Ex Post Regression**

$$kW_{ih} = \beta_{0h} + \beta_{1h} * date + \beta_{2h} * treat_i * eventDay + \beta_{3h} * same\ day\ adj_i + v_{ih} + \varepsilon_{ih}$$

**Table 6: Regression Description**

| Model Term | Description |
|---|---|
| $kW_{ih}$ | Net electrical demand in kW for customer i, in hour h |
| $\beta_{0h}$ | Mean demand for all customers on proxy days in hour h |
| $\beta_{1h}$ | Regression coefficient for the date variable for hour h. Captures date-specific departures from the mean |
| date | Set of four indicator variables for event day and three proxy days |
| $\beta_{2h}$ | Regression coefficient of interest |
| $treat_i$ | Indicator variable for the SEP participant group |
| $eventDay$ | Indicator variable for the SEP event day |
| $treat_i * eventDay$ | Interaction term equal to 1 for treated customers on the event day and 0 otherwise |
| $\beta_{3h}$ | Regression coefficient for the same day adjustment for individual i |
| $same\ day\ adj_i$ | Average demand of customer i in event start hour-2 and event start hour -3 |
| $v_{ih}$ | Customer fixed effects variable for customer i in hour h |
| $\varepsilon_{ih}$ | Error term |

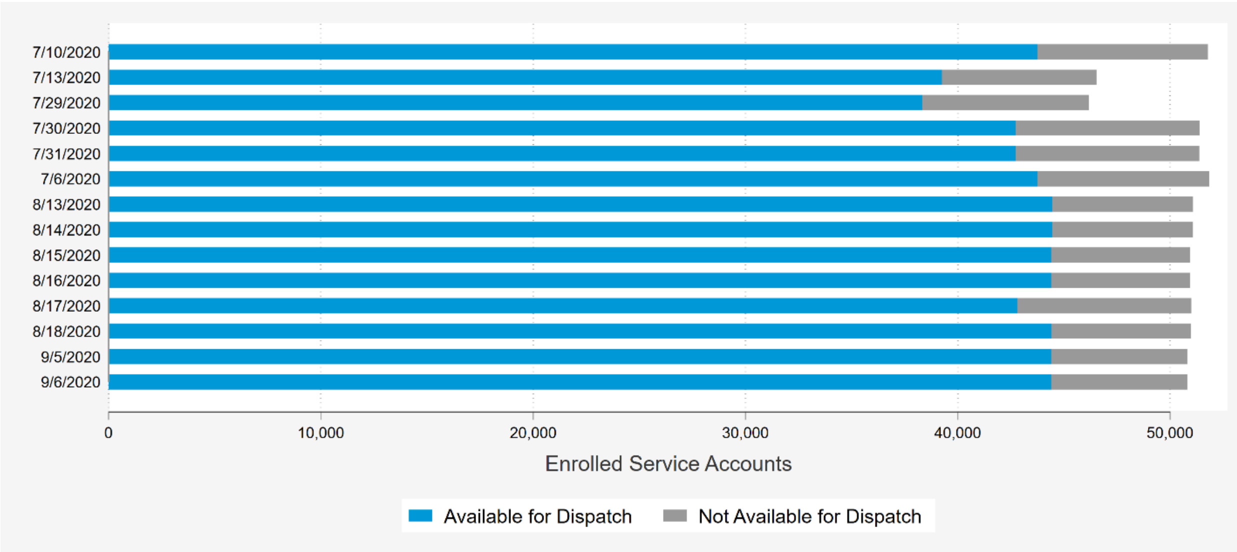
Equation 1 shows the regression implemented for every event and every hour of the day. The dependent variable, $kW_{ih}$ is the net electrical demand in kW for a given hour and premise. The independent variable date is a set of indicator variables differentiating the four dates used in each event regression, one for the event day and three for the proxy days. The variable of interest in this model is the interaction term between treatment and event. The $\beta_{2h}$ term captures the coefficient on this interaction and represents the average impact of the SEP event. The $v_{ih}$ term captures the customer fixed effects and the error term captures any remaining unobserved differences. The same day adjustment variable is the average demand from the same day in a two hour window with a one hour buffer that improves the fit of the model.

For each of the 14 events and 24 hours of the day, this regression estimates per customer impacts which are then extended to the aggregate impacts based on the number of participants dispatched for each event. The regression model is run separately for every All Customers as well as each subcategory of LCA, Low Income (CARE status), NEM, Size, Tariff, Sublap, and Vendor. The subcategories are shown in Table 4.

## Available For Dispatch

During summer 2020 a subset of enrolled SEP participants were not available for dispatch due to contractual issues with one of the thermostat providers. SCE transitioned the vendor hired to manage and dispatch this brand of thermostat and participants had to accept updated terms and conditions before they were available for dispatch. The percentage of enrolled customers that were available for dispatch grew steadily over the course of the summer from approximately 83% in July to over 87% by September. To further complicate matters, SCE was not able to identify which enrolled customers were available for dispatch. During the August 17th SEP event approximately 1,600 enrolled accounts from a different thermostat manufacturer were unavailable due to a system issue between dispatch portals.

**Figure 10: Distribution of Enrolled Accounts Available for Dispatch by Event Date**



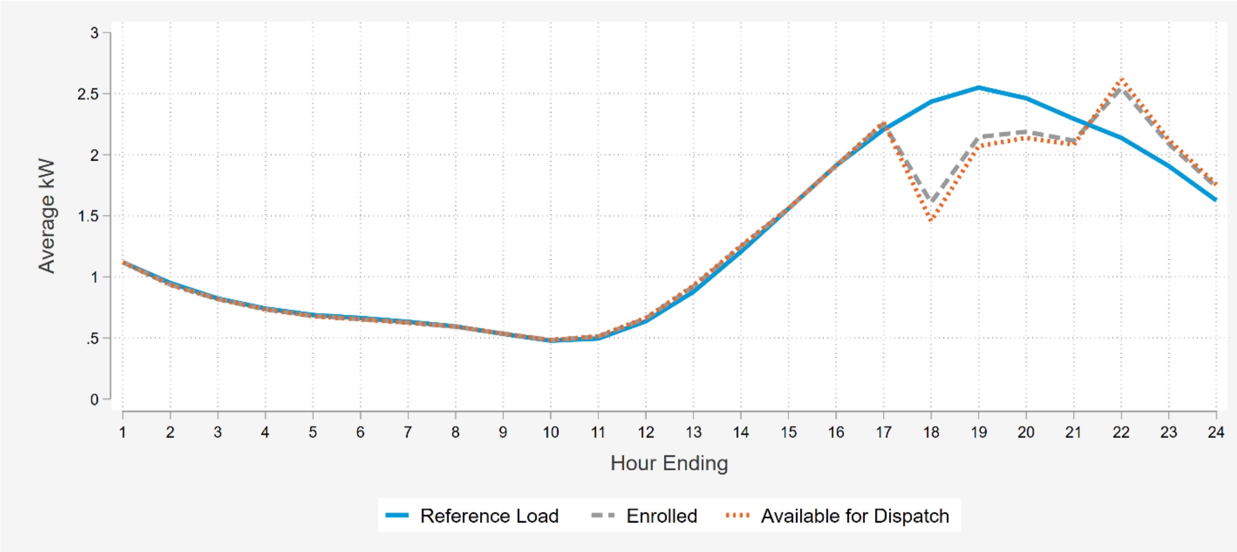

Because we only know how many accounts were available versus not available, we could not restrict the ex post analysis to the accounts that were "available for dispatch." Instead we analyze all accounts that were receiving a bill from SCE during the summer 2020 season. The fact that approximately 15% of the enrolled accounts were not actually participating in demand response on a given event day necessarily dilutes the average customer impacts and explains why the average customer impacts were lower in 2020 compared to 2019.

SCE expects the contract issue that led to participating accounts not being available for dispatch in 2020 to be resolved prior to summer 2021. So going forward we expect all enrolled accounts to be available for dispatch. In preparation for the ex ante analysis, DSA estimated an alternative set of ex post impacts where the average customer impacts were scaled up to account for the proportion of participants not available for dispatch on a given event day. The calculation is simple. Consider a segment with an ex post impact of 0.6 kW per enrolled service account number on an event day where 85% of the enrolled accounts were available for dispatch.

$$Average\ Impact\ Per\ Available\ Account = \frac{0.6\ kW}{85\%} = 0.706\ kW$$

The underlying assumption with this calculation is that all observed demand response impacts came from the participants that were available for dispatch and the participants that were not available produced no demand impact. Figure 11 provides a visual representation of how this alternative set of ex post results differs from the primary ex post impacts for the July 10th SEP event.

**Figure 11: Comparison of Per-Customer Impacts on July 10, 2020**




While the average impacts per customer will vary depending on the customer base used (available for dispatch or enrolled), the aggregate impacts are always the same. To continue the example, the 0.6kW per enrolled participant and 0.706 kW per available account provides 30.9 MW of aggregate savings.

$$Average\ Impact\ Per\ Enrolled\ Account * Enrolled\ Accounts = \ 0.6\ kW * 51{,}426 = 30{,}856kW$$

$$Average\ Impact\ Per\ Available\ Account * Available\ Accounts = \ 0.706\ kW * (51{,}426 * 0.85) = 30{,}856kW$$

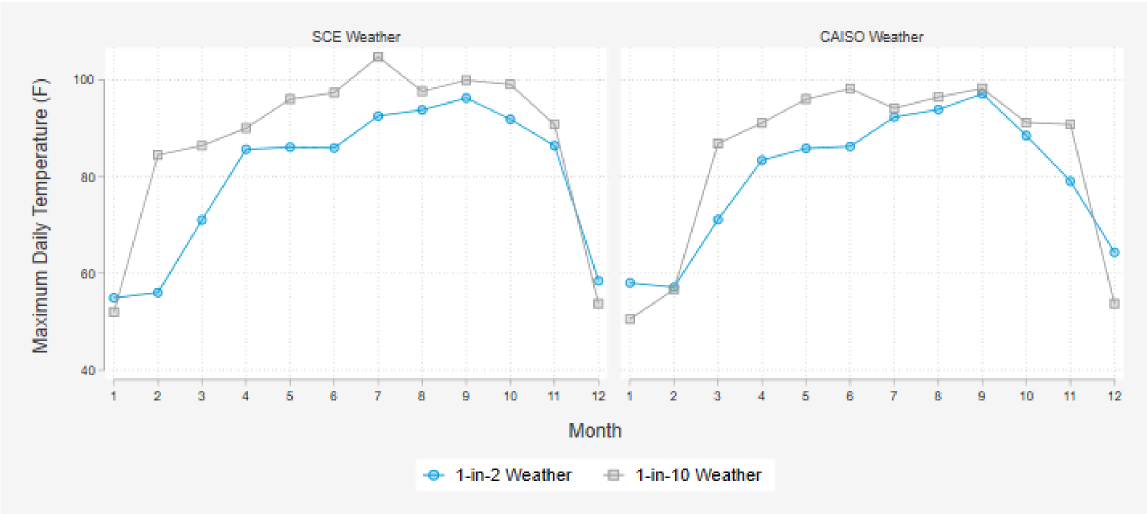
## 3.2 EX ANTE METHODS

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 estimation 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 conditions for a normal year
- 1-in-10 weather reflects conditions that would be observed in an extreme year
- Average weekdays and a monthly system peak 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 12 compares the maximum daily temperature for each month of the year for monthly system peak days using the 1-in-2 and 1-in-10 weather for the SCE and CAISO

forecasts. The forecasts across weather stations are weighted using the number of active SEP participants at the conclusion of PY2020 that were shown in Table 5. These weights are assumed to hold 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 11°F higher than the CAISO forecast for a monthly system peak day in July 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 July system peak day.

**Figure 12: Monthly System Peak Day Comparison by Forecast**

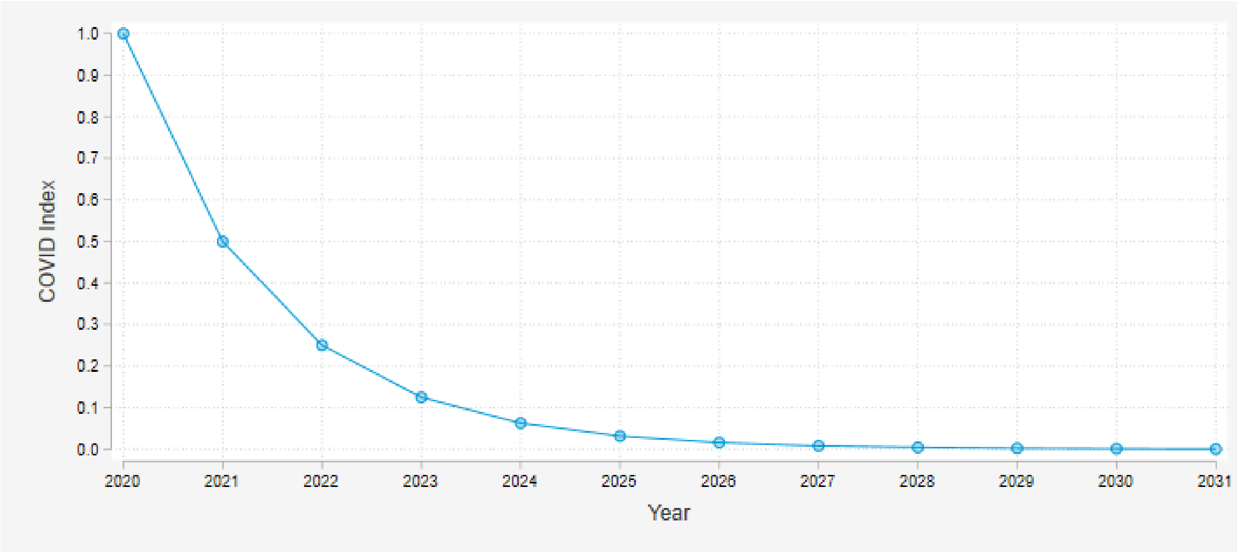



During PY2020 SEP events were dispatched at different times of day and the duration of events varied from one to four hours. Ex ante estimation requires a single event profile to be selected. The ex ante event profile was selected to mirror the CAISO RA window, which begins at 4pm and ends at 9pm for all months of the year. This event profile avoids post-event snapback during the RA window. Dispatch from 5pm to 9pm was a common event profile in PY2019 and occurred twice in PY2020, which makes the translation of ex post results to ex ante relatively straightforward and free of modeling assumptions. There were no five hour events during PY2020, or prior years so we assume the impacts during the final hour of the RA window will reflect the expected impacts during the fourth hour of an SEP event dispatch.

## COVID-19 Effects

In March of 2020, the COVID pandemic created mass shutdowns across the United States. As many businesses in the SCE territory closed, residents were forced into spending more time at home. Lockdowns varied in severity over the course of 2020, but all PY2020 SEP events are assumed to have occurred under a full COVID scenario. In order to forecast potential program impacts in the upcoming years, SCE provided a "glide path" which details their assumptions for how COVID effects will linger in years to come. This effect, called the "COVID Index" is shown in Figure 13.

**Figure 13: COVID Glide Path**



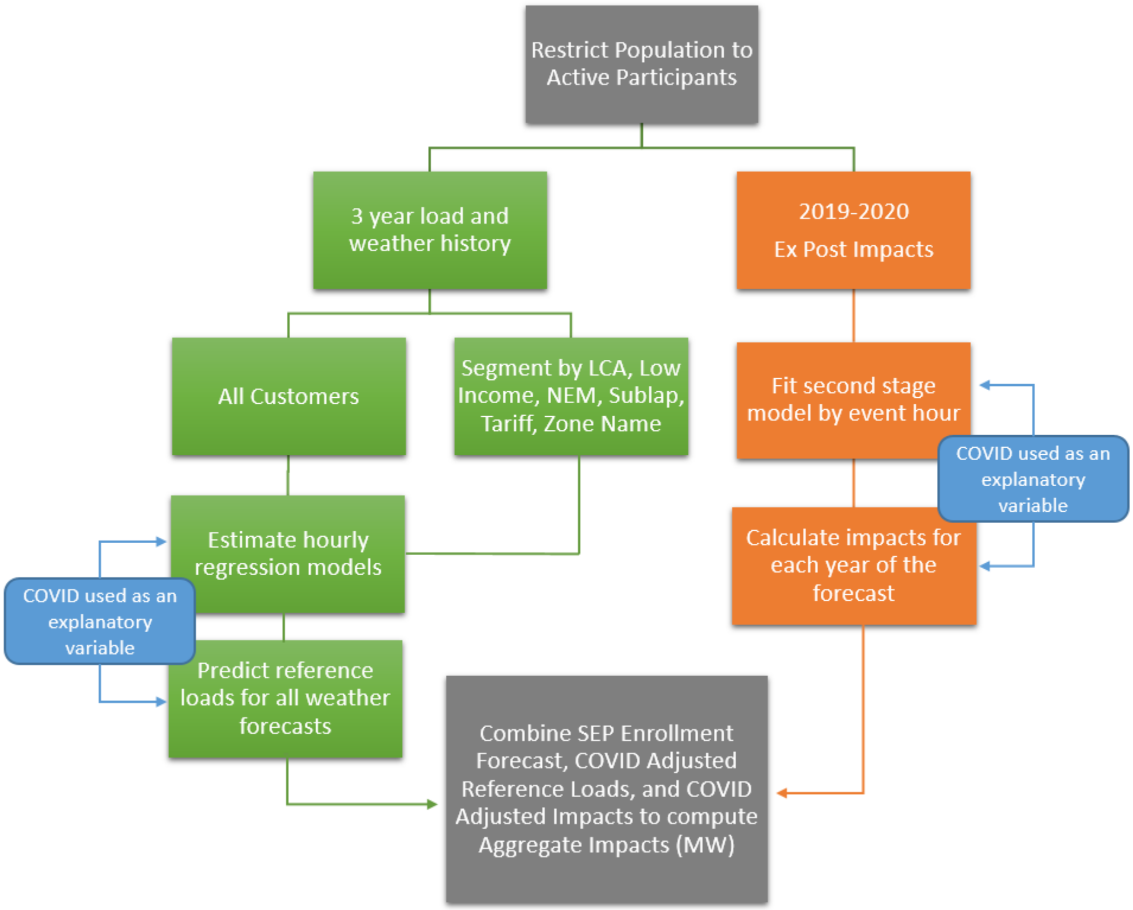

The glide path is used as the input for two key ex ante components. First, the COVID index is used to differentiate historical reference loads from the 2020 reference loads. Average customer load is assumed to remain fairly consistent over time, and in previous studies, the same average customer reference load has been used for each forecasted year. However, the pandemic shifted residential loads, so moving forward, each year uses a blended reference load assuming a weighted average of the no-COVID and COVID reference scenarios. Second, because the analysis uses 2019 and 2020 impacts to develop the second stage model, a COVID indicator variable is included to capture differences in impacts between the years. For forecasting, the COVID index is applied to each year from 2021 to 2031 to capture any lingering effects of the pandemic.

## Overview of Evaluation Method Selected

Figure 14 provides an overview of the SEP ex ante estimation methodology. The left side of the figure, in green, lists the steps involved in modeling reference loads – or what average customer loads would be absent SEP. The right side of the figure, in orange, lists the steps used to estimate SEP load impacts. The ex ante segmentation is similar to the ex post segmentation of customers, but excludes the "size" and "vendor" segments. We calculate the share of active participants by LCA, Low Income (CARE Status), NEM, sub-LAP, Tariff, and Zone Name. We assume these ratios will hold constant over time as the enrollment forecast grows. We use the territory wide events from 2019 and all PY 2020 events to estimate the second stage model, described further in the Ex Ante Impacts Model Section.

The reference loads, average per-customer impacts, and enrollment forecast are combined to produce the aggregate savings.

**Figure 14: 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, the model specification was also applied to the subcategories of the LCA, Low Income (CARE Status), NEM, sub-LAP, Tariff, and Zone Name categories. The specific modeling steps taken were:

- Merge hourly load data and hourly weather data for all active SEP participants for January 2018 through October 2020.
- Drop any SEP event days.
- Drop any customers who were dually enrolled in other programs (namely SDP).
- Drop dates where 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 peak day could fall before or after the time change.

- Create a COVID indicator variable equal to 1 beginning March 1, 2020 and zero otherwise.
- Estimate the regression model shown in Equation 2.

**Equation 2: Reference Load Regression Model Specification**

$$Net\ kW_i = \beta_0 + \beta_1 * CDD65 + \beta_2 * bins\_60 + \beta_3 * bins\_65 + \beta_4 * bins\_70 + \beta_5 * bins\_75 + \beta_{6-10} * DayOfWeek + \beta_{11} * COVID + \varepsilon_i$$

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 – Glossary of Terms**

| Model Term | Description |
|---|---|
| Net $kW_i$ | Average net electrical demand in kW during interval i |
| β0 | The model intercept |
| CDD65 | Cooling degree days base 65°F |
| β1 | Regression coefficient for the CDD65 term |
| β1bins_60, bins_65, bins_70, bins_75 | Quantile smoothing spline which allows for different temperature slopes at different temperature ranges |
| β2-β5 | Regression coefficients for the spline terms |
| DayOfWeek | Indicator variables for each of the 5 weekdays |
| β6- β10 | Regression coefficients for five weekday variables |
| COVID | Indicator variable equal to 1 for days on or after March 1, 2020; 0 for days prior to the COVID pandemic |
| β11 | Regression coefficient for the COVID indicator term |
| $\varepsilon_i$ | Error term |

The regression coefficients estimated for each model run were then used to predict average hourly demand for electricity for the array of ex ante weather conditions. Weighted average conditions were computed for each of the segments using the respective model and the number of active SEP participants mapped to each constituent weather station. Figure 15 shows the 2021 predicted reference loads for all customers in black, with the LCA, Low Income (CARE Status), NEM, Tariff, and Zone Name categories on an August system peak day using SCE 1-in-2 weather. Due to the number of subcategories, the figure below is shown 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 form some of the other subcategories.

Like the PY2018 and PY2019 evaluations, the Big Creek/Ventura LCA has the highest reference load during the RA window while the South Orange County region has the smallest reference load during the RA window.

**Figure 15: 2021 Reference Load by Segment: August System Peak Day, SCE 1-in-2 Weather**

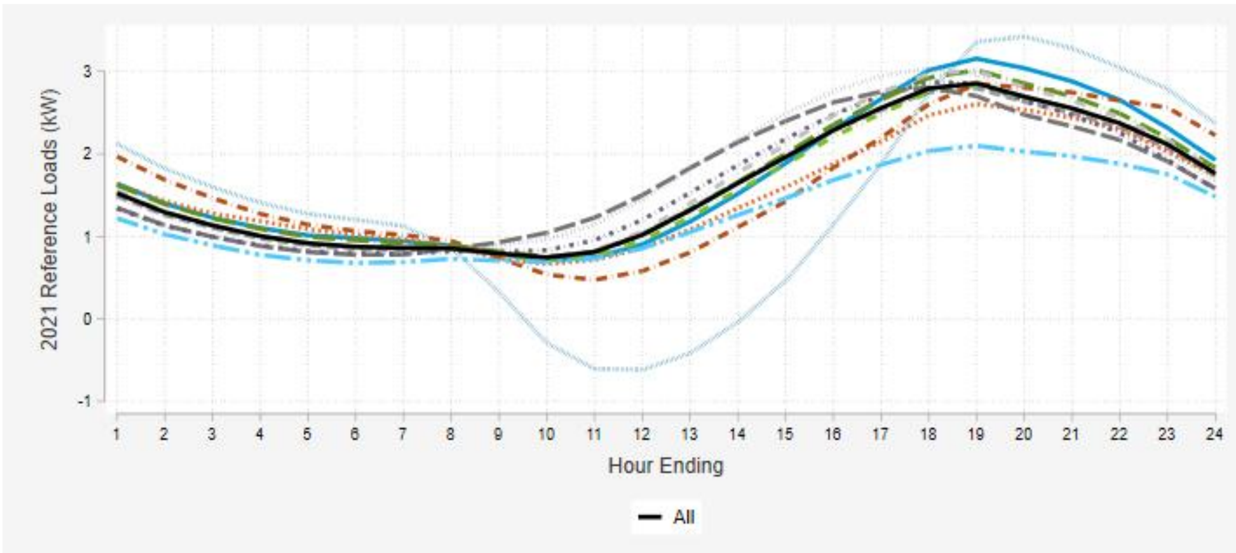
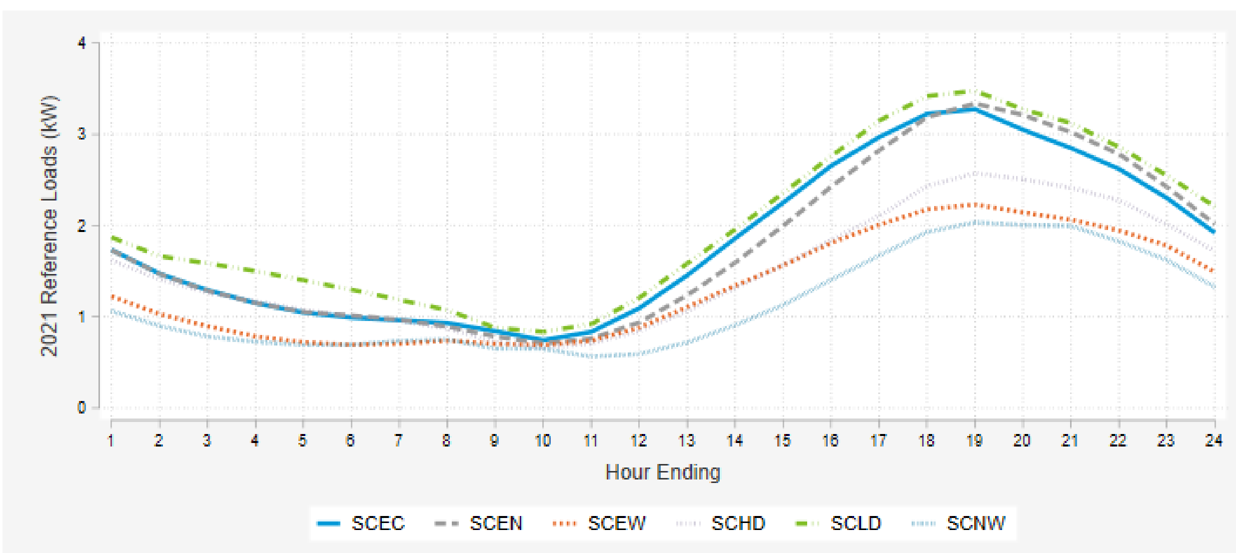


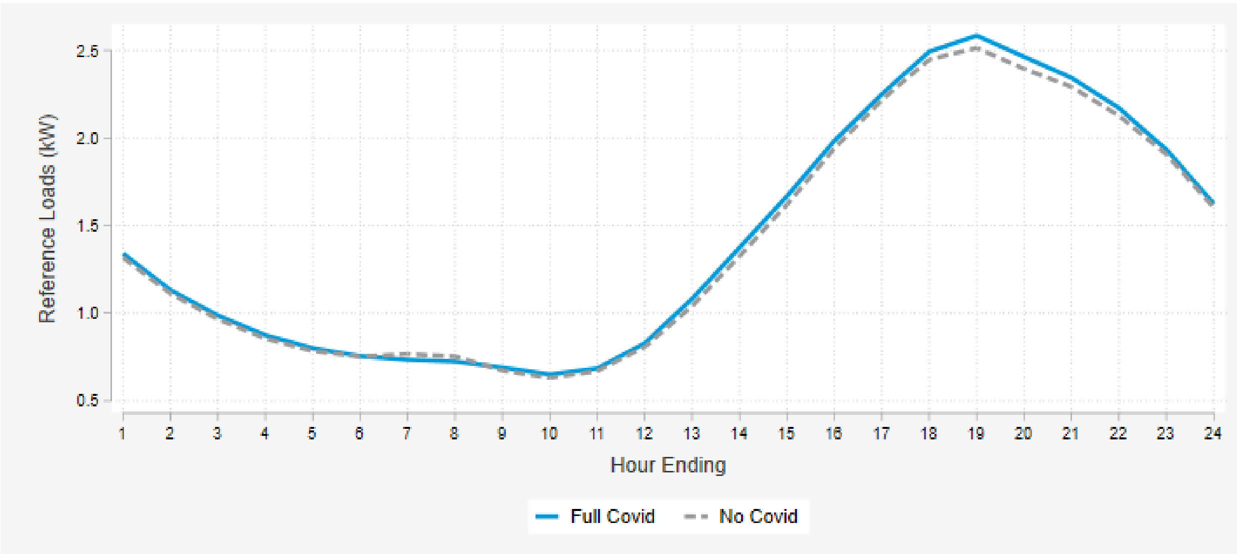

Figure 16 shows the modeled 2021 reference loads for each of the six sub-LAPs on an August system peak day using SCE 1-in-2 weather. The COVID index is set to 50% when predicting 2021 reference loads meaning that the predictions are a simple average of the "COVID" and "No COVID" load patterns.

**Figure 16: 2021 Reference Load by Sub-LAP: August System Peak Day, SCE 1-in-2 Weather**




As the COVID impact is forecasted to vary in the coming years, as shown in Figure 13, the forecasted reference loads will shift incrementally toward the no COVID scenario each year. By predicting a reference load with and without COVID, the slight variations show how COVID has influenced residential energy consumption. There is slightly higher use during the peak period, and smoother use in the mornings. The blue curve is indicative of the 2020 usage, the gray represents standard, non-pandemic usage, and each year of the forecast will be a blend of these two curves. Figure 17 shows these curves for the "All Customer" category on a Typical Event Day under CAISO 1-in-2 weather conditions.

**Figure 17: Reference Loads with and Without COIVD, CAISO 1-in-2 Weather, Typical Event Day**




## Ex Ante Impacts Model

In order to estimate SEP per customer load reductions under varying conditions, DSA fitted a second stage model using the PY2019 and PY2020 ex post impacts as the dependent variable and temperature and a COVID indicator as the independent variables.

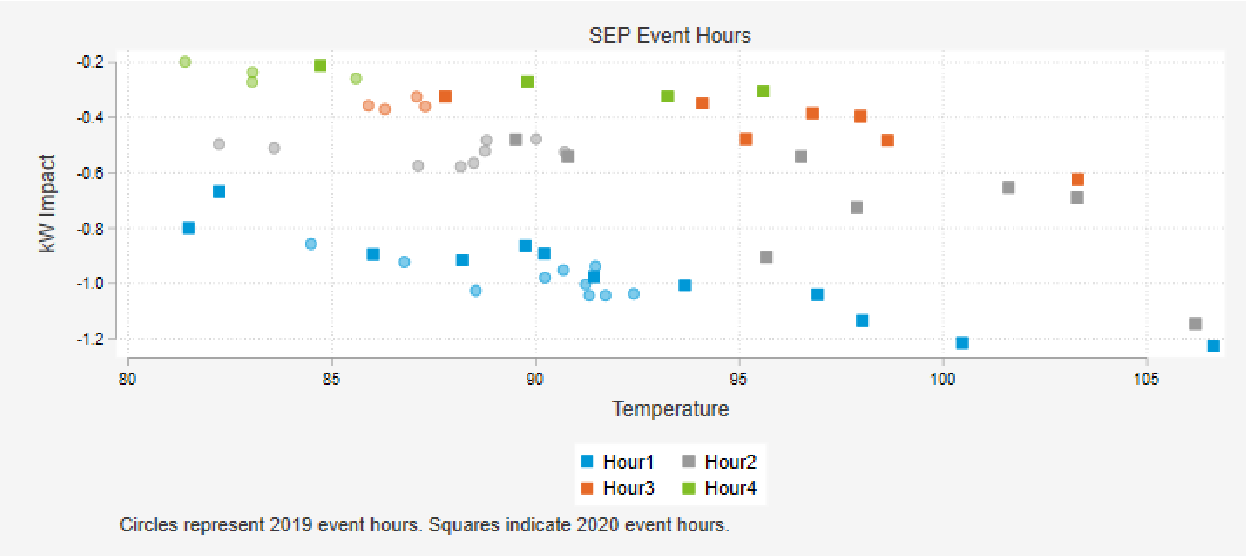
A separate linear regression model was fitted for each of the four observed SEP event hours as well as the three hours of post-event snapback. Figure 18 shows the results for the "All Customers" category, but a similar process was performed for each of the subcategories. Event hour impacts are negative (a reduction in demand) and post-event snapback hours are positive (an increase in demand). As observed in the ex post results, impacts are largest during the first event hour and diminish significantly in the second, third, fourth hours of the event. Similarly, the post-event snapback is largest during the hour immediately following the event and shrinks in each subsequent hour.

A key caveat to the PY2020 events deals with the partial event hours. Many of the events started and ended mid-hour. In this case, we omitted the partial start hour of an event as well as the final partial hour. For the partial hour events that started in the first 30 minutes of an hour, we use the first full hour as a second event hour and this event will not have an hour 1. Events that start in the second 30 minutes of an hour will use the first fill hour and event hour 1. 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.

A second change to the PY2020 events was the occurrence of weekend events. Due to extreme heat and COVID stay-at-home orders, weekend days look similar to weekdays in PY2020. We tested the second stage model with and without weekend indicators and found no statistical significance of weekend in the model. Traditionally, system peak days are expected to fall on weekdays. Because of this, we estimate reference loads using only weekdays.

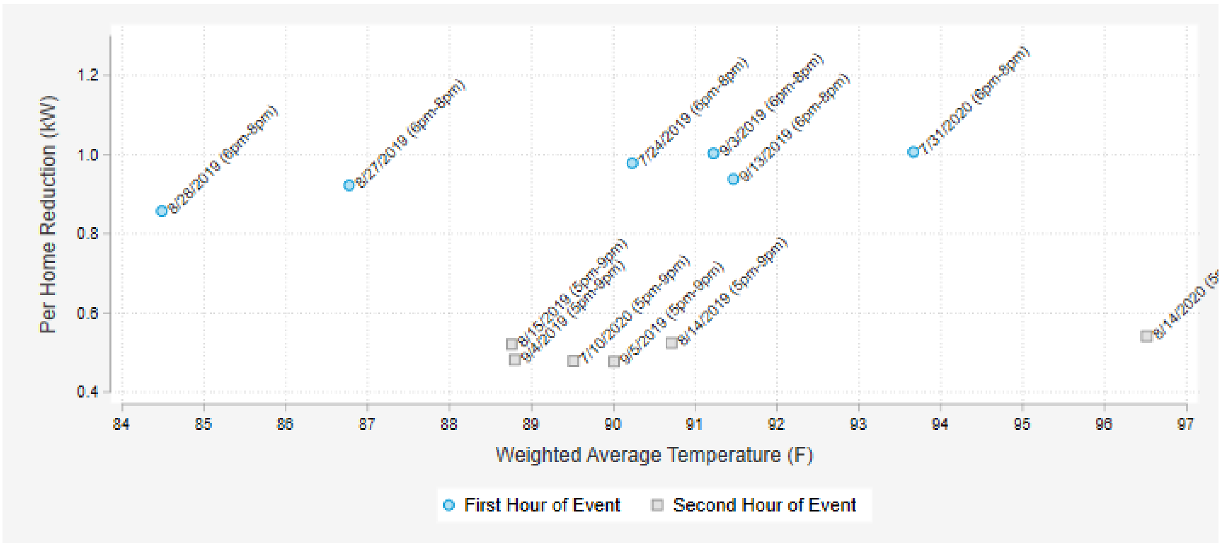
Figure 18 shows the PY2019 and PY2020 hourly impacts by event hour. PY2019 impacts are circles and PY2020 impacts are squares. Each color represents a different event hour, with blue representing Hour 1 of the events and consistently showing the largest impacts regardless of temperature. Because events vary in length, there are more Hour 1 impacts than Hour 4 impacts. Impacts are largest in the first hour of an event and due to the structure of the dispatch, impacts diminish with each subsequent hour. While individual OEM's are experimenting with various dispatch strategies, the majority of participating thermostats are dispatched using a 4-degree setback.

**Figure 18: Per Customer SEP Impacts by Event Hour**




The decision to model impacts a function of event hour rather than hour of the day was informed by the results of the ex post analysis. Figure 19 illustrates the issue using the ex post results from the PY2019 territory wide events and PY2020 full hour events during hour ending 19 (6pm to 7pm). There were a total of 17 events active from 6pm to 7pm during the two summers. However, for some of these events, the event hour was either 3 or 4, and for a few events, the partial hours do not allow for a clean hour 1 and hour 2 of the event. Date and event labels are provided. Figure 19 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 19: Hour Ending 19 Event Impacts vs. Temperature, by Event Hour**




The average kW impact per participant household across the six days where hour ending 19 was the first event hour was 0.95 kW with an average temperature of 89.6°F. The average kW impact per participant household across the six days where hour ending 19 was the second event hour was just 0.50 kW with an average temperature of 90.7°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. The reason hourly position is so important is because of how the thermostat providers modify set points. By increasing the set point up to four degrees (F) at the beginning of the event, SEP achieves a large impact initially. 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 more consistent impacts 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. Pre-cooling of homes can also help slow the deterioration of load impacts by extending the amount of time it takes the home to warm to its event set point. Pre-cooling can also reduce participant opt-outs through increased participant comfort.

# 4 EX POST RESULTS

The ex post results document the measured impacts for each SEP event called during PY2020. The variation in event start times, durations, and observed weather conditions provide useful information on the key drivers of SEP load impacts.

## 4.1 OVERALL RESULTS

SEP called 14 events in 2020 during the months of July through September. Table 8 shows average hourly impacts by event date. Five of the PY2020 events did not start or end at the top of the hour. This creates a challenge for the analysis because residential meters collect hourly interval data. When an event begins mid-hour the ex post impacts for that hour are diluted by the portion of the hour prior to dispatch as shown in Figure 27. Similarly, when an event ends mid-hour the ex post impacts for that hour include a mix of DR (load reduction) and snapback (load increase). Partial event hours are excluded from the average and aggregate impact values in Table 8. In addition to event impacts, Table 8 shows two Average Event Day segments based on the most common event windows for summer 2020. These were created using a customer-weighted average of each event that shares the applicable dispatch profile.

Note that participant count varies during the SEP season. As customers enroll and exit SEP, the count of dispatched homes fluctuates. In general, territory wide event participation declined over the course of summer 2020.

Impacts are reported in the last two columns as average per customer kW reductions and average aggregate MW reductions. These values are calculated by taking the average of the hourly impacts. The largest per customer reduction occurred on August 16, 2020 with 0.8 kW reduced per customer. This event was 105 minutes long but only included one full event hour. It was also one of four weekend events called in 2020. Because load impacts are largest during the first hour of dispatch, short events have larger average impacts than longer events.

The general trend for SEP events is a large reduction in the first hour of an event followed by diminishing reductions in each subsequent hour. While longer event windows can contribute to greater overall savings for the day, they will create lower average hourly impacts. This effect is evident in the two average event day windows. The longer window (5pm-9pm) has a lower average hourly kW reduction and lower average aggregate hourly MW reduction than the shorter window (7pm-8pm). However, the longer window actually has a slightly higher Hour 1 impact (0.91 kW compared to 0.75 kW). As the event progresses, this reduction decreases to 0.21 kW during Hour 4, ultimately diluting the average. Hourly breakdowns are provided in Figure 20 through Figure 23.

**Table 8: 2020 SEP Event Impacts**

| Event Date | Dispatch Region | Participants | Average Event Temp | Daily Max Temp | Average Full Hour Impact (kW Reduction) | Average Aggregate Full Hour Impact (MW Reduction) |
|---|---|---|---|---|---|---|
| 7/6/2020 (7pm-8pm) | Territory Wide | 51,842 | 86.0 | 89.9 | 0.76 | 39.1 |
| 7/10/2020 (5pm-9pm) | Territory Wide | 51,776 | 88.4 | 92.6 | 0.42 | 21.8 |
| 7/13/2020 (7pm-8pm) | SCEC, SCHD, SCLD, SCNW, SCEW | 46,529 | 81.5 | 87.2 | 0.67 | 31.4 |
| 7/29/2020 (7pm-8pm) | SCEC, SCHD, SCLD, SCNW, SCEW | 46,178 | 82.2 | 86.9 | 0.55 | 25.6 |
| 7/30/2020 (7pm-8pm) | Territory Wide | 51,383 | 89.7 | 92.0 | 0.72 | 36.9 |
| 7/31/2020 (6pm-8pm) | Territory Wide | 51,371 | 92.2 | 95.6 | 0.64 | 33.1 |
| 8/13/2020 (7pm-8pm) | Territory Wide | 51,079 | 90.2 | 94.4 | 0.78 | 39.7 |
| 8/14/2020 (5pm-9pm) | Territory Wide | 51,071 | 94.6 | 98.6 | 0.50 | 25.4 |
| 8/15/2020 (3pm-7pm) | SCEC, SCEN, SCEW, SCHD, SCNW | 50,939 | 96.8 | 97.9 | 0.53 | 27.2 |
| *8/16/2020 (5:40pm-7:25pm) | SCEC, SCEN, SCEW, SCHD, SCNW | 50,939 | 88.2 | 95.6 | 0.80 | 40.7 |
| *8/17/2020 (3:10pm-7:10pm) | Territory Wide | 51,002 | 94.7 | 95.7 | 0.48 | 24.3 |
| *8/18/2020 (1:40pm-5:40pm) | Territory Wide | 50,977 | 100.0 | 101.6 | 0.66 | 33.5 |
| *9/5/2020 (5:30pm-8:25pm) | Territory Wide | 50,809 | 104.7 | 107.8 | 0.77 | 39.3 |
| *9/6/2020 (4:40pm-8:25pm) | Territory Wide | 50,809 | 102.9 | 108.6 | 0.70 | 35.5 |
| Average Event Day (7pm-8pm) | Territory Wide | 51,437 | 88.6 | 92.0 | 0.75 | 38.6 |
| Average Event Day (5pm-9pm) | Territory Wide | 51,426 | 91.5 | 95.6 | 0.46 | 23.6 |

*Hourly impacts correspond to full event hours. Partial hours are excluded.

Average ex post load impacts for both Average Event Day windows are provided in Figure 20 and Figure 21. Aggregate load impacts are provided in Figure 22 and Figure 23. The 7pm to 8pm window includes impact estimates from July 6, July 30, and August 13. The 5pm to 9pm window incorporates results from July 10 and August 14. The following figures provide detail on average number of participants, temperature, average event impact and percent impact. These figures are obtained from the Microsoft Excel ex post load impact table generators that accompany this report. Estimated reference load, observed load, impact, and temperature are provided by the hour, with an included visual display of the load curves and significance of the impact. The average impact value provided under the 'Event Characteristics' heading aligns with the average hourly impacts shown in Table 8.

There is a subtle difference between the reference load and estimated load with DR during the hour immediately preceding dispatch for many of the 2020 events and the average event days. This is the result of one of the thermostat manufacturers implementing a pre-cooling algorithm for each event day through August 14. Beginning August 15, this manufacturer stopped pre-cooling in advance of events like the rest of the participating devices.

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 20 MW during the hour immediately following dispatch – and may be an important consideration for event planning as SEP enrollment grows. The 7pm-8pm Average Event Day has a larger average event despite less extreme temperatures than the 5pm-9pm Average Event Day. These one hour events have an average aggregate savings of 38.6 MW compared to the average aggregate savings of 23.6 MW for the four hour events called from 5pm to 9pm. However, if we compare just the first hour of dispatch, the 5pm-9pm Average Event Day delivered approximately 8 MW more load reduction.

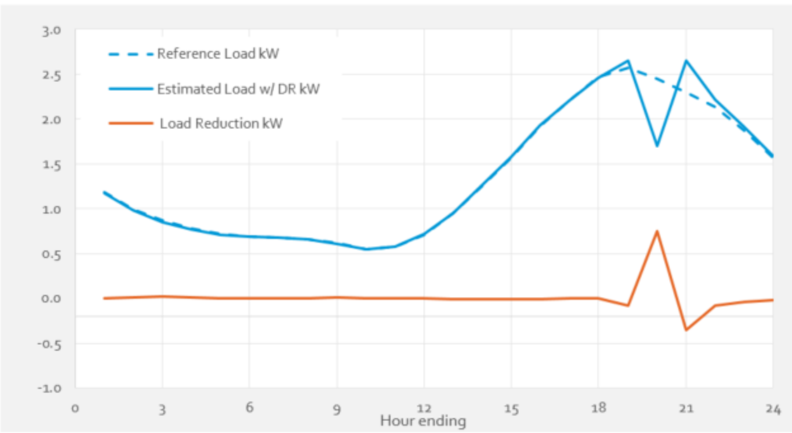
## Figure 20: SEP Ex Post Load Impact per Participant for Average 2020 Event (7pm-8pm) (kW)

**Table 1: Menu options**

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Date | Average Event Day (7pm-8pm) |

**Table 2: Event day information**

| | |
|---|---|
| Event Hours | 7pm-8pm |
| Sites Dispatched | 51,437 |
| Daily Max Temp | 92.0 |
| Average Impact - kW | 0.75 |
| Average Impact - % | 30.6% |
| Full Hours Only - Average Impact - kW | 0.75 |
| Full Hours Only - Average Impact - % | 30.6% |




| Hour Ending | Reference Load | Estimated Load w/ DR | Load Reduction | % Load Reduction | Avg Temp, site weighted |
|---|---|---|---|---|---|
| | kW | kW | kW | | F |
| 1 | 1.18 | 1.17 | 0.01 | 0% | 72.5 |
| 2 | 0.99 | 0.98 | 0.01 | 1% | 71.1 |
| 3 | 0.87 | 0.85 | 0.02 | 2% | 70.0 |
| 4 | 0.78 | 0.77 | 0.01 | 2% | 69.2 |
| 5 | 0.72 | 0.71 | 0.00 | 1% | 68.7 |
| 6 | 0.69 | 0.69 | 0.00 | 0% | 68.2 |
| 7 | 0.68 | 0.68 | 0.00 | 0% | 68.0 |
| 8 | 0.66 | 0.66 | 0.00 | 0% | 68.4 |
| 9 | 0.62 | 0.61 | 0.01 | 2% | 70.6 |
| 10 | 0.55 | 0.55 | 0.00 | 1% | 74.2 |
| 11 | 0.58 | 0.58 | 0.00 | 0% | 79.1 |
| 12 | 0.71 | 0.71 | 0.00 | 0% | 83.6 |
| 13 | 0.95 | 0.95 | -0.01 | -1% | 86.8 |
| 14 | 1.26 | 1.27 | -0.01 | -1% | 89.2 |
| 15 | 1.57 | 1.58 | -0.01 | -1% | 90.6 |
| 16 | 1.92 | 1.93 | -0.01 | 0% | 91.5 |
| 17 | 2.21 | 2.21 | 0.00 | 0% | 92.0 |
| 18 | 2.46 | 2.46 | 0.00 | 0% | 91.6 |
| 19 | 2.57 | 2.65 | -0.08 | -3% | 90.5 |
| 20 | 2.45 | 1.70 | 0.75 | 31% | 88.6 |
| 21 | 2.30 | 2.65 | -0.35 | -15% | 84.7 |
| 22 | 2.13 | 2.21 | -0.08 | -4% | 80.7 |
| 23 | 1.87 | 1.92 | -0.04 | -2% | 78.7 |
| 24 | 1.57 | 1.59 | -0.02 | -2% | 77.0 |
| Daily | Reference Load | Estimated Load w/ DR | Energy Savings | % Change | Avg Temp, site weighted |
| | kWh | kWh | kWh Δ | | F |
| | 32.27 | 32.07 | 0.20 | 1% | 79.4 |

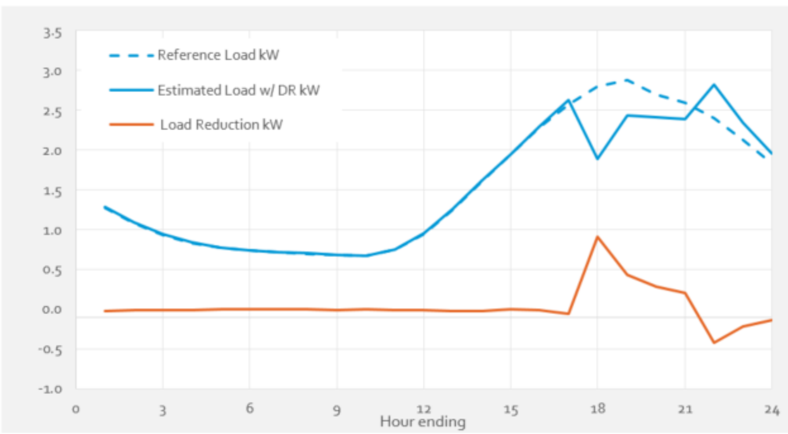
## Figure 21: SEP Ex Post Load Impact per Participant for Average 2020 Event (5pm-9pm) (kW)

**Table 1: Menu options**

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Date | Average Event Day (5pm-9pm) |

**Table 2: Event day information**

| | |
|---|---|
| Event Hours | 5pm-9pm |
| Sites Dispatched | 51,426 |
| Daily Max Temp | 95.6 |
| Average Impact - kW | 0.46 |
| Average Impact - % | 16.7% |
| Full Hours Only - Average Impact - kW | 0.46 |
| Full Hours Only - Average Impact - % | 16.7% |




| Hour Ending | Reference Load | Estimated Load w/ DR | Load Reduction | % Load Reduction | Avg Temp, site weighted |
|---|---|---|---|---|---|
| | kW | kW | kW | | F |
| 1 | 1.27 | 1.29 | -0.02 | -2% | 74.3 |
| 2 | 1.08 | 1.09 | -0.01 | -1% | 73.7 |
| 3 | 0.94 | 0.95 | -0.01 | -1% | 72.9 |
| 4 | 0.83 | 0.85 | -0.01 | -1% | 72.0 |
| 5 | 0.77 | 0.77 | 0.00 | -1% | 71.1 |
| 6 | 0.74 | 0.74 | 0.00 | 0% | 70.2 |
| 7 | 0.71 | 0.72 | 0.00 | 0% | 69.8 |
| 8 | 0.70 | 0.70 | 0.00 | -1% | 70.3 |
| 9 | 0.68 | 0.69 | -0.01 | -1% | 72.9 |
| 10 | 0.68 | 0.67 | 0.00 | 0% | 77.3 |
| 11 | 0.75 | 0.75 | -0.01 | -1% | 81.9 |
| 12 | 0.95 | 0.95 | -0.01 | -1% | 86.2 |
| 13 | 1.25 | 1.27 | -0.02 | -2% | 89.1 |
| 14 | 1.60 | 1.62 | -0.02 | -1% | 91.7 |
| 15 | 1.95 | 1.94 | 0.01 | 0% | 93.6 |
| 16 | 2.29 | 2.29 | -0.01 | 0% | 94.9 |
| 17 | 2.57 | 2.63 | -0.06 | -2% | 95.6 |
| 18 | 2.80 | 1.89 | 0.91 | 32% | 94.7 |
| 19 | 2.87 | 2.44 | 0.44 | 15% | 93.0 |
| 20 | 2.70 | 2.41 | 0.29 | 11% | 90.9 |
| 21 | 2.59 | 2.39 | 0.21 | 8% | 87.2 |
| 22 | 2.40 | 2.82 | -0.42 | -18% | 83.4 |
| 23 | 2.13 | 2.34 | -0.21 | -10% | 80.8 |
| 24 | 1.83 | 1.96 | -0.13 | -7% | 79.3 |
| **Daily** | **Reference Load** | **Estimated Load w/ DR** | **Energy Savings** | **% Change** | **Avg Temp, site weighted** |
| | kWh | kWh | kWh Δ | | F |
| | 37.06 | 36.18 | 0.88 | 2% | 82.0 |

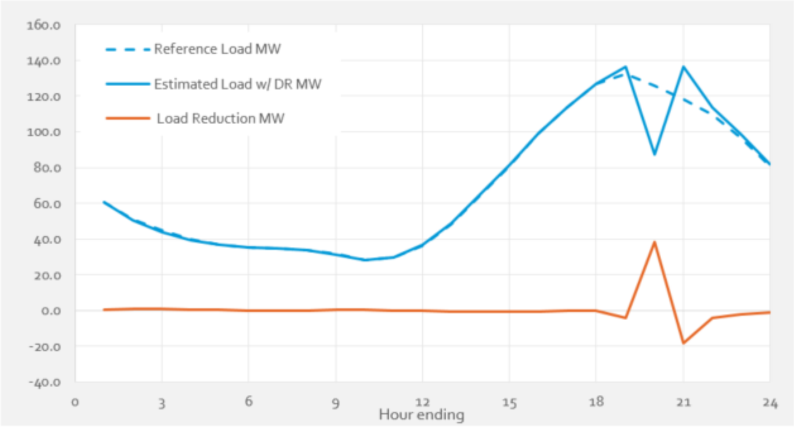
**Figure 22: Aggregate SEP Ex Post Load Impact for Average 2020 Event (7pm-8pm) (MW)**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Aggregate |
| Category | All |
| Subcategory | All Customers |
| Date | Average Event Day (7pm-8pm) |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 7pm-8pm |
| Sites Dispatched | 51,437 |
| Daily Max Temp | 92.0 |
| Average Impact - MW | 38.59 |
| Average Impact - % | 30.6% |
| Full Hours Only - Average Impact - MW | 38.59 |
| Full Hours Only - Average Impact - % | 30.6% |




| Hour Ending | Reference Load | Estimated Load w/ DR | Load Reduction | % Load Reduction | Avg Temp, site weighted |
|---|---|---|---|---|---|
| | MW | MW | MW | | F |
| 1 | 60.66 | 60.39 | 0.27 | 0% | 72.5 |
| 2 | 51.17 | 50.44 | 0.73 | 1% | 71.1 |
| 3 | 44.77 | 43.75 | 1.03 | 2% | 70.0 |
| 4 | 40.06 | 39.40 | 0.66 | 2% | 69.2 |
| 5 | 36.87 | 36.67 | 0.20 | 1% | 68.7 |
| 6 | 35.30 | 35.41 | -0.11 | 0% | 68.2 |
| 7 | 34.95 | 34.79 | 0.16 | 0% | 68.0 |
| 8 | 33.94 | 33.77 | 0.17 | 0% | 68.4 |
| 9 | 31.76 | 31.24 | 0.52 | 2% | 70.6 |
| 10 | 28.36 | 28.15 | 0.21 | 1% | 74.2 |
| 11 | 29.78 | 29.91 | -0.13 | 0% | 79.1 |
| 12 | 36.55 | 36.73 | -0.18 | 0% | 83.6 |
| 13 | 48.67 | 49.03 | -0.36 | -1% | 86.8 |
| 14 | 64.60 | 65.15 | -0.55 | -1% | 89.2 |
| 15 | 80.57 | 81.29 | -0.72 | -1% | 90.6 |
| 16 | 98.79 | 99.20 | -0.41 | 0% | 91.5 |
| 17 | 113.42 | 113.55 | -0.13 | 0% | 92.0 |
| 18 | 126.76 | 126.63 | 0.13 | 0% | 91.6 |
| 19 | 132.15 | 136.29 | -4.14 | -3% | 90.5 |
| 20 | 125.97 | 87.38 | 38.59 | 31% | 88.6 |
| 21 | 118.17 | 136.29 | -18.12 | -15% | 84.7 |
| 22 | 109.51 | 113.81 | -4.29 | -4% | 80.7 |
| 23 | 96.43 | 98.56 | -2.13 | -2% | 78.7 |
| 24 | 80.64 | 81.87 | -1.23 | -2% | 77.0 |
| Daily | Reference Load | Estimated Load w/ DR | Energy Savings | % Change | Avg Temp, site weighted |
| | MWh | MWh | MWh Δ | | F |
| | 1,659.86 | 1,649.70 | 10.16 | 1% | 79.4 |



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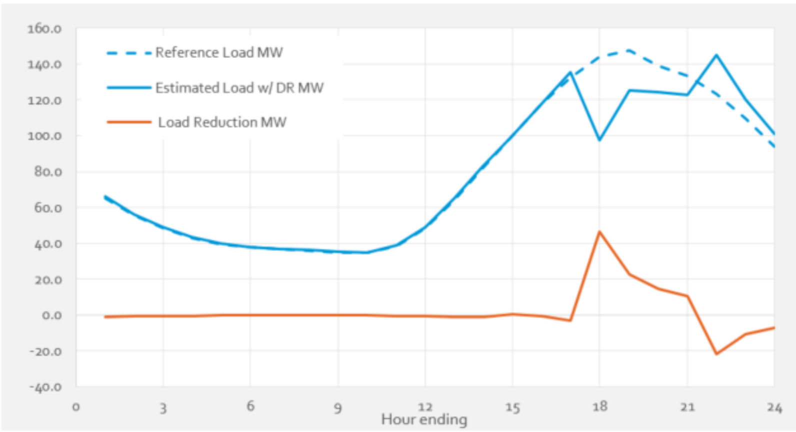
### Figure 23: Aggregate SEP Ex Post Load Impact for Average 2020 Event (5pm-9pm) (MW)

**Table 1: Menu options**

| | |
|---|---|
| Program | SEP |
| Type of Result | Aggregate |
| Category | All |
| Subcategory | All Customers |
| Date | Average Event Day (5pm-9pm) |

**Table 2: Event day information**

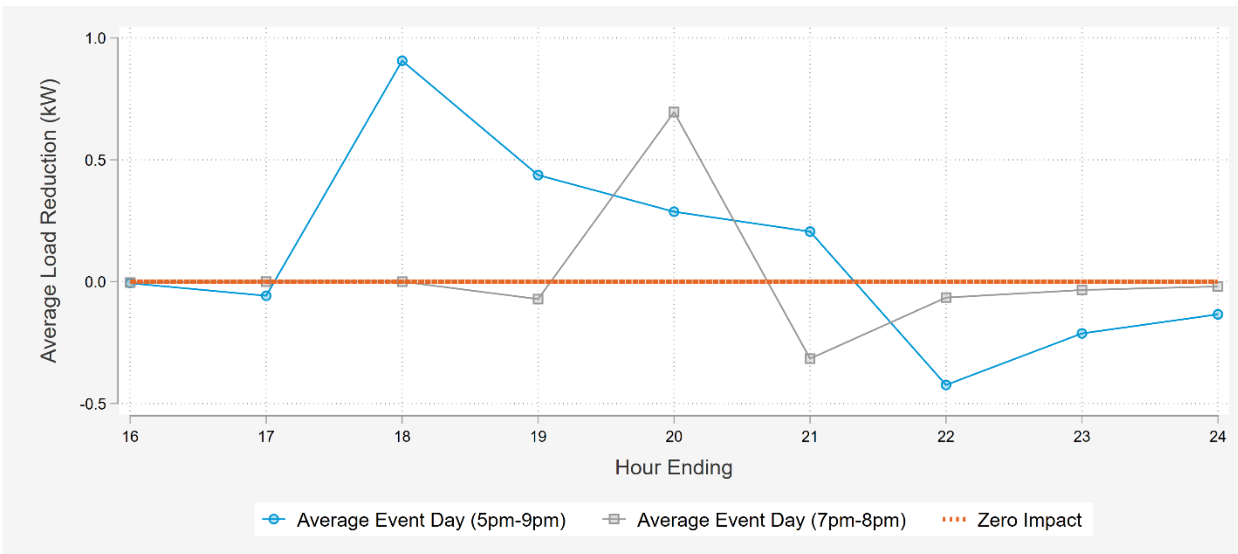
| | |
|---|---|
| Event Hours | 5pm-9pm |
| Sites Dispatched | 51,426 |
| Daily Max Temp | 95.6 |
| Average Impact - MW | 23.59 |
| Average Impact - % | 16.7% |
| Full Hours Only - Average Impact - MW | 23.59 |
| Full Hours Only - Average Impact - % | 16.7% |




| Hour Ending | Reference Load | Estimated Load w/ DR | Load Reduction | % Load Reduction | Avg Temp, site weighted |
|---|---|---|---|---|---|
| | MW | MW | MW | | F |
| 1 | 65.39 | 66.37 | -0.98 | -2% | 74.3 |
| 2 | 55.44 | 55.91 | -0.47 | -1% | 73.7 |
| 3 | 48.27 | 48.72 | -0.45 | -1% | 72.9 |
| 4 | 42.86 | 43.46 | -0.60 | -1% | 72.0 |
| 5 | 39.56 | 39.77 | -0.21 | -1% | 71.1 |
| 6 | 37.80 | 37.89 | -0.09 | 0% | 70.2 |
| 7 | 36.74 | 36.78 | -0.04 | 0% | 69.8 |
| 8 | 36.00 | 36.22 | -0.22 | -1% | 70.3 |
| 9 | 34.93 | 35.25 | -0.31 | -1% | 72.9 |
| 10 | 34.73 | 34.65 | 0.08 | 0% | 77.3 |
| 11 | 38.42 | 38.76 | -0.34 | -1% | 81.9 |
| 12 | 48.64 | 49.06 | -0.42 | -1% | 86.2 |
| 13 | 64.12 | 65.26 | -1.14 | -2% | 89.1 |
| 14 | 82.24 | 83.37 | -1.13 | -1% | 91.7 |
| 15 | 100.11 | 99.78 | 0.33 | 0% | 93.6 |
| 16 | 117.63 | 117.96 | -0.33 | 0% | 94.9 |
| 17 | 132.30 | 135.27 | -2.97 | -2% | 95.6 |
| 18 | 143.88 | 97.30 | 46.58 | 32% | 94.7 |
| 19 | 147.79 | 125.31 | 22.48 | 15% | 93.0 |
| 20 | 138.82 | 124.08 | 14.74 | 11% | 90.9 |
| 21 | 133.29 | 122.73 | 10.56 | 8% | 87.2 |
| 22 | 123.29 | 145.09 | -21.80 | -18% | 83.4 |
| 23 | 109.55 | 120.46 | -10.91 | -10% | 80.8 |
| 24 | 94.04 | 100.94 | -6.90 | -7% | 79.3 |
| Daily | Reference Load | Estimated Load w/ DR | Energy Savings | % Change | Avg Temp, site weighted |
| | MWh | MWh | MWh Δ | | F |
| | 1,905.84 | 1,860.38 | 45.45 | 2% | 82.0 |

Figure 24 shows the average load impacts, by hour, for the two 2020 average event windows. Reductions in demand (kW) are presented as positive numbers and increases in demand are presented as negative values. The slight negative impact during the hour preceding dispatch (hour ending 17 for the 5pm-9pm events and hour ending 19 for the 7pm-8pm events) are the result of one thermostat manufacturer implementing pre-cooling. Impacts are largest during the first of hour of dispatch for a 5-9pm event and decline in each subsequent event hour. Following each event, there is a "snapback" period where demand exceeds the reference load by 0.3-0.4 kW in the hour immediately following dispatch. For the remainder of the evening, this snapback diminishes as impacts return to zero.

**Figure 24: Hourly Load Reductions for Average Event Days**




## 4.2 PERFORMANCE ON SYSTEM EMERGENCY DAYS

Summer 2020 brought two large heat waves to California. On August 14 and August 15, there were rolling outages which impacted a small number of the participant and control customers in the SEP analysis. These customers remained in the ex post analysis. Figure 25 shows the ex post table generator for the aggregate impacts on August 14. In hour ending 20, there is a noticeable drop in the reference load, showing how the outage reduced aggregate (and average customer) consumption. With a lower reference load, there is less load to reduce, resulting in lower impacts. While it is unclear what the program would have delivered absent the rolling outages, the event was able to provide 25.4 MW of aggregate savings, or 0.5 kW per participant, to assist with the system's recovery.

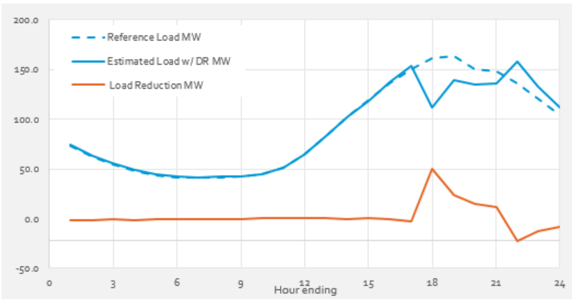
**Figure 25: System Outage Event, August 14, 2020**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Aggregate |
| Category | All |
| Subcategory | All Customers |
| Date | 8/14/2020 (5pm-9pm) |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 5pm-9pm |
| Sites Dispatched | 51,071 |
| Daily Max Temp | 98.6 |
| Average Impact - MW | 25.40 |
| Average Impact - % | 16.3% |
| Full Hours Only - Average Impact - MW | 25.40 |
| Full Hours Only - Average Impact - % | 16.3% |




| Hour Ending | Reference Load | Estimated Load w/ | Load Reduction | % Load Reduction | Avg Temp, site |
|---|---|---|---|---|---|
| | MW | MW | MW | | F |
| 1 | 72.79 | 74.77 | -1.98 | -3% | 78.5 |
| 2 | 61.72 | 63.33 | -1.60 | -3% | 77.8 |
| 3 | 53.95 | 55.09 | -1.14 | -2% | 76.9 |
| 4 | 47.38 | 48.90 | -1.53 | -3% | 75.6 |
| 5 | 43.48 | 44.36 | -0.88 | -2% | 74.5 |
| 6 | 41.25 | 41.92 | -0.67 | -2% | 73.4 |
| 7 | 40.72 | 41.15 | -0.43 | -1% | 73.1 |
| 8 | 41.22 | 41.76 | -0.54 | -1% | 73.2 |
| 9 | 42.25 | 42.78 | -0.53 | -1% | 76.0 |
| 10 | 44.71 | 44.29 | 0.42 | 1% | 80.3 |
| 11 | 51.19 | 51.04 | 0.15 | 0% | 85.2 |
| 12 | 64.28 | 63.94 | 0.35 | 1% | 89.6 |
| 13 | 82.78 | 82.85 | -0.07 | 0% | 92.5 |
| 14 | 102.02 | 102.17 | -0.15 | 0% | 95.1 |
| 15 | 119.50 | 118.75 | 0.76 | 1% | 96.5 |
| 16 | 136.27 | 137.02 | -0.76 | -1% | 97.6 |
| 17 | 150.39 | 153.76 | -3.37 | -2% | 98.6 |
| 18 | 161.74 | 111.30 | 50.44 | 31% | 98.0 |
| 19 | 163.55 | 139.57 | 23.98 | 15% | 96.5 |
| 20 | 150.16 | 134.84 | 15.31 | 10% | 94.1 |
| 21 | 147.80 | 135.95 | 11.85 | 8% | 89.8 |
| 22 | 135.89 | 158.35 | -22.46 | -17% | 85.9 |
| 23 | 120.36 | 132.84 | -12.48 | -10% | 83.6 |
| 24 | 103.90 | 112.02 | -8.12 | -8% | 82.0 |
| Daily | Reference Load | Estimated Load w/ | Energy Savings | % Change | Avg Temp, site |
| | MWh | MWh | MWh Δ | | F |
| | 2,179.27 | 2,132.71 | 46.55 | 2% | 85.2 |

Figure 26 shows the second system outage date, August 15, 2020. This was a Saturday event that started earlier in the day than typical events. There were average aggregate savings of 27.2 MW over the course of the four hour event.

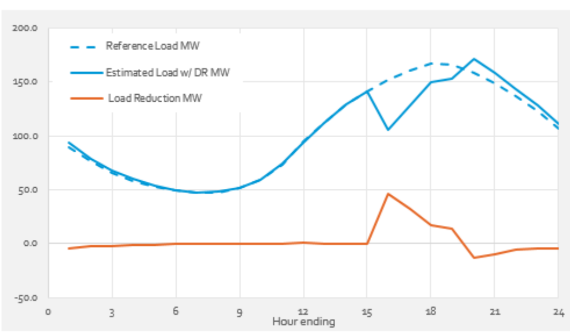
**Figure 26: System Outage Event, August 15, 2020**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Aggregate |
| Category | All |
| Subcategory | All Customers |
| Date | 8/15/2020 (3pm-7pm) |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 3pm-7pm |
| Sites Dispatched | 50,939 |
| Daily Max Temp | 97.9 |
| Average Impact - MW | 27.23 |
| Average Impact - % | 16.9% |
| Full Hours Only - Average Impact - MW | 27.23 |
| Full Hours Only - Average Impact - % | 16.9% |




| Hour Ending | Reference Load | Estimated Load w/ DR | Load Reduction | % Load Reduction | Avg Temp, site weighted |
|---|---|---|---|---|---|
| | MW | MW | MW | | F |
| 1 | 88.85 | 93.15 | -4.30 | -5% | 80.1 |
| 2 | 76.04 | 78.74 | -2.70 | -4% | 79.2 |
| 3 | 65.74 | 67.84 | -2.10 | -3% | 78.2 |
| 4 | 58.33 | 59.89 | -1.57 | -3% | 77.5 |
| 5 | 52.72 | 53.79 | -1.07 | -2% | 76.6 |
| 6 | 49.22 | 49.57 | -0.34 | -1% | 75.8 |
| 7 | 46.85 | 47.61 | -0.76 | -2% | 75.3 |
| 8 | 47.59 | 47.79 | -0.20 | 0% | 75.5 |
| 9 | 51.12 | 51.16 | -0.05 | 0% | 79.0 |
| 10 | 58.76 | 59.37 | -0.61 | -1% | 83.6 |
| 11 | 73.53 | 73.87 | -0.34 | 0% | 88.8 |
| 12 | 95.09 | 93.97 | 1.13 | 1% | 92.9 |
| 13 | 112.38 | 112.38 | 0.01 | 0% | 95.0 |
| 14 | 128.75 | 128.76 | -0.01 | 0% | 97.3 |
| 15 | 140.77 | 141.12 | -0.35 | 0% | 97.7 |
| 16 | 151.83 | 105.63 | 46.20 | 30% | 96.9 |
| 17 | 160.45 | 128.27 | 32.18 | 20% | 97.9 |
| 18 | 166.73 | 149.68 | 17.05 | 10% | 96.8 |
| 19 | 166.37 | 152.90 | 13.47 | 8% | 95.6 |
| 20 | 157.92 | 171.12 | -13.20 | -8% | 92.7 |
| 21 | 148.34 | 158.74 | -10.40 | -7% | 86.9 |
| 22 | 136.89 | 143.01 | -6.12 | -4% | 84.0 |
| 23 | 123.23 | 127.67 | -4.44 | -4% | 82.2 |
| 24 | 106.24 | 111.04 | -4.80 | -5% | 81.4 |
| Daily | Reference Load | Estimated Load w/ DR | Energy Savings | % Change | Avg Temp, site weighted |
| | MWh | MWh | MWh Δ | | F |
| | 2,463.74 | 2,407.06 | 56.67 | 2% | 86.1 |

Following the system outage events, the heat wave continued and the system peak day occurred on August 18th with a daily maximum temperature of 101.6°F. The event on this day followed five consecutive days of SEP events, yet was able to maintain an effective dispatch. The aggregate impacts are shown in Figure 27. The event occurred from 1:40pm to 5:40pm. The partial event hours (from 1:40pm to 2:00pm and 5:00 to 5:40pm) are highlighted in orange and the full event hours are shown in green. The table generator provides savings for the full event as well as the "Full Hours Only", which includes 2pm (hour ending 15) to 5pm (hour ending 17). The initial partial hour is skewed because 40 minutes of the hour had no demand response. The second partial hour actually includes 20 minutes of snapback. Due to these partial hour deflations, it is clearer to focus on the Full Hours Only average load reduction of 33.5 MW on this System Peak day.

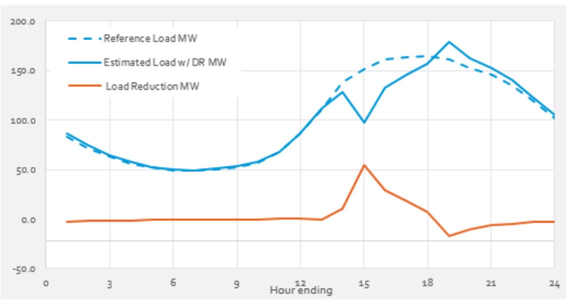
**Figure 27: System Peak Day, August 18, 2020**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Aggregate |
| Category | All |
| Subcategory | All Customers |
| Date | 8/18/2020 (1:40pm-5:40pm) |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 1:40pm-5:40pm |
| Sites Dispatched | 50,977 |
| Daily Max Temp | 101.6 |
| Average Impact - MW | 23.54 |
| Average Impact - % | 15.1% |
| Full Hours Only - Average Impact - MW | 33.52 |
| Full Hours Only - Average Impact - % | 21.5% |




| Hour Ending | Reference Load MW | Estimated Load w/ MW | Load Reduction MW | % Load Reduction | Avg Temp, site F |
|---|---|---|---|---|---|
| 1 | 83.52 | 86.84 | -3.32 | -4% | 78.5 |
| 2 | 71.43 | 73.71 | -2.27 | -3% | 77.7 |
| 3 | 62.70 | 64.54 | -1.84 | -3% | 76.9 |
| 4 | 55.94 | 57.48 | -1.54 | -3% | 76.1 |
| 5 | 51.71 | 52.24 | -0.53 | -1% | 75.5 |
| 6 | 48.93 | 49.65 | -0.72 | -1% | 75.2 |
| 7 | 48.61 | 49.43 | -0.82 | -2% | 75.1 |
| 8 | 49.61 | 50.64 | -1.03 | -2% | 75.1 |
| 9 | 52.66 | 53.35 | -0.69 | -1% | 76.9 |
| 10 | 56.90 | 57.50 | -0.59 | -1% | 81.2 |
| 11 | 67.73 | 67.67 | 0.06 | 0% | 86.5 |
| 12 | 86.44 | 86.50 | -0.06 | 0% | 91.0 |
| 13 | 110.44 | 111.46 | -1.03 | -1% | 94.9 |
| 14 | 137.55 | 127.71 | 9.83 | 7% | 99.1 |
| 15 | 151.74 | 97.73 | 54.01 | 36% | 100.5 |
| 16 | 161.55 | 132.53 | 29.02 | 18% | 101.6 |
| 17 | 163.17 | 145.63 | 17.54 | 11% | 98.0 |
| 18 | 164.53 | 157.24 | 7.29 | 4% | 94.2 |
| 19 | 161.62 | 179.14 | -17.52 | -11% | 91.5 |
| 20 | 152.30 | 162.32 | -10.03 | -7% | 88.7 |
| 21 | 145.86 | 152.48 | -6.63 | -5% | 85.6 |
| 22 | 135.04 | 140.21 | -5.17 | -4% | 83.4 |
| 23 | 119.84 | 122.99 | -3.15 | -3% | 81.8 |
| 24 | 101.72 | 104.78 | -3.06 | -3% | 80.6 |
| Daily | Reference Load MWh | Estimated Load w/ MWh | Energy Savings MWh Δ | % Change | Avg Temp, site F |
| | 2,441.52 | 2,383.78 | 57.75 | 2% | 85.2 |

## 4.3 RESULTS BY CATEGORY

Demand Side Analytics estimated the SEP impacts for all events for a variety of segments of interest. The average impacts based on territory wide events are presented in Table 9. The sub-LAP category is notable because events are dispatched by sub-LAP. The average events discussed in Section 4.1 are also compiled using the territory wide events, but only include those with the standard event windows of 5pm to 9pm and 7pm to 8pm. On some event days only specific sub-LAPs were dispatched. The 'Dispatch Region' column in Table 8 indicates events where a subset of sub-LAPs were dispatched. SCEC and SCEW are the two largest sub-LAPs and make up 85% of the participant population. The average load impacts vary slightly by sub-LAP, but the percent load impacts throughout most of the region are approximately 16-19%. The exception being SCNW (11%). SCNW is the second smallest of the six with only 903 participants. The average reference load for this SCNW is the lowest of all sub-LAPs (2.44 kW) suggesting relatively low demand. SCLD only had 48 participants. This small sample size leads to increased noise in the estimation as well as wide confidence intervals.

**Table 9: Ex Post Load Impact Estimates by Customer Category**

| Segmentation Variable | Segment Description | Participants | Avg. Reference Load (kW) | Avg. DR Load (kW) | Avg. Load Impact (kW) | % Load Impact | Agg. Load Impact (MW) |
|---|---|---|---|---|---|---|---|
| All | | 51,113 | 3.03 | 2.54 | 0.49 | 16% | 25.2 |
| LCA | Big Creek/Ventura | 6,072 | 3.30 | 2.71 | 0.59 | 18% | 3.6 |
| | LA Basin | 43,667 | 2.99 | 2.52 | 0.48 | 16% | 20.8 |
| | Outside | 1,374 | 3.03 | 2.46 | 0.57 | 19% | 0.8 |
| Low Income | CARE | 7,359 | 3.20 | 2.73 | 0.47 | 15% | 3.4 |
| | Non-CARE | 43,754 | 3.00 | 2.51 | 0.50 | 17% | 21.7 |
| NEM | NEM Customer | 11,257 | 3.38 | 2.75 | 0.62 | 18% | 7.0 |
| | Non-NEM Customer | 39,856 | 2.93 | 2.48 | 0.46 | 16% | 18.1 |
| Size | Above Mean kW | 25,328 | 4.18 | 3.50 | 0.68 | 16% | 17.3 |
| | Below Mean kW | 25,785 | 1.90 | 1.59 | 0.30 | 16% | 7.8 |
| Sublap | SCEC | 20,656 | 3.48 | 2.90 | 0.58 | 17% | 12.0 |
| | SCEN | 5,166 | 3.45 | 2.81 | 0.64 | 19% | 3.3 |
| | SCEW | 23,013 | 2.55 | 2.17 | 0.38 | 15% | 8.8 |
| | SCHD | 1,326 | 2.99 | 2.42 | 0.57 | 19% | 0.8 |
| | SCLD | 48 | 4.17 | 3.50 | 0.67 | 16% | 0.0 |
| | SCNW | 903 | 2.44 | 2.16 | 0.27 | 11% | 0.2 |
| Tariff | Dynamic | 14,126 | 3.03 | 2.53 | 0.50 | 17% | 7.1 |
| | Flat | 36,987 | 3.03 | 2.54 | 0.49 | 16% | 18.1 |
| [redacted] | | | | | | | |
| Zone | Remainder of System | 21,925 | 3.20 | 2.66 | 0.54 | 17% | 11.8 |
| | South Orange County | 10,681 | 2.41 | 2.04 | 0.37 | 15% | 3.9 |
| | South of Lugo | 18,507 | 3.19 | 2.68 | 0.51 | 16% | 9.4 |

Regardless of segment, there is not much variety in the percent load impacts. The size segment has the highest and lowest average load impact, with 0.30 kW impact for participants less than 1.82 kW during the resource adequacy window and 0.68 kW for participants greater than 1.82 kW during the RA window. However, when considering these impacts relative to their reference load, the percent impacts are both 16%.

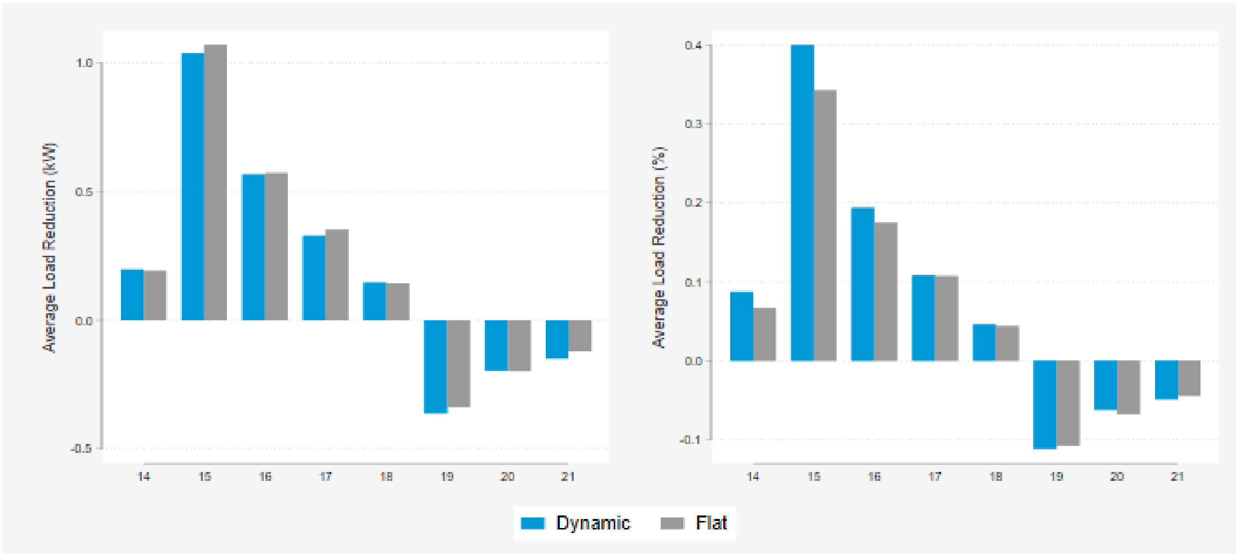
Overall, most segments are similar to the "All Customers" category with 16% load impact. The average aggregate load impact across all territory wide events is 25.2 MW. The following figures show segment specific impacts for the summer peak day event on August 18, 2020. The event occurred from 1:40pm to 5:40pm. The partial hours add some nuance to this event. We consider hour ending 15 to be "event hour 1", even though this dismisses the first 20 minutes of the event. However, this is the better assumption than using hour ending 14 as event hour 1, which would drastically reduce the impact.

In Figure 28, "All Customers" are represented by a black line, and the zero impact line is drawn in gray. Figure 28 shows just the sub-LAP breakout. The "All" category represents a participant weighted average of each segment category and is therefore shown approximately in the middle of the sub-LAPs. SCLD stands out as an outlier with the largest snapback. Recall from Table 9 that this sub-LAP only has an average of 48 customers during all territory wide events, which leads to a wide margin of error in the estimates.

**Figure 28: Average Customer Impact on System Peak Day, by Sub-LAP**


Figure 29 shows the average reductions for SEP participants who face flat and dynamic time-of-use (TOU) rates. The left side of Figure 29 shows absolute impacts in kW by hour and the right side shows percent savings. Participants on dynamic rates show smaller load impacts, but larger percent impacts. The SEP participants who faced dynamic pricing in 2020 were mostly part of a randomized encouragement pilot to enroll in TOU before the default transition and may not reflect the load shapes or SEP impacts of participants who were on a flat rate in 2020 once they have transitioned to TOU. SCE began the default TOU rollout in 2020, but approximately 72% of SEP participants were still on a flat rate at the end of the 2020 demand response season.

**Figure 29: Average and Percent Impacts on System Peak Day, by Tariff and Hour Ending**




[redacted]

[redacted]

[redacted]

## 4.4 COMPARISON TO PRIOR YEAR

SEP PY2020 events were called during similar event windows as the PY 2019 events. There were slightly fewer events in 2020, but 2020 events were more likely to be dispatched to all sub-LAP's compared to 2019. For all 2020 events, at least five of the six sub-LAPs were dispatched, whereas 2019 included events that were only dispatched to single sub-LAPs. Summer 2020 experienced hotter temperatures. For the territory wide events in 2019, average event temperatures ranged from 80.4°F to 86.2°F. In 2020, the average event temperatures spanned from 81.5°F to 104.7°F. With a wider range of event temperatures, 2020 events provided deeper insight for ex ante forecasting across a wide range of temperatures. Demand response is a tool that works best under hot conditions. In PY2020, six of the 14 events were dispatched as "Reliability" events. Whereas PY2019 did not require reliability events, and only dispatched for "Measurement & Evaluation" and "Economic" purposes.

Peak temperature during the average event days falls between 2pm and 5pm and the events typically started at 5pm or 6pm. In 2017 and 2018, average event hours included the 2pm-6pm window, which is concurrent with the peak temperature of the day. AC load tends to lag behind temperature due to heat buildup and occupancy, suggesting that an event window following the peak temperature of the day may better capture the peak AC usage window. Notice in Table 8 that on an average event day, the average event temperatures are about four degrees lower than the daily max. However, Table 10 indicates that despite the window shift, average 2019 event temperatures fall between the 2017 and 2018 event temperatures, and 2020 average event temperatures exceed that of all other years.

The overall SEP population grew slightly from 2018 to 2019, but decreased in 2020. The decrease may be due to lower enrollments caused by COVID, or higher opt-outs during the season. The customer counts vary over the course of the season as customer participation is different for every event. The SEP participant population was smaller in PY2020 by about 800 customers, when comparing the average 5pm to 9pm event days.

The standard 9 to 5 workday results in many households unoccupied during the 2017 & 2018 event window. If more individuals are home during the new window (5pm to 9pm), the likelihood of participant opt out may increase. Future analysis should consider the impact of opt outs to determine the number of dispatched participants that successfully complete an event. Given COVID stay-at-home orders and work-from-home trends that modified lifestyles during the 2020 pandemic, household occupancy changes may have influenced opt out behaviors. The extreme heat resulted in six consecutive event days in PY2020. While customers were likely to be at home because of COVID conditions, the rolling outages and increased awareness to grid challenges may have influenced customers to remain in the program.

The average reference load is larger in 2020 than any other year, with COVID being a contributing factor. The load impacts are smaller in 2020 (0.46kW) than in 2019 (0.53kW), but larger than in 2018 (0.42 kW). On a percent basis, 2020 exhibited the smallest percent impact of all four years, but the highest reference loads. The 2019 and 2020 average events are analyzed with the same window and difference in impacts between these two years can mostly be attributed to the dispatch issues of 2020.

**Table 10: Comparison of Historical and Current Average Event Ex Post Load Impact Estimates**

| Measure | 2017 | 2018 | 2019 (5-9PM) | 2020 (5-9PM) |
|---|---|---|---|---|
| Avg. Reference Load (kW) | 2.31 | 1.50 | 2.50 | 2.74 |
| Avg. Load Impact (kW) | 0.64 | 0.42 | 0.53 | 0.46 |
| % Load Impact | 27.8% | 27.9% | 21.1% | 16.7% |
| Avg. Event Temperature (°F) | 89.8 | 75.7 | 84.9 | 91.5 |
| Event Hours | 2-6PM | 2-6PM | 5-9PM | 5-9PM |
| Heat Buildup (Avg. °F, 12 AM to 5 PM) | 81.4 | 75.4 | 81.1 | 79.9 |
| Participants | 34,120 | 51,089 | 52,239 | 51,426 |

There were 14 SEP events in 2020. Weather conditions, opt out patterns, population differences, and the COVID pandemic contributed to differences in the impact estimates, but the dispatch challenges are the most effectual difference between PY2019 and PY2020. The PY2020 effect indicates that across all enrolled thermostats, the average impact was 0.46 kW. Given only about 85% of thermostats were available for dispatch over the course of the summer, this impact could be scaled up to 0.54 kW per dispatched customer, which is in line with the PY2019 average impact estimate. This process is described further in Section 4.5.

## 4.5 COMPARISON TO 2019 EX ANTE

Following the grid emergencies and rolling blackouts in California during summer 2020, there has been significant scrutiny of the performance of different market actors, including demand response programs like SEP. 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 2019 ex ante analysis. There are two elements to consider when reviewing the accuracy of the 2019 ex ante projections.

1. Did the actual number of enrollments match the projected number of enrollments in the PY2019 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, 2020 SEP ex post impacts fell well short of the MW projections in the 2019 ex ante analysis. SCE projected 25,000 new enrollments in SEP for 2020, but only achieved 7,000. SCE froze enrollments for the largest thermostat manufacturer due to unforeseen contract issues and halted marketing and acquisition campaigns during the COVID-19 outbreak. Due to the same contract issues, between 6,000 and 8,000 of the approximately 51,000 enrolled account were not available for dispatch during 2020 events. The "not available for dispatch" households can be viewed as a reduction in enrollments or a dilution of the average customer impact, but the impact on the MW performance of the program is the same.

In Table 11, Table 12, and Table 13 we compare the ex post results from select territory wide 2020 events to our 2019 ex ante results for monthly system peak conditions at comparable weather conditions. Table 11 compares the July 10$^{th}$ SEP event impacts to our projected 2020 impacts for a July Monthly System Peak Day at SCE 1-in-2 weather conditions, which has a warmer weighted average maximum daily temperature by just 0.4°F. As discussed above, the actual number of enrolled customers during summer 2020 was lower than projected in the 2019 enrollment forecast. The "2020 ex post" results row shows that the per-customer impacts were also noticeably lower. However, approximately 15% of the 51,776 enrolled households were not available for dispatch on July 10$^{th}$. The final row of Table 11 shows our estimated average customer impacts for households that were available for dispatch. The 2019 ex ante analysis assumed that all enrolled customers were available for dispatch so this is the more appropriate comparison when assessing the accuracy of the per-customer impacts in the 2019 ex ante analysis. The "Hour 1" per-customer impacts are well-aligned at 0.98 kW, but in subsequent event hours the program slightly underperformed compared to the 2019 ex ante projections.

**Table 11: July 10, 2020 Ex Post Impacts vs. Comparable 2019 Ex Ante Conditions**

| 7/10/2020 (5-9 PM) | | | Per-Customer Impact (kW) | | | |
|---|---|---|---|---|---|---|
| Results | Daily Max Temp (F) | Customers | Hour 1 | Hour 2 | Hour 3 | Hour 4 |
| SCE 1-in-2 July Peak Day (2019 Ex Ante Predictions for 2020) | 93.0 | 59,649 | 0.98 | 0.58 | 0.39 | 0.27 |
| 2020 Ex Post | 92.6 | 51,776 | 0.83 | 0.40 | 0.27 | 0.18 |
| 2020 Ex Post Available for Dispatch | 92.6 | 43,754 | 0.98 | 0.48 | 0.32 | 0.21 |

Table 12 presents a similar comparison for August 14, 2020. This was one of the days that California experienced rolling blackouts due to a critical shortfall of supply. Despite the actual weather conditions being slightly warmer than SCE 1-in-10 conditions for an August System Peak Day, the ex post results among the households available for dispatch fell short of the 2019 ex ante projections. It is important to note that in Hour 2 and Hour 3 of the August 14$^{th}$ event, approximately 4% of the SEP participants and matched controls were experiencing an outage and thus delivered zero load impact. The CAISO Flex Alert in place on August 14$^{th}$ likely also reduced consumption among the SEP participants and matched controls and placed downward pressure on the SEP ex post load impacts for the day. CAISO Flex alerts coincided with six of the PY2020 events.

**Table 12: August 14, 2020 Ex Post Impacts vs. Comparable 2019 Ex Ante Conditions**

| 8/14/2020 (5-9 PM) | | | Per-Customer Impact (kW) | | | |
|---|---|---|---|---|---|---|
| Results | Daily Max Temp (F) | Customers | Hour 1 | Hour 2 | Hour 3 | Hour 4 |
| SCE 1-in-10 August Peak Day (2019 Ex Ante Predictions for 2020) | 97.2 | 60,249 | 1.24 | 0.72 | 0.48 | 0.35 |
| 2020 Ex Post | 98.6 | 51,071 | 0.99 | 0.47 | 0.30 | 0.23 |
| 2020 Ex Post Available for Dispatch | 98.6 | 44,444 | 1.14 | 0.54 | 0.34 | 0.27 |

Table 13 presents a similar comparison for the September 6, 2020 SEP event. Actual weather conditions for this event were significantly hotter than SCE 1-in-10 conditions for a September Monthly System Peak Day. September 6$^{th}$ was also a Sunday. The "Hour" column in this table is not as clean as the two previous events because the September 6$^{th}$ event began at 4:40 pm Pacific Daylight Time. SEP impacts are generally largest at the beginning of an event and get smaller over the course of the event so each of the ex post hourly impacts presented in Table 13 are likely smaller than if we were able to measure impacts of the true first, second, and third hour of the event. Caveats aside, the per-customer impacts among the households available for dispatch were reasonably consistent with the 2019 ex ante projections for this event day.

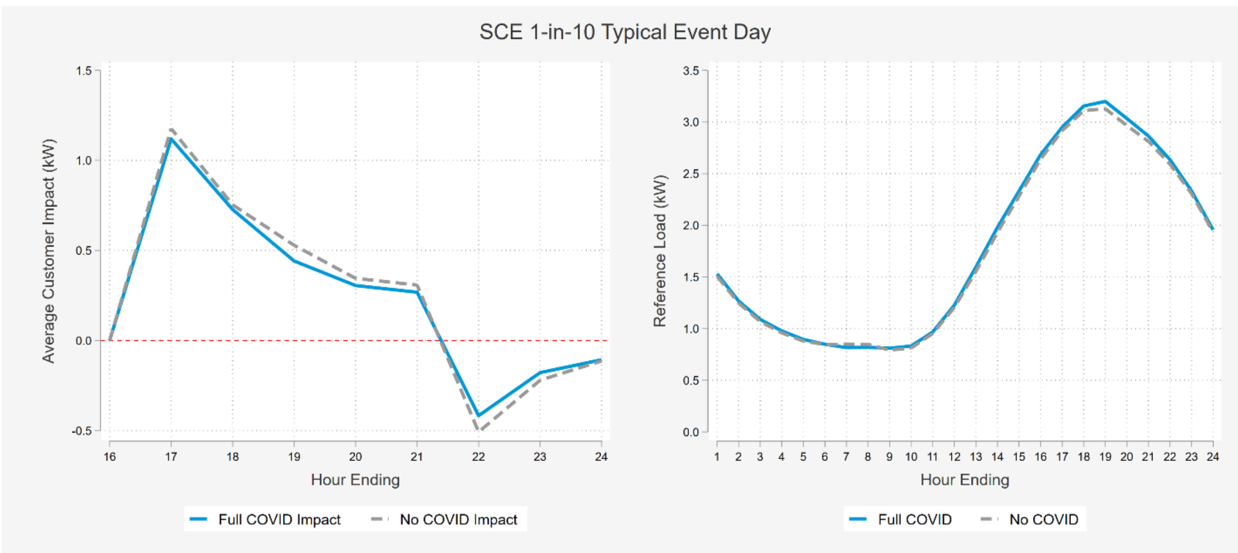
**Table 13: September 6, 2020 Ex Post Impact vs. Comparable 2019 Ex Ante Conditions**

| 9/6/2020 (4:40-8:25 PM) | | | Per-Customer Impact (kW) | | | |
|---|---|---|---|---|---|---|
| Results | Daily Max Temp (F) | Customers | *Hour 1 | *Hour 2 | *Hour 3 | *Hour 4 |
| SCE 1-in-10 September Peak Day (2019 Ex Ante Predictions for 2020) | 99.7 | 61,726 | 1.20 | 0.69 | 0.46 | 0.34 |
| 2020 Ex Post | 108.6 | 50,809 | 1.07 | 0.60 | 0.42 | |
| 2020 Ex Post Available for Dispatch | 108.6 | 44,400 | 1.22 | 0.69 | 0.48 | |
| * The 9/6/2020 event did not begin at the top of the hour. The Hour 1 ex post impacts presented in the table actually span minute 21 to 80 of the event. Hour 2 is minute 81 to 140. Hour 3 is minute 141 to 200. | | | | | | |

# 5 EX ANTE RESULTS

The ex ante results for SEP assume increasing aggregate MW impacts based on the growth projections in SCE's enrollment forecast. Since it relies 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. The per-customer impacts also grow slightly over the forecast horizon as the estimated COVID effect dissipates. Figure 31 compares the average customer SEP impacts and reference loads with and without our estimated COVID effect for SCE 1-in-10 Typical Event Day conditions. Reference loads are slightly higher under COVID and demand response impacts are slightly smaller under COVID, but the differences are subtle.

**Figure 31: Comparison of Impacts and Reference Loads With and Without COVID**




The average customer reference loads and impacts for each year of the ex ante forecast were calculated using a blend of the "Full COVID" and "No COVID" values according to the COVID glide path provided by SCE.

## 5.1 ENROLLMENT FORECAST

SCE provided the eleven-year forecast of SEP enrollments 2021-2031, shown in Table 14, representing the expected number of participants as of August of each calendar year.

**Table 14: SEP Enrollment Forecast, 2021-2031**

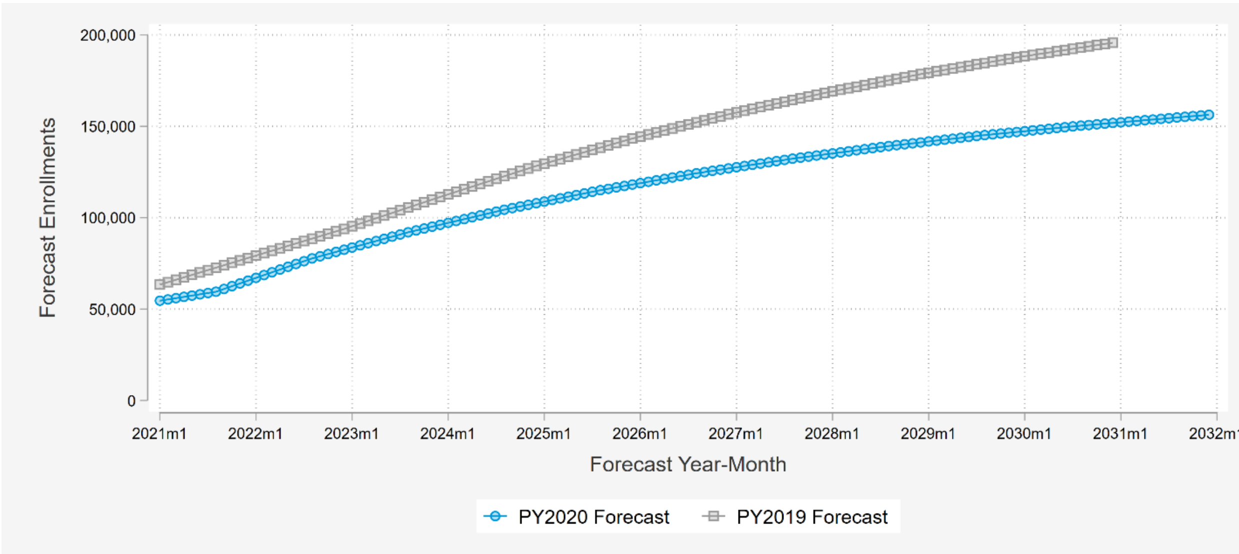
| Year | Enrollment |
|---|---|
| 2021 | 59,498 |
| 2022 | 77,727 |
| 2023 | 92,015 |
| 2024 | 104,372 |
| 2025 | 115,060 |
| 2026 | 124,303 |
| 2027 | 132,298 |
| 2028 | 139,212 |
| 2029 | 145,192 |
| 2030 | 150,364 |
| 2031 | 154,838 |

In order to place the forecast on an even basis, DSA imputed the estimated enrollments in each month of the forecast. Figure 32 compares this new forecast with the 2020-2030 forecast we received for the PY2019 SEP evaluation. The PY2020 forecast is lower than the prior year's forecast for several reasons.

- 2020 enrollments were much lower than projected due to contract issues with one of the thermostat manufacturers and the decision to suspend customer acquisition campaigns during the COVID-19 pandemic.
- Following the grid emergencies during summer 2020, SCE anticipates more aggressive acquisition efforts for the Summer Discount Plan (SDP) program in the short term. Because SEP and SDP target a similar type of customer, the increased emphasis on SDP marketing is expected to reduce the growth trajectory of SEP.

As discussed in Section 5.4, the lower enrollment forecast reduces the estimated aggregate MW impacts. However, the total number of enrollments are still expected to triple over the next decade from the current level of approximately 50,000 to over 150,000 enrollments by 2031. SCE plans to work with CPUC staff to remove enrollment barriers for SEP and is planning to launch a new initiative where customers who receive a free thermostat through the direct install energy efficiency program are enrolled in SEP.

**Figure 32: Comparison on PY2020 and PY2019 SEP Enrollment Forecasts**




## 5.2 OVERALL RESULTS

Figure 33 shows the average ex ante load impact per SEP participant for each hour of an August system peak day in 2021 using the SCE 1-in-2 weather forecast. Figure 34 shows the 2021 per-participant impact estimates using SCE 1-in-10 weather for an August system peak day. These figures are taken 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 specifics sets of results. Per customer (kW) and aggregate (MW) impacts are available for each forecast year 2021-2031 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, 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. In Figure 33 and Figure 34, the five hours of the RA window are shaded light green. Hours ending 17 through 21 correspond to the RA window of 4pm to 9pm.

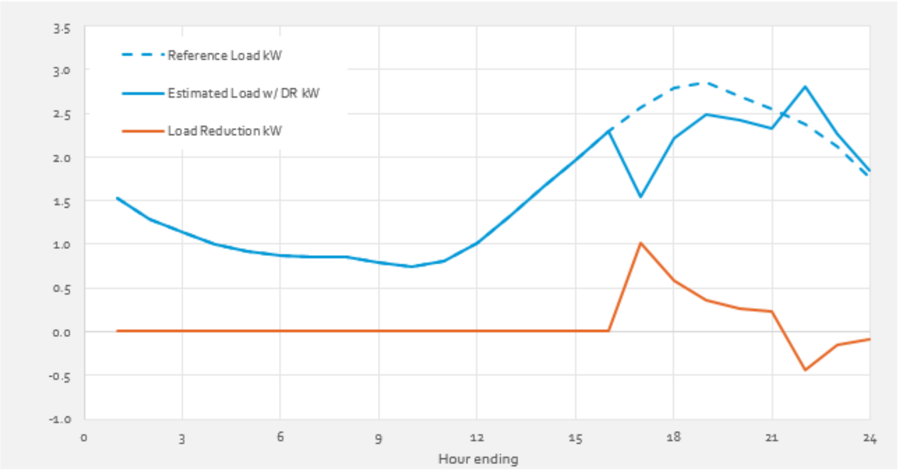
**Figure 33: SEP Average Load Impact (kW) per Customer in 2021: August System Peak Day, SCE 1-in-2 Weather**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Weather Year | SCE 1-in-2 |
| Day Type | Monthly System Peak Day |
| Month | August |
| Forecast Year | 2021 |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 4pm-9pm (RA Hours 4pm-9pm) |
| Sites Dispatched | 59,498 |
| Daily Max Temp (F) | 93.3 |
| Average Impact (kW) | 0.49 |
| % Load Reduction (Event window) | 18.4% |
| Covid Index | 0.50 |




| Hour Ending | Reference Load kW | Estimated Load w/ DR kW | Load Reduction kW | % Load Reduction | Avg Temp, site weighted F |
|---|---|---|---|---|---|
| 1 | 1.53 | 1.53 | 0.00 | 0.0% | 78.1 |
| 2 | 1.29 | 1.29 | 0.00 | 0.0% | 77.0 |
| 3 | 1.14 | 1.14 | 0.00 | 0.0% | 76.2 |
| 4 | 1.01 | 1.01 | 0.00 | 0.0% | 75.3 |
| 5 | 0.92 | 0.92 | 0.00 | 0.0% | 74.6 |
| 6 | 0.88 | 0.88 | 0.00 | 0.0% | 74.1 |
| 7 | 0.86 | 0.86 | 0.00 | 0.0% | 73.5 |
| 8 | 0.86 | 0.86 | 0.00 | 0.0% | 73.5 |
| 9 | 0.79 | 0.79 | 0.00 | 0.0% | 75.6 |
| 10 | 0.75 | 0.75 | 0.00 | 0.0% | 79.6 |
| 11 | 0.81 | 0.81 | 0.00 | 0.0% | 83.7 |
| 12 | 1.02 | 1.02 | 0.00 | 0.0% | 87.3 |
| 13 | 1.32 | 1.32 | 0.00 | 0.0% | 89.7 |
| 14 | 1.65 | 1.65 | 0.00 | 0.0% | 91.8 |
| 15 | 1.96 | 1.96 | 0.00 | 0.0% | 93.3 |
| 16 | 2.29 | 2.29 | 0.00 | 0.0% | 93.3 |
| 17 | 2.56 | 1.55 | 1.01 | 39.6% | 92.8 |
| 18 | 2.80 | 2.21 | 0.59 | 21.1% | 91.3 |
| 19 | 2.86 | 2.49 | 0.37 | 12.8% | 89.8 |
| 20 | 2.69 | 2.42 | 0.27 | 10.0% | 88.1 |
| 21 | 2.55 | 2.32 | 0.24 | 9.2% | 84.7 |
| 22 | 2.37 | 2.81 | (0.44) | -18.5% | 81.5 |
| 23 | 2.12 | 2.27 | (0.15) | -7.2% | 79.4 |
| 24 | 1.77 | 1.85 | (0.08) | -4.7% | 77.9 |

| Daily | Reference Load kWh | Estimated Load w/ DR kWh | Energy Savings kWh Δ | % Change | Avg. Daily Weighted Temp F |
|---|---|---|---|---|---|
| | 38.78 | 36.98 | 1.80 | 4.6% | 82.6 |

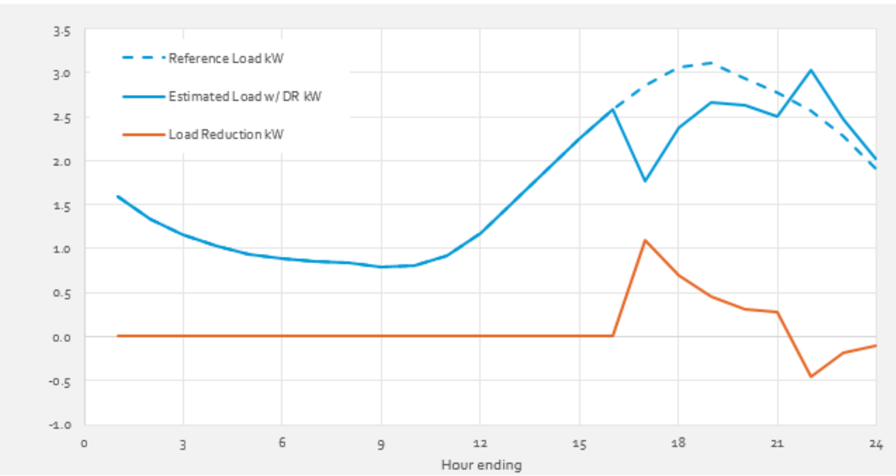
**Figure 34: SEP Average Load Impact (kW) per Customer in 2020: Typical Event Day, SCE 1-in-10 Weather**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Weather Year | SCE 1-in-10 |
| Day Type | Monthly System Peak Day |
| Month | August |
| Forecast Year | 2021 |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 4pm-9pm (RA Hours 4pm-9pm) |
| Sites Dispatched | 59,498 |
| Daily Max Temp (F) | 96.8 |
| Average Impact (kW) | 0.56 |
| % Load Reduction (Event window) | 19.1% |
| Covid Index | 0.50 |




| Hour Ending | Reference Load kW | Estimated Load w/ DR kW | Load Reduction kW | % Load Reduction | Avg Temp, site weighted F |
|---|---|---|---|---|---|
| 1 | 1.59 | 1.59 | 0.00 | 0.0% | 79.3 |
| 2 | 1.34 | 1.34 | 0.00 | 0.0% | 78.1 |
| 3 | 1.16 | 1.16 | 0.00 | 0.0% | 77.0 |
| 4 | 1.03 | 1.03 | 0.00 | 0.0% | 76.0 |
| 5 | 0.93 | 0.93 | 0.00 | 0.0% | 75.0 |
| 6 | 0.88 | 0.88 | 0.00 | 0.0% | 74.1 |
| 7 | 0.86 | 0.86 | 0.00 | 0.0% | 73.3 |
| 8 | 0.85 | 0.85 | 0.00 | 0.0% | 73.3 |
| 9 | 0.79 | 0.79 | 0.00 | 0.0% | 75.8 |
| 10 | 0.81 | 0.81 | 0.00 | 0.0% | 80.8 |
| 11 | 0.93 | 0.93 | 0.00 | 0.0% | 86.5 |
| 12 | 1.18 | 1.18 | 0.00 | 0.0% | 90.2 |
| 13 | 1.53 | 1.53 | 0.00 | 0.0% | 92.0 |
| 14 | 1.90 | 1.90 | 0.00 | 0.0% | 93.7 |
| 15 | 2.24 | 2.24 | 0.00 | 0.0% | 95.3 |
| 16 | 2.58 | 2.58 | 0.00 | 0.0% | 96.8 |
| 17 | 2.85 | 1.76 | 1.09 | 38.4% | 96.7 |
| 18 | 3.07 | 2.38 | 0.69 | 22.5% | 96.1 |
| 19 | 3.11 | 2.65 | 0.45 | 14.5% | 94.8 |
| 20 | 2.94 | 2.63 | 0.31 | 10.5% | 91.9 |
| 21 | 2.78 | 2.51 | 0.27 | 9.8% | 88.4 |
| 22 | 2.57 | 3.02 | (0.46) | -17.8% | 85.1 |
| 23 | 2.28 | 2.47 | (0.19) | -8.3% | 82.7 |
| 24 | 1.91 | 2.02 | (0.11) | -5.6% | 81.3 |
| Daily | Reference Load kWh | Estimated Load w/ DR kWh | Energy Savings kWh Δ | % Change | Avg. Daily Weighted Temp F |
| | 42.09 | 40.02 | 2.07 | 4.9% | 84.8 |

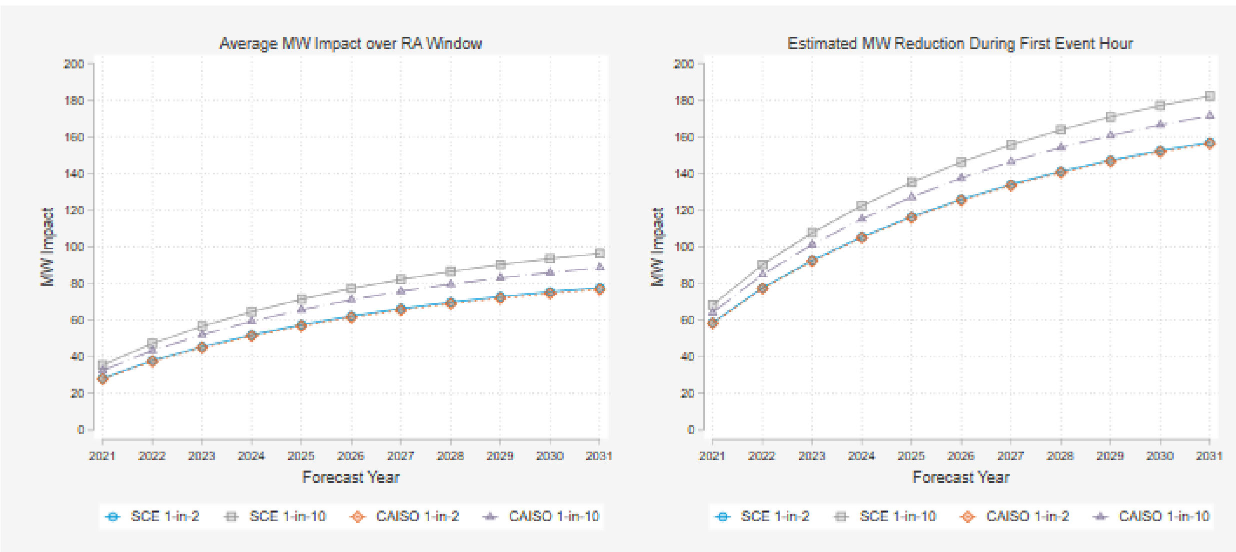


Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

### 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 35 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 and COVID assumptions discussed in Section 3.2 and Section 5.1. The left panel of Figure 35 shows the average SEP MW impact over the five hour RA window. 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 during event hours 2-5. The difference between these two views of load reduction capability has important implications for valuation of SEP as a capacity resource.

**Figure 35: Aggregate SEP Impacts over Time by Weather Conditions: Typical Event Day**




The SCE and CAISO 1-in-2 weather conditions are very similar for a typical event day. Although not identical, it is difficult to distinguish the two trends in Figure 35. There is more variance in the 1-in-10 conditions, with the SCE 1-in-10 forecast showing more extreme peaking conditions than the CAISO 1-in-10 forecast. The more extreme weather assumptions lead to higher reference loads, per-participant impacts, and MW capability in the SCE 1-in-10 aggregate ex ante impacts.

Table 15 shows the aggregate ex ante load impact estimates in forecast year 2021 by hour and peaking conditions for a typical event day. The estimated load impact of SEP in 2021 ranges from 58.3 MW to 68.3 MW during hour ending 17. Estimated impacts decline across the RA window and range from 13.1 MW to 17.1 MW in hour ending 21.

**Table 15: 2021 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 | 58.6 | 58.3 | 68.3 | 64.2 |
| 18 | 34.2 | 33.4 | 44.1 | 40.0 |
| 19 | 20.7 | 20.3 | 28.9 | 25.7 |
| 20 | 15.2 | 15.0 | 19.3 | 17.7 |
| 21 | 13.1 | 13.1 | 17.1 | 15.4 |
| **RA Window** | **28.4** | **28.0** | **35.5** | **32.6** |

In addition to the typical event day, ex ante impacts were estimated for average weekdays and monthly system peak days. Table 16 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 17 presents the same results using CAISO 1-in-2 and CAISO 1-in-10 weather. The SCE 1-in-2 and both CAISO weather year conditions show the largest impacts on September peak days. The SCE 1-in-10 estimates are largest for the July monthly system peak day. In PY2019, these findings were the same. In PY2018, the aggregate impacts were largest in August for SCE 1-in-2 weather and September for SCE 1-in-10 weather.

**Table 16: Aggregate Load Impacts (MW) on Monthly System Peak Days 2021-2031: SCE Weather**

| Weather Year | Month | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-in-2 | January | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | February | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | March | 0.6 | 0.8 | 1.1 | 1.3 | 1.5 | 1.6 | 1.7 | 1.8 | 1.9 | 2.0 | 2.0 |
| | April | 21.0 | 27.5 | 34.0 | 39.4 | 44.0 | 47.9 | 51.3 | 54.2 | 56.7 | 58.8 | 60.7 |
| | May | 22.0 | 29.0 | 35.6 | 41.1 | 45.7 | 49.7 | 53.2 | 56.1 | 58.7 | 60.9 | 62.8 |
| | June | 21.9 | 29.0 | 35.4 | 40.7 | 45.3 | 49.1 | 52.5 | 55.4 | 57.8 | 60.0 | 61.8 |
| | July | 29.0 | 38.5 | 46.4 | 53.2 | 58.9 | 63.8 | 68.1 | 71.7 | 74.9 | 77.6 | 80.0 |
| | August | 29.4 | 39.4 | 47.3 | 53.9 | 59.6 | 64.5 | 68.7 | 72.3 | 75.5 | 78.1 | 80.5 |
| | September | 33.2 | 43.9 | 52.3 | 59.5 | 65.6 | 70.9 | 75.5 | 79.4 | 82.7 | 85.7 | 88.2 |
| | October | 29.2 | 38.4 | 45.7 | 51.9 | 57.2 | 61.7 | 65.6 | 69.0 | 71.9 | 74.4 | 76.6 |
| | November | 21.1 | 27.8 | 33.1 | 37.6 | 41.4 | 44.7 | 47.4 | 49.8 | 51.9 | 53.7 | 55.3 |
| | December | 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 |
| | February | 17.0 | 21.9 | 27.6 | 32.3 | 36.2 | 39.6 | 42.5 | 45.0 | 47.2 | 49.0 | 50.6 |
| | March | 21.5 | 27.8 | 34.6 | 40.2 | 45.0 | 49.1 | 52.7 | 55.7 | 58.3 | 60.6 | 62.5 |
| | April | 24.3 | 31.7 | 39.1 | 45.2 | 50.5 | 55.0 | 58.8 | 62.2 | 65.0 | 67.5 | 69.7 |
| | May | 31.0 | 40.5 | 49.5 | 57.0 | 63.4 | 68.9 | 73.6 | 77.7 | 81.2 | 84.3 | 86.9 |
| | June | 32.0 | 42.0 | 51.0 | 58.5 | 65.0 | 70.5 | 75.3 | 79.4 | 82.9 | 86.0 | 88.6 |
| | July | 40.2 | 53.1 | 63.8 | 73.0 | 80.8 | 87.5 | 93.3 | 98.3 | 102.6 | 106.3 | 109.5 |
| | August | 33.5 | 44.8 | 53.6 | 61.1 | 67.6 | 73.1 | 77.8 | 81.9 | 85.5 | 88.5 | 91.2 |
| | September | 36.1 | 47.7 | 56.8 | 64.6 | 71.3 | 77.0 | 81.9 | 86.1 | 89.8 | 93.0 | 95.7 |
| | October | 36.6 | 47.9 | 56.8 | 64.5 | 71.0 | 76.6 | 81.4 | 85.6 | 89.1 | 92.2 | 95.0 |
| | November | 27.1 | 35.4 | 41.9 | 47.5 | 52.3 | 56.4 | 59.9 | 62.9 | 65.5 | 67.8 | 69.8 |
| | December | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Table 17: Aggregate Load Impacts (MW) on Monthly System Peak Days 2021-2031: CAISO Weather**

| Weather Year | Month | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-in-2 | January | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | February | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | March | 0.6 | 0.8 | 1.1 | 1.3 | 1.5 | 1.7 | 1.8 | 1.9 | 2.0 | 2.1 | 2.1 |
| | April | 19.1 | 25.0 | 31.0 | 35.9 | 40.1 | 43.7 | 46.8 | 49.4 | 51.7 | 53.7 | 55.4 |
| | May | 21.0 | 27.6 | 34.0 | 39.2 | 43.7 | 47.5 | 50.8 | 53.6 | 56.1 | 58.2 | 60.0 |
| | June | 22.6 | 30.0 | 36.5 | 42.0 | 46.7 | 50.7 | 54.1 | 57.1 | 59.6 | 61.8 | 63.7 |
| | July | 28.2 | 37.5 | 45.3 | 51.9 | 57.5 | 62.3 | 66.4 | 70.0 | 73.1 | 75.7 | 78.0 |
| | August | 28.6 | 38.3 | 45.9 | 52.4 | 58.0 | 62.7 | 66.8 | 70.3 | 73.4 | 76.0 | 78.3 |
| | September | 32.6 | 43.1 | 51.4 | 58.5 | 64.6 | 69.8 | 74.2 | 78.1 | 81.4 | 84.3 | 86.8 |
| | October | 25.1 | 33.2 | 39.6 | 45.0 | 49.6 | 53.5 | 56.9 | 59.8 | 62.3 | 64.5 | 66.4 |
| | November | 6.2 | 8.5 | 10.2 | 11.7 | 13.0 | 14.0 | 14.9 | 15.7 | 16.3 | 16.9 | 17.4 |
| | December | 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 |
| | February | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | March | 22.8 | 29.5 | 36.7 | 42.6 | 47.7 | 52.1 | 55.8 | 59.0 | 61.8 | 64.2 | 66.2 |
| | April | 27.6 | 35.7 | 44.1 | 51.0 | 56.9 | 61.9 | 66.2 | 70.0 | 73.2 | 76.0 | 78.4 |
| | May | 31.0 | 40.5 | 49.5 | 57.0 | 63.4 | 68.9 | 73.6 | 77.7 | 81.2 | 84.3 | 86.9 |
| | June | 33.2 | 43.6 | 52.9 | 60.7 | 67.4 | 73.1 | 78.0 | 82.3 | 86.0 | 89.1 | 91.9 |
| | July | 29.7 | 39.5 | 47.6 | 54.5 | 60.4 | 65.4 | 69.8 | 73.5 | 76.8 | 79.5 | 81.9 |
| | August | 32.3 | 43.2 | 51.7 | 59.0 | 65.2 | 70.5 | 75.1 | 79.1 | 82.5 | 85.4 | 88.0 |
| | September | 34.8 | 46.0 | 54.8 | 62.3 | 68.8 | 74.3 | 79.1 | 83.2 | 86.7 | 89.7 | 92.4 |
| | October | 27.5 | 36.2 | 43.1 | 49.0 | 54.0 | 58.3 | 61.9 | 65.1 | 67.8 | 70.2 | 72.3 |
| | November | 27.1 | 35.4 | 41.9 | 47.5 | 52.3 | 56.4 | 59.9 | 62.9 | 65.5 | 67.8 | 69.8 |
| | December | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## 5.3 RESULTS BY CATEGORY

Table 18 presents the aggregate SEP impacts for a typical event day in 2021 under each set of weather conditions by local capacity area. The majority of SEP participants are located in the LA Basin LCA so this LCA shows the majority of the projected load reduction capacity. Because ex ante impacts are modeled separately by segment, the subcategories may not add up exactly to the SEP Total, which based on a pooled model of all participants.

**Table 18: Ex Ante Aggregate Impacts (MW) by LCA, 2021 Forecast Year: Typical Event Day**

| LCA | Enrollment | SCE 1-in-2 | CAISO 1-in-2 | SCE 1-in-10 | CAISO 1-in-10 |
|---|---|---|---|---|---|
| Big Creek/Ventura | 7,073 | 4.1 | 4.1 | 4.2 | 4.2 |
| LA Basin | 50,825 | 23.6 | 23.2 | 30.2 | 27.3 |
| Outside LA Basin | 1,600 | 0.8 | 0.9 | 0.9 | 0.9 |
| **SEP Total** | **59,498** | **28.4** | **28.0** | **35.5** | **32.6** |

Approximately 85% of SEP participants are located in the LA Basin LCA, and between 83% and 85% of the ex ante MW impacts are located in the LA Basin. Reference loads and average customer impacts in the LA Basin LCA are slightly lower than Big Creek/Ventura or Outside LA Basin. For SCE 1-in-2 weather conditions the Big Creek/Ventura LCA has an average customer impact of 0.58 kW, Outside LA Basin has an average customer impact of 0.53 kW and LA Basin has an average customer impact of 0.46 kW.

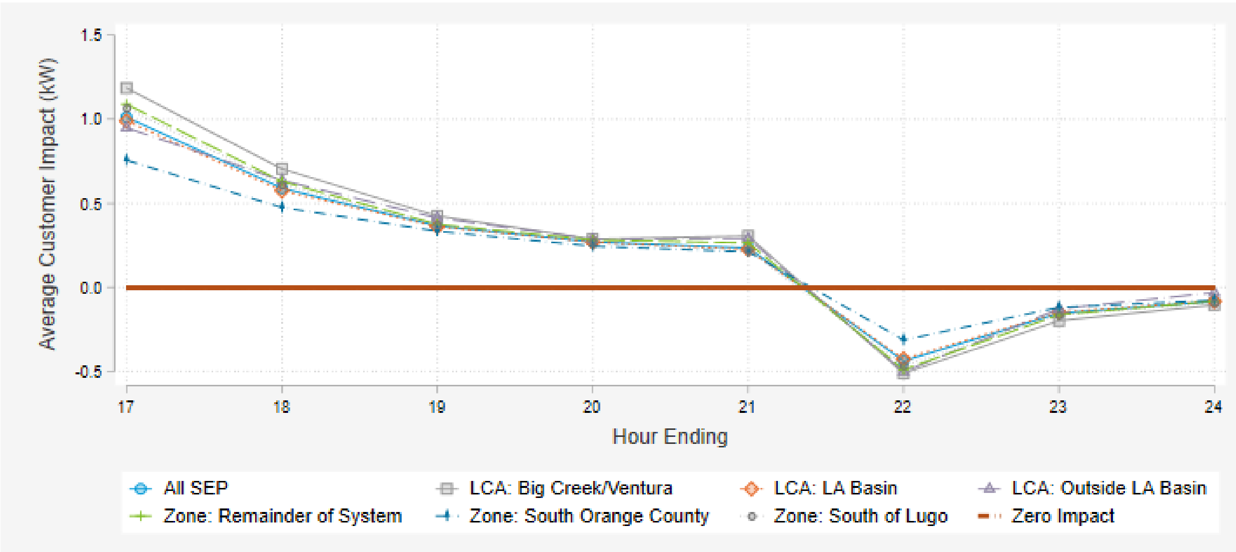
Table 19 provides a similar breakdown for each region of the SCE system affected by the SONGS closure. For SCE 1-in-2 weather conditions, 36.9% of the SEP load reduction is expected to come from South of Lugo, 16.7% from South Orange County, and 46.7% from the Remainder of the System unaffected by the SONGS closure. While South Orange County has 21% of the customers, the average customer impacts are approximately 16-17% of the total reduction. Remainder of the System makes up for the difference with approximately 43% of the customers and 46% of the impacts.

**Table 19: Ex Ante Aggregate 2021 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 | 25,515 | 13.2 | 13.2 | 15.7 | 15.0 |
| South Orange County | 12,431 | 4.7 | 4.7 | 6.0 | 5.2 |
| South of Lugo | 21,552 | 10.5 | 10.2 | 13.7 | 12.3 |
| **SEP Total** | **59,498** | **28.4** | **28.0** | **35.5** | **32.6** |

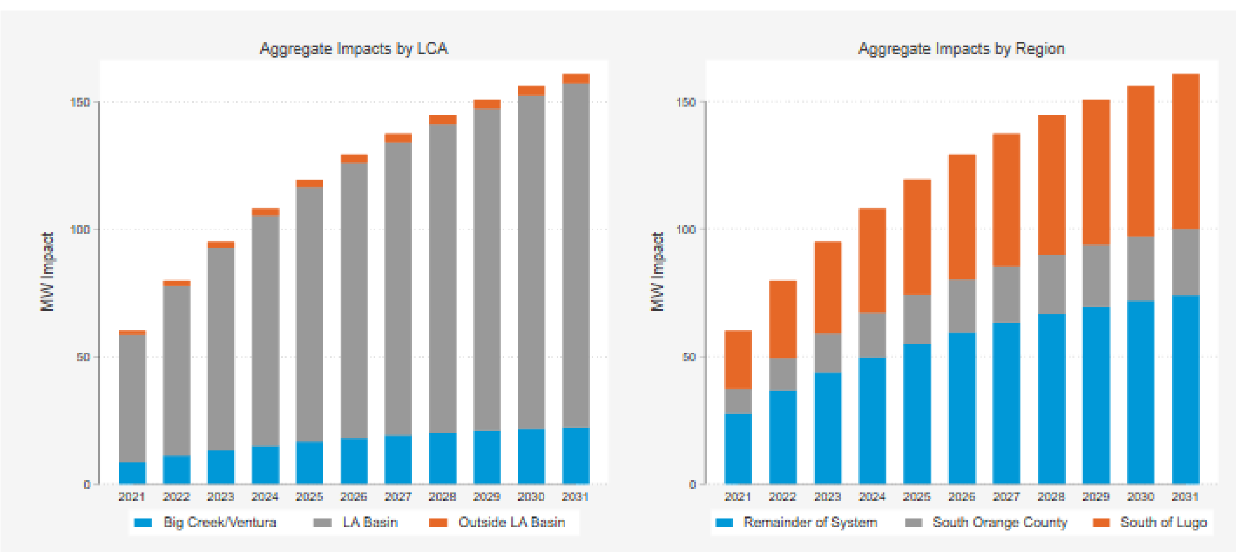
Readers should note that the aggregate impacts shown in Table 18 and Table 19 are an average across the five hour RA window. Figure 36 shows the average impact on an August system peak day by segment and hour across the RA window and post-event snapback period using SCE 1-in-2 weather and reveals that that average MW impacts across the RA window mask a significant amount of inter-hour diversity in estimated performance. In Figure 36, load reductions are presented as a positive impact and load increases are presented 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 36: Average Customer Impacts by Segment and Hour: August System Peak Day, SCE 1-in-2**




As shown in Figure 36, the per-participant impact is greatest during the first hour of event dispatch. The forecasted enrollments is the same in each hour. Figure 37 shows the projected aggregate MW impacts for SEP 2021-2031 by LCA and Region using SCE 1-in-2 weather conditions for an August system peak day.

**Figure 37: First Event Hour Ex Ante MW Reduction by LCA and Region: August System Peak Day, SCE 1-in-2 Weather**



## 5.4 COMPARISON TO PRIOR YEAR

Table 20 compares the average customer impacts on an absolute and percent basis and shows the weighted average temperature (°F) across the SEP population for the 2021 August system peak day using SCE 1-in-2 weather. The underlying ex ante weather for PY2020 is identical to PY2019. Temperature variations occur due to the changing regional distribution of enrolled customers. Per customer impacts are similar across the RA window, but percent impacts are slightly lower in 2020.

**Table 20: Comparison of PY2019 and PY2020 Average Customer Impacts: 2021 August System Peak Day, SCE 1-in-2 Weather**

| Hour Ending | 2019 (kW) | 2020 (kW) | 2019 (%) | 2020 (%) | 2019 (Temp) | 2020 (Temp) |
|---|---|---|---|---|---|---|
| 17 | 0.93 | 1.01 | 39.8% | 39.6% | 93.1 | 92.8 |
| 18 | 0.56 | 0.59 | 21.4% | 21.1% | 91.6 | 91.3 |
| 19 | 0.40 | 0.37 | 14.2% | 12.8% | 90.1 | 89.8 |
| 20 | 0.30 | 0.27 | 10.3% | 10.0% | 88.5 | 88.1 |
| 21 | 0.30 | 0.24 | 10.3% | 9.2% | 85.1 | 84.7 |
| **RA Window Average** | **0.50** | **0.49** | **18.3%** | **18.4%** | **89.7** | **89.3** |

Table 21 shows the same comparison for SCE 1-in-10 weather. The PY2020 average customer impacts during the RA window are smaller than the PY2019 impacts on an absolute basis. However, due to differences in reference loads, the percent impacts are slightly larger for PY 2020.

**Table 21: Comparison of PY2019 and PY2020 Average Customer Impacts: 2021 August System Peak Day, SCE 1-in-10 Weather**

| Hour Ending | 2019 (kW) | 2020 (kW) | 2019 (%) | 2020 (%) | 2019 (Temp) | 2020 (Temp) |
|---|---|---|---|---|---|---|
| 17 | 1.09 | 1.09 | 41.7% | 38.4% | 97.0 | 96.7 |
| 18 | 0.66 | 0.69 | 22.1% | 22.5% | 96.5 | 96.1 |
| 19 | 0.48 | 0.45 | 14.7% | 14.5% | 95.2 | 94.8 |
| 20 | 0.35 | 0.31 | 10.8% | 10.5% | 92.4 | 91.9 |
| 21 | 0.35 | 0.27 | 10.8% | 9.8% | 88.8 | 88.4 |
| **RA Window Average** | **0.59** | **0.56** | **19.0%** | **19.1%** | **94.0** | **93.6** |

Table 22 and Table 23 show the same comparison for CAISO 1-in-2 and CAISO 1-in-10 weather conditions on an August system peak day in 2021. The CAISO ex ante weather conditions are slightly cooler in the PY2020 ex ante estimates for an August system peak day compared to the PY2019 ex ante estimates for both 1-in-2 and 1-in-10 conditions. Absolute impacts are similar for CAISO 1-in-10 conditions. The PY2020 percent impacts are lower in CAISO 1-in-2 weather conditions, but higher in CIASO 1-in-10 conditions.

**Table 22: Comparison of PY2019 and PY2020 Average Customer Impacts: 2021 August System Peak Day, CAISO 1-in-2 Weather**

| Hour Ending | 2019 (kW) | 2020 (kW) | 2019 (%) | 2020 (%) | 2019 (Temp) | 2020 (Temp) |
|---|---|---|---|---|---|---|
| 17 | 0.93 | 1.01 | 40.0% | 38.7% | 92.7 | 92.4 |
| 18 | 0.55 | 0.57 | 21.4% | 20.1% | 90.6 | 90.4 |
| 19 | 0.39 | 0.34 | 14.3% | 11.7% | 88.7 | 88.5 |
| 20 | 0.29 | 0.26 | 10.4% | 9.4% | 87.0 | 86.7 |
| 21 | 0.29 | 0.23 | 10.4% | 8.9% | 84.3 | 84.0 |
| **RA Window Average** | **0.49** | **0.48** | **18.5%** | **17.6%** | **88.7** | **88.4** |

**Table 23: Comparison of PY2019 and PY2020 Average Customer Impacts: 2021 August System Peak Day, CAISO 1-in-10 Weather**

| Hour Ending | 2019 (kW) | 2020 (kW) | 2019 (%) | 2020 (%) | 2019 (Temp) | 2020 (Temp) |
|---|---|---|---|---|---|---|
| 17 | 1.02 | 1.07 | 40.5% | 40.2% | 96.1 | 95.7 |
| 18 | 0.62 | 0.66 | 21.6% | 23.0% | 95.3 | 94.9 |
| 19 | 0.45 | 0.43 | 14.4% | 14.5% | 93.7 | 93.3 |
| 20 | 0.33 | 0.30 | 10.5% | 10.7% | 91.3 | 90.8 |
| 21 | 0.32 | 0.25 | 10.5% | 9.7% | 87.0 | 86.6 |
| **RA Window Average** | **0.55** | **0.54** | **18.6%** | **19.5%** | **92.7** | **92.2** |

We offer the following observations about the comparisons shown in Table 20 through Table 23.

- The 2021 forecasted impacts are very similar between the two evaluation years. PY2020 impacts tend to be about 0.01-0.03 kW lower than PY2019. Weighted average temperatures are slightly cooler in 2020, and there is a 50% COVID impact in the 2020 forecast. The COVID impact increases reference loads and decreases impacts, leading to the smaller percent impacts shown in three of the four weather scenarios.

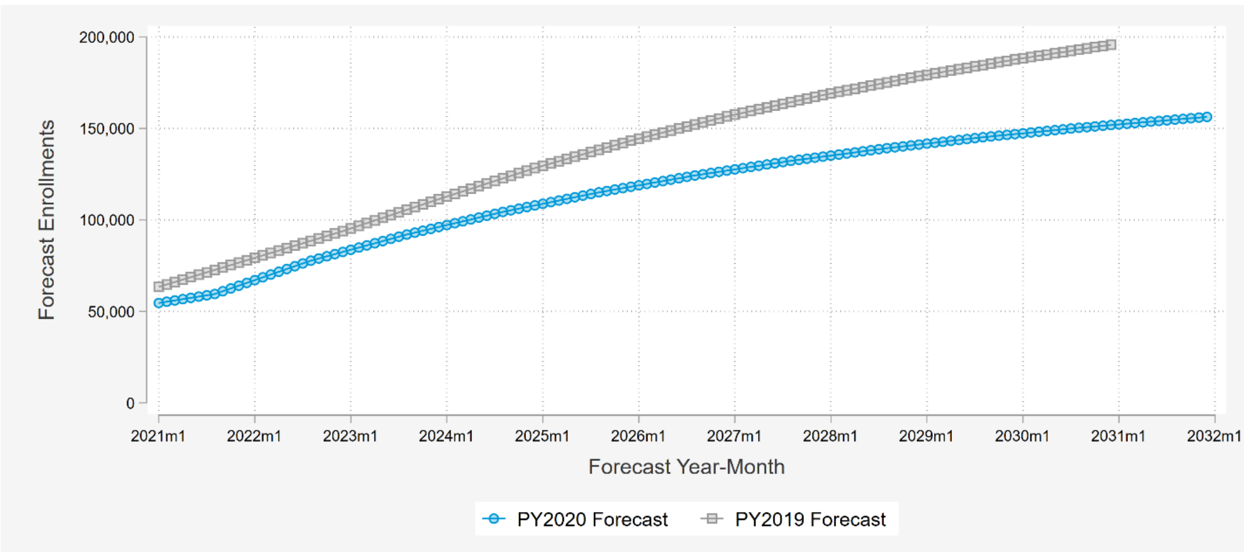
- While both sets of ex ante results show the largest impact during the first event hour with decaying impacts each subsequent hour, the PY2020 ex ante impacts show a steeper decline in impacts across the event than the PY2019 impacts. Opt outs are a potential explanation for the steeper decline. One hypothesis is that participants are more likely to be home and opt-out of an SEP due to COVID (PY2020) than during an SEP event in the prior to lockdowns (PY2019). We were able to gather opt-out data for approximately 30% of SEP thermostats in 2020, but the calculation methodology was inconsistent across providers. For the PY2021 impact evaluation we will explore the possibility of collecting device-level opt out data from all thermostat providers in a consistent format for analysis.

- The weighted average temperatures decreased slightly between the PY2019 and PY2020 ex ante analyses due to a small shift in the regional balance of the SEP participant population.

## AGGREGATE IMPACTS

In addition to the variation in average participant impacts discussed in the prior section, aggregate impact estimates are affected by the estimated number of SEP enrollments. As discussed in Section 5.1, the PY2020 enrollment forecast is noticeably lower than the PY2019 enrollment for every year. We modify the annual forecasts to monthly assuming linear growth. However, in this section we do not recalculate the PY2019 ex ante impacts. Instead, we compare the PY2020 ex ante impacts to the official PY2019 ex ante numbers that were filed. Figure 38 compares the values on a monthly basis over an 11-year horizon.

**Figure 38: Comparison of Ex Ante Enrollments: PY2020 vs. PY2019**




For a 2021 typical event day, the PY2019 ex ante impacts assumed 77,971 participants. For comparison, the PY2020 ex ante impacts assume 59,498 participants – a reduction of 23%. The differences in the two forecasts become more pronounced over time. Holding all other factors constants, the lower enrollment projection would maintain a 23% reduction in predicted aggregate MW reduction by 2030. As discussed in the previous section, the ex ante average customer impacts are also lower for PY2020 than PY2019 due to a steeper decline in impacts across the event.

Typically, the only difference in impacts across years for the ex ante forecast is the enrollment forecast. Average per customer impacts are usually consistent across years. However, due to the assumed diminishing effect of COVID, the per-customer impacts do not remain constant over time. When the PY2019 ex ante results were submitted, the influence of the pandemic was still unforeseen. The PY2020 forecast predicts approximately a 50% lingering effect of COVID in 2021. This will become increasingly muted over time and will change per customer impacts for each subsequent year. The results resented in this section focus on the 2021 forecast.

Table 24 compares the PY2019 and PY2020 aggregate ex ante load reduction estimates for forecast year 2021 on a typical event day using SCE peaking conditions. The 2020 average estimated performance across the five-hour RA window is 18% lower for 1-in-2 conditions and 27% lower for 1-in-10 conditions.

**Table 24: Comparison of 2021 Aggregate Typical Event Day Ex Ante Impacts (MW): PY2019 vs. PY2020 with SCE Weather**

| Hour Ending | SCE 1-in-2 | | SCE 1-in-10 | |
|---|---|---|---|---|
| | PY2019 | PY2020 | PY2019 | PY2020 |
| 17 | 63.3 | 58.6 | 91.08 | 68.3 |
| 18 | 39.5 | 34.2 | 54.44 | 44.1 |
| 19 | 28.7 | 20.7 | 39.45 | 28.9 |
| 20 | 20.9 | 15.2 | 29.02 | 19.3 |
| 21 | 20.3 | 13.1 | 28.78 | 17.1 |
| **RA Window Average** | **34.5** | **28.4** | **48.6** | **35.5** |

Table 25 presents the same comparison using CAISO peaking conditions. Aggregate MW impacts are 19% lower for 1-in-2 weather and 26% lower for 1-in-10 weather.

**Table 25: Comparison of 2021 Aggregate Typical Event Day Ex Ante Impacts (MW): PY2019 vs. PY2020 with CAISO Weather**

| Hour Ending | CAISO 1-in-2 | | CAISO 1-in-10 | |
|---|---|---|---|---|
| | PY2019 | PY2020 | PY2019 | PY2020 |
| 17 | 63.7 | 58.3 | 81.6 | 64.2 |
| 18 | 39.2 | 33.4 | 49.3 | 40.0 |
| 19 | 28.6 | 20.3 | 35.8 | 25.7 |
| 20 | 20.9 | 15.0 | 26.3 | 17.7 |
| 21 | 20.4 | 13.1 | 25.8 | 15.4 |
| **RA Window Average** | **34.6** | **28.0** | **43.7** | **32.6** |

## 5.5 EX POST TO EX ANTE COMPARISON

Weather conditions during PY2020 event days were warmer than the 1-in-2 ex ante weather conditions for the average 5pm to 9pm events. The observed weather during PY2020 was milder than 1-in-10 peak conditions. Figure 39 is reproduced from the MS Excel ex post reporting template and shows the average SEP 5pm to 9pm event from PY2020. Figure 40 shows the average customer ex ante impacts for SCE 1-in-2 weather.

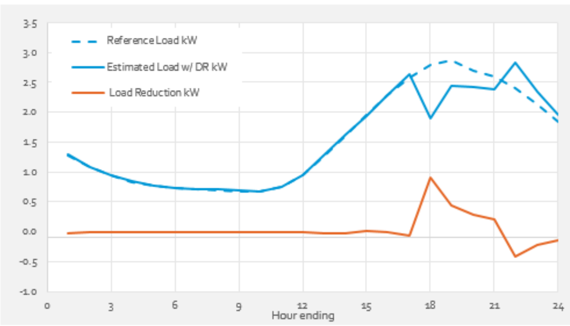
**Figure 39: PY2020 Ex Post Average Event Day 5pm-9pm**

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Date | Average Event Day (5pm-9pm) |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 5pm-9pm |
| Sites Dispatched | 51,426 |
| Daily Max Temp | 95.6 |
| Average Impact - kW | 0.46 |
| Average Impact - % | 16.7% |
| Full Hours Only - Average Impact - kW | 0.46 |
| Full Hours Only - Average Impact - % | 16.7% |




| Hour Ending | Reference Load | Estimated Load w/ DR | Load Reduction | % Load Reduction | Avg Temp, site weighted |
|---|---|---|---|---|---|
| | kW | kW | kW | | F |
| 1 | 1.27 | 1.29 | -0.02 | -2% | 74.3 |
| 2 | 1.08 | 1.09 | -0.01 | -1% | 73.7 |
| 3 | 0.94 | 0.95 | -0.01 | -1% | 72.9 |
| 4 | 0.83 | 0.85 | -0.01 | -1% | 72.0 |
| 5 | 0.77 | 0.77 | 0.00 | -1% | 71.1 |
| 6 | 0.74 | 0.74 | 0.00 | 0% | 70.2 |
| 7 | 0.71 | 0.72 | 0.00 | 0% | 69.8 |
| 8 | 0.70 | 0.70 | 0.00 | -1% | 70.3 |
| 9 | 0.68 | 0.69 | -0.01 | -1% | 72.9 |
| 10 | 0.68 | 0.67 | 0.00 | 0% | 77.3 |
| 11 | 0.75 | 0.75 | -0.01 | -1% | 81.9 |
| 12 | 0.95 | 0.95 | -0.01 | -1% | 86.2 |
| 13 | 1.25 | 1.27 | -0.02 | -2% | 89.1 |
| 14 | 1.60 | 1.62 | -0.02 | -1% | 91.7 |
| 15 | 1.95 | 1.94 | 0.01 | 0% | 93.6 |
| 16 | 2.29 | 2.29 | -0.01 | 0% | 94.9 |
| 17 | 2.57 | 2.63 | -0.06 | -2% | 95.6 |
| 18 | 2.80 | 1.89 | 0.91 | 32% | 94.7 |
| 19 | 2.87 | 2.44 | 0.44 | 15% | 93.0 |
| 20 | 2.70 | 2.41 | 0.29 | 11% | 90.9 |
| 21 | 2.59 | 2.39 | 0.21 | 8% | 87.2 |
| 22 | 2.40 | 2.82 | -0.42 | -18% | 83.4 |
| 23 | 2.13 | 2.34 | -0.21 | -10% | 80.8 |
| 24 | 1.83 | 1.96 | -0.13 | -7% | 79.3 |
| Daily | Reference Load | Estimated Load w/ DR | Energy Savings | % Change | Avg Temp, site weighted |
| | kWh | kWh | kWh Δ | | F |
| | 37.06 | 36.18 | 0.88 | 2% | 82.0 |

The "Average Impact (kW)" characteristic in Figure 40 is slightly higher than the ex post impacts. Because the ex post had challenges with dispatch, the ex post impacts are diluted and represent the average impact for an enrolled participant, rather than per a dispatched participant. These impacts were modified for ex ante analysis to ensure that all customers were dispatched. Additionally, ex ante temperatures are four degrees lower in this scenario and reference loads are lower, but the COVID adjustment is predicted to be half of the 2020 COVID impact. The average kW impact for hours ending 17 through 20 in this set of ex ante results is 0.48 kW per participating household. The CAISO 1-in-2 results are similar to the SCE 1-in-2 scenario, with an average event impact of 0.48 kW.

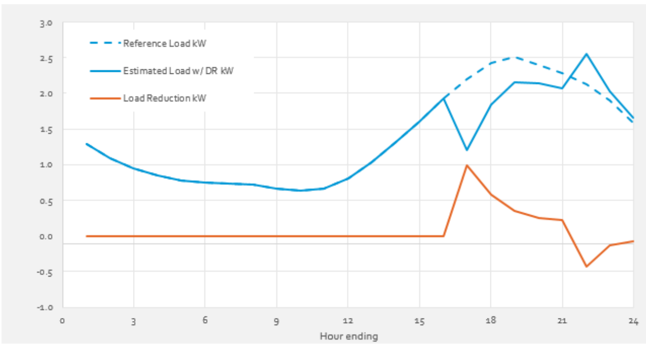
## Figure 40: Ex Ante Typical Event Day under SCE 1-in-2 Conditions: 4pm to 9pm

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Weather Year | SCE 1-in-2 |
| Day Type | Typical Event Day |
| Month | Typical Event |
| Forecast Year | 2021 |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 4pm-9pm (RA Hours 4pm-9pm) |
| Sites Dispatched | 59,498 |
| Daily Max Temp (F) | 91.5 |
| Average Impact (kW) | 0.48 |
| % Load Reduction (Event window) | 20.6% |
| Covid Index | 0.50 |




| Hour Ending | Reference Load kW | Estimated Load w/ DR kW | Load Reduction kW | % Load Reduction | Avg Temp, site weighted F |
|---|---|---|---|---|---|
| 1 | 1.29 | 1.29 | 0.00 | 0.0% | 73.8 |
| 2 | 1.08 | 1.08 | 0.00 | 0.0% | 72.7 |
| 3 | 0.94 | 0.94 | 0.00 | 0.0% | 71.8 |
| 4 | 0.84 | 0.84 | 0.00 | 0.0% | 71.0 |
| 5 | 0.78 | 0.78 | 0.00 | 0.0% | 70.3 |
| 6 | 0.74 | 0.74 | 0.00 | 0.0% | 69.6 |
| 7 | 0.74 | 0.74 | 0.00 | 0.0% | 69.1 |
| 8 | 0.72 | 0.72 | 0.00 | 0.0% | 69.4 |
| 9 | 0.67 | 0.67 | 0.00 | 0.0% | 71.9 |
| 10 | 0.63 | 0.63 | 0.00 | 0.0% | 76.2 |
| 11 | 0.66 | 0.66 | 0.00 | 0.0% | 80.6 |
| 12 | 0.80 | 0.80 | 0.00 | 0.0% | 84.5 |
| 13 | 1.04 | 1.04 | 0.00 | 0.0% | 87.3 |
| 14 | 1.32 | 1.32 | 0.00 | 0.0% | 89.3 |
| 15 | 1.61 | 1.61 | 0.00 | 0.0% | 90.9 |
| 16 | 1.92 | 1.92 | 0.00 | 0.0% | 91.3 |
| 17 | 2.19 | 1.21 | 0.99 | 44.9% | 91.5 |
| 18 | 2.42 | 1.85 | 0.58 | 23.7% | 90.6 |
| 19 | 2.50 | 2.16 | 0.35 | 13.9% | 88.9 |
| 20 | 2.40 | 2.14 | 0.25 | 10.6% | 86.6 |
| 21 | 2.29 | 2.07 | 0.22 | 9.6% | 83.2 |
| 22 | 2.12 | 2.55 | (0.43) | -20.4% | 80.0 |
| 23 | 1.89 | 2.03 | (0.14) | -7.2% | 77.9 |
| 24 | 1.59 | 1.66 | (0.07) | -4.5% | 76.1 |
| Daily | Reference Load kWh | Estimated Load w/ DR kWh | Energy Savings kWh Δ | % Change | Avg. Daily Weighted Temp F |
| | 33.20 | 31.46 | 1.74 | 5.3% | 79.8 |

Figure 41 shows the average customer impacts for SCE 1-in-10 conditions, which assume a weighted average maximum daily temperature of 99.2°F. The predicted load impact across the five hour RA window is 0.60 kW and the estimated load impact during the first four hours of dispatch is 0.67 kW. The average post-event load increase estimates are 0.46 kW, 0.20 kW, and 0.11 kW during hours ending 22, 23, and 24.

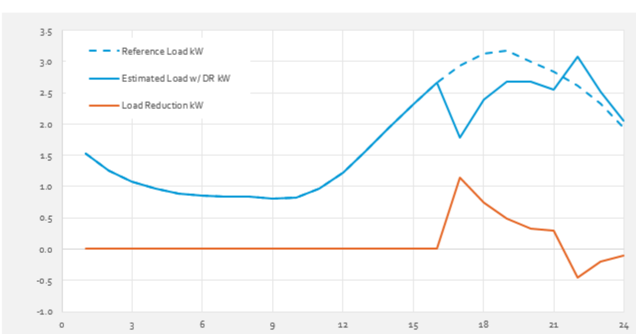
## Figure 41: Ex Ante Typical Event Day under SCE 1-in-10 Conditions: 4pm to 9pm

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Weather Year | SCE 1-in-10 |
| Day Type | Typical Event Day |
| Month | Typical Event |
| Forecast Year | 2021 |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 4pm-9pm (RA Hours 4pm-9pm) |
| Sites Dispatched | 59,498 |
| Daily Max Temp (F) | 99.2 |
| Average Impact (kW) | 0.60 |
| % Load Reduction (Event window) | 19.8% |
| Covid Index | 0.50 |




| Hour Ending | Reference Load kW | Estimated Load w/ DR kW | Load Reduction kW | % Load Reduction | Avg Temp, site weighted F |
|---|---|---|---|---|---|
| 1 | 1.52 | 1.52 | 0.00 | 0.0% | 78.1 |
| 2 | 1.26 | 1.26 | 0.00 | 0.0% | 76.6 |
| 3 | 1.08 | 1.08 | 0.00 | 0.0% | 75.3 |
| 4 | 0.97 | 0.97 | 0.00 | 0.0% | 74.5 |
| 5 | 0.89 | 0.89 | 0.00 | 0.0% | 73.6 |
| 6 | 0.85 | 0.85 | 0.00 | 0.0% | 73.0 |
| 7 | 0.83 | 0.83 | 0.00 | 0.0% | 72.4 |
| 8 | 0.83 | 0.83 | 0.00 | 0.0% | 72.9 |
| 9 | 0.80 | 0.80 | 0.00 | 0.0% | 76.1 |
| 10 | 0.82 | 0.82 | 0.00 | 0.0% | 81.2 |
| 11 | 0.96 | 0.96 | 0.00 | 0.0% | 86.7 |
| 12 | 1.22 | 1.22 | 0.00 | 0.0% | 91.0 |
| 13 | 1.57 | 1.57 | 0.00 | 0.0% | 93.7 |
| 14 | 1.96 | 1.96 | 0.00 | 0.0% | 95.9 |
| 15 | 2.31 | 2.31 | 0.00 | 0.0% | 97.7 |
| 16 | 2.66 | 2.66 | 0.00 | 0.0% | 98.9 |
| 17 | 2.93 | 1.78 | 1.15 | 39.2% | 99.2 |
| 18 | 3.13 | 2.39 | 0.74 | 23.6% | 98.5 |
| 19 | 3.16 | 2.68 | 0.49 | 15.3% | 96.7 |
| 20 | 3.00 | 2.67 | 0.33 | 10.8% | 93.5 |
| 21 | 2.84 | 2.55 | 0.29 | 10.1% | 89.9 |
| 22 | 2.61 | 3.08 | (0.46) | -17.7% | 86.5 |
| 23 | 2.32 | 2.52 | (0.20) | -8.6% | 83.6 |
| 24 | 1.95 | 2.06 | (0.11) | -5.7% | 81.6 |
| Daily | Reference Load kWh | Estimated Load w/ DR kWh | Energy Savings kWh Δ | % Change | Avg. Daily Weighted Temp F |
| | 42.47 | 40.26 | 2.22 | 5.2% | 85.3 |

CAISO 1-in-10 peak conditions are less extreme than SCE 1-in-10 weather conditions for a typical event day. Figure 42 shows the ex ante average SEP customer impacts for a typical event day in 2021. The weighted average maximum daily temperature is 96.0°F and the average impact across the five hour RA window is 0.55 kW.

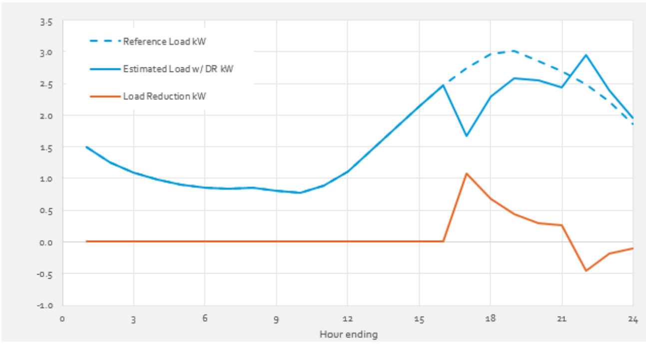
## Figure 42: Ex Ante Typical Event Day under CAISO 1-in-10 Conditions: 4pm to 9pm Dispatch

Table 1: Menu options

| | |
|---|---|
| Program | SEP |
| Type of Result | Average Customer |
| Category | All |
| Subcategory | All Customers |
| Weather Year | CAISO 1-in-10 |
| Day Type | Typical Event Day |
| Month | Typical Event |
| Forecast Year | 2021 |

Table 2: Event day information

| | |
|---|---|
| Event Hours | 4pm-9pm (RA Hours 4pm-9pm) |
| Sites Dispatched | 59,498 |
| Daily Max Temp (F) | 96.0 |
| Average Impact (kW) | 0.55 |
| % Load Reduction (Event window) | 19.3% |
| Covid Index | 0.50 |




| Hour Ending | Reference Load kW | Estimated Load w/ DR kW | Load Reduction kW | % Load Reduction | Avg Temp, site weighted F |
|---|---|---|---|---|---|
| 1 | 1.49 | 1.49 | 0.00 | 0.0% | 77.6 |
| 2 | 1.26 | 1.26 | 0.00 | 0.0% | 76.5 |
| 3 | 1.09 | 1.09 | 0.00 | 0.0% | 75.5 |
| 4 | 0.98 | 0.98 | 0.00 | 0.0% | 74.7 |
| 5 | 0.90 | 0.90 | 0.00 | 0.0% | 73.9 |
| 6 | 0.86 | 0.86 | 0.00 | 0.0% | 73.4 |
| 7 | 0.85 | 0.85 | 0.00 | 0.0% | 73.0 |
| 8 | 0.85 | 0.85 | 0.00 | 0.0% | 73.3 |
| 9 | 0.80 | 0.80 | 0.00 | 0.0% | 76.0 |
| 10 | 0.78 | 0.78 | 0.00 | 0.0% | 80.3 |
| 11 | 0.89 | 0.89 | 0.00 | 0.0% | 85.1 |
| 12 | 1.11 | 1.11 | 0.00 | 0.0% | 89.3 |
| 13 | 1.44 | 1.44 | 0.00 | 0.0% | 92.1 |
| 14 | 1.80 | 1.80 | 0.00 | 0.0% | 94.2 |
| 15 | 2.13 | 2.13 | 0.00 | 0.0% | 95.5 |
| 16 | 2.47 | 2.47 | 0.00 | 0.0% | 96.0 |
| 17 | 2.74 | 1.67 | 1.08 | 39.3% | 95.9 |
| 18 | 2.96 | 2.29 | 0.67 | 22.7% | 95.2 |
| 19 | 3.01 | 2.58 | 0.43 | 14.3% | 93.6 |
| 20 | 2.85 | 2.55 | 0.30 | 10.4% | 90.8 |
| 21 | 2.69 | 2.43 | 0.26 | 9.6% | 87.0 |
| 22 | 2.49 | 2.94 | (0.45) | -18.1% | 83.9 |
| 23 | 2.22 | 2.39 | (0.18) | -8.1% | 81.8 |
| 24 | 1.86 | 1.95 | (0.10) | -5.3% | 80.0 |
| Daily | Reference Load kWh | Estimated Load w/ DR kWh | Energy Savings kWh Δ | % Change | Avg. Daily Weighted Temp F |
| | 40.51 | 38.50 | 2.01 | 5.0% | 83.9 |

Aggregate ex ante impacts for 2021 are larger than the PY2020 ex post impacts because of the projected increase in enrollment and the assumption that all enrolled customers will be available for dispatch in the future. The average number of households dispatched during the average PY2020 event from 5pm to 9pm was 51,426. The average number of households dispatched during the average 7pm to 8pm event was 51,842. The enrollment forecast for an August monthly peak day in PY2021 is approximately 16% higher at 59,498. Table 26 compares the aggregate impacts for the two most common PY2020 event profiles to the August monthly peak day ex ante estimates for PY2021. Because the PY2020 events varied in duration, we show the average impact during the first hour of dispatch. In order to facilitate an "apples to apples" comparison, Table 26 also includes a column where PY2020 aggregate impacts are recalculated using the forecasted enrollment levels for PY2020. This shows that holding enrollment equal, forecasted impacts are expected to be larger in 2021 than the ex post impacts produced in 2020, because we assume the dispatch challenges will not persist in future years. Additionally, the COVID index is expected to drop from full COVID to about half by 2021, which influences forecasted reference loads as well as the average customer impact.

### Table 26: Comparison of PY2020 Ex Post Impacts to PY2021 Ex Ante Typical Event Day Impacts

| Event Date | Max Daily Temp (F) | Participants | Hour 1 kW | Hour 1 MW | Hour 1 MW at 2021 Enrollment |
|---|---|---|---|---|---|
| Average Event Day (5pm-9pm) | 93.4 | 51,426 | 0.91 | 46.6 | 53.9 |
| Average Event Day (7pm-8pm) | 89.9 | 51,842 | 0.76 | 39.4 | 45.2 |
| 2021 August Peak Day SCE 1-in-2 (4pm-9pm) | 93.3 | 59,498 | 1.01 | 60.1 | N/A |
| 2021 August Peak Day SCE 1-in-10 (4pm-9pm) | 96.8 | 59,498 | 1.09 | 64.9 | N/A |
| 2021 August Peak Day CAISO 1-in-2 (4pm-9pm) | 93.2 | 59,498 | 1.01 | 60.1 | N/A |
| 2021 August Peak Day CAISO 1-in-10 (4pm-9pm) | 95.9 | 59,498 | 1.07 | 63.7 | N/A |

# 6 DISCUSSION

Based on the 2020 ex post and ex ante load impact evaluation results, we highlight the following considerations for program design and future load impact evaluations.

- Contract issues with one of the participating thermostat manufacturers led to approximately 15% of participating households being unavailable for dispatch during summer 2020 DR events. SCE was not able to determine which households were available for dispatch so all enrolled accounts continued to receive bill credits. This led to lower average customer ex post impacts compared to prior years. In the ex ante analysis, we assume that all enrolled customers will be available for dispatch. It will be important for SCE to monitor contract terms and conditions with all participating vendors and thermostat manufacturers to ensure the lack of availability observed in 2020 doesn't happen in the future.

- The extreme weather conditions of summer 2020 highlighted the value of weather-sensitive programs like SEP as a grid resource. SEP load impacts increase with temperature so its capability is greatest during emergency conditions like the ones observed in California during the August and September heat waves.

    - ✓ Typically system peaking conditions are expected to occur on weekdays, but during the August and September heat waves of 2020, the California grid was highly constrained on four weekend days. SEP was called for emergency dispatch on all four of these critical weekend days. In the 2020 ex post evaluation, DSA observed no significant differences in performance between weekday and weekend events.

    - ✓ All four weekend events were called at extreme temperatures when SEP load impacts are the largest. In order to better understand the weekday versus weekend performance of SEP, it would be beneficial to call some weekend measurement and evaluation events at milder temperatures in 2021.

- The COVID-19 pandemic affected all aspects of life in 2020. In the ex ante modeling of reference loads and impacts, we included a COVID indicator variable to capture the differences between summer 2020 and prior years. At a high level, we estimated slightly higher reference loads under COVID and slightly lower load impacts holding other conditions constant. In the ex ante projections, the COVID effect is gradually withdrawn from 2021 to 2031.

    - ✓ For the 2021 ex ante evaluation, it will be important to decide what to set the COVID term equal to for 2021 loads and event impacts. The COVID glide path provided by SCE sets the index to 50% for 2021, but this assumption should be revisited based on the success of vaccinations and other factors.

- 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.

- The rollout of default TOU in SCE territory is underway. The COVID-19 pandemic altered the initial rollout plan, but customers are gradually being transitioned during 2021. As shown in Table 4, almost 28% of SEP participants faced time-varying pricing during PY2020. The rollout of default TOU may alter SEP participant reference loads and potentially change the average load impact of SEP dispatch.

    - ✓ Figure 29 showed that ex post percent impacts on the 2020 system peak day (August 18, 2020) were larger for SEP participants that faced dynamic pricing, but comparable on kW basis.

- SEP does not hold a consistent load shed under the current event profile. Event impacts are largest during the first hour of dispatch and deteriorate in each subsequent hour. During summer 2020, several vendors tested strategies to produce a more consistent load impact across dispatch hours.

    - ✓ This type of testing is incredibly valuable for selected the optimal dispatch profile for the SEP program to maximize economic benefits while limiting customer fatigue and discomfort.

    - ✓ If additional testing is planned for summer 2021, we recommend SCE allow DSA's evaluation team to work with the thermostat vendors to design the testing plan.

    - ✓ Once a preferred profile or profiles is determined, we can include this dimension in the ex ante analysis.